EB-2016-0160

ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act 1998*, Schedule B to the *Energy Competition Act*, 1998, S.O. 1998, c.15;

AND IN THE MATTER OF an Application by Hydro One Networks Inc. for an Order or Orders approving or fixing just and reasonable rates and other service charges for the transmission of electricity as of January 1, 2017 and January 1, 2018.

CROSS-EXAMINATION COMPENDIUM OF THE SCHOOL ENERGY COALITION (Planning Panel)

November 29, 2016

Jay Shepherd P.C.
2200 Yonge Street, Suite 1302
Toronto, ON M4S 2C6

Mark Rubenstein
Tel: 416-483-3300
Fax: 416-483-3305

Counsel for the School Energy Coalition

Transmission Capital Expenditures

EB-2014-0140	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Total Transmission Stations Capital	284.7	262.7	322.5	355.3	458.8	449.5	429.7	451.9	487.3	447.6
Total Transmission Lines Capital	71.6	70.6	66.8	124.8	120.5	132.4	118.9	145.5	149.5	152.5
Total Sustaining Capital	**356.3**	**333.2**	**389.3**	**480.0**	**579.3**	**581.9**	**548.6**	**597.4**	**636.7**	**600.1**
Total Development Capital	**523.1**	**415.9**	**329.4**	**171.7**	**195.6**	**209.7**	**211.8**	**148.0**	**116.4**	**155.5**
Total Operations Capital	**7.6**	**8.8**	**15.2**	**17.7**	**38.5**	**38.4**	**37.4**	**44.4**	**25.2**	**18.8**
Total Capital Common Corporate Costs and Other Costs	**49.1**	**52.3**	**42.1**	**49.1**	**85.8**	**69.4**	**68.5**	**58.0**	**60.4**	**57.0**
Total Transmission Capital	**936.1**	**810.2**	**776.0**	**718.5**	**899.2**	**899.4**	**866.3**	**847.8**	**838.8**	**831.4**

Source:EB-2014-0140: A-16-8, p.3

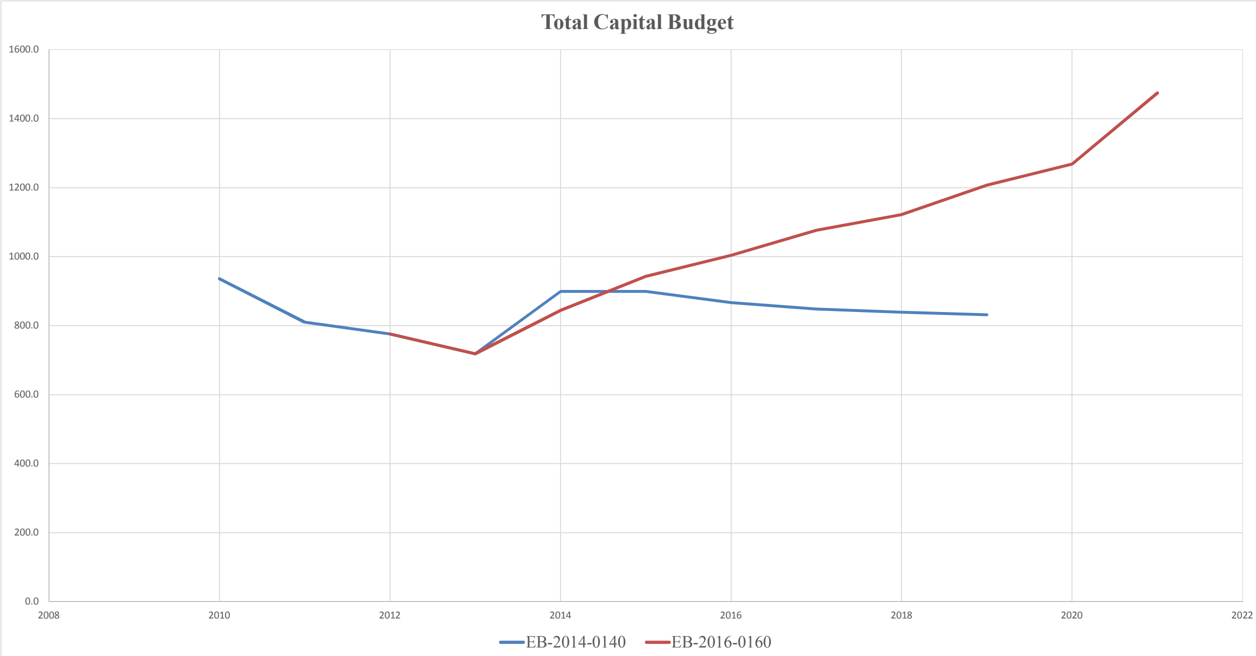
EB-2016-0160		2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Total Transmission Stations Capital		322.5	355.3	481.3	565.8	552.2	537.5	496.2			
Total Transmission Lines Capital		66.8	124.8	140.0	128.4	172.2	239.3	345.9			
Total Sustaining Capital		**389.3**	**480.0**	**621.3**	**694.3**	**724.3**	**776.8**	**842.1**	**825.7**	**915.2**	**1118.1**
Total Development Capital		**329.4**	**171.7**	**131.6**	**166.0**	**166.0**	**196.4**	**170.2**	**244.0**	**254.0**	**258.3**
Total Operations Capital		**15.2**	**17.7**	**28.4**	**15.6**	**30.1**	**25.4**	**30.8**	**58.8**	**21.1**	**24.7**
Total Capital Common Corporate Costs and Other Costs		**42.1**	**49.1**	**63.4**	**67.1**	**83.5**	**77.6**	**79.1**	**79.1**	**78.2**	**73.8**
Total Transmission Capital		**776.0**	**718.5**	**844.6**	**943.0**	**1003.8**	**1076.1**	**1122.2**	**1207.5**	**1268.6**	**1474.9**

Source: B1-3-1, Attach 1 *Source: A-3-1, p.13*

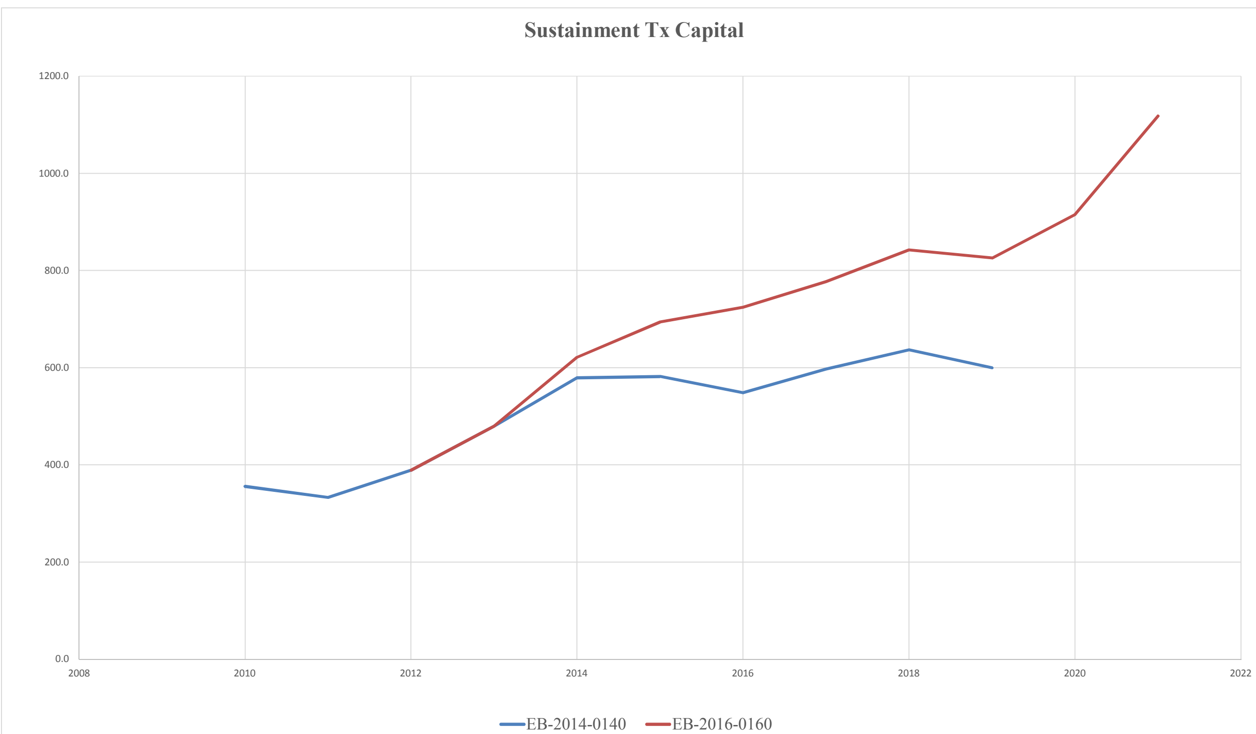
Total Transmission Capital	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
EB-2014-0140	936.1	810.2	776.0	718.5	899.2	899.4	866.3	847.8	838.8	831.4		
EB-2016-0160			776.0	718.5	844.6	943.0	1003.8	1076.1	1122.2	1207.5	1268.6	1474.9

Total Sustaining Capital	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
EB-2014-0140	356.3	333.2	389.3	480.0	579.3	581.9	548.6	597.4	636.7	600.1		
EB-2016-0160			389.3	480.0	621.3	694.3	724.3	776.8	842.1	825.7	915.2	1118.1

Sustaining Capital Breakdown	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
EB-2014-0140 Tx Stations Capex	284.7	262.7	322.5	355.3	458.8	449.5	429.7	451.9	487.3	447.6
EB-2014-0140 Tx Lines Capex	71.6	70.6	66.8	124.8	120.5	132.4	118.9	145.5	149.5	152.5
EB-2016-0160 Tx Stations Capex			322.5	355.3	481.3	565.8	552.2	537.5	496.2	
EB-2016-0160 Tx Lines Capex			66.8	124.8	140.0	128.4	172.2	239.3	345.9	

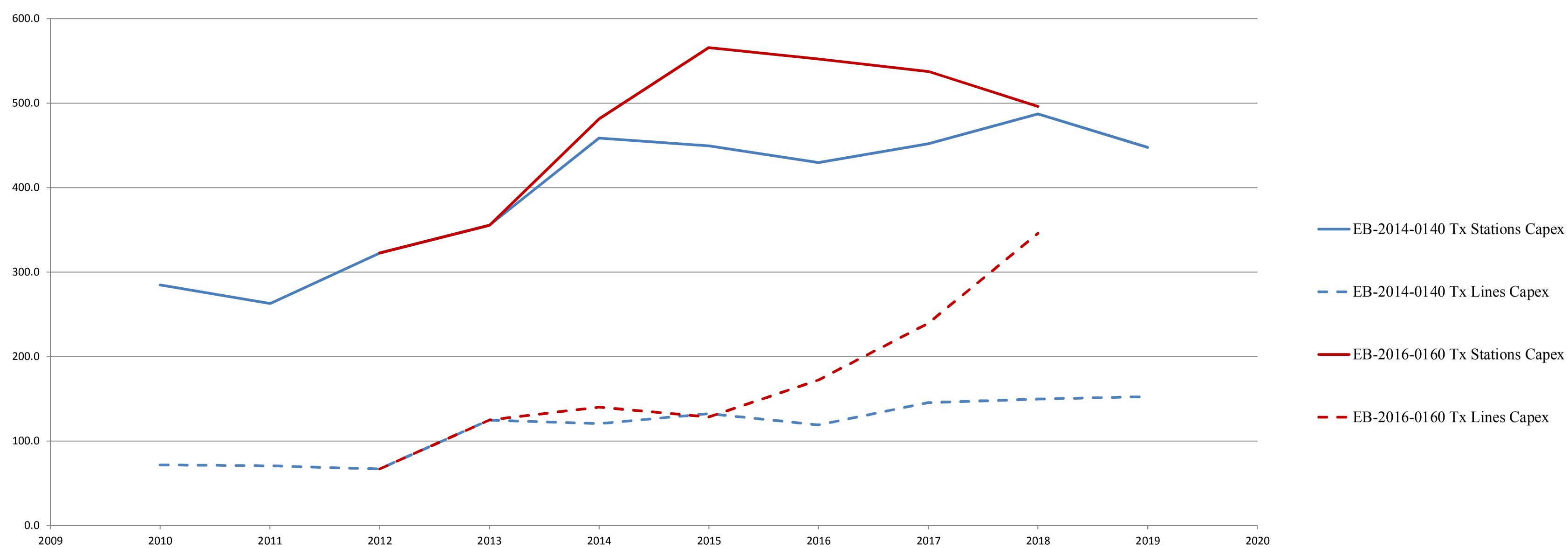


Total Capital Budget
1600.0
1400.0
1200.0
1000.0
800.0
600.0
400.0
200.0
0.0
2008
2010
2012
2014
2016
2018
2020
2022
EB-2014-0140
EB-2016-0160



Sustainment Tx Capital
1200.0
1000.0
800.0
600.0
400.0
200.0
0.0
2008
2010
2012
2014
2016
2018
2020
2022
EB-2014-0140
EB-2016-0160

Sustaining Capital (Lines and Stations)



HYDRO ONE'S INVESTMENT PLANNING PROCESS: AN OVERVIEW

1. INTRODUCTION

At Hydro One, investment planning is performed annually and consists of the steps illustrated in Figure 1.

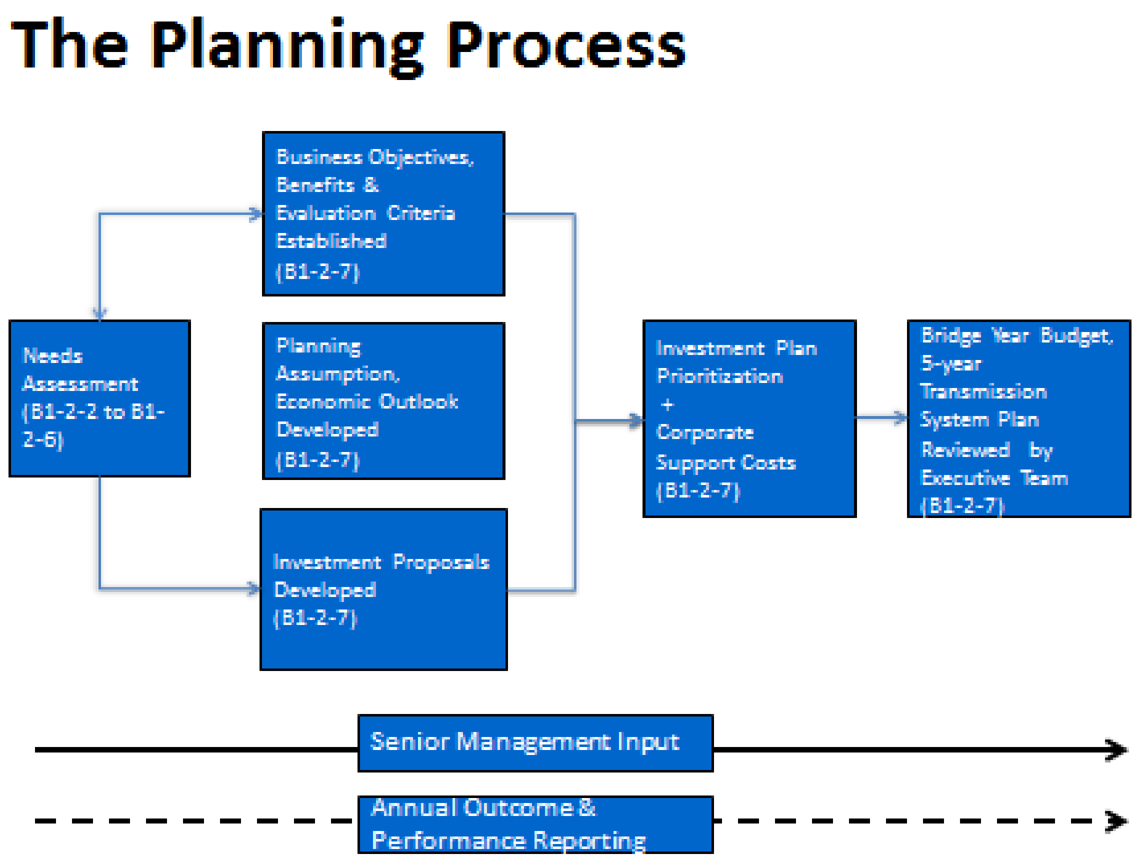


Figure 1

Part Two of the Transmission System Plan describes this process.

Witness: Michael Vels/Mike Penstone

DEVELOPING THE INVESTMENT PLAN

1. INTRODUCTION

This Exhibit details the investment planning process that takes identified investment needs, turns them into candidate investments, and then inputs them into a prioritization process that yields an investment plan.

The investment planning process draws upon the previous year's efforts to identify investment needs, evaluating and prioritizing proposed individual investments that address these needs, based on the business objectives. The end product is a fully prioritized investment plan.

The key steps in developing the investment plan are shown in Figure 1 below.

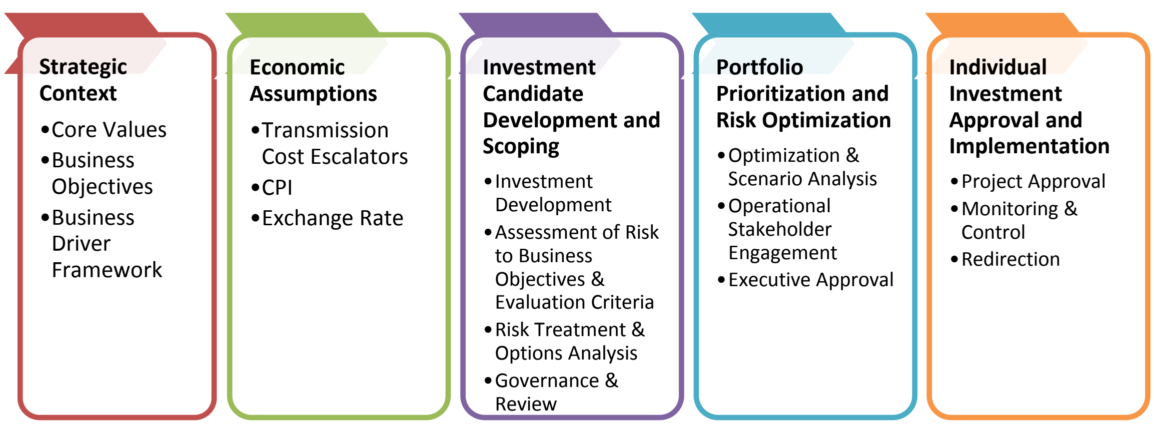


Figure 1: Investment Planning Process

School Energy Coalition (SEC) INTERROGATORY #024

Reference:

B1/2/7

Interrogatory:

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

Response:

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

Witness: Mike Penstone

Ontario Energy Board (Board Staff) INTERROGATORY #015

Reference:

Exhibit B1/Tab2/Sch 4/p. 8 - Section 3.2: Reliability Risk Modeling Approach, Table 1 – Relative Change in Reliability Risk]

"Table 1 below summarizes the expected relative decrease in risk, for each critical asset class and for the system as a whole, as a result of the 2017 and 2018 investment plan. For comparison the table also provides the relative increase in risk which will occur if no assets were replaced in the two year period."

Table 1: Relative Change in Reliability Risk

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

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

Interrogatory:

a) Please provide a description of the methodology, the detailed calculations and the supporting data used to populate Table 1 above.

b) Does Table 1 above show the overall probability of asset failures in each asset class contributing to SAIDI, CAIDI or some other metric?

c) Is the relationship between level of capital investment and the Relative Change in Risk values shown in Table 1 linear, or are there inflection points driven by different individual investments or overall levels of investment?

d) Did Hydro One evaluate any alternative investment plans other than the "proposed investment" and "without investment" cases shown in Table 1?
   i. If yes, please provide the investment level and projected reliability risk performance of these alternative investment portfolios.
   ii. If no, please explain how the proposed plan optimizes capital investment costs against reliability risk.

Witness: Mike Penstone

e) Has Hydro One ranked its capital investments to facilitate forced prioritization of the most effective reliability risk mitigation projects if the approved level of capital investment is less than Hydro One has requested?
   i. If yes, please provide the prioritized project list.
   ii. If no, please explain how the most effective risk mitigation projects will be prioritized if the approved capital investment level is less than requested.

Response:

a) The data in the table was summarized by running the risk model as described in Exhibit B1-02-04. The example of relative change in risk from Jan 1, 2017 to Dec 21, 2018 as per the proposed investment for lines (-2%) will be presented here.

   Hazard curves that describe the asset survival risk by asset type are the basis for the risk model. Hydro One uses a report prepared by Foster Associates as basis for determining hazard curves, which is based on analysis of Hydro One's historical data (reference Exhibit I, Tab 1, Schedule 20, Part b).

   Next, the demographic profile of the asset (for this example the asset type is lines) is multiplied by the age-specific hazard rate to obtain a risk profile for the assets as a function of their age. The overall probability is the sum of this profile. This operation is carried out for each asset type over the rate filing period for all replacements.

   The asset risk calculation for lines with planned replacements until December 2018 is shown in the table below.

Total				
Age	**Circuit KM**	**Proportion of Total**	**Hazard Rate**	**1.053%**
0.00	14.87	0.05%	0.00%	0.000000%
1.00	34	0.11%	0.00%	0.000000%
2.00	101	0.34%	0.00%	0.000000%
3.00	122	0.41%	0.00%	0.000000%
4.00	445	1.51%	0.00%	0.000001%
5.00	93	0.31%	0.00%	0.000000%
6.00	160	0.54%	0.00%	0.000001%
7.00	117	0.40%	0.00%	0.000001%
8.00	269	0.91%	0.00%	0.000005%
9.00	28	0.10%	0.00%	0.000001%
10.00	34	0.11%	0.00%	0.000001%

For example, there are 506 circuit-km of 75 year old lines making up about 1.7% of the population with an annual probability of failure of 1.94% given that these conductors survived previously to 74 years. Therefore the probability of failure of these 75 year old, 506 circuit-km is 0.0194 x 0.017. This calculation is performed for each age group over the entire demographic distribution and summed to produce the overall probability of failure.

This process is conducted for the present assets and after the planned replacements identified in this filing, representing a 1.056% and 1.031% probability of failure respectively. The ratio of these probabilities determines the relative risk as it appears in Table 1.

$$1.031\%/1.056\% - 1 = -2\%.$$

As presented for lines, each asset type's demographic profile was multiplied by their age-specific hazard rates to obtain a risk profile for the assets as a function of their age. This was summed up as in the example for lines and these values are presented in Figure1 below under 'supporting data'. Future demographic asset distributions were used for the 'Proposed Investment' and 'Do Nothing' scenarios. For the 'proposed investment', the future demographics takes into account the aging of assets that are not replaced as well as those that are removed due to replacement. For the 'Do Nothing' scenario the presently installed assets are aged to the end of 2018.

Supporting Data				Calculations for Table 1				
Asset Type	Proposed Investment for 2017/18		"Do Nothing" After 2016	Relative Change in Risk from Jan 1, 2017 to Dec 31, 2018 as per proposed investment		Relative Change in Risk from Jan 1, 2017 to Dec 31, 2018 without investment		% of Interruption Duration *
	Jan. 1, 2017	End of Rate Filing Period	Jan. 2019					
Lines	1.056%	1.031%	1.17%	1.03 / 1.06 -1 =	-2%	1.17 / 1.06 - 1 =	11%	69%
Transformers	1.694%	1.535%	1.92%	1.54 / 1.69 -1 =	-9%	1.92 / 1.69 - 1 =	14%	9%
Breakers	2.610%	2.633%	3.05%	2.63 / 2.61 - 1 =	1%	3.05 / 2.61 - 1 =	17%	6%
				(-2% x 69%) + (-9% x 9%) + (1% x 6%) =	-2%	(-2% x 69%) + (-9% x 9%) + (1% x 6%) =	10%	

Figure 1

The totals in the bottom row as filed and presented in Table 1 utilize the SAIDI interruption data to weigh the overall probabilities of failure of each asset type as shown above. Figure 1 reductions applied to the test years spending will have a compounding effect on system risks and cost pressures now and in the future.

The proposed test year Sustaining investment plan is directionally focused on maintaining equipment reliability and overall system reliability, through continued Sustaining Capital expenditures, while containing the test year Sustaining OM&A expenditures increases to less than inflation.

Sustaining programs strive to continuously innovate through adopting new technologies and approaches. Value will be derived by using innovative analytic tools and technologies. Efficient data collection and manipulation improves the effectiveness and consistency in investment plans. Value is also achieved through optimizing life cycle costs and targeting the right balance of capital and OM&A expenditures. In determining the appropriate maintenance strategies consideration is given to various approaches such as condition-based maintenance and time-based maintenance. Benchmarking against other utilities helps ensure that activities are in line with industry standards and practices.

Continued growth in the fleet replacement rates for key assets is imperative to manage the long-term reliability and lifecycle cost of the transmission fleet to the benefit of the ratepayer. Reducing Sustaining Capital funding will require increased Sustaining OM&A funding to maintain assets that are at end of life and should be replaced.

3.0 RELIABILITY OVERVIEW

Throughout the Sustaining exhibits, references are made to asset reliability and to system reliability. It is important to understand the difference between these two dimensions, as they are related, but need to be analysed separately to have a clear picture of trends and developing risk.

As a consequence of the redundancy often found in the transmission system, it's not unusual for an equipment defect or failure to have only a momentary impact on the power system, or in some cases no noticeable impact to end-use customers at all. For example, Hydro One Transmission typically has redundant transformers at load delivery stations, so that power can continue to be supplied to downstream customers during routine maintenance or in the event of a failure. In the event of a power system fault, depending on fault location and how the protections operate to clear the faulted zone, there may be no delivery interruption at all, or a very short interruption (fractions of a second to a few seconds), or the delivery points could be lost for an extended period of time (minutes to hours). These delivery point interruptions are tracked at the corporate level and benchmarked with peers.

Hydro One Transmission analyses equipment condition and defects as a leading indicator to major equipment performance (i.e. transformers, breakers, protections, circuits). As trends in major equipment performance begin to shift, there will be a lagging effect on broader system reliability. In managing the power system, specifically Sustaining investments, it is imperative to understand the leading-lagging spectrum of equipment condition, to major equipment performance, to system or delivery performance. By the time delivery impact begins to degrade, there would be significant underlying performance issues with major equipment that would take significant time and money to rebound from. Figure 1 represents the increasing impact to Customers as equipment defects evolve to major equipment outages that can impact delivery performance.

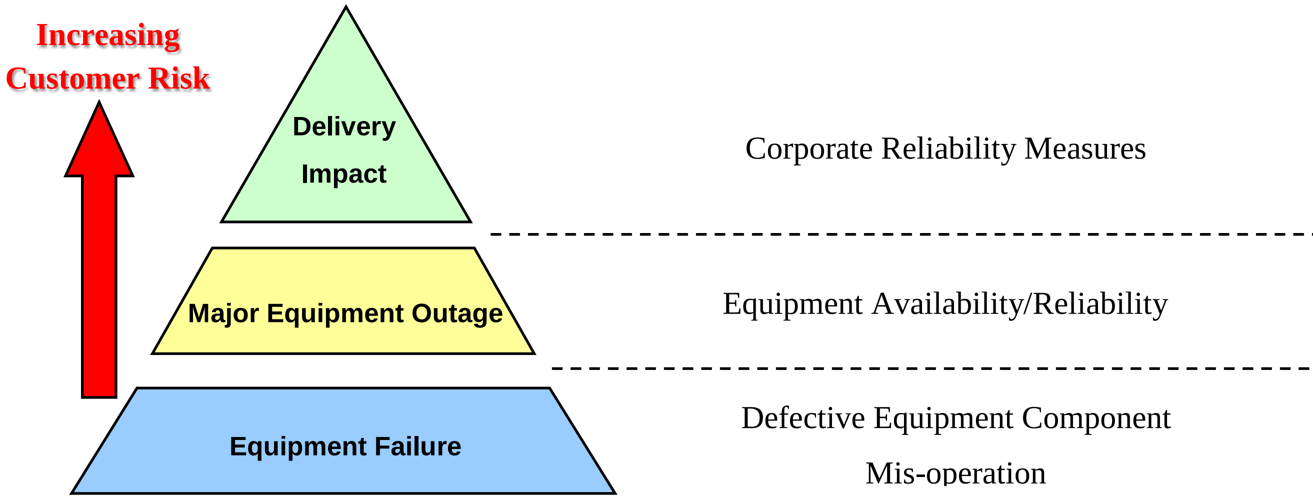


Figure 1: System Impact Hierarchy Model

Throughout the Sustaining exhibits, references are made to the impact of a particular asset to system reliability. This is most often expressed in terms of the frequency and duration of power interruptions. Figures 2 through 5 demonstrate the relative contribution between various assets to the system-wide delivery measures. Note that Lines assets that impact delivery performance are typically assessed against the entire system (radial single-point supplies and reinforced multi-circuit supplies), whereas Stations assets are expressed in terms of the multi-circuit delivery performance.

Figures 2 shows the 10-year history of the contribution of equipment failure to the frequency of delivery points interruptions for both delivery points; whereas Figure 3 focuses only on the frequency of the delivery point interruptions for only the reinforced or multi-circuit supplied delivery points.

There is an increasing trend of the number of equipment failures causing interruptions to customers, although there is some variability year over year. With the failure of Station equipment having a much more significant impact than Lines equipment. Sustaining capital and maintenance programs are largely focused on managing these reliability risks.

- System-wide assessments of reliability performance and reliability risk;
- Asset condition;
- Customer needs and preferences; and
- Sustainment forecast and external constraints.

In addition, Hydro One also employs benchmarking, such as the Transmission Total Cost Benchmarking study, to compare planned levels of capital and OM&A investments against peer transmission companies. The Total Cost Benchmarking study is found in Exhibit B2, Tab 2, Schedule 1.

3. SYSTEM RELIABILITY PERFORMANCE AND RELIABILITY RISK

Transmission system reliability performance can be measured in terms of frequency and average duration of forced delivery point interruptions that interrupt power supply to customers, and equipment unavailability which is the amount of time that major transmission equipment is out of service due to forced outages.

Reliability performance is typically measured in Canada by T-SAIFI and T-SAIDI, which reflect the average frequency and duration of interruptions per delivery point on the transmission system. Hydro One employs these metrics to measure performance of the transmission system and has maintained relatively constant system-wide reliability performance over the past 10 years, placing in the 1st quartile amongst its Canadian peers. Hydro One's performance metrics are shown in Figures 8 through 11, found in Exhibit B1, Tab 1, Schedule 3.

While T-SAIFI and T-SAIDI are important metrics, they are lagging indicators of future transmission system reliability performance. By the time these metrics worsen, considerable equipment issues will have already developed. It is therefore important to target leading indicators such as reliability risk. Existing asset condition provides a static view which is insufficient to predict future reliability, as assets will continue to deteriorate over time. In addition, it will take considerable time to plan, design and construct transmission assets to remedy the deteriorated equipment.

Hydro One has modified its asset management approach to include reliability risk as a leading indicator of future transmission system performance. Hydro One's approach has been informed by the development of this approach in other jurisdictions. This approach is new for Hydro One and the company intends to further develop the reliability risk approach and refine its application in the sustainment planning process.

3.1 Reliability Risk

Equipment unavailability is a measure of the amount of time that power equipment is not available for use on the system due to forced outages. As shown in Figures 12 and 13 in Exhibit B1, Tab 1, Schedule 3, station equipment unavailability has continued to trend upward in the recent past while line equipment unavailability is expected to trend upwards based on asset condition assessments and the demographics of lines assets. While equipment unavailability does not necessarily lead to customer interruptions, due to planned redundancy on Hydro One's transmission system, it is a leading indicator of future reliability issues.

Equipment reliability risk similarly serves as an indicator of the potential for future reliability issues. Hydro One has historically taken a risk management approach to preventing equipment failure, but has not previously attempted to quantify reliability risk. Hydro One has recently developed a system risk model to quantify and understand the relative level of reliability risk of its transmission fleet. The risk model's output is an overall risk metric, which is indicative of the risk of reliability improvement or degradation at various investment levels.

Reliability risk is a metric which gauges the extent of reliability risk improvement or degradation at various investment levels. It is derived using a probabilistic calculation based on asset demographics and the historical relationship between asset age and the occurrence of failure or replacement.

Reliability risk is used by Hydro One in its asset management process to gauge the impact of its investments on future transmission system reliability. It also provides a directional indicator to inform the appropriate level and pacing of sustainment investments. The reliability model is not used to identify specific asset needs and investments. These are determined by condition assessments and other asset specific information, as described in Exhibit B1, Tab 2, Schedule 5.

3.2 Reliability risk modeling approach

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

The output of the risk model is a measure of the system reliability risk resulting from planned investments relative to a baseline. The model considers both the expected impact of asset replacement and the continued aging and deterioration of existing assets. Additional details on the structure and application of the reliability risk model are available in Appendix 1 of this schedule.

Hydro One has used this model to gauge the expected reduction in risk achieved through the sustainment capital investments planned for the 2017 and 2018 test years. Table 1 below summarizes the expected relative decrease in risk, for each critical asset class and for the system as a whole, as a result of the 2017 and 2018 investment plan. For comparison the table also provides the relative increase in risk which will occur if no assets were replaced in the two year period.

Table 1: Relative Change in Reliability Risk

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

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

4. ASSET CONDITION

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

---

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

Equipment performance is a leading indicator of future system reliability. By the time system reliability has measurably degraded, equipment performance will have deteriorated and a significant increase in asset level investment to return to historical reliability levels is required. Sustainment investments are made to preserve performance of critical asset groups by evaluating assets at both an individual asset level and at a station or line level. This prioritizes investment needs to identify the most effective reliability alternative. This approach helps preserve overall system reliability.

Hydro One undertakes an annual detailed assessment of the cited performance measures. This assessment is taken into account along with other factors (such as asset condition) when establishing and prioritizing operating, maintenance and capital programs. For further details see Exhibit B1, Schedule 2, Tab 7, Developing the Investment Plan.

5.4 Delivery Point Performance Outliers

Delivery point performance is evaluated according to the Customer Delivery Point Performance (CDPP) Standard that Hydro One developed, filed with and subsequently approved by the Board in EB-2002-0424. The performance standard is used as a trigger to initiate assessment and follow up with affected customers to:

- Determine the root cause of unreliability;
- Perform technical and financial evaluations; and
- Decide on remedial action to improve reliability.

Figure 14 is a summary of the transmission Group and Individual Customer Delivery Point Performance Outliers as determined by the CDPP Standard criteria from 2007, the first year of formal CDPP reporting.

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #021

Reference:

Exhibit B1-2-2, Attachment 2 Transmission Customer Engagement: Investing for the Future March 2016, slides 11-12

Interrogatory:

a) For the Multi-Circuit System, please complete the following Table:

Contribution to SAIDI*	2011	2012	2013	2014	2015
% equipment					
% tree contact					

* excluding planned interruptions, interruptions due to customer activity and Force Majeure events.

b) For the Multi-Circuit System, please complete the following Table:

Contribution to SAIFI*	2011	2012	2013	2014	2015
% equipment					
% tree contact					

* excluding planned interruptions, interruptions due to customer activity and Force Majeure events.

c) For the Single-Circuit System, please complete the following Table:

Contribution to SAIDI*	2011	2012	2013	2014	2015
% equipment					
% tree contact					

* excluding planned interruptions, interruptions due to customer activity and Force Majeure events.

d) For the Single-Circuit System, please complete the following Table:

Contribution to SAIFI*	2011	2012	2013	2014	2015
% equipment					
% tree contact					

* excluding planned interruptions, interruptions due to customer activity and Force Majeure events.

Witness: Mike Penstone

Response:

a) For the Multi-Circuit System:

Contribution to SAIDI*	2011	2012	2013	2014	2015
% equipment	67%	57%	49%	29%	56%
% tree contact	19%	9%	0%	0%	0%

* excluding planned interruptions, interruptions due to customer activity and Force Majeure events.

b) For the Multi-Circuit System:

Contribution to SAIFI*	2011	2012	2013	2014	2015
% equipment	37%	24%	20%	16%	35%
% tree contact	3%	1%	1%	1%	0%

* excluding planned interruptions, interruptions due to customer activity and Force Majeure events.

c) For the Single-Circuit:

Contribution to SAIDI*	2011	2012	2013	2014	2015
% equipment	21%	74%	31%	51%	53%
% tree contact	15%	11%	8%	4%	12%

* excluding planned interruptions, interruptions due to customer activity and Force Majeure events.

d) For the Single-Circuit System:

Contribution to SAIFI*	2011	2012	2013	2014	2015
% equipment	20%	13%	14%	11%	11%
% tree contact	5%	4%	2%	2%	3%

* excluding planned interruptions, interruptions due to customer activity and Force Majeure events.

Association of Major Power Consumers in Ontario (AMPCO)
INTERROGATORY #023

Reference:

Exhibit B1-2-2, Attachment 2 Transmission Customer Engagement: Investing for the Future March 2016, slide 15

Interrogatory:

a) Please explain spike in unplanned outage hours due to equipment failure in 2015.

Response:

a) In 2015, approximately 20-25% of the total 272,000 unplanned outage hours was due to capacitor banks being out of service for long durations that were initially caused by failures of equipment associated with the capacitor. The requirement of a capacitor bank for support of local and network voltage control considers many factors: peak load, upcoming outage needs, contingency management and outage coordination availability. In cases where local reactive power was needed to support peak load, capacitors were returned to service expeditiously. In other cases where voltage support was not immediately required, resources were reallocated to more critical sustainment or capital work on the transmission network.

Witness: Mike Penstone

Exhibit I, Tab 06, Schedule 20, Attachment 1

		Historic		Bridge	Test		
		2014	2015	2016	2017	2018	Source
Transformer Portfolio							
EB-2014-0140	# Replacements	26	26	26			III/iii/D1/2/1, p.15
	% of Fleet	3.6%	3.6%	3.6%			
	Capital ($M)	162.9	105.7	120.1			
	OM&A ($M)	23.3	23.7	22.8			
EB-2016-0160	# Replacements	24	21	19	27	22	B1/2/6, p.9 (Table 3)
	% of Fleet	3.3%	2.9%	2.6%	3.7%	3.1%	
	Capital ($M)	132.0	115.5	104.5	148.5	121.0	
	OM&A ($M)	24.1	20.0	20.7	24.7	22.4	
Circuit Breaker Portfolio							
EB-2014-0140	# Replacements	125	150	147			III/iii/D1/2/1, p.24
	% of Fleet	2.7%	3.3%	3.2%			
	Capital ($M)	68.9	82.7	83.2			
	OM&A ($M)	17.3	19.4	19.8			
EB-2016-0160	# Replacements	83	31	43	66	132	B1/2/6, p.17 (Table 5)
	% of Fleet	1.8%	0.7%	0.9%	1.5%	2.9%	
	Capital ($M)	58.1	21.7	30.1	46.2	92.4	
	OM&A ($M)	20.2	23.4	18.7	19.4	18.9	
Protection Systems Portfolio							
EB-2014-0140	# Replacements	350	365	450			III/iii/D1/2/1, p.36
	% of Fleet	2.9%	3.0%	3.7%			
	Capital ($M)	56.3	57.9	70.5			
	OM&A ($M)	10.6	10.3	11.7			
EB-2016-0160	# Replacements	610	266	367	449	528	B1/2/6, p.29 (Table 8)
	% of Fleet	5.0%	2.2%	3.0%	3.7%	4.4%	
	Capital ($M)	76.3	33.3	45.9	56.1	66.0	
	OM&A ($M)	8.8	8.5	9.5	10.3	10.5	
Conductor Portfolio							
EB-2014-0140	Replacements (km)	113	99	60			III/iii/D1/2/1, p.43
	% of Fleet	0.4%	0.3%	0.2%			
	Capital ($M)	33.2	36.8	29.3			
	OM&A ($M)	13.1	14.2	14.5			
EB-2016-0160	Replacements (km)	93	201	183	192	440	B1/2/6, p.36 (Table 9)
	% of Fleet	0.3%	0.7%	0.6%	0.6%	1.5%	
	Capital ($M)	40.7	58.4	76.9	67.1	143.1	
	OM&A ($M)	6.7	6.2	6.8	7.0	7.1	
Wood Pole Portfolio							
EB-2014-0140	# Replacements	850	850	850			III/iii/D1/2/1, p.50
	% of Fleet	2.0%	2.0%	2.0%			
	Capital ($M)	27.2	27.7	28.2			
	OM&A ($M)	4.4	4.1	4.2			
EB-2016-0160	# Replacements	897	845	850	850	850	B1/2/6, p.43 (Table 10)
	% of Fleet	2.2%	2.0%	2.0%	2.0%	2.0%	
	Capital ($M)	43.6	38.5	38.3	35.3	35.3	
	OM&A ($M)	6.7	6.2	6.8	7.0	7.1	
Steel Structure Portfolio							
EB-2014-0140	# Refurbishments	350	350	400			
	# Replacements	4	4	12			III/iii/D1/2/1, p.58
	% of Fleet	0.7%	0.7%	0.8%			
	Capital ($M)	11.1	10.7	16			
	OM&A ($M)	4.4	4.1	4.2			
EB-2016-0160	# Renewal	121	300	462	1250	1600	B1/2/6, p.54 (Table 11)
	% of Fleet	0.2%	0.6%	0.9%	2.4%	3.1%	
	Capital ($M)	5.1	4.6	8.8	42.5	54.4	
	OM&A ($M)	6.2	5.7	6.3	6.3	6.4	
Underground Cable Portfolio							
EB-2014-0140	Replacements (km)	5	5.5	2			III/iii/D1/2/1, p.67
	% of Fleet	1.7%	1.9%	0.7%			
	Capital ($M)	19.4	28.1	15.1			
	OM&A ($M)	4.4	4.8	4.9			
EB-2016-0160	Replacements (km)	3.1	0	0	0	4.8	B1/2/6, p.66 (Table 13)
	% of Fleet	1.1%	0.0%	0.0%	0.0%	1.8%	
	Capital ($M)	20.6	3.5	1.4	2.3	22.5	
	OM&A ($M)	4.0	4.1	5.0	5.1	5.2	

The potential risks to system and customer reliability as a result of this long-term demographic pressure needs to be managed through continued capital replacement programs. As can be seen in Figure 8, continuing at the historic rate of replacement would result in the percentage of transformers beyond their expected service life to increase to 35% by 2024. However at the proposed replacement rate of 26 transformers a year, the percentage of transformers beyond their expected service life will improve from 24% to 19% over the next 10 years.

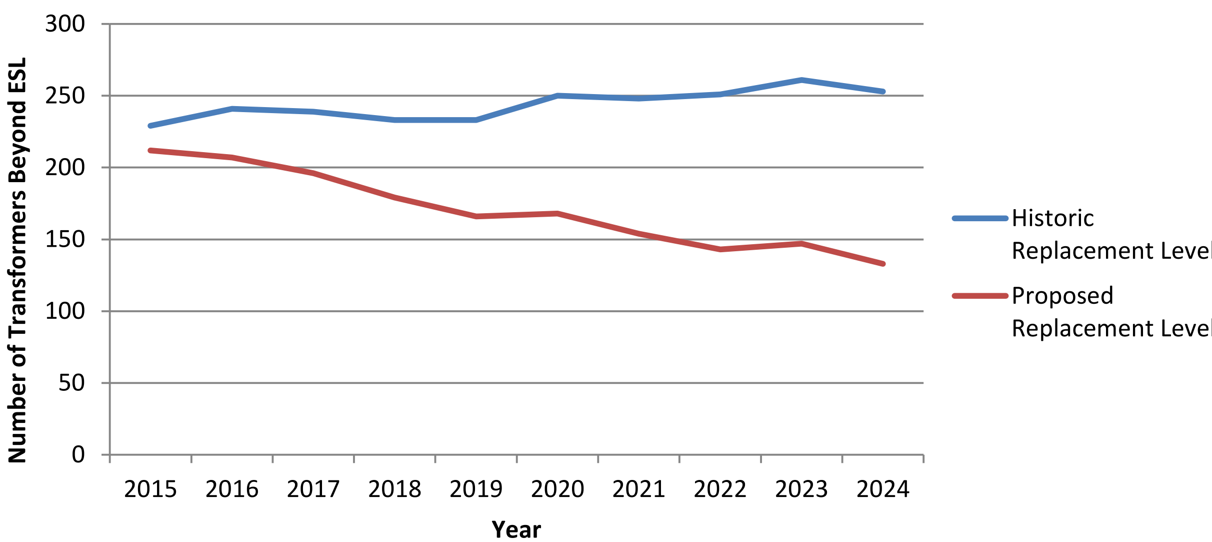


Figure 8: Projection of Transformers Beyond Expected Service Life

<u>Performance</u>

The forced outage frequency of transformers is relatively stable, as outlined in Figure 9. However, transformers failures can have a significant impact to local and system reliability. Transformer forced outages are one of the leading causes to customer delivery point interruptions, and represent 26% of the equipment-caused events impacting delivery point interruptions with multiple supplies over the past 10 years. To mitigate this risk the transformer replacements in the test years are focused on replacing transformers that are at the highest risk of causing delivery point interruptions and impacting the bulk electricity system.

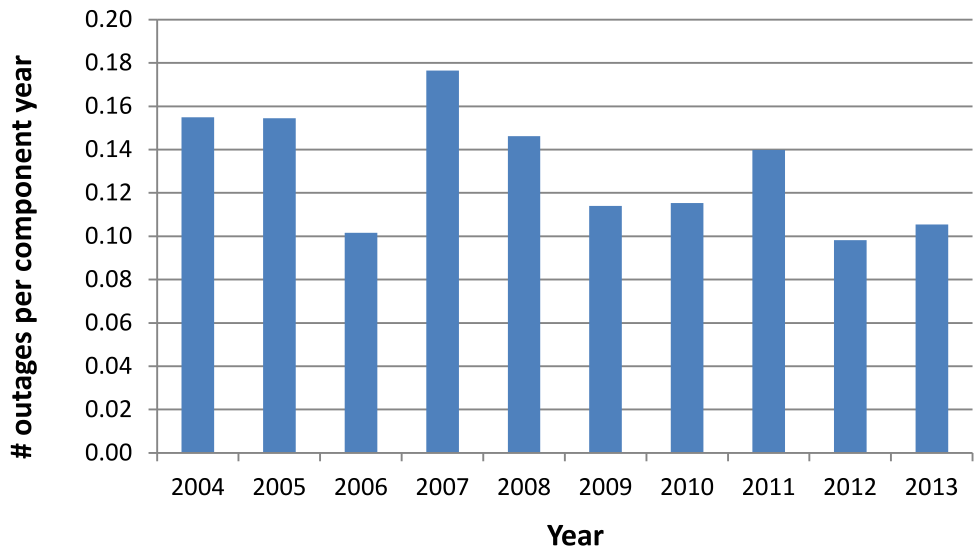


Figure 9: Forced Outage Frequency due to Transformer Failures

<u>Condition</u>

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

Based on results gathered, currently 8% of Hydro One Transmission's transformer population has condition that puts it in high or very high risk, as outlined in Figure 10.

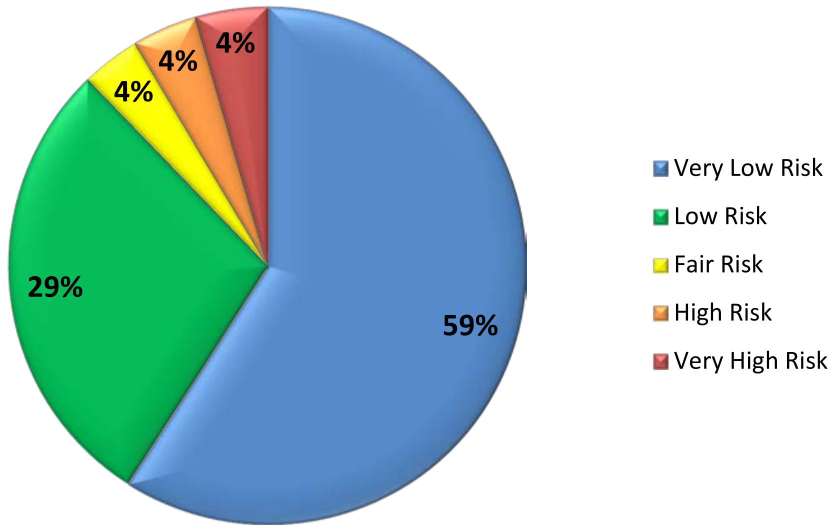


Figure 10: Transformer Fleet Condition Assessment

The transformers which tend to be in the worst condition are also those which are approaching or beyond their expected service life. Transformer condition is generally correlated to asset age, as well as how it has been operated and maintained throughout its service life. Sustaining capital and maintenance programs are targeted at transformers in degraded condition typically with high or very high risk of failure.

To date, the sustaining replacements have addressed many of the transformers with the highest probability of failure along with a number of maintenance activities have focused on remedial actions to mitigate the most significant risks. However to maintain the condition of the fleet, given the demographics and utilization, a continued replacement program beyond historic accomplishment rates is required to maintain or gradually improve the overall fleet condition.

<u>Other Influencing Factors</u>

Other factors driving the increase in transformer replacements are summarized below.

- Oil Leaks - Provincial regulations require that oil leaks are mitigated either through temporary measures such as absorbent materials and drip trays, through typically expensive refurbishment to re-gasket transformers, or replacement. Replacement is often the best technical and economical solution for aged transformers.

- Environmental Compliance Approval ("ECA") Commitments - (formerly CofA). Often ECA approvals come with a condition of bringing other aspects of the transmission station up to modern standards within a specified period of time, typically 3 years. Transformers are usually the influencing factor in ECA commitments for both spill containment and noise limits.

- Polychlorinated Biphenyl ("PCB") Contamination – Approximately 25% of bushings older than 1985 are forecast to contain oil with a PCB concentration of greater than 50 ppm. Environment Canada has a regulated end-of-use date of 2025 for oil volumes greater than 50 ppm. Replacements of this equipment will be required to maintain environmental compliance.

Cost Trends and Impacts

Transformer Portfolio	Historic			Bridge	Test	
	2011	2012	2013	2014	2015	2016
# of Replacements*	16	12	15	26	26	26
% of Fleet	2.2%	1.7%	2.1%	3.6%	3.6%	3.6%
Capital ($M)	81.1	100.5	120.7	162.9	105.7	120.1
OM&A ($M)	30.2	23.2	21.8	23.3	23.7	22.8

**Note that transformer replacements above are conducted under both the categories of Power Transformers and Station Re-Investment as outlined in Exhibit D1, Tab 3, Schedule 2.*

The capital replacement rate in the test years is consistent with the bridge year forecast, which is an increase over historic level. Continued renewal of the fleet at this rate should be sufficient to maintain an acceptable level of risk through the test years. There is some variability in capital expenditures year over year, which is mostly a function of the type and size of transformers being planned for replacement.

OM&A expenditures are generally consistent year over year with some minor variation as accomplishment of targeted programs is completed.

Transformers are a major element in ensuring a reliable bulk electricity system. Transformer failures are directly impactive to load customers, either through loss of load or significant risk exposure of single supply until such time the transformer can be replaced. Maintaining the fleet in an adequate condition will help preserve reliability in line with good utility practice and regulatory obligations.

4.1.2 Circuit Breakers

Asset Overview

Hydro One Transmission has 4,604 circuit breakers in service, as outlined in Table 4. High voltage ("HV") breakers are installed in 500 kV, 230 kV or 115 kV positions, and medium voltage ("MV") breakers are installed at 44 kV, 27.6 kV, 13.8 kV or 12.5 kV positions.

Table 4: Circuit Breakers by Type

Circuit Breaker Type	***Number of Circuit Breakers***		
	HV	***MV***	***Total***
Oil	479	1339	1818
SF6	642	937	1579
Air Blast	182	27	209
GIS	91	21	112
Metalclad	0	845	845
Vacuum	0	41	41

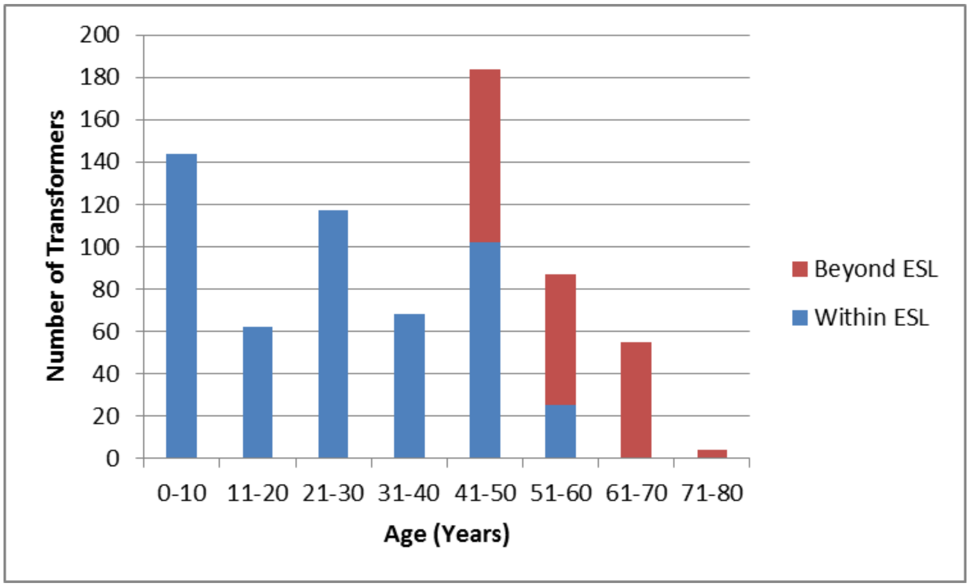


Figure 2: Demographics of the Transformer Fleet

The potential risks to system and customer reliability as a result of this long-term demographic pressure needs to be managed through continued capital replacement programs.

Performance

The forced outage frequency and duration of transformers are relatively stable, as demonstrated in Figures 3 and 4. However, transformers failures can have a significant impact to local and system reliability and current reliability performance is not a sufficient indicator of asset needs.

Transformer forced outages are one of the leading causes of customer delivery point interruptions, and represent 18% of the equipment caused events impacting delivery point interruptions with multiple supplies over the past 10 years. To mitigate this risk, the proposed transformer replacements in the test years are focused on replacing transformers that may lead to delivery point interruptions and impacting system reliability, customer satisfaction and other adverse outcomes. This is determined through the Asset Risk Assessment process outlined in Exhibit B1, Tab 2, Schedule 5.

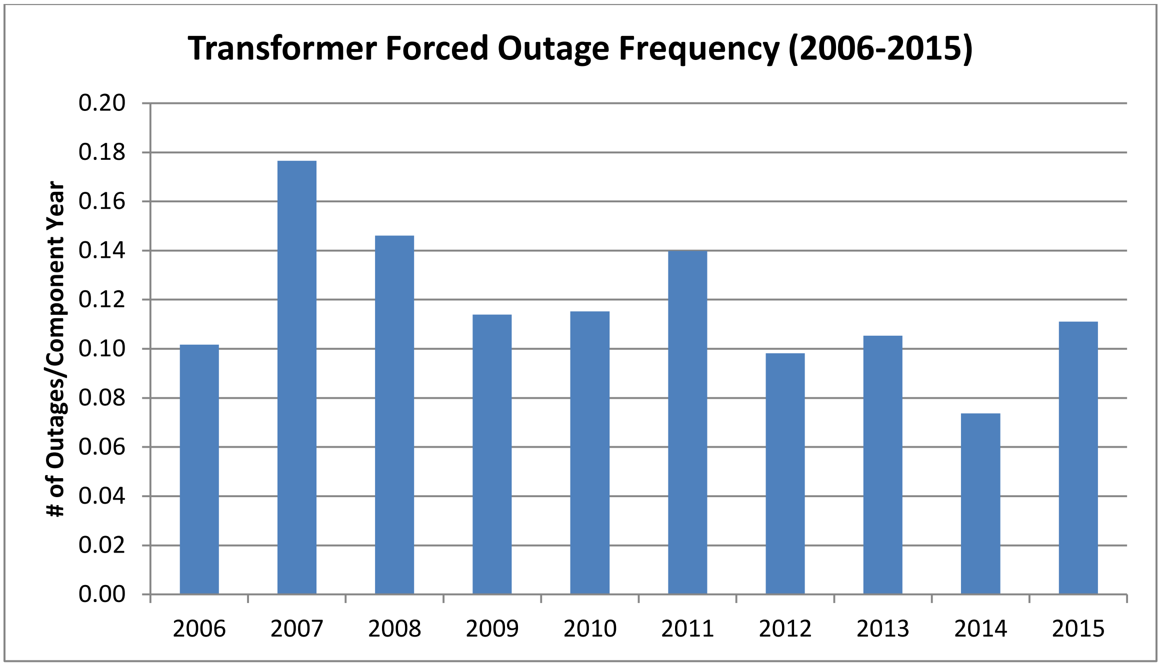


Figure 3: Forced Outage Frequency of Transformers

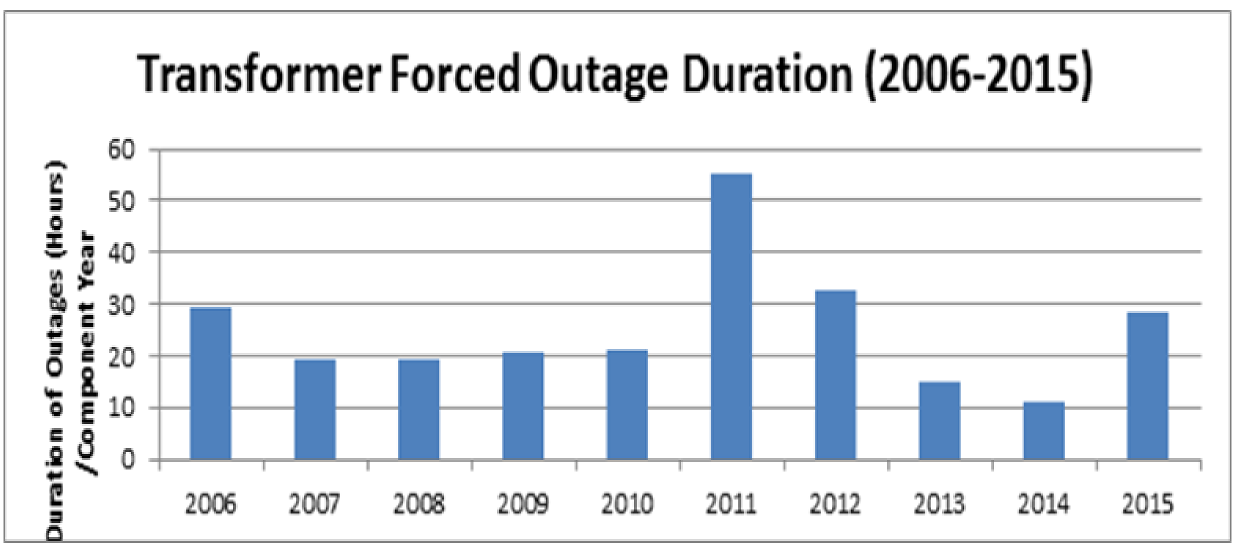


Figure 4: Forced Outage Duration of Transformers

<u>Condition</u>

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

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

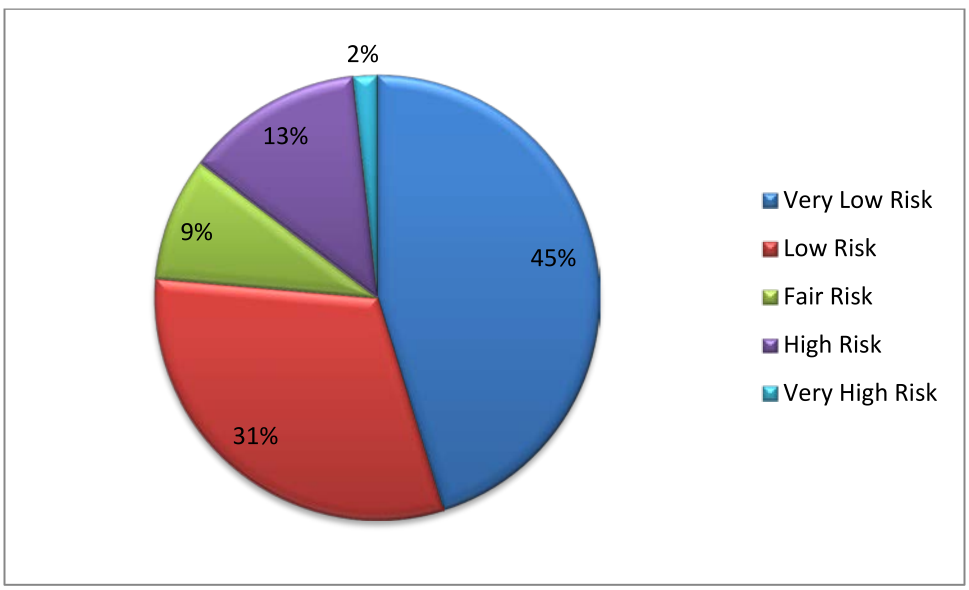


Figure 5: Transformer Fleet Condition Assessment

To date, the sustaining replacements have addressed many of the transformers with the highest probability of failure, along with a number of maintenance activities that have focused on remedial actions to mitigate the most significant risks. This has stabilized overall condition of the asset fleet.

<u>Other Influencing Factors</u>

Other factors considered when determining the need for transformer replacement include:

- Oil Leaks - Provincial regulations require that oil leaks are mitigated either through temporary measures such as absorbent materials and drip trays, through typically expensive refurbishment to re-gasket transformers, or replacement. Replacement is often the best technical and economical solution for transformers with these problems.

- Environmental Compliance Approval ("ECA") Commitments - formerly Conditions of Approval, or "CofA". Often ECA approvals include conditions requiring transmission station equipment to meet modern environmental standards within a specified period of time, typically 3 years. Transformers are usually the influencing factor in ECA commitments for both spill containment and noise limits.
- Safety - Power transformers can experience catastrophic explosions and fire if their condition is deteriorated. Power transformer outages can represent a concern for employee and public safety as individuals may be exposed to unneeded risks and harmed from the results of transformer failure as well as through prolonged power outages.
- Standardization – Replacement and upgrades of older transformers allows the equipment fleet to better achieve standardized configurations that meet up to date standards, which in turn mitigate safety and environmental risks. Modern transformers are more efficient with lower electrical losses.
- System Evolution – Load growth and renewable generation connections may lead to an increase in capacity requirement that is beyond the functional capability of existing transformers.

Table 3 below provides the historic replacement rate of transformers.

Table 3: Transformer Replacement Rate

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

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

2.2 Circuit Breakers

2.2.1 Asset Overview

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

However at the proposed replacement rate, the percentage of breakers beyond their expected service life will have a more gradually increase from 8% to 10% over the next 10 years.

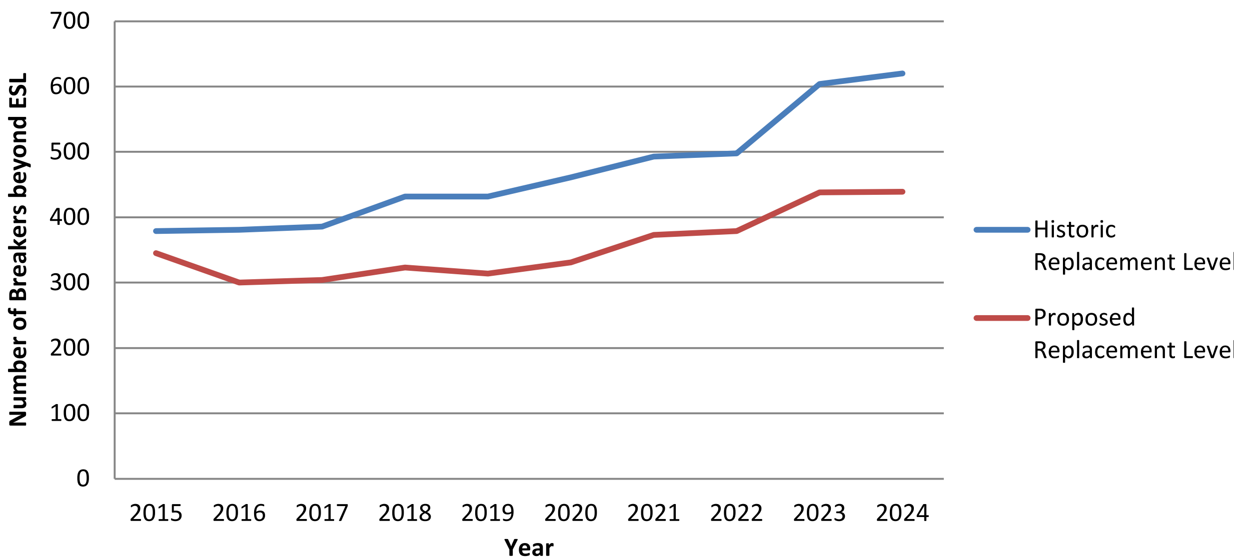


Figure 13: Projection of Circuit Breakers Beyond Expected Service Life

<u>Performance</u>

As displayed in Figure 14, Hydro One Transmission’s circuit breaker reliability for the entire circuit breaker population has been generally stable over the past five years.

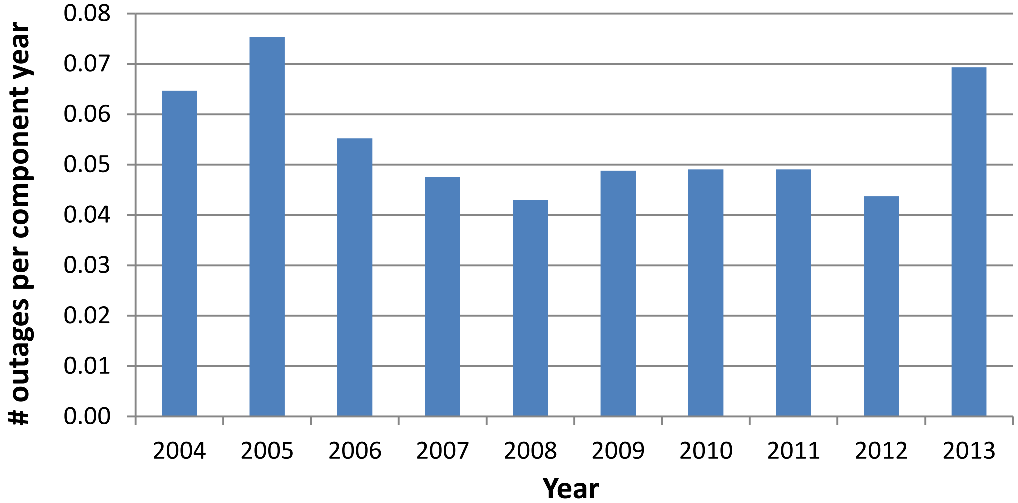


Figure 14: Forced Outages Frequency due to Circuit Breaker Failures

In 2013 there was a marked degradation in performance at the fleet population level which is primarily attributed to a much higher number of forced outages on air blast circuit breakers than previous years. This trend is notable in Figure 15, where the performance data for the different breaker interrupting mediums technologies is depicted.

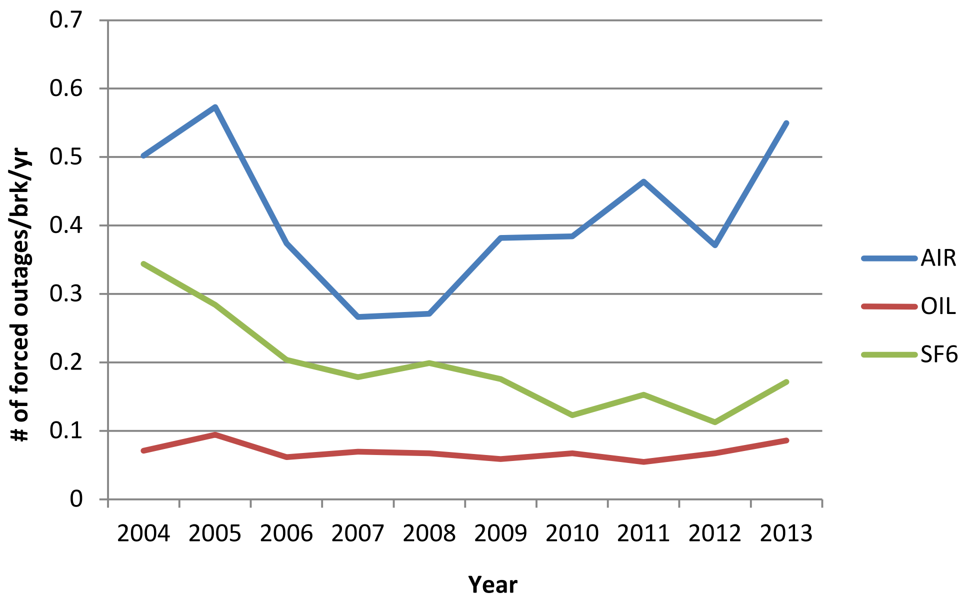


Figure 15: Forced Outage Frequency due to Circuit Breaker Failures by Type

Condition

Circuit breaker condition is a leading predictive indicator of equipment reliability. Condition is primarily based on feedback from preventive maintenance and corrective maintenance programs through diagnostic testing such as breaker timing, breaker oil analysis, history of deficiencies, etc. The components generally degrade as a function of time and usage. In some cases the degradation is reversible through replacement of wear components during maintenance but in many cases replacement is the only technical or economically viable solution.

Based on the results gathered, currently 16% of Hydro One Transmission's circuit breaker population has condition that puts it in high or very high risk, as outlined in Figure 16.

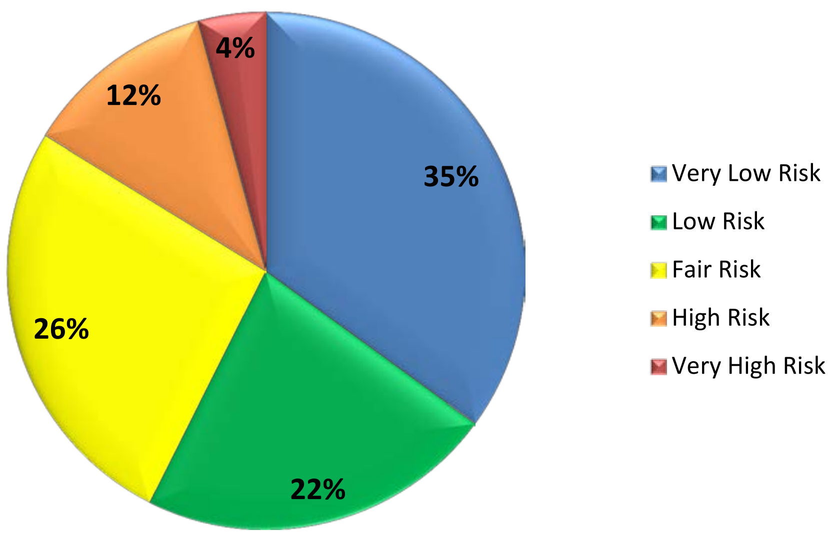


Figure 16: Circuit Breaker Fleet Condition Assessment

Other Influencing Factors

Other factors affecting circuit breakers that drive replacements requirements are summarized below.

- Safety - As the circuit breaker design has evolved over the past 50+ years, so has the safety standards and the requirement for safer work methods to protect utility workers. Early generation metalclad switchgear is most notable for having significant arc flash and electrical burn hazards in the event of equipment failure. These risks become more significant as the equipment ages.

- Technical Obsolescence - Many breakers are no longer supported by vendors and aftermarket parts are not available and/or cost effective. This is a significant factor for air blast circuit breakers, some first generation SF6 circuit breakers, and certain types of metalclad and oil circuit breakers.

- Equipment Operations - Breakers that have exceeded their expected service life in terms of number of operations are considered for replacement. Due to their frequent operation, this is most typical of capacitor and reactor breaker positions.

- Environmental Impact – Minimizing SF6 emissions and their resultant impact as a greenhouse gas to the environment is considered in the replacement or refurbishment plans for SF6 breakers.

Cost Trends and Impacts

Circuit Breaker Portfolio	**Historic**			**Bridge**	**Test**	
	2011	**2012**	**2013**	**2014**	**2015**	**2016**
# of Replacements*	100	55	57	125	150	147
% of Fleet	2.2	1.2	1.2	2.7	3.3	3.2
Capital ($M)	55.8	39.7	54.5	68.9	82.7	83.2
OM&A ($M)	19.3	18.5	20.7	17.3	19.4	19.8

** Note that circuit breaker replacements in the test years are a combination of both the categories Circuit Breakers and Station Re-Investment as outlined in Exhibit D1, Tab 3, Schedule 2.*

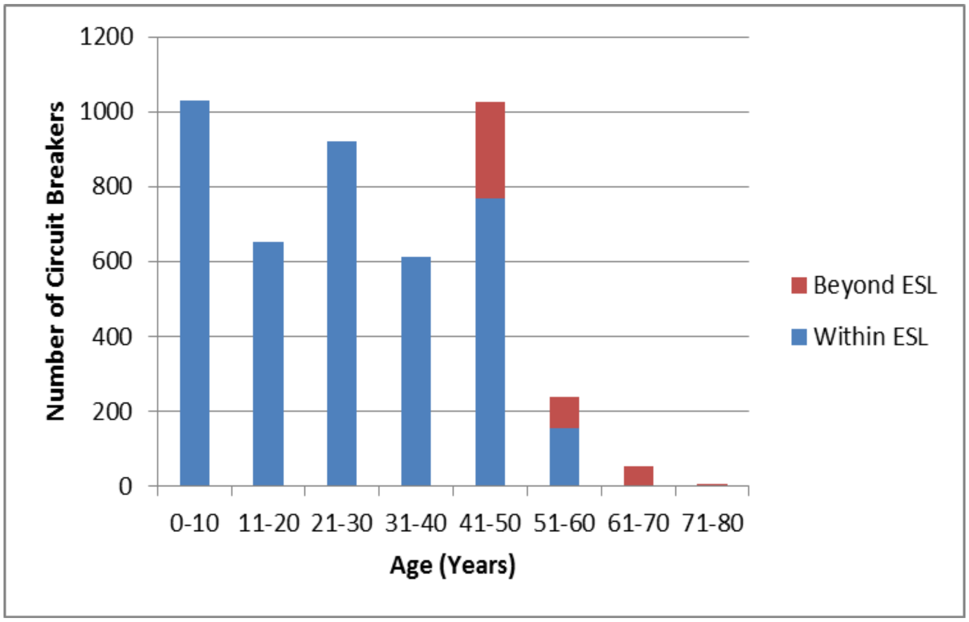


Figure 7: Demographics of the Circuit Breaker Fleet

Historic replacements have been generally sufficient to maintain a relatively small portion of the overall circuit breakers in operation beyond their ESL. Within the overall population, there are certain circuit breaker types which are operating at or beyond their ESLs.

- Approximately 80% of the high voltage air blast circuit breakers are beyond their ESL. These breakers are typically installed at system critical network stations;
- A large portion of the aged inventory is oil circuit breakers. Replacement is focused on only the worst performing and/or technically obsolete models.
- A significant portion of the metalclad breakers are operating well beyond their expected life. Legacy designs come with inherent safety risks that require mitigation.

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.

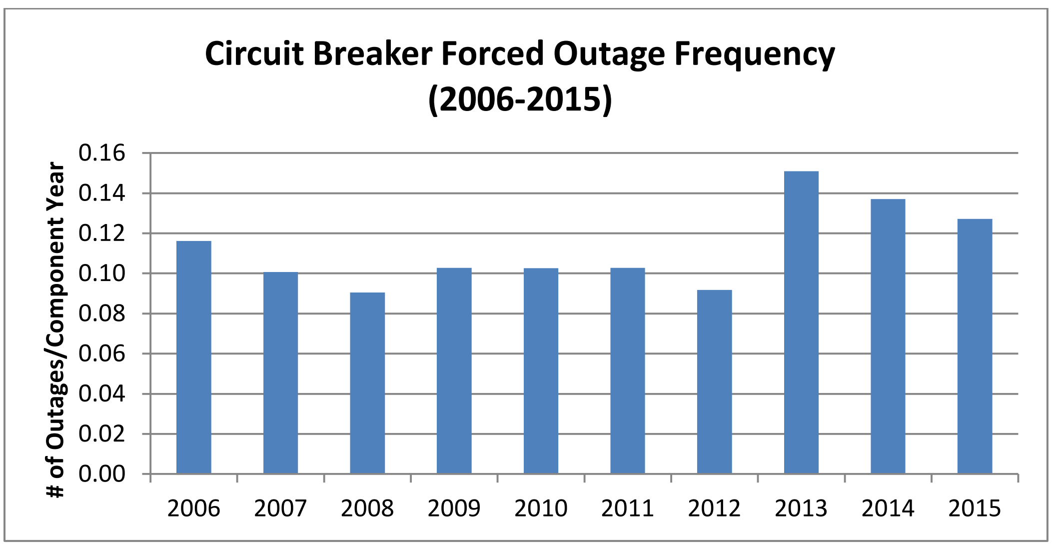


Figure 8: Forced Outages Frequency of Circuit Breakers

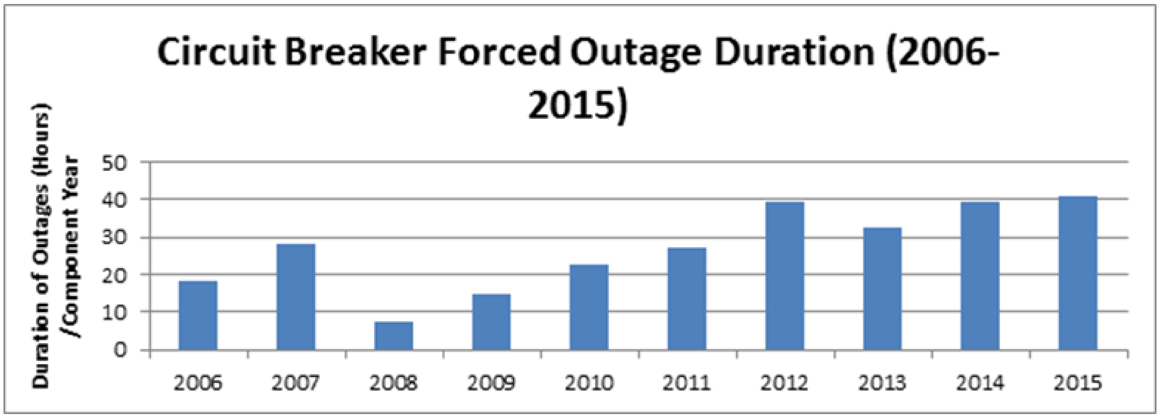


Figure 9: Forced Outage Duration Caused by Circuit Breakers

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.

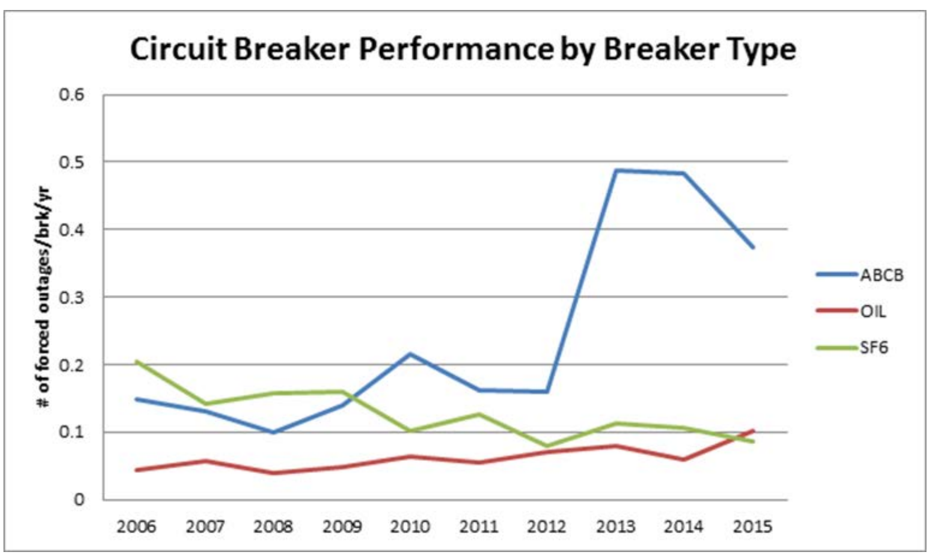


Figure 10: Forced Outage Frequency of Circuit Breaker by Type

Condition

Witness: Chong Kiat Ng

Circuit breaker condition is primarily based on assessment from preventive maintenance and corrective maintenance programs through diagnostic testing such as breaker timing, breaker oil analysis, history of deficiencies, and other tests. The components generally degrade over time based on the amount of usage. In some cases the degradation can be addressed through replacement of worn components during maintenance, but in many cases replacement of the circuit breaker is the only viable solution.

Currently 11% of Hydro One's circuit breakers rated high or very high risk based on asset condition, as outlined in Figure 11.

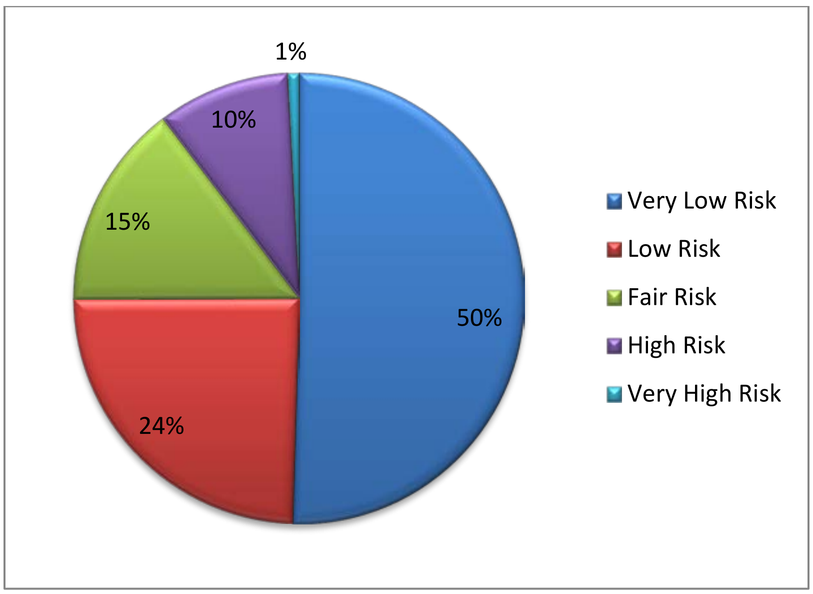


Figure 11: Circuit Breaker Fleet Condition Assessment

<u>Other Influencing Factors</u>

Other factors considered when determining the need for circuit breaker replacement include:

- Safety - As the circuit breaker design has evolved over the past 50+ years, so have safety standards and the requirement for safer work methods to protect utility workers. Early generation metalclad switchgear is most notable for having significant arc flash and electrical burn hazards in the event of equipment failure. These risks become more significant as the equipment ages.

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

Table 5: Circuit Breaker Replacement Rate

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

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

Circuit breakers are a major element in ensuring a reliable bulk electricity system. Breaker failures are directly impactive to load customers, either through loss of load or

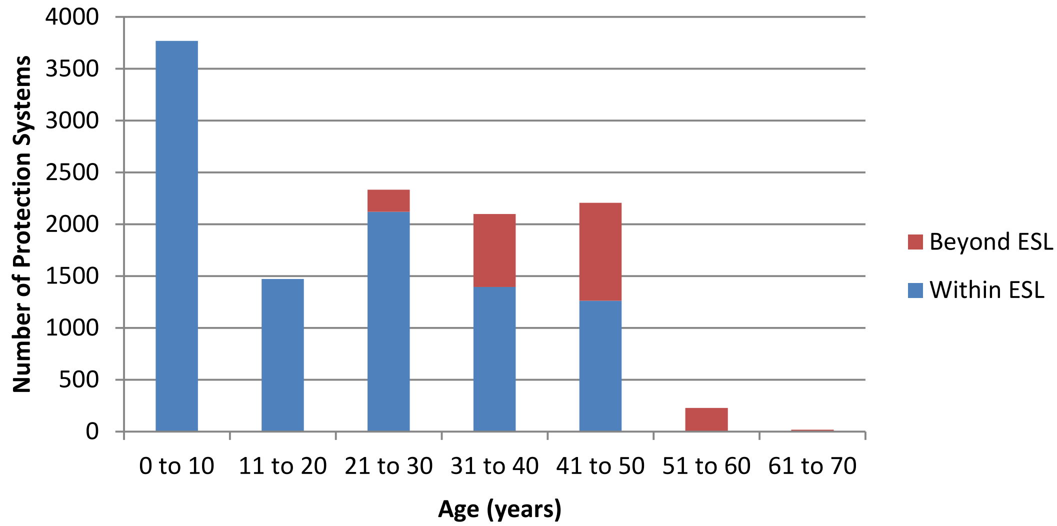


Figure 18: Demographics of Protection Systems Fleet

The potential risks to system and customer reliability as a result of this long-term demographic pressure needs to be managed through increasing capital replacement programs. As can be seen in Figure 19, continuing at the historic rate of replacement would result in the percentage of protection systems beyond their expected service life increasing to 25% by 2025. However at the proposed replacement rate of 450 protection systems a year will allow the percentage of protection systems beyond expected service life to remain relatively constant over the next 10 years.

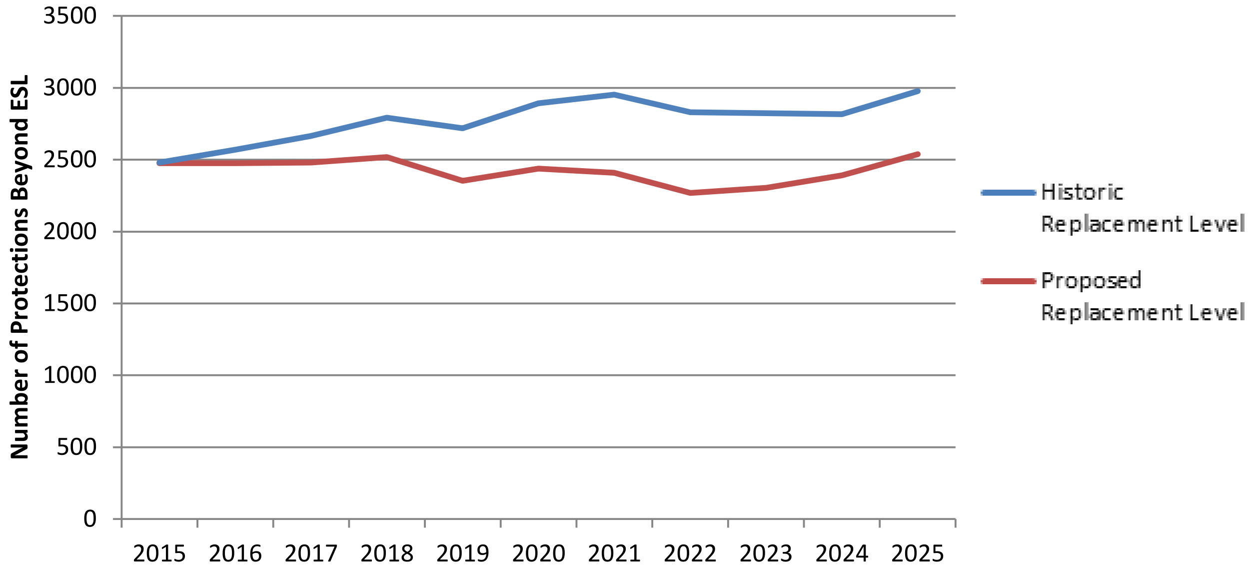


Figure 19: Projection of Protection Systems Beyond Expected Service Life

<u>Performance</u>

The forced outage frequency of equipment caused by protection systems has been a relatively declining trend for lines equipment and a relatively stable trend for station equipment over the past 10 years, as outlined in Figure 20. Protection systems play a critical role in ensuring the safe and reliable operation of the transmission system. The systems must be both dependable (operating when required) and secure (not operating on faults in adjacent protection zones) to ensure the reliability of supply. Protection systems cannot be out of service for longer than several days without incurring significant penalties in market inefficiency, disrupting planned outages, or impacting provincial or interconnected system reliability. To mitigate this risk the protection system replacements in the test years are focused on replacing protection systems that are at the highest risk of causing delivery point interruptions and impacting to the bulk electricity system.

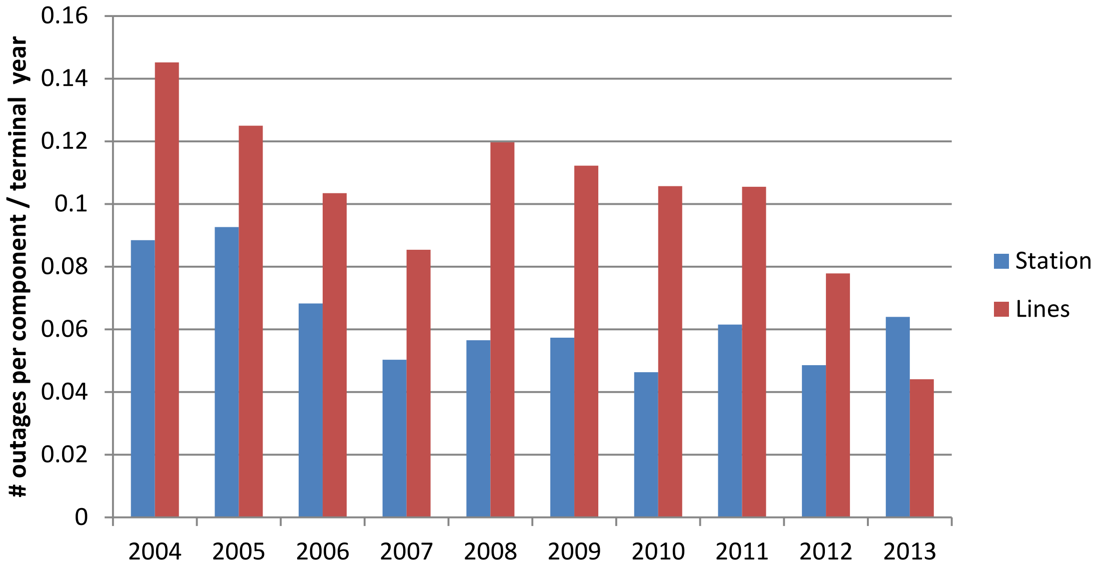


Figure 20: Station and Lines Equipment Direct Forced Outage Frequency Caused by Protection Equipment

PALC relays, one type of solid state protection system, have shown an increase in recorded defects and trouble calls over the last 10 years. Performance data shown in Figure 21 demonstrates an overall increasing trend in defects affecting PALC relays, with the moving 4 year average increasing 63% over the last the 6 years. Targeted investment to replace PALC relays is required to arrest the increasing trend and maintain reliability.

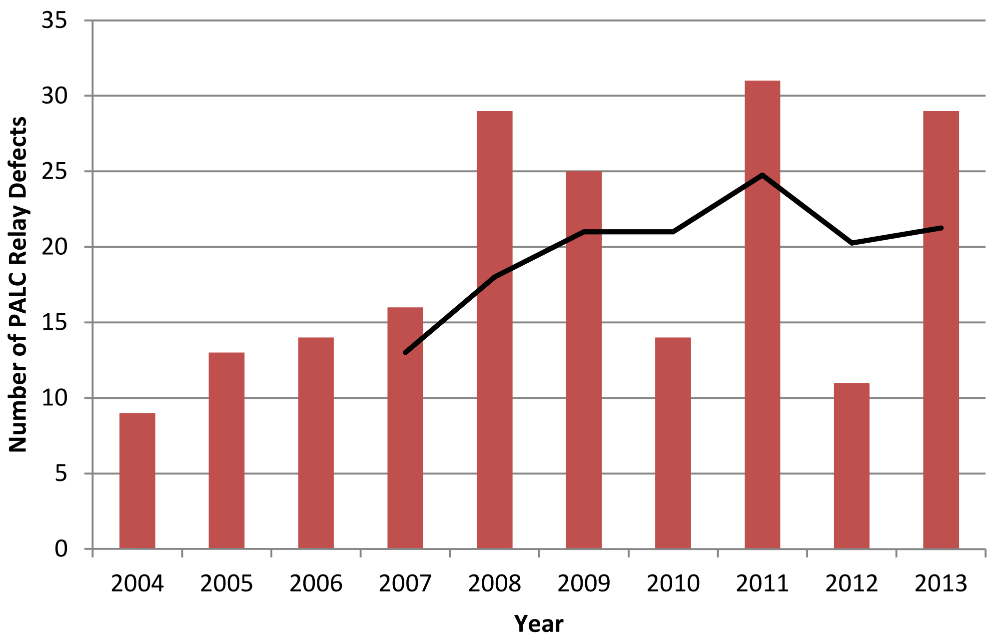


Figure 21: Historic Performance of PALC Relays

Condition

Protection system condition is an important indicator of equipment reliability. Condition is primarily based on age and general findings from the preventive and corrective maintenance programs. The internal components degrade as a function of time, which can alter the performance of the relay. This is primarily a concern with electromechanical systems, however component aging or defects and thermal cycling can also affect solid state and microprocessor based protection systems. However, as microprocessor based protections are a relatively new technology, detailed condition metrics and indicators are not as well established.

Based on results gathered, currently 26% of Hydro One Transmission's protection system population has a condition that puts it in high or very high risk, as outlined in Figure 22.

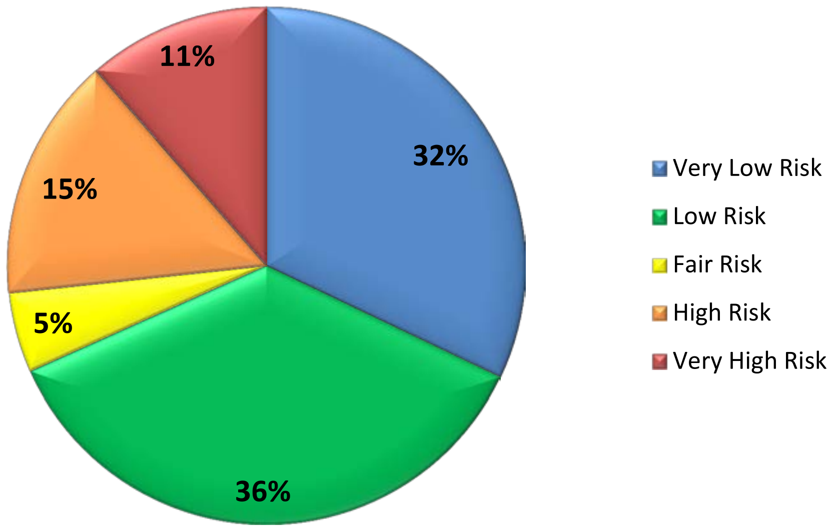


Figure 22: Protection Systems Fleet Condition Assessment

The protection systems which tend to be in the worst condition are also those operating beyond their expected service life or are identified as high risk such as PALC relays. Maintenance programs and re-verification intervals take into account the limitations and risks associated with each technological vintage to ensure continued and reliable operation. Electromechanical systems, as a result, require more frequent re-verification in contrast to microprocessor based systems to ensure reliable operation.

The sustaining capital replacement programs are targeted at replacing protections systems critical to system and customer reliability and with a high or very high risk of failure. However to maintain the condition of the fleet, given the demographics, a continued replacement program beyond historic replacement rates is required to maintain or gradually improve the overall fleet condition.

Other Influencing Factors

Other factors driving the increase in protection system replacements are summarized below.

- Safety – Operating protection systems beyond their expected service life increases the risk of systems failing to operate and potentially exposing workers and the public to the harm associated with uncontrolled flow of energy. Proactive replacements are required to mitigate this risk.

- Technical Obsolescence – Many protection systems are no longer available, limiting the availability of spares and support; which can adversely impact outage planning and overall system reliability. This is a significant factor for electromechanical and solid state systems.

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

Cost Trends and Impacts

Protection Systems Portfolio	Historic			Bridge	Test	
	2011	2012	2013	2014	2015	2016
# of Replacements*	389	350	340	350	365	450
% of Fleet	3.5%	2.9%	2.8%	2.9%	3.0%	3.7%
Capital ($M)	28.5**	53.5	53.8	56.3	57.9	70.5
OM&A ($M)	11.3	9.7	9.7	10.6	10.3	11.7

**Note that protection replacements above are conducted under both the categories of Protection and Station Re-Investment as outlined in Exhibit D1, Tab 3, Schedule 2.*
***Note: Excludes capital expenditures for protection replacements included under Station Re-Investment*

The capital replacement rate in the test years is increasing over the bridge and historic levels. Continued renewal of the fleet at an increased rate is required to maintain an acceptable level of risk over the test years and prevent an increase of protections operating beyond their expected service. This will be achieved by greater deployment of modular, prefabricated PCT buildings at load stations where a significant numbers of protections are in need of replacement; focused replacements of system critical protections; targeted replacements of failure prone relays such as PALC based systems; and bundling work opportunities with major refurbishment or re-investment projects.

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

Protections are a critical component in ensuring a safe and reliable bulk electricity system, and maintaining a reliable supply to customers. Maintaining the fleet in an adequate condition will help preserve reliability in line with good utility practice and regulatory obligations.

The potential risks to system and customer reliability as a result of this long term demographic pressure needs to be managed through continuous capital replacement programs. As can be seen in Figure 15, the current replacement rate of 450 protection systems per year will allow the percentage of protection systems beyond ESL to slightly reduce over the next 10 years.

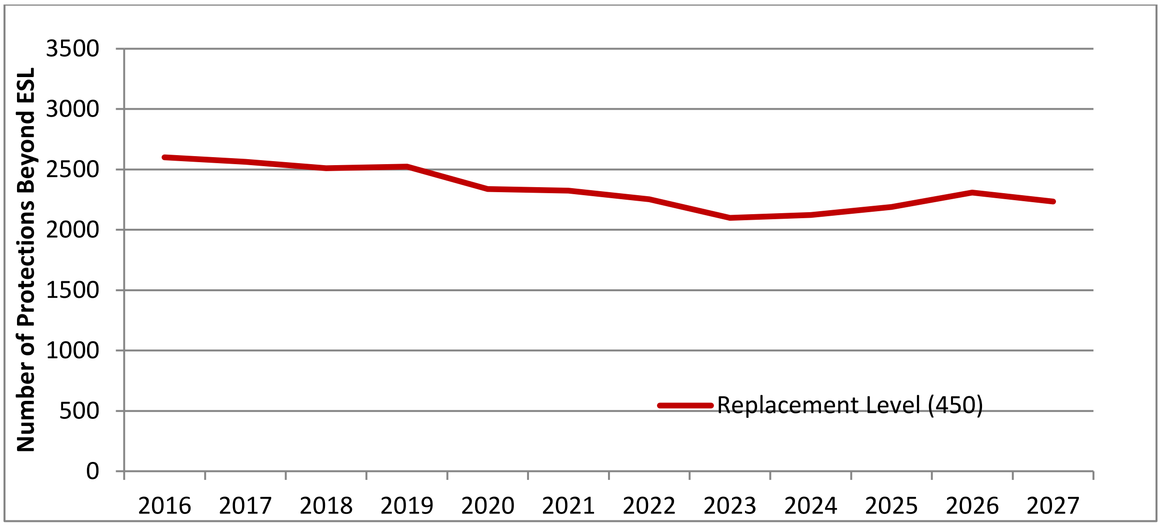


Figure 15: Projection of Protection Systems Beyond Expected Service Life

<u>Performance</u>

The forced outage frequency of equipment caused by protection systems has been declining for lines equipment and a relatively stable trend for station equipment over the past 10 years, as outlined in Figure 16.

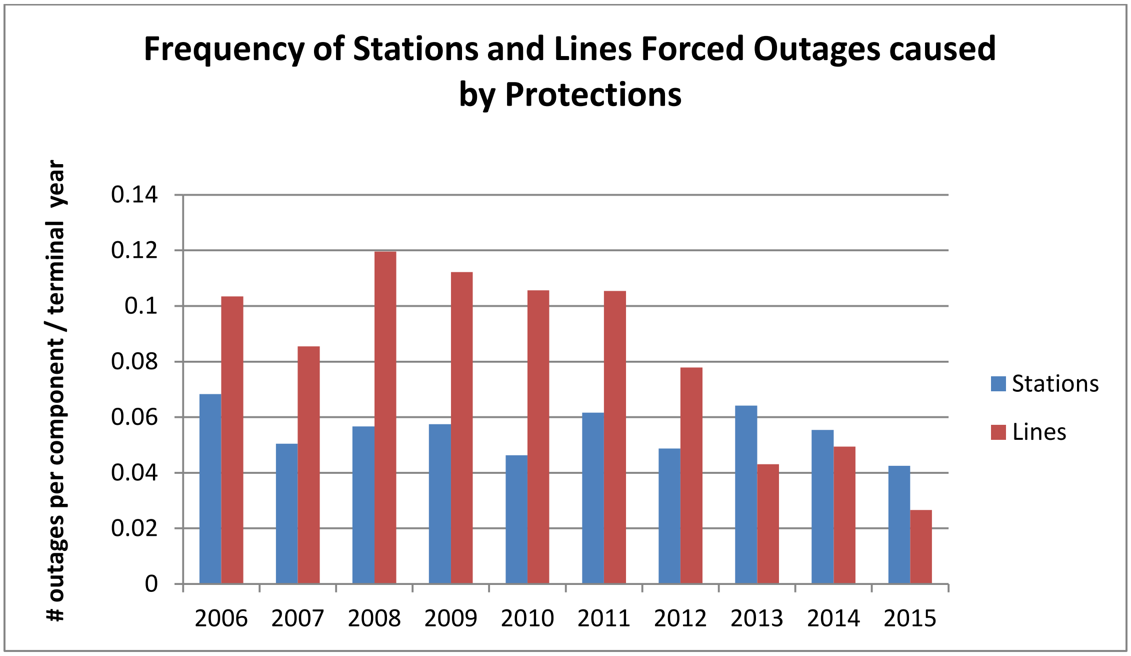


Figure 16: Frequency of Stations and Lines Forced Outages caused by Protections

Protection systems play a critical role in ensuring the safe and reliable operation of the transmission system. The systems must be both dependable (operating when required) and secure (not operating on faults in adjacent protection zones) to ensure the reliability of supply. To mitigate this risk, the protection system replacements in the test years are focused on replacing protection systems that have a high likelihood of causing delivery point interruption and impacting the bulk electricity system.

Programmable Auxiliary Logic Controller (PALC) relays, one type of solid state protection system, have shown an increase in recorded defects and trouble calls over the years. Hydro One has been actively replacing PALC relays and approximately 200 PALCs have been replaced in 2014 and 2015. See Figure 17 below for the historical annual defects. Currently, Hydro One still has approximately 400 PALC relays in the system and plans to replace them over the following five years.

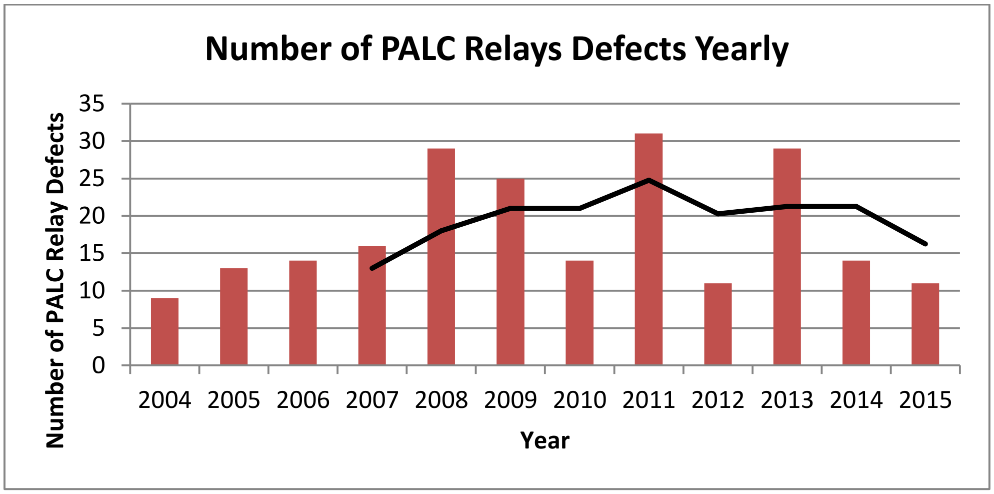


Figure 17: Historic Performance of PALC Relays

Condition

Protection system condition is an important indicator of equipment reliability. Condition is primarily based on age and findings from the preventive and corrective maintenance programs. The internal components degrade as a function of time, which can alter the performance of the relay. This is primarily a concern with electromechanical systems, but component aging or defects and thermal cycling can also affect solid state and microprocessor based protection systems. Microprocessor based protections are a relatively new technology, detailed condition metrics and indicators are not as well established. Protection Systems Fleet Condition Assessment is shown in Figure 18.

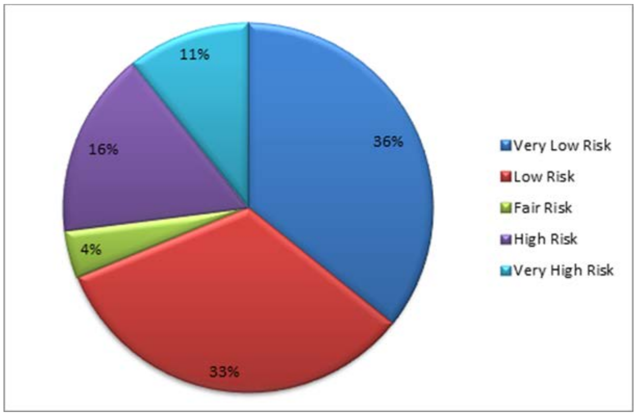


Figure 18: Protection Systems Fleet Condition Assessment

The protection systems which tend to be in the worst condition are also those operating beyond their expected service life or are identified as high risk, such as PALC relays. Maintenance programs and re-verification intervals take into account the limitations and risks associated with each technological vintage to ensure continued and reliable operation. Electromechanical systems, as a result, require more frequent re-verification in contrast to microprocessor based systems to ensure reliable operation. The sustaining capital replacement programs are targeted at replacing protections systems critical to system and customer reliability and with a high or very high risk of failure.

Other Influencing Factors

Other factors driving protection system replacements are summarized below.

- Safety – Operating protection systems beyond their expected service life increases the risk of systems failing to operate and potentially exposing workers and the public to the harm associated with uncontrolled flow of energy. Proactive replacements are required to mitigate this risk.
- Technology Obsolescence – Many protection systems are no longer available, limiting the availability of spares and support; which can adversely impact outage

planning and overall system reliability. This is a significant factor for electromechanical and solid state systems.

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

Table 8: Protection Replacement Rate

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

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

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

Asset Assessment Details

<u>Demographics</u>

Hydro One Transmission uses an expected service life ("ESL") of approximately 70 years for conductors; although this can vary based on several factors, environmental conditions being the primary factor. The average age of transmission conductor fleet is currently 52 years of age and 19% of the conductors are currently beyond their expected service life. The demographics of the conductor population is outlined in Figure 24.

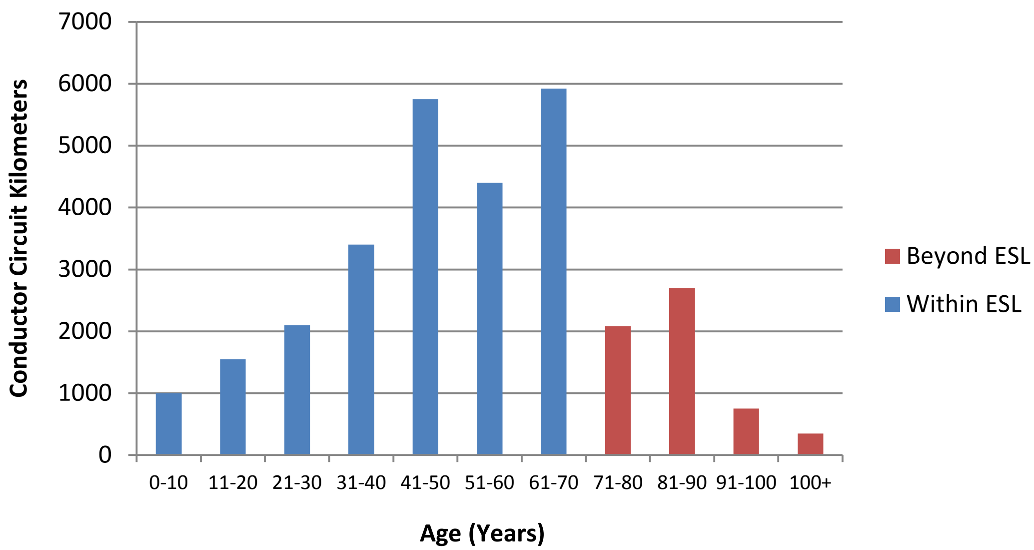


Figure 24: Demographics of Conductor Fleet

Although there have been recent increases in replacement rates to deal with immediate risks; as Figure 25 demonstrates by 2024 the number of conductors beyond their expected service life will nearly double. Hence a significant increase in future replacements will be required to maintain acceptable fleet demographics. If untended this would significantly increase the risk associated with system and customer reliability, as well as impacting exposure to public safety risks on populated areas, road crossings, public use of transmission corridors, etc.

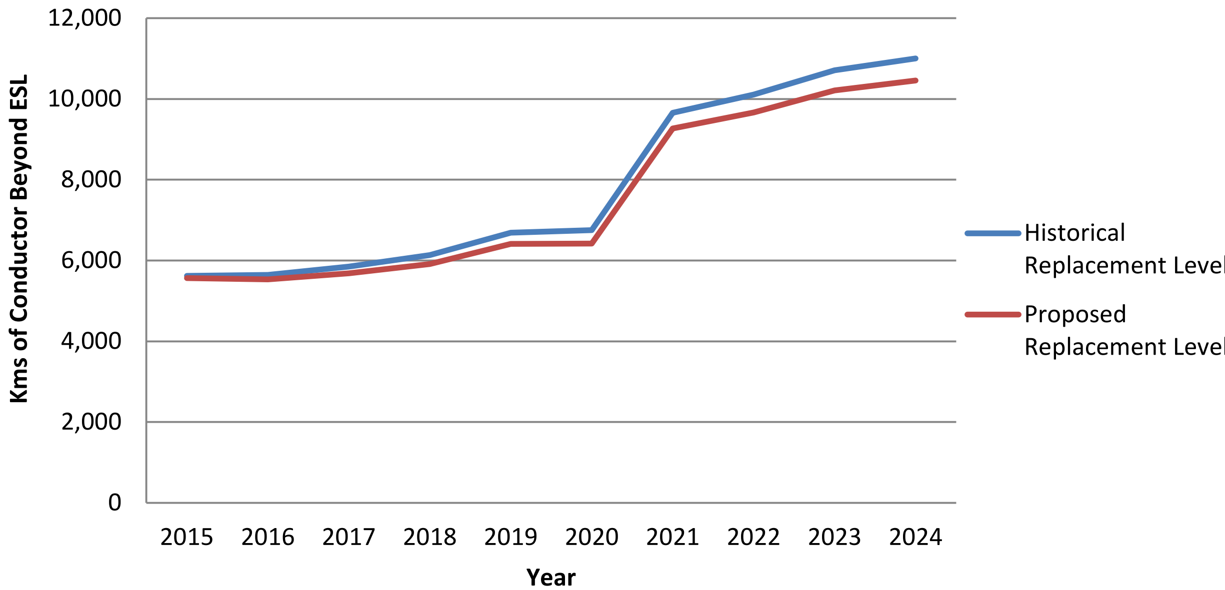


Figure 25: Projection of Conductor Beyond Expected Service Life

<u>Performance</u>

Conductor failure can have very negative consequences both in terms of reliability and safety. The number of forced outages due to conductor failures has shown slight improvement over the past 10 years, as outlined in Figure 26.

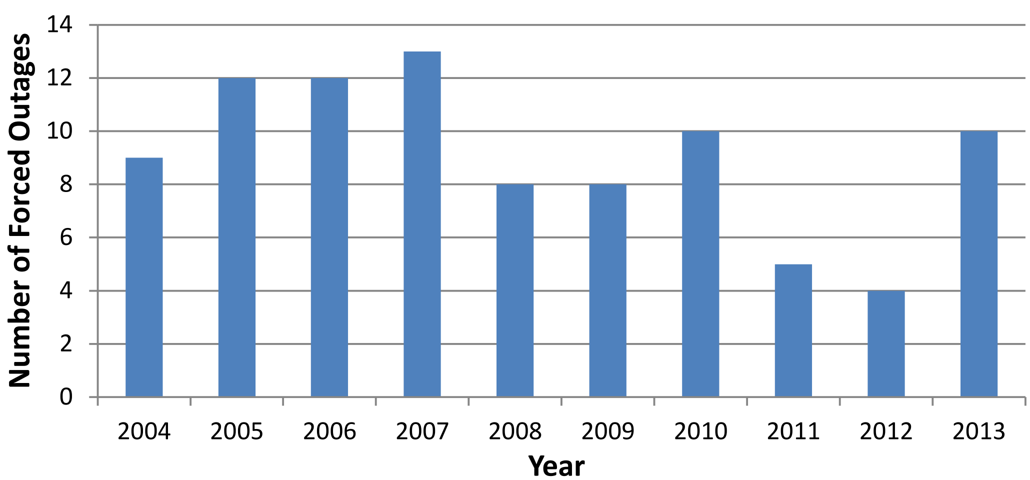
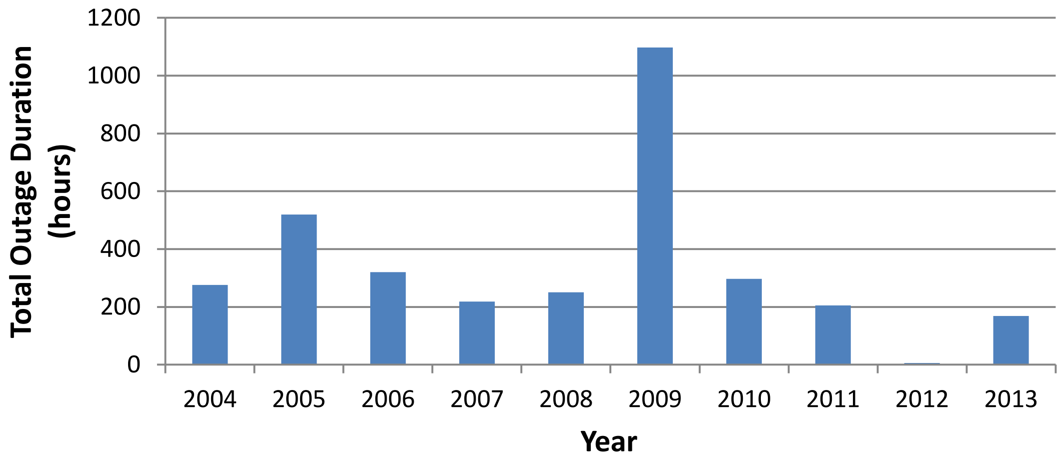


Figure 26: Forced Outage due to Conductor and related Hardware Failures

The forced outage duration due to conductor failure, displayed in Figure 27, demonstrates that conductor outage duration has been relatively stable over the last 10 years.



**Note: The extreme outage duration in 2009 was due to an emergency conductor replacement on B10H/B20H circuits.*

Figure 27: Forced Outage Duration due to Conductor and related Hardware Failures

It is expected that the outage frequency and duration performance will deteriorate given the demographics and condition of the fleet over the next 10 to 20 years if programs are not increased.

<u>Condition</u>

Hydro One Transmission has implemented a condition assessment program to assess condition of conductors after they reach 50 years of age. The corrosivity of the surrounding environment will have a significant impact on the condition of the conductor.

The results from these tests and previous studies carried out on life expectancy of conductors indicate that currently 8% of Hydro One Transmission's conductor population has condition that puts it in fair or high risk, as outlined in Figure 28.

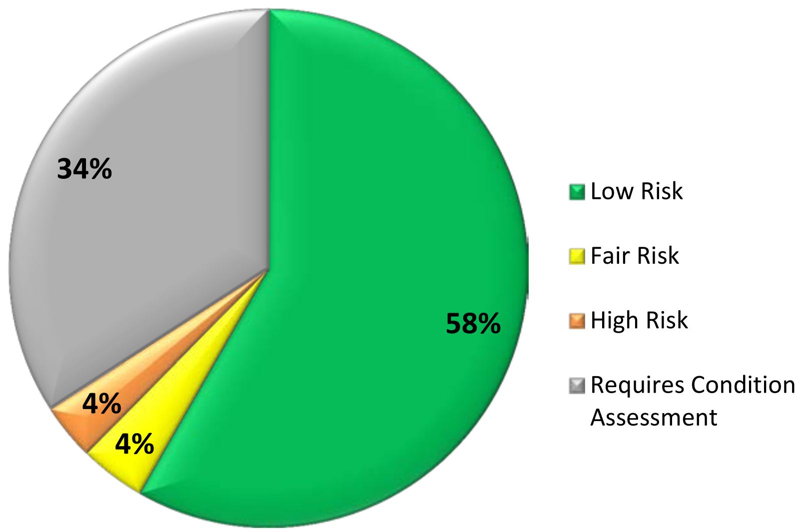


Figure 28: Conductor Fleet Condition Assessment

Hydro One Transmission continues to assess the merits of utilizing the use of a remote controlled conductor assessment device that can be used on energized lines and crawls along the conductor to non-destructively assess conductor condition.

Other Influencing Factors

- Aeolian Vibration - Geographical location, line orientation and more importantly conductor tension contribute to level of vibration each circuit experiences, which directly influences the useful lifespan of a conductor. Hydro One Transmission has experienced premature conductor failures due to a combination of conductor condition and conductor fatigue due to vibration.

- Safety – Given that transmission lines operate in the public domain, additional consideration must be given to the consequence of failure and potential impact on safety of the public. Factors as right-of-way use and proximity to road crossings are factors when assessing risk.

Cost Trends and Impacts

Conductor Portfolio	Historic			Bridge	Test	
	2011	2012	2013	2014	2015	2016
Kms of Circuit Replacements	37	22	75	113	99	60
% of Fleet	0.1%	0.1%	0.3%	0.4%	0.3%	0.2%
Capital ($M)	10.2	8.6	17.8	33.2	36.8	29.3
OM&A ($M)	10.6	10.6	9.4	13.1	14.2	14.5

The capital replacement rate has increased in recent years from a historic level of 0.1% to on average 0.3% of the fleet per year. Continued renewal of the fleet at this rate should be sufficient to continue to maintain the current level of risk through the test years. The circuits being addressed in the bridge and test years have all been identified as in poor condition through the testing and assessment process. The proposed OM&A expenditures level has increased slightly due to the need for more condition assessments to manage the risk of an aging fleet.

4.2.2 Transmission Wood Pole Structures

Asset Overview

Hydro One Transmission has approximately 42,000 wood pole structures. Wood has been a popular material for use in building transmission lines because of its cost effectiveness and reliability over the life of the asset. The majority of the wood pole structure population is located in Northern Ontario, typically in remote locations with difficult access. These wood pole structures are utilized on 230 kV and 115 kV circuits depending on the geographic location and security requirements of the line. The majority of transmission wood pole circuits support radial feed circuits, and as a result wood pole or cross-arm failure can often result in a direct customer outage.

When a conductor is determined to have reached the point of needing refurbishment, all major components within that line section including the structures, shieldwire, u-bolts and insulators are assessed and refurbished to meet future system requirements. This work of bundling conductor replacement with refurbishment of other transmission line components that also need replacement at the same time is a cost effective approach that is now used when replacing all conductors.

3.1.3 Asset Assessment Details

Demographics

Hydro One uses an expected service life ("ESL") of 70 years for conductors; although this can vary based on several factors, with environmental conditions being the primary factor. The average age of the transmission conductor fleet is currently 52 years and 19% of the conductors are currently beyond their expected service life. The demographics of the conductor population are outlined in Figure 20.

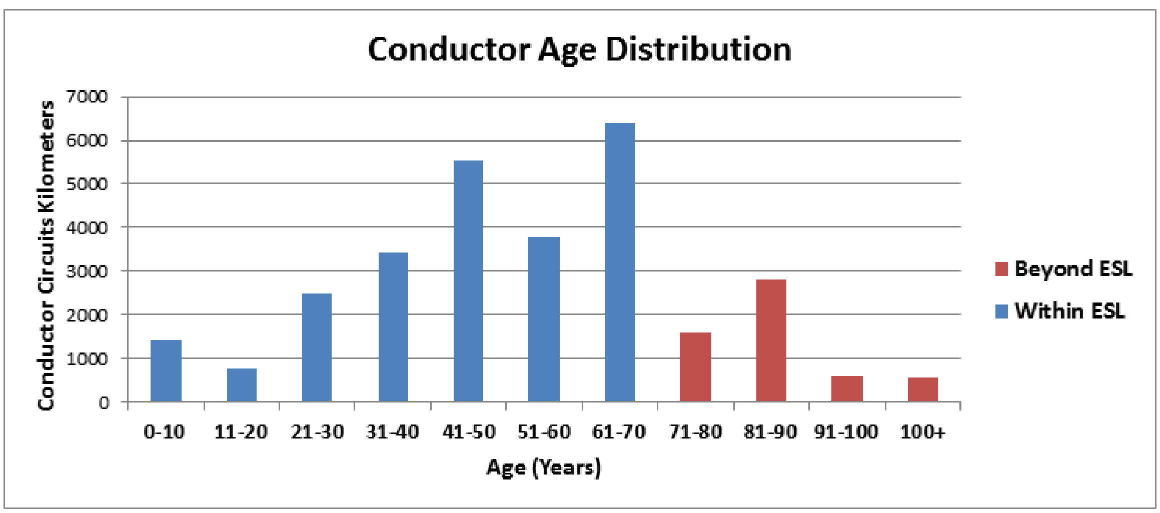


Figure 20: Demographics of Conductor Fleet

Witness: Chong Kiat Ng

Although there have been recent increases in replacement rates to deal with immediate risks, Figure 21 demonstrates that by 2025 the number of conductors beyond their expected service life will increase by over 90%. Hence an increase in future replacements is required to maintain acceptable fleet demographics. If untended, this requirement would significantly increase the risk associated with system and customer reliability, as well as impacting exposure to public safety risks on populated areas, road crossings, and public use of transmission corridors.

The following graph illustrates kilometers of conductors beyond ESL at both historical replacement rate of 120 circuit km/year (average of 2013-2015) and proposed replacement rate of 490 circuit km/year (average of 2017-2026).

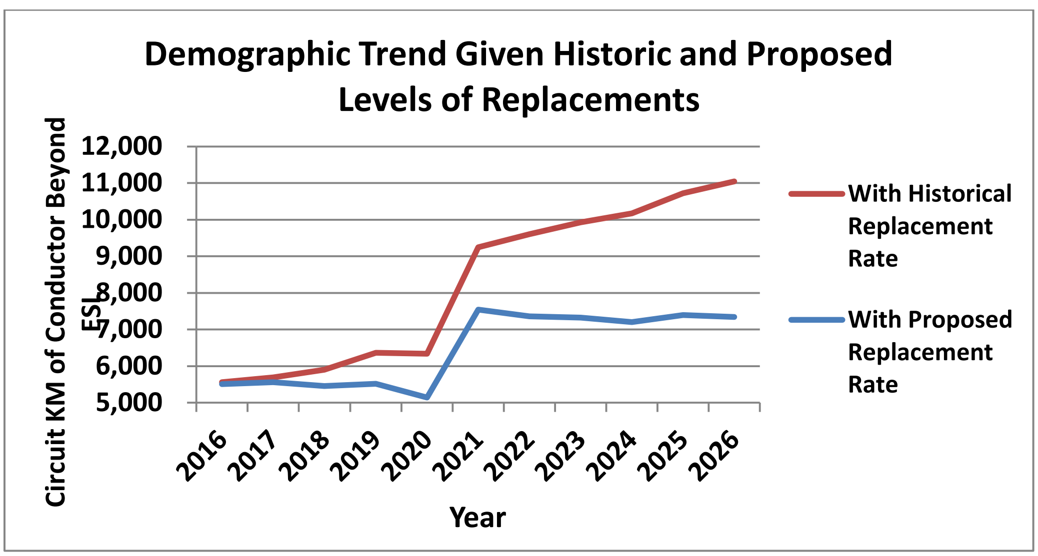


Figure 21: Projection of Conductor Beyond Expected Service Life

Performance

Conductor failure can have very negative consequences both in terms of reliability and safety. The number of forced outages due to conductor failures has improved over the past 10 years, as outlined in Figure 22.

Witness: Chong Kiat Ng

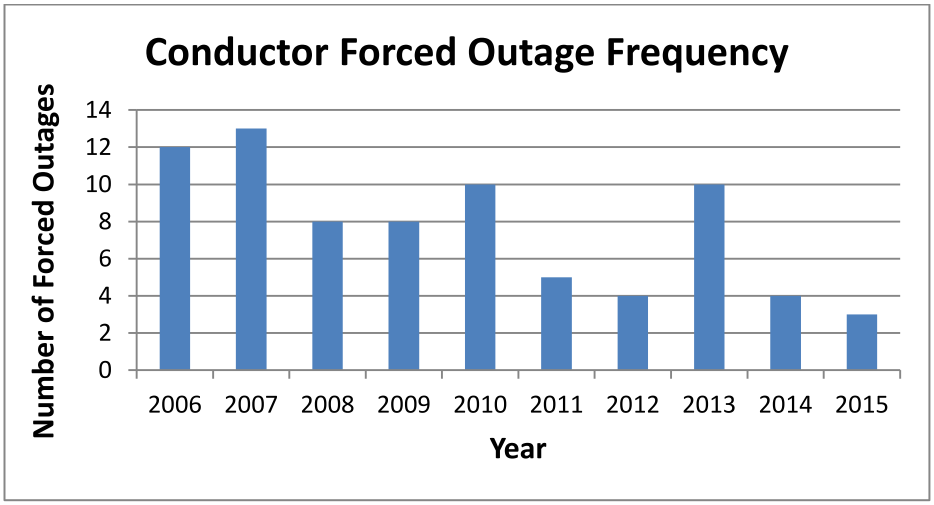
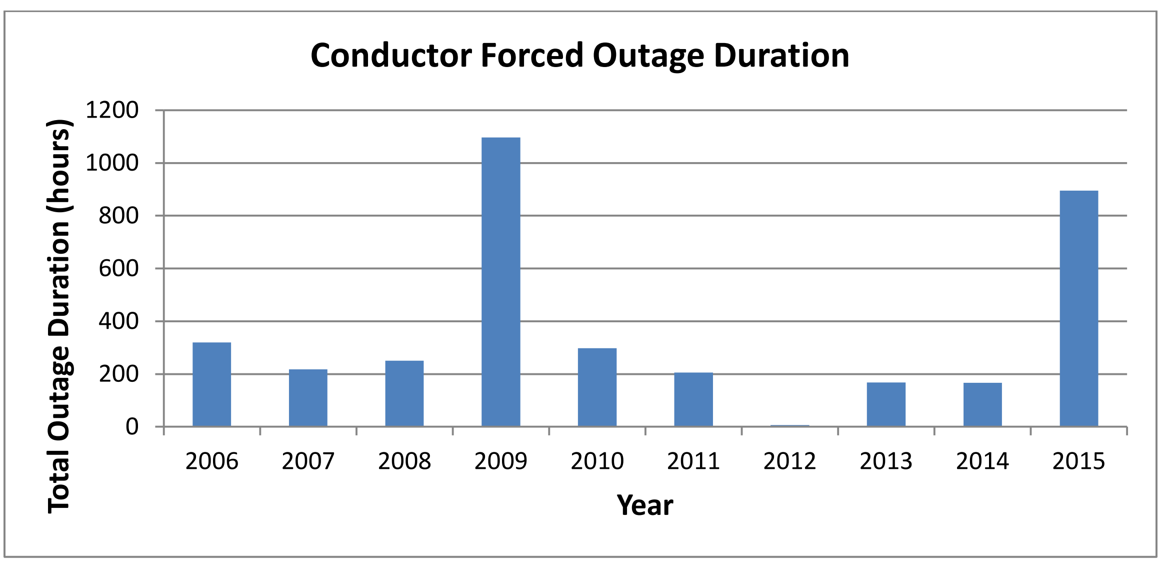


Figure 22: Forced Outage due to Conductor and related Hardware Failures

The forced outage duration due to conductor failure, displayed in Figure 23, demonstrates that conductor outage duration has been relatively stable over the last 10 years with the exception of the abnormality in 2009 and 2015.



**Note: The extreme outage duration in 2009 was due to an emergency conductor replacement on B10H/B20H circuits.*

Figure 23: Forced Outage Duration due to Conductor Failure

Witness: Chong Kiat Ng

Outage frequency and duration performance is anticipated to deteriorate based on the results of condition assessment derived from actual aged conductor sample testing.

<u>Condition</u>

Hydro One executes a condition assessment program to determine the condition of conductors after they reach 50 years of age. The corrosivity of the surrounding environment will have a significant impact on the condition of the conductor.

The results from these assessments and previous studies carried out on life expectancy of conductors indicate that 9% of conductor fleet is known to be high risk, 20% is fair risk, 40% is low risk, and 31% needs assessment as outlined in Figure 24.

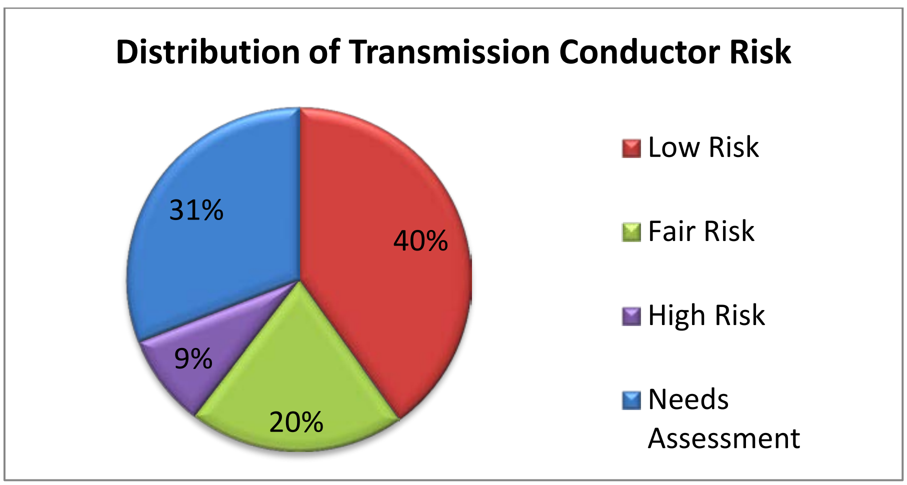


Figure 24: Conductor Fleet Condition Assessment

Hydro One has relied on conductor sample removal combined with laboratory testing as a condition assessment methodology, and is migrating to a remote controlled conductor assessment device that can be used on energized lines, hence eliminating the requirement for conductor sample extraction and line outages. Additional detail on this preventative maintenance work can be found in Exhibit C1, Tab 2, Schedule 2.

Witness: Chong Kiat Ng

Other Influencing Factors

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

Table 9: Conductor Replacement Rate

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

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

3.2 Transmission Wood Pole Structures

3.2.1 Asset Overview

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

Performance

The majority of transmission wood pole structures are located in Northern Ontario and many of these structures support radial circuits. As a result, a wood pole or cross-arm can often result in a direct customer outage. Many of these northern wood pole circuits feed major industrial customers and without an adequate supply of power, these customers are often forced to shut down until power is restored.

The number of forced outages due to wood pole structure failures has shown slight improvement over the past 10 years, as outlined in Figure 32, based on the current rate of replacement to address end of life wood poles and the defective Gulfport structures on the system.

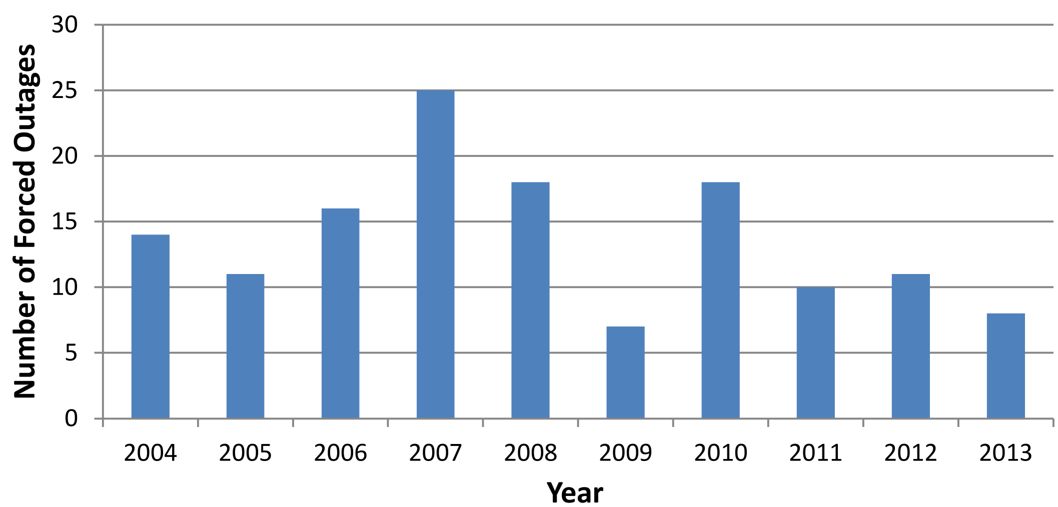


Figure 32: Forced Outages Due to Wood Pole Failures

The forced outage duration due to wood pole failures, displayed in Figure 33, demonstrates that wood pole outage duration has been stable over the last 10 years, except for the extreme spike in 2010. This type of year is not unexpected given many of these circuits are radial supplies and in remote locations, with difficult access.

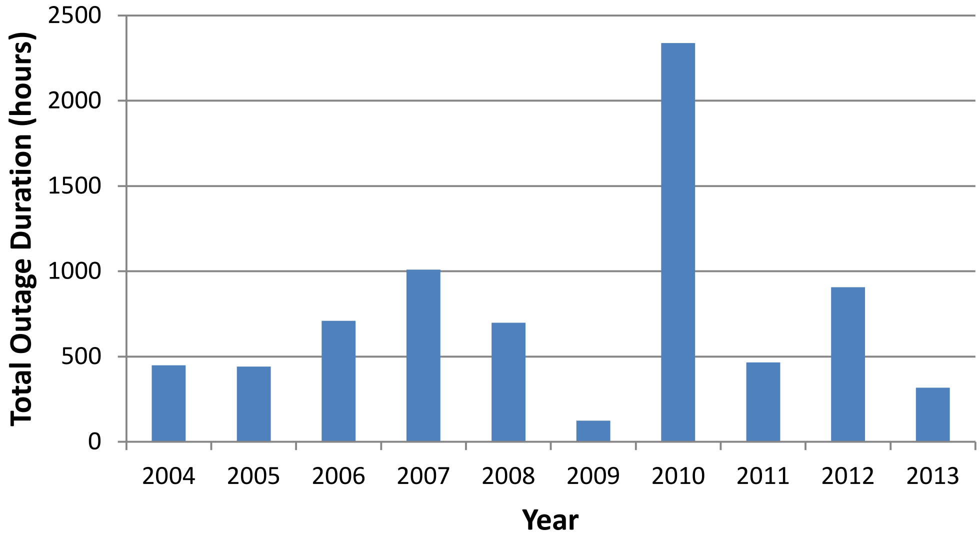


Figure 33: Forced Outage Duration due to Wood Pole Failures

At the current rate of replacement, this level of reliability is expected to remain consistent over the next 10 years hence maintaining current level of customer interruption performance.

<u>Condition</u>

Wood structures deteriorate over time; the rate of deterioration depends on location, weather, type of wood, treatment, insects and wildlife. As a result, uniform deterioration does not occur and the condition of wood structures varies, even in the same location. Wood pole structures are comprised of either a single pole or multiple wood poles with a wood cross-arm which is bolted to the poles to support the insulator strings and conductors. Due to the nature of the design, the wood cross-arm tends to be the weak link and is typically the primary cause of failure.

Wood pole assessments are undertaken to inspect the condition of cross-arms and pole tops, and to evaluate the soundness of the wood near the ground line. Based on the current condition assessment, 16% of Hydro One Transmission's wood pole population has condition that puts it in fair or high risk, as outlined in Figure 34. The assessment is continuously reviewed and adjusted as new conditions are reported or factors are considered. Approximately 10% of the wood pole population needs to be assessed to determine their current condition risk.

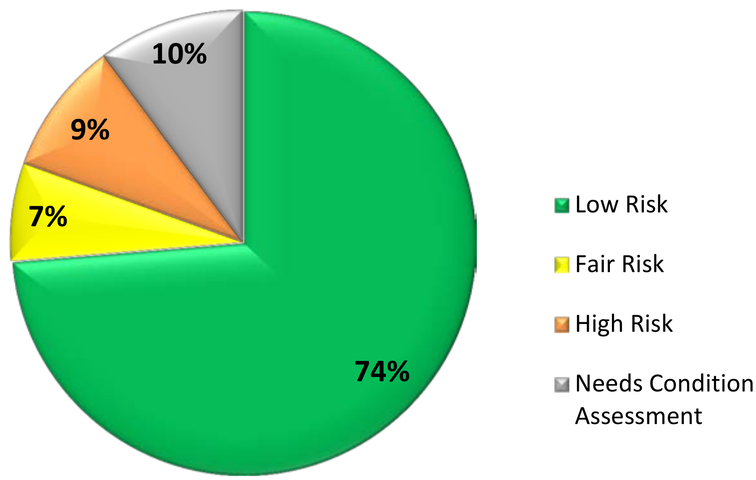


Figure 34: Wood Pole Fleet Condition Assessment

The number of poles reaching the end of life identified each year through condition assessments is in-line with the current replacement rate, and hence the number of wood poles in fair and high risk condition is expected to remain stable. As a result, reliability and safety risks will be in-line with past performance.

Cost Trends and Impacts

Wood Pole Portfolio	Historic			Bridge	Test	
	2011	2012	2013	2014	2015	2016
# of Replacements	862	763	830	850	850	850
% of Fleet	2.1%	1.8%	2.0%	2.0%	2.0%	2.0%
Capital ($M)	30.1	27.2	32.7	27.2	27.7	28.2
OM&A ($M)	2.9	4.4	3.1	4.4	4.1	4.2

CSA guidelines, performance data, asset demographics and the consequence of failure to system and customer reliability when making replacement decisions related to wood poles. This will result in a continuation of the strategy to proactively replace wood poles to reduce wood pole failures that impact customer reliability, and minimize emergency response activities that have a higher risk of negatively impacting environmentally sensitive areas.

3.2.3 Asset Assessment Details

<u>Demographics</u>

Based on Hydro One's experience, the normal expected service life ("ESL") used for wood poles is 50 years. Wood poles and cross-arms are normally treated with preservatives in order to prevent premature decay and extend their expected service life. The average age of the wood pole fleet is currently 33 years and 27% of the wood poles are currently beyond their expected service life. The demographics of the wood pole population are outlined in Figure 26.

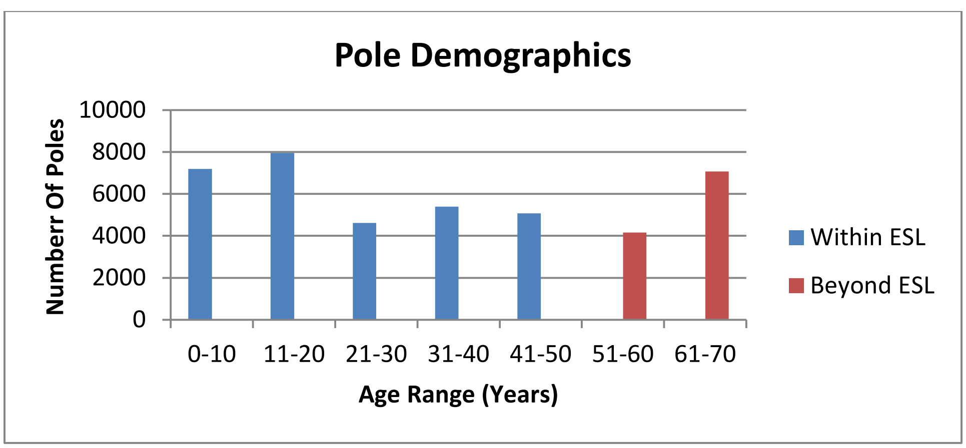


Figure 26: Demographics of the Wood Pole Fleet

Hydro One is proposing to maintain the current historic replacement rate of approximately 2% over the test years. As can be seen in Figure 27, at this rate of replacement the number of wood poles beyond their expected service life will improve from the present 27% to 19% by 2024.

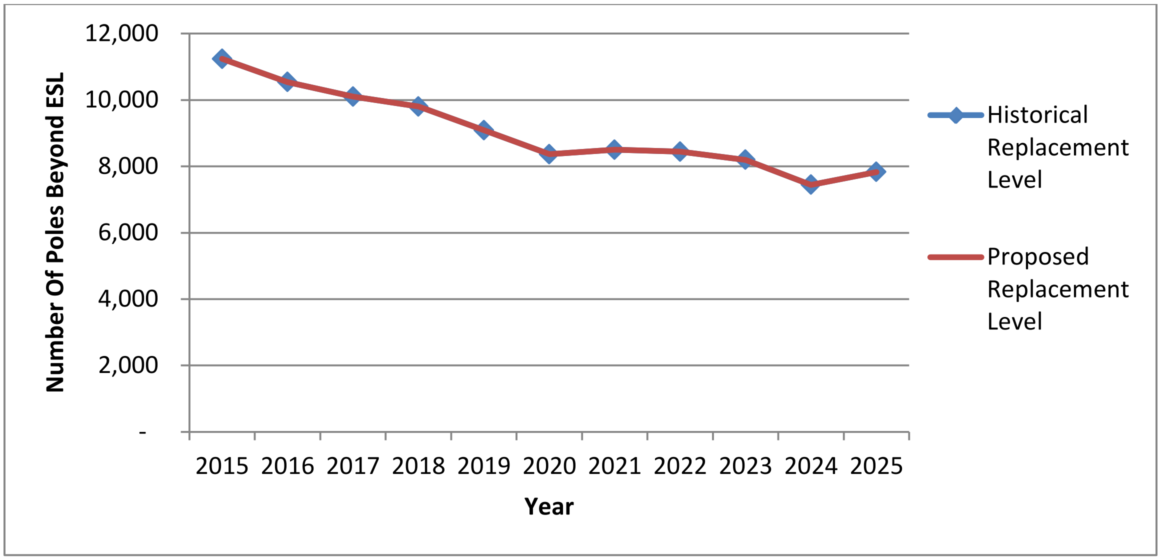


Figure 27: Projection of Wood Poles Beyond Expected Service Life

<u>Performance</u>

The majority of transmission wood pole structures are located in Northern Ontario and many of these structures support radial circuits. As a result, a wood pole or cross-arm can often result in a direct customer outage. Many of these northern wood pole circuits feed major industrial customers and without an adequate supply of power, these customers are often forced to shut down until power is restored.

The number of forced outages due to wood pole structure failures has improved over the past 10 years, as outlined in Figure 28, based on the current rate of replacement to address end of life wood poles and the reduction of the higher risk defective Gulfport structures on the system.

Witness: Chong Kiat Ng

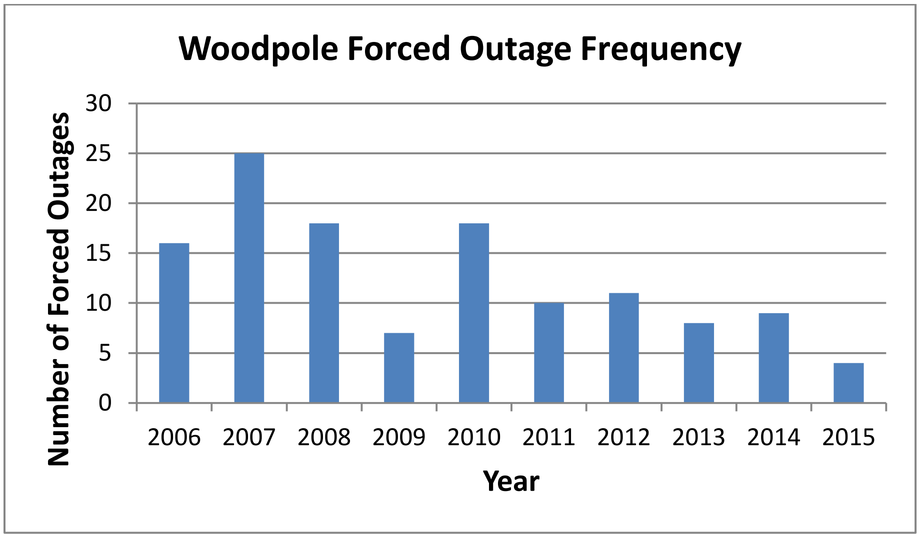


Figure 28: Forced Outages Due to Wood Pole Failures

The forced outage duration due to wood pole failures, displayed in Figure 29, demonstrates improvement over the past 10 years, except for the extreme spike in 2010. This type of year is not unexpected given many of these circuits are radial supplies and in remote locations, with difficult access.

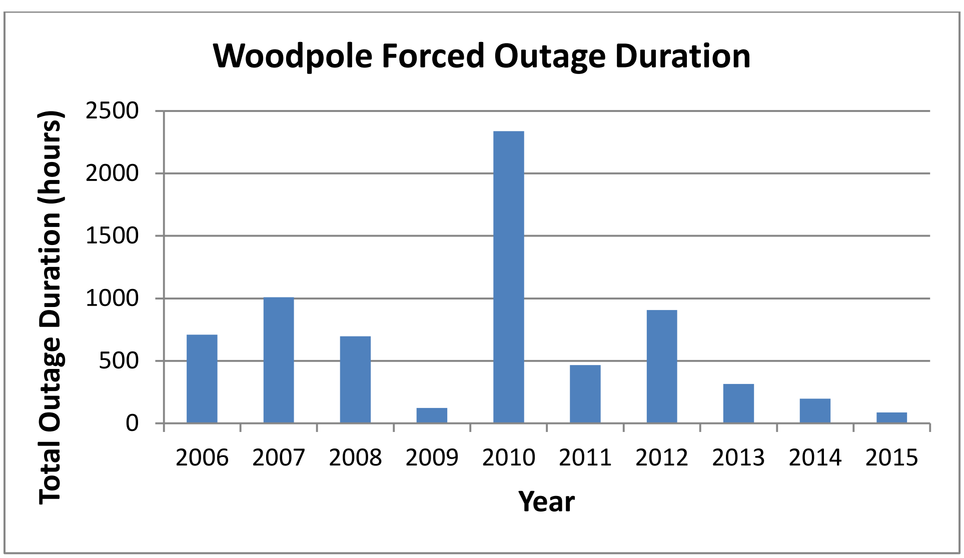


Figure 29: Forced Outage Duration due to Wood Pole Failures

Witness: Chong Kiat Ng

At the current rate of replacement, the frequency and duration of outages is expected to remain consistent with recent years.

Condition

Wood structures deteriorate over time; the rate of deterioration depends on location, weather, type of wood, treatment, insects and wildlife. As a result, uniform deterioration does not occur and the condition of wood structures varies, even in the same location. Wood pole structures are comprised of either a single pole or multiple wood poles with a wood cross-arm which is bolted to the poles to support the insulator strings and conductors. Due to the nature of the design, the wood cross-arm tends to be the weak link and is typically the primary cause of failure.

Wood pole assessments are undertaken to inspect the condition of cross-arms and pole tops, and to evaluate the soundness of the wood near the ground line, which is consistent with industry practices. Based on the current condition assessment, 3% of Hydro One's wood pole population is high risk, as outlined in Figure 30. The assessment is regularly updated as new conditions are reported or factors are considered. Approximately 6% of the wood pole population needs to be assessed to determine their condition risk, 20% is fair risk, and 71% is low risk.

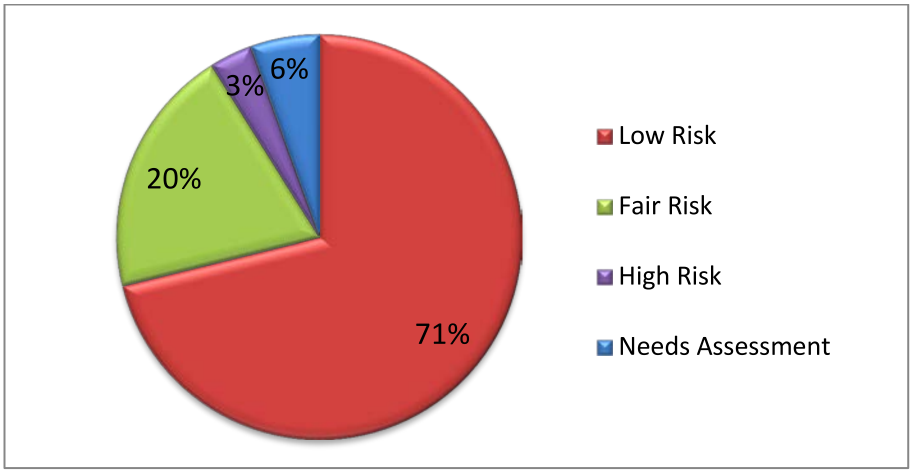


Figure 30: Wood Pole Fleet Condition Assessment

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

Table 10: Wood Pole Replacement Rate

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

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

Witness: Chong Kiat Ng

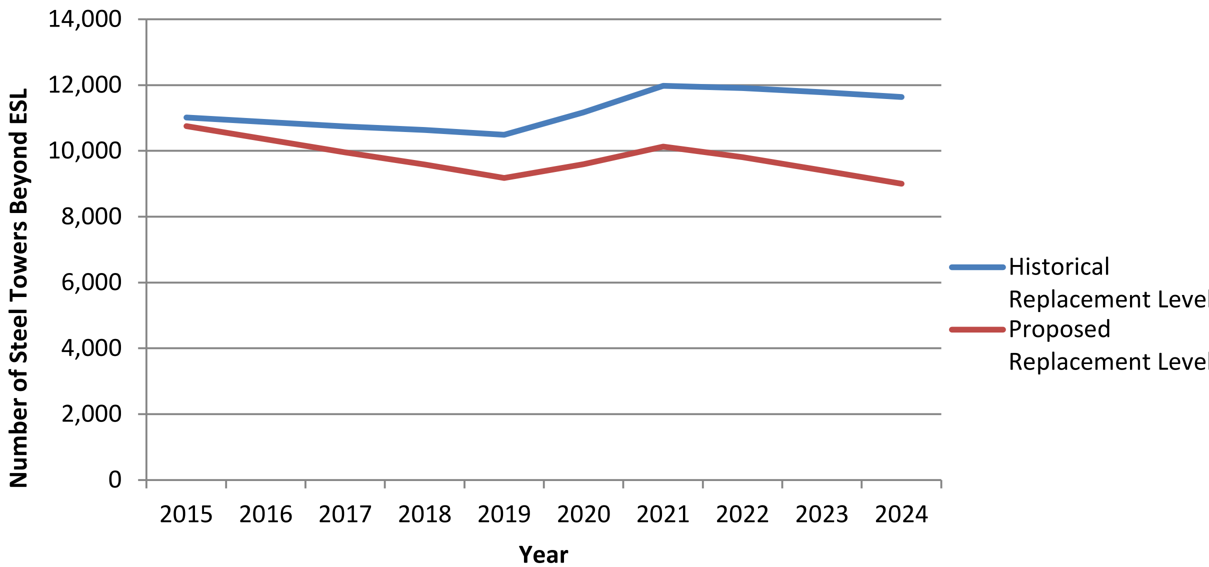


Figure 37: Projection of Steel Structures Beyond Expected Service Life

<u>Performance</u>

Forced outages for steel structures represents the number of times an outage is caused due to a steel structure failure such as failed, broken or bent tower member. It excludes forced outages caused by external interferences (animal contact, weather, etc.). Although single circuit tower outages typically do not result in delivery point interruptions, a multiple circuit tower failure can result in customer outages.

The number of forced outages due to steel structure failures has shown slight increase over the past 10 years, as outlined in Figure 38. With the current condition of the steel structures and the demographics of the fleet, it is expected that an increase in the capital programs will be required to prevent future increases in forced outages due to steel structures.

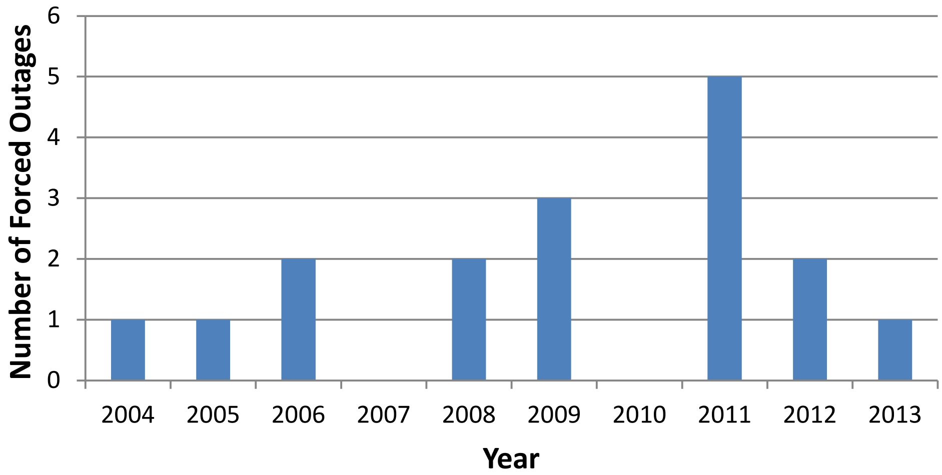


Figure 38: Forced Outages due to Steel Structure Failures

The forced outage duration due to steel structure failures, displayed in Figure 39, demonstrates a stable outage duration trend over the last 10 years, except for the extreme spikes in 2004 and 2005. These type of spikes are not unexpected given the very remote locations of some of the circuits, with difficult access. This can place considerable strain on the system as it may result in loss of supply to large customers including local distribution companies and generation connections.

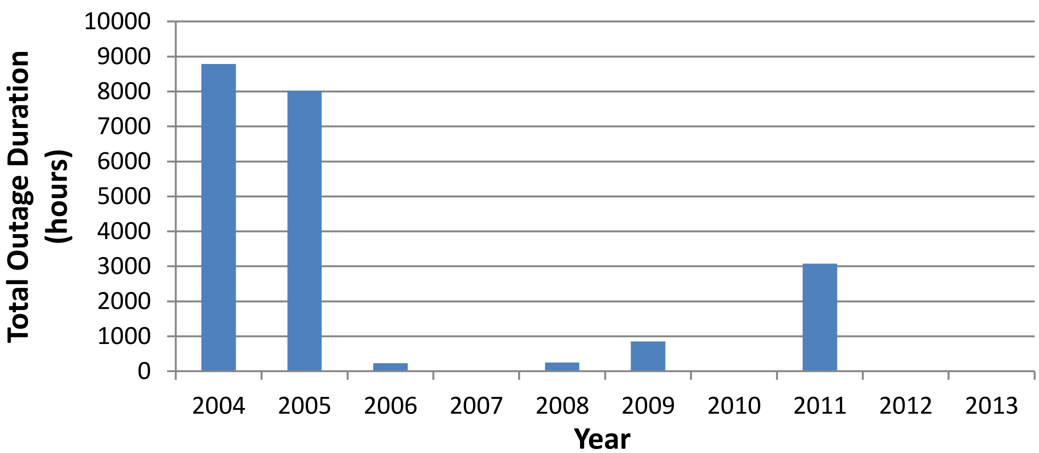


Figure 39: Forced Outage Duration due to Steel Structure Failures

<u>Condition</u>

The condition of the steel structures is determined through inspections, patrols and detailed corrosion assessment. Towers are visually inspected in accordance with NACE ("Nation Association of Corrosion Engineers") guidelines on the degree of corrosion. Detailed corrosion assessment includes climbing towers and measuring the remaining thickness of protective coating, loss of metal if any and assessment of bolts and fittings.

Based on the current assessment of condition, 3% of Hydro One Transmission steel structures have condition in the fair or high risk category, as outlined in Figure 40, and meet the current refurbishment/coating criteria. This assessment is continuously reviewed and adjusted as new conditions are reported or factors are considered. An additional 14% of steel structures need to be assessed in order to determine their condition.

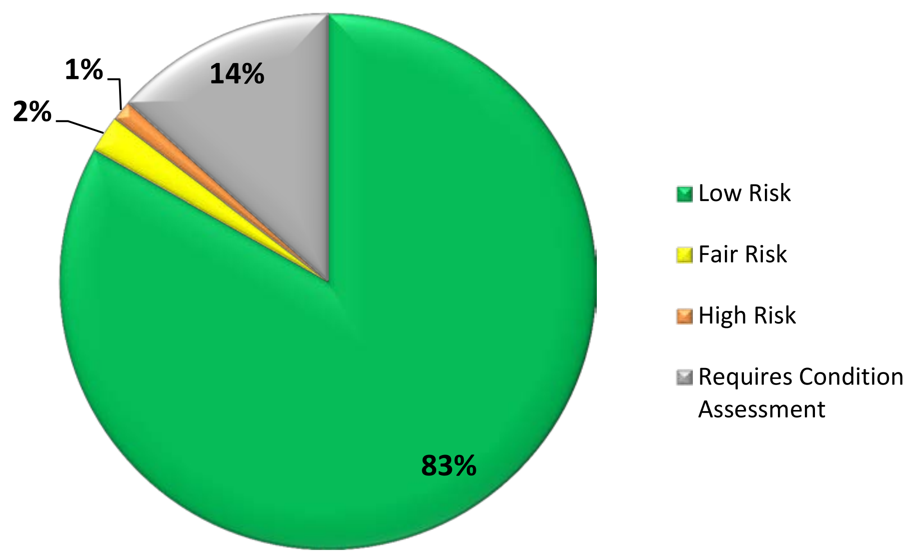


Figure 40: Steel Structure Fleet Condition Assessment

In order to maintain the condition of the fleet, the rate of refurbishment/coating will need to be increased. Towers in fair and high condition will require coating within the next 5 years. Should they exceed this optimum time to coat, the structures will eventually require either partial or full replacement.

Other Influencing Factors

- Innovation - Hydro One Transmission is continuing to investigate using alternative recoating products in order to reduce the amount of steel surface preparation and increase the drying process. This should reduce outage time and therefore permit a higher number of towers to be coated within the limited outage windows. Hydro One Transmission also continues to explore new steel tower coatings that are longer lasting than those that are currently commercially available.

Cost Trends and Impacts

Steel Structure Portfolio	Historic			Bridge	Test	
	2011	2012	2013	2014	2015	2016
# of Refurbishments	0	226	218	350	350	400
# of Replacements	0	0	17	4	4	12
% of Fleet	0%	0.5%	0.5%	0.7%	0.7%	0.8%
Capital ($M)	0.6	8.7	13.3	11.1	10.7	16.0
OM&A ($M)	4.7	4.8	3.1	4.4	4.1	4.2

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

OM&A expenditures are relatively stable with assessment activities performed frequently to assess zinc coating thickness and member condition.

4.2.4 Transmission Underground Cables

Asset Overview

Hydro One's transmission system consists of approximately 290 km of underground cables that supply city centres in Toronto, Ottawa and Hamilton with short sections in London, Sarnia, Picton, Windsor and Thunder Bay. Transmission underground cables are typically extensions to, or links between, portions of the overhead transmission system operating at 230 kV and 115 kV. Underground cables are mainly used in urban areas where it is either impossible, or extremely difficult to build overhead transmission lines due to legal, environmental and safety reasons.

Depending on the cable design the three phase conductors may be contained together within a steel pipe or each phase conductor self-contained in its own sheath and installed separately underground. Transmission underground cables are systems, similar to transmission lines, made up of numerous components all of which need to integrate and function properly in order to deliver power with the reliability that is demanded.

There are three different types of high voltage underground cables in use on the transmission system: Low-Pressure Oil-Filled ("LPOF") cables, High-Pressure Oil-Filled Pipe-Type ("HPOF") cables, and Extruded Cross Linked Polyethylene ("XLPE") cables.

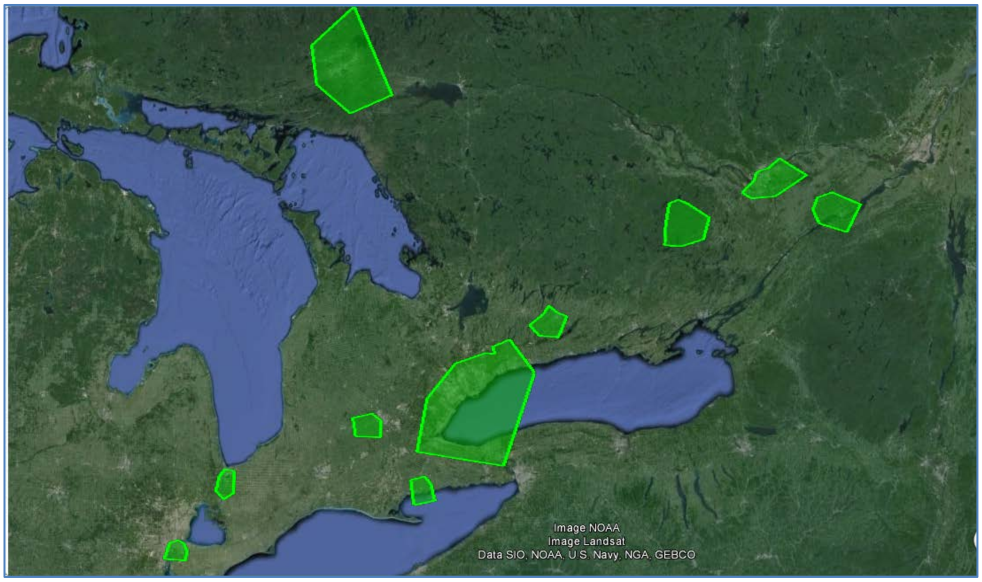


Figure 32: C4 & C5 corrosion regions in Ontario (courtesy of EPRI).

An effective tower coating program can maintain a steel tower structure at its design capacity indefinitely by re-application of the coating approximately every 35 to 65 years.

If towers are not re-coated prior to corrosion and metal loss, the opportunity is lost and the tower will ultimately have to be replaced.

3.3.3 Asset Assessment Details

<u>Demographics</u>

Hydro One has approximately 52,000 steel structures; the demographic of the steel structure population is outlined in Figure 33. There are approximately 13,000 steel structures are located in heavy corrosion zones such as Windsor, Sarnia, Hamilton and GTA. 7,500 of them currently meet tower coating criteria and approximately an additional 4,700 steel structures will meet this tower coating criteria over the next 10 years if the historical coating rate is maintained. The demographic of the steel structures in heavy corrosion zones are outlined in Figure 34.

Witness: Chong Kiat Ng

Hydro One uses an average expected service life ("ESL") of 80 years for steel structures if the structures are not re-coated. Currently 2,100 structures in high corrosion zones are beyond ESL and exceed the coating criteria. These structures will need detailed engineering assessment and potentially require heavy refurbishment or even complete replacement.

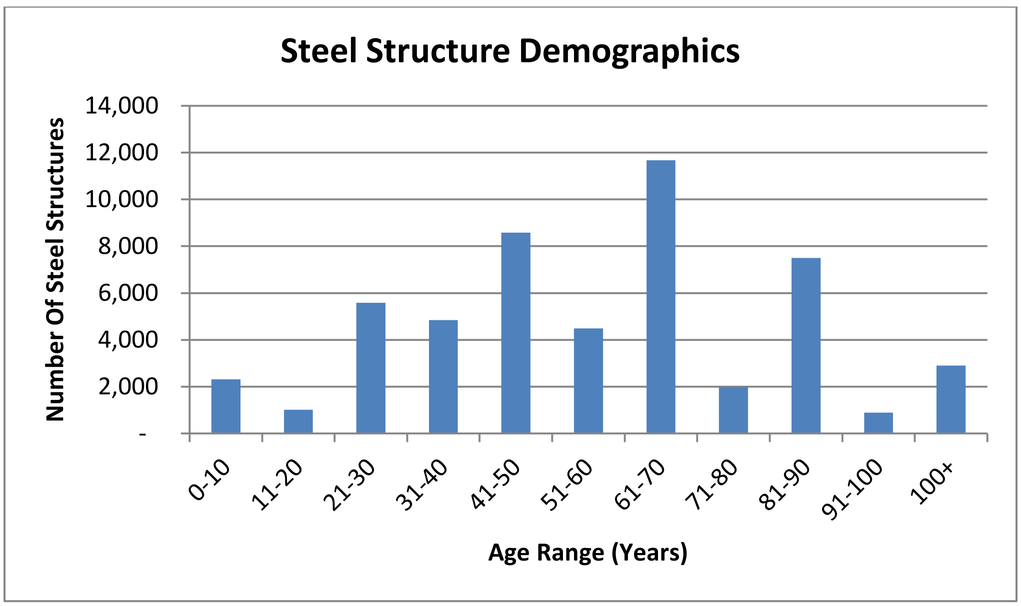


Figure 33: Demographics of Steel Structure Fleet province wide

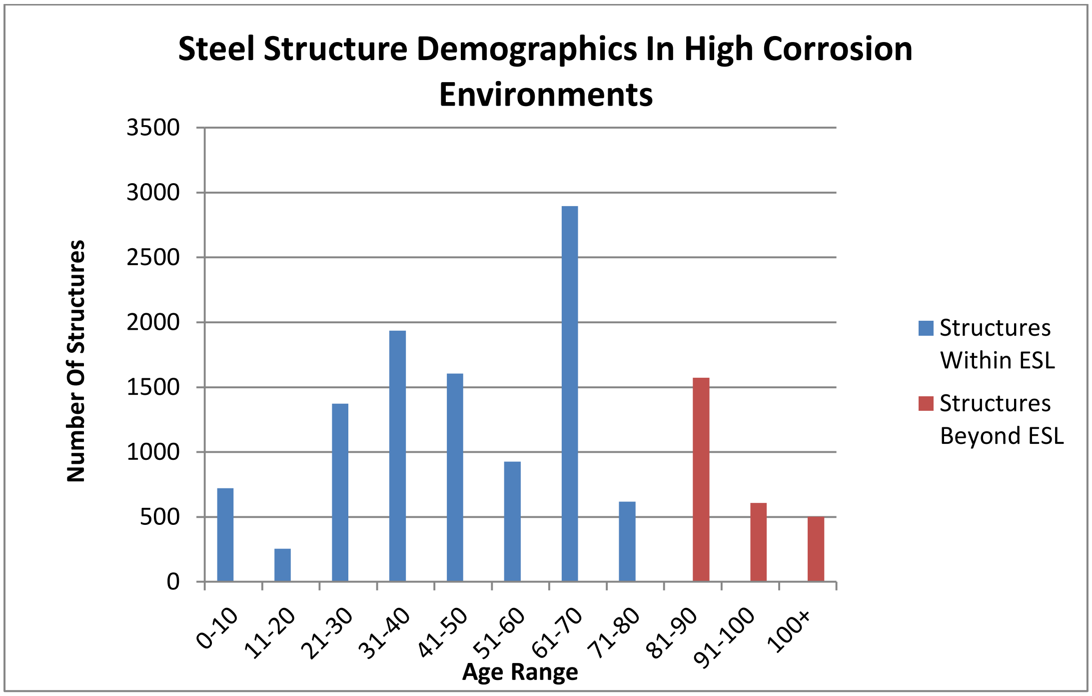


Figure 34: Demographics of Steel Structure Fleet in Heavy Corrosion Zones

Based on the historical data, the average rate for structure renewal is about 200 towers per year. As outlined in Figure 35, at historic tower coating rates, the steel structures requiring coating in high corrosion zones will increase by 34% in 10 years. However, with planned coating plan, all structures requiring coating will be coated in the next 10 years.

Witness: Chong Kiat Ng

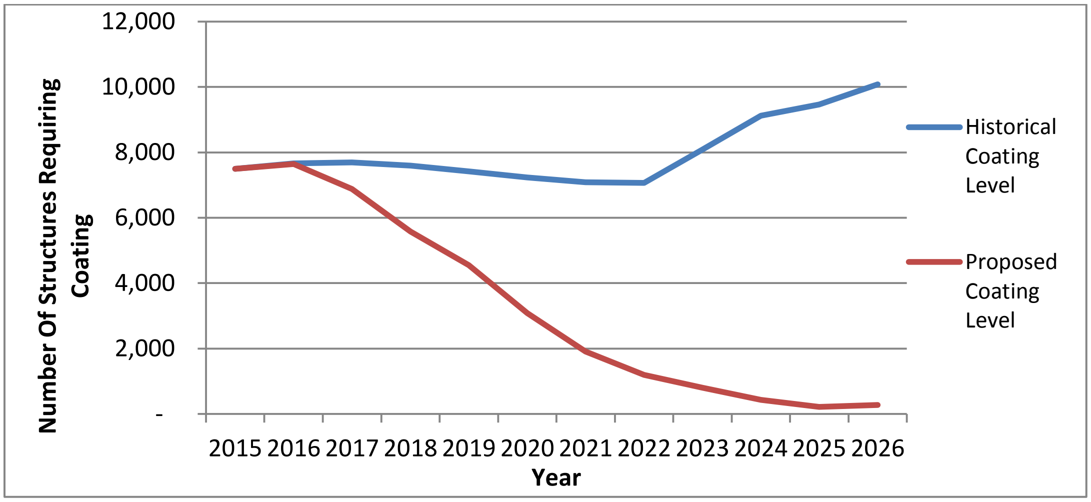


Figure 35: Projection of Steel Structures requiring Coating

Performance

Forced outages for steel structures represent the number of times an outage is caused by steel structure failure such as complete tower collapse, or a broken (or bent) tower member. It excludes forced outages caused by external interferences such as animal contact and weather related incidents.

The number of forced outages due to steel structure failures has shown slight decrease over the past 10 years as outlined in Figure 36. With the current condition of the steel structures and the demographics of the fleet, it is expected that increased capital programs will be required to prevent future increases in forced outages due to steel structure failures.

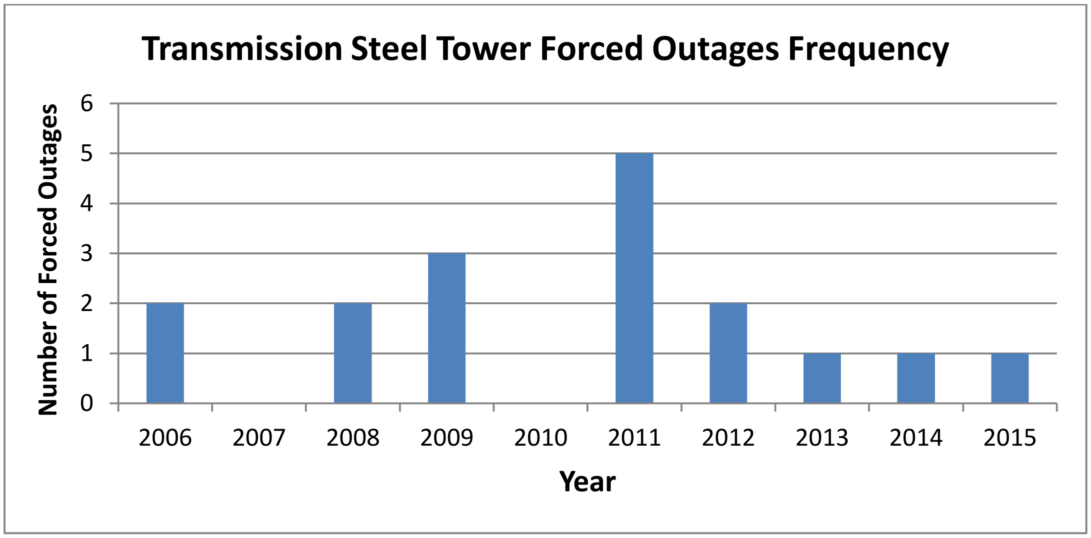


Figure 36: Forced Outages due to Steel Structure Failures

The forced outage duration due to steel structure failures, displayed in Figure 37, demonstrates a stable outage duration trend over the last 10 years, except for the spike in 2011. This type of spike is not unexpected given the very remote locations of some of the circuits with difficult access. This can place considerable strain on the system as it may result in loss of supply to large customers including local distribution companies and generation connections.

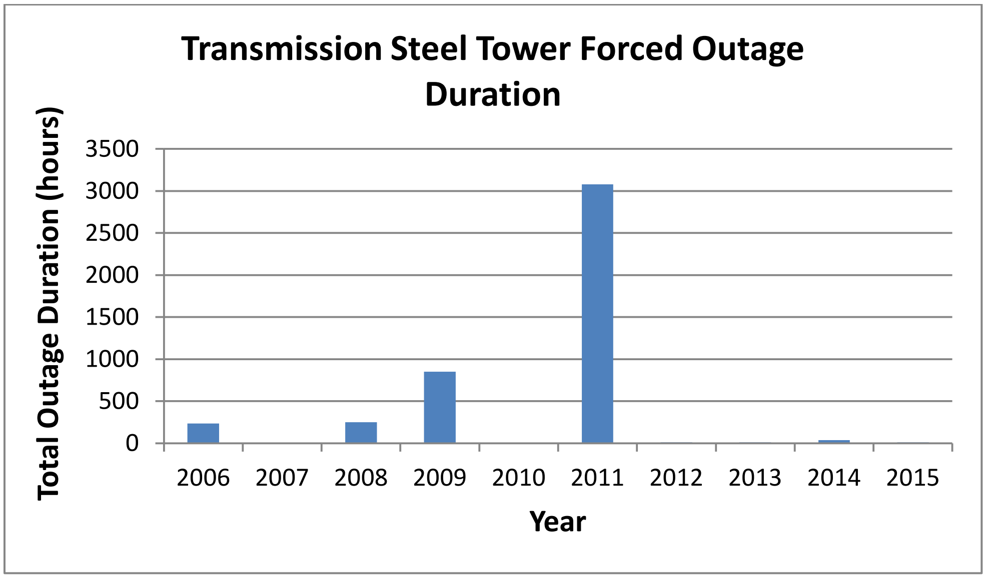


Figure 37: Forced Outage Duration due to Steel Structure Failures

<u>Condition</u>

Transmission steel structure condition assessment is initiated based on demographics, geographic zone and result of study conducted by industry experts over the past several years. The initial assessment results will be verified by the established Hydro One maintenance program which includes inspections, patrols and detail corrosion assessment. Towers are visually inspected in accordance with NACE ("Nation Association of Corrosion Engineers") guidelines on the degree of corrosion. Detailed corrosion assessment includes climbing towers and measuring the remaining thickness of protective coating, loss of metal if any and assessment of bolts and fittings.

Based on the current assessment, 4% of Hydro One's steel structures require major refurbishment or replacement as outlined in Figure 38. 14% of the steel structures require coating and will be addressed in the steel structure coating program. This assessment is continuously reviewed and updated as more structures meet the coating criteria every year.

Witness: Chong Kiat Ng

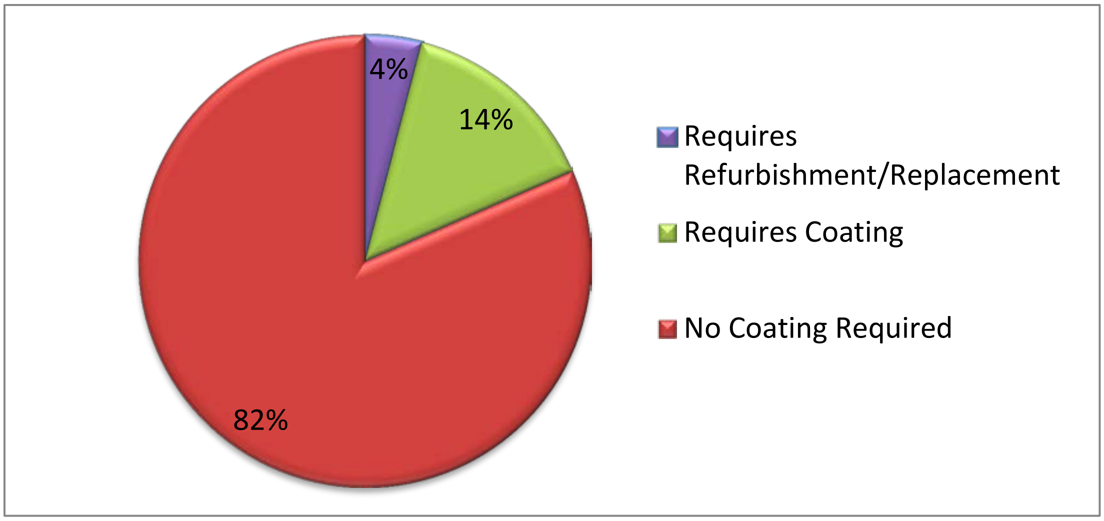


Figure 38: Steel Structure Fleet Condition Assessment

In order to maintain the condition of the fleet, the rate of refurbishment/coating will need to be increased as per Hydro One's investment plan.

<u>Other Influencing Factors</u>

- Innovation - Hydro One is continuing to investigate the use of alternative coating products in order to reduce the cycle time involved in the re-coating process by potentially reducing the amount of steel surface preparation and decreasing the drying time which is coating product dependent. This will reduce outage time, when required, and permit a higher number of towers to be coated each year.
- Work Method – A revised work method has been established that allows for tower coating in live line conditions. This live line work method will minimize the outage constraints and maximize the quantity of towers to be coated.

Witness: Chong Kiat Ng

Table 11: Steel Structure Replacement

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

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

3.4 Transmission Lines Insulators

3.4.1 Asset Overview

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

Asset Assessment Details

Demographics

Hydro One Transmission uses a normal expected service life ("ESL") of 50 years for underground transmission cables, which is based primarily on the original design expectations. However, due to the very rigorous maintenance program employed by Hydro One Transmission a number of cables beyond this age are still in satisfactory operating condition. The average age of the underground cable fleet is currently about 37 years and about 16% of cables are beyond their expected service life. The demographics of the underground cable population is outlined in Figure 42.

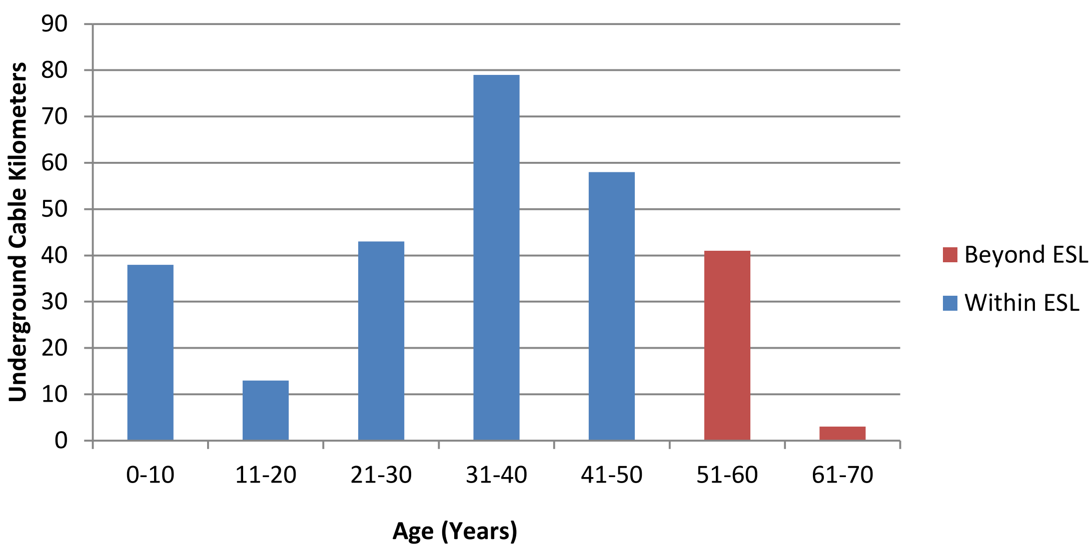


Figure 42: Demographics of Underground Cables Fleet

The potential risks to reliability and safety as a result of the aging demographics and deteriorating cable condition needs to be managed through a continued rigorous maintenance program to detect developing defects, as well as through capital replacement programs. As can be seen in Figure 43, continuing at the historic rate of replacement would result in the percentage of underground cables beyond their expected service life increasing to 30% by

2024. However at the proposed replacement rate, the percentage of underground cables beyond their expected service life will increase from 16% to 20% by 2024.

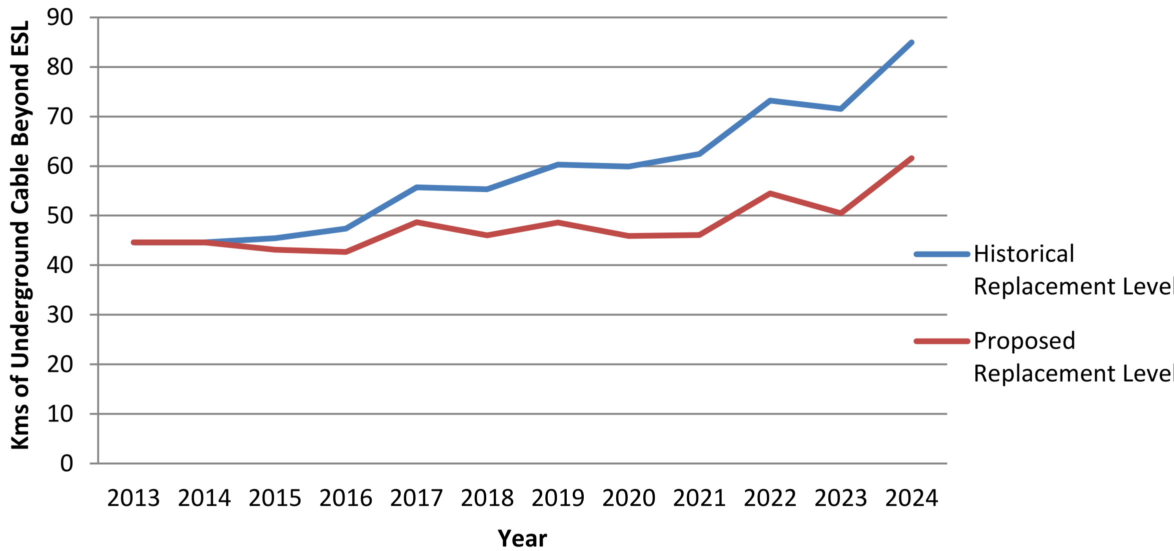


Figure 43: Projection of Underground Cables Beyond Expected Service Life

Performance

The underground transmission cables were first designed and installed with built-in redundancy and capacity so that failures would not immediately result in outages to customers. Many of these cables are still in service and are starting to experience the effects of aging and the increased loading due to the expansion in the downtown areas. There has been minimal impact in customer reliability due to underground cable failures over the last 10 years; however as the asset ages there is increased risk of failure with the underground system.

The number of forced outages due to a failure on part of the underground cable system has shown a slight improvement over the past 10 years, as outlined in Figure 44. There have been a number of major component replacement projects during the past 10 years including joint, termination, oil pressure system and bonding upgrades which have contributed to this reduction in the forced outages.

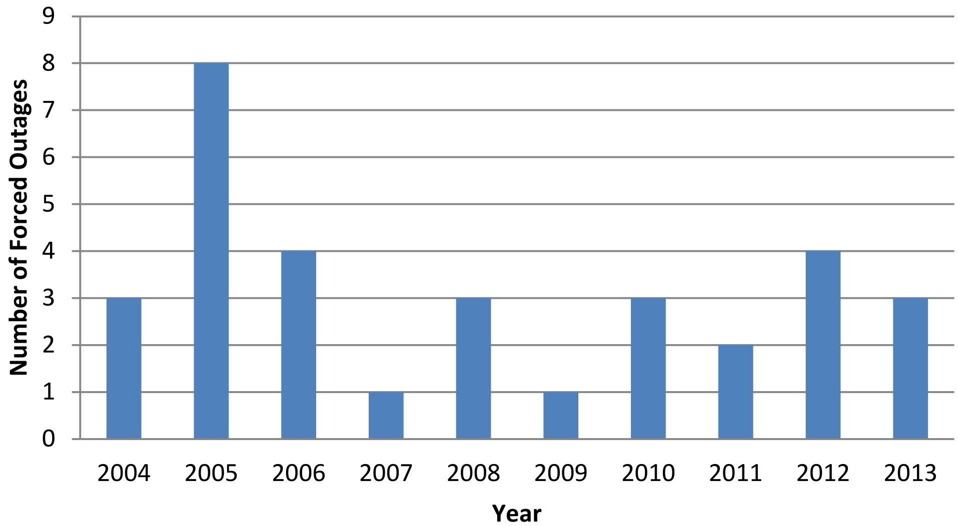


Figure 44: Forced Outages due to Underground Cable Failures

The forced outage duration of each occurrence was increasing significantly during the period from 2008 to 2011 but has been minimal during the last two years, as depicted in Figure 45. This recent decrease is mainly contributable to the replacement of two high risk end of life cable circuits H2JK and K6J. However, the increase in outage duration is representative of problems becoming more serious.

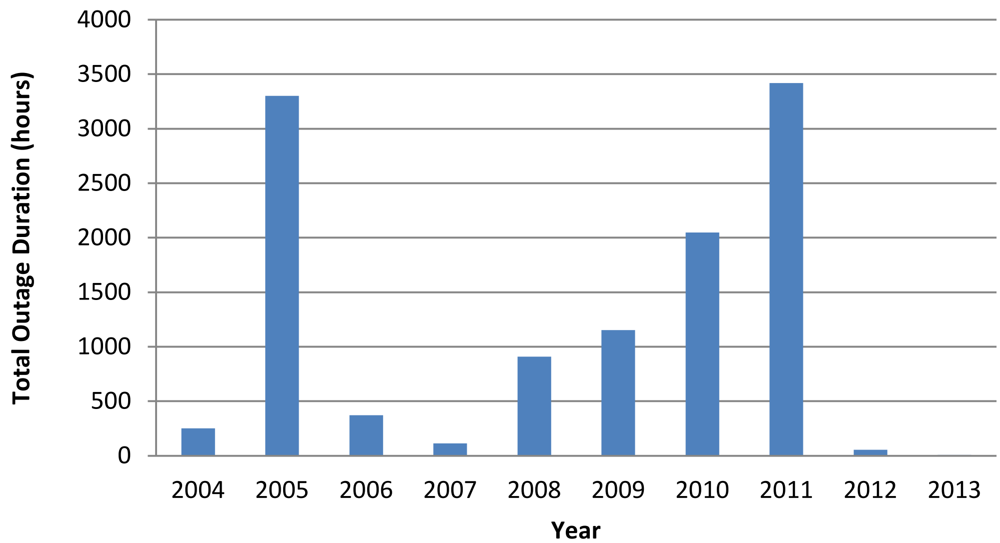


Figure 45: Duration of Forced Outages due to Underground Cable Failures

The forced outages depicted in Figure 44 and 45 are failures that were significant enough to require the circuit to be forced out of service. There are many other cases where equipment defects and cable leaks have occurred but were not severe enough to force the circuit from service but instead were addressed under a planned outage. Considering the deteriorating condition and demographics of the fleet, the continuation of a rate of replacement consistent with the bridge year is required to maintain the current forced outage frequency.

Condition

Hydro One Transmission assesses its underground cable fleet condition based on a variety of factors. This assessment is continuously reviewed and adjusted as new conditions are reported or factors are considered. Not all sections of a buried cable are accessible for maintenance inspections and diagnostics, but the inspections are generally representative of the entire cable system.

Based on the current assessment of the underground cable fleet condition, 14% of Hydro One Transmission's underground cable population has condition that puts it in the fair or high risk, as outlined in Figure 46.

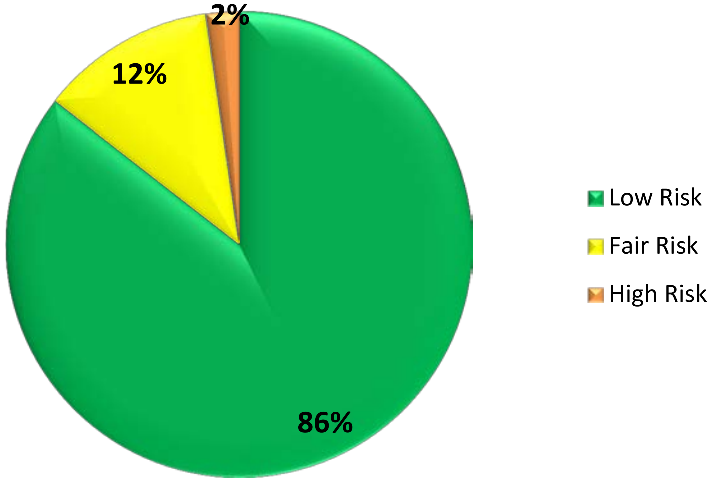


Figure 46: Underground Cable Fleet Condition Assessment

Underground cables located in major cities where loading has increased significantly since the original installation, impact the aging process and condition trend of these cables, as well as the likelihood of cable failures. In order to maintain the condition of the fleet, given the demographics and utilization, continued renewal of the fleet is required.

<u>Other Influencing Factors</u>

Other factors driving the increase in underground cable replacements are summarized below.

- Technical Obsolescence – There are some types of underground cables technology that are no longer available and supported by manufacturers. This is a significant factor for low pressure oil filled cables that rely on gravity feed oil reservoirs that are no longer available.

- Environmental Impacts – The failure of an underground cable can result in the leakage of oil into the surrounding area. In 2003, a downtown Toronto cable circuit

3.5.2 Asset Strategy

Hydro One has employed and will continue with its rigorous maintenance program (involving inspections, analysis, and diagnostic testing of cables, vaults, jackets and potheads) that extends the life of these assets. Hydro One plans to continue forward with an average replacement rate consistent with the bridge year in order to manage the reliability and environmental risks associated with operating an aged underground cable population.

3.5.3 Asset Assessment Details

<u>Demographics</u>

Hydro One uses a normal expected service life ("ESL") of 50 years for underground transmission cables, which is based primarily on the original design expectations. However, due to the best practice maintenance program and low historical electrical loadings these cables have been subjected to, a number of cables beyond this age are still in satisfactory operating condition. The average age of the underground cable fleet is currently about 37 years and about 19% of cables are beyond their expected service life.

The demographics of the underground cable population are outlined in Figure 44.

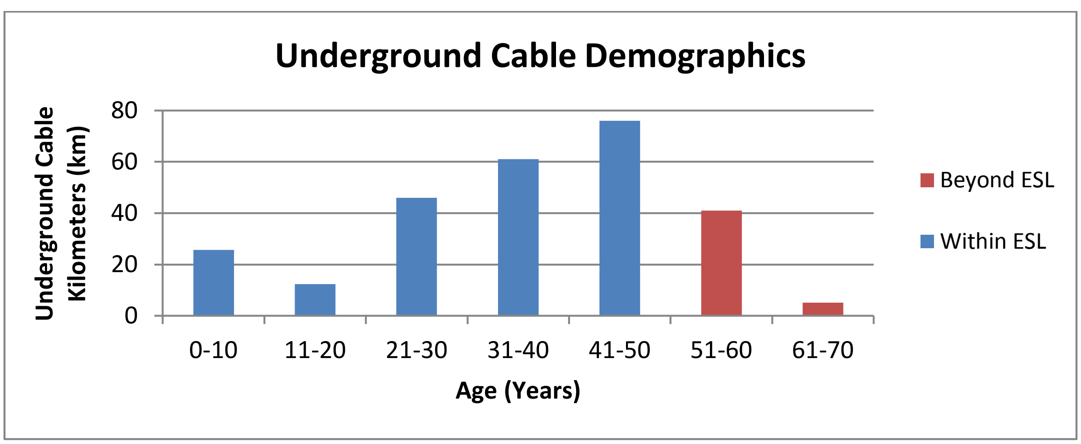


Figure 44: Demographics of Underground Cables Fleet

Witness: Chong Kiat Ng

The potential risks to reliability and safety as a result of the aging demographics and deteriorating cable condition needs to be managed through a continued rigorous maintenance program to detect developing defects, as well as through capital replacement programs. As can be seen in Figure 45, continuing at the historic rate of replacement would result in the percentage of underground cables beyond their expected service life increasing to 40% by 2025. At the proposed replacement rate, the percentage of underground cables beyond their expected service life still will increase from 19% to 35% by 2024.

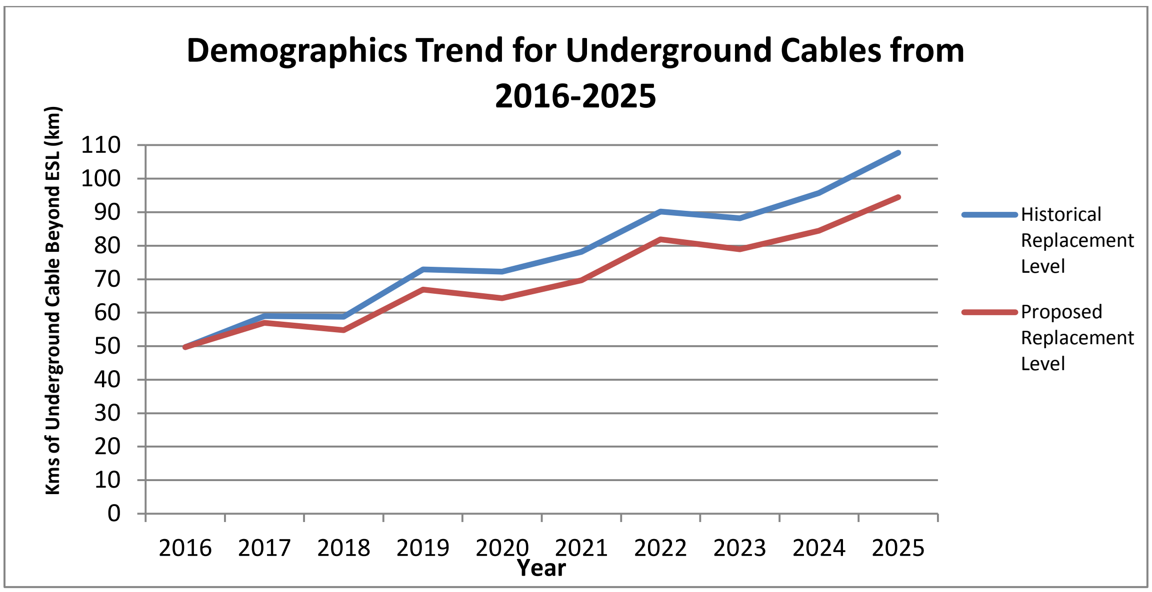


Figure 45: Projection of Underground Cables Beyond Expected Service Life

<u>Performance</u>

The number of forced outages due to a failure on part of the underground cable system has shown a slight improvement over the past 10 years, as outlined in Figure 46. There have been a number of major component replacement projects during the past 10 years including joint, termination, oil pressure system and bonding upgrades which have contributed to this reduction in the forced outages.

Witness: Chong Kiat Ng

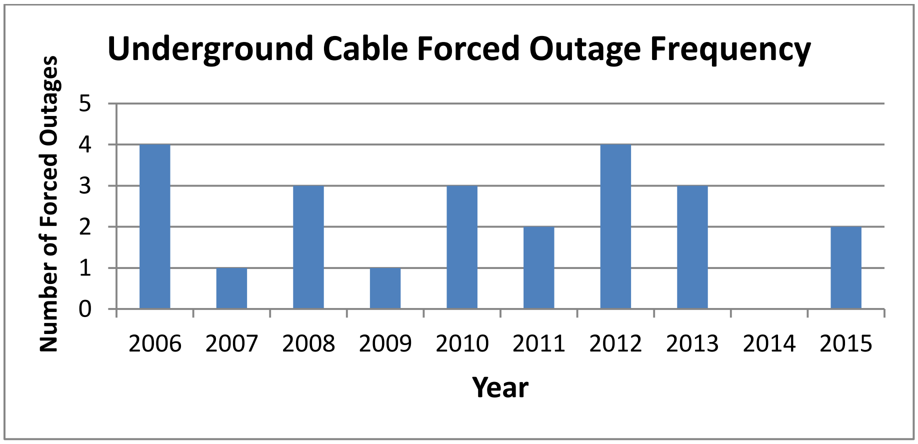


Figure 46: Forced Outages due to Underground Cable Failures

The forced outage duration of each occurrence was increasing significantly during the period from 2008 to 2011 but has been minimal during the last four years, as depicted in Figure 47. This recent decrease is mainly attributable to the replacement of two high risk end of life cable circuits H2JK and K6J.

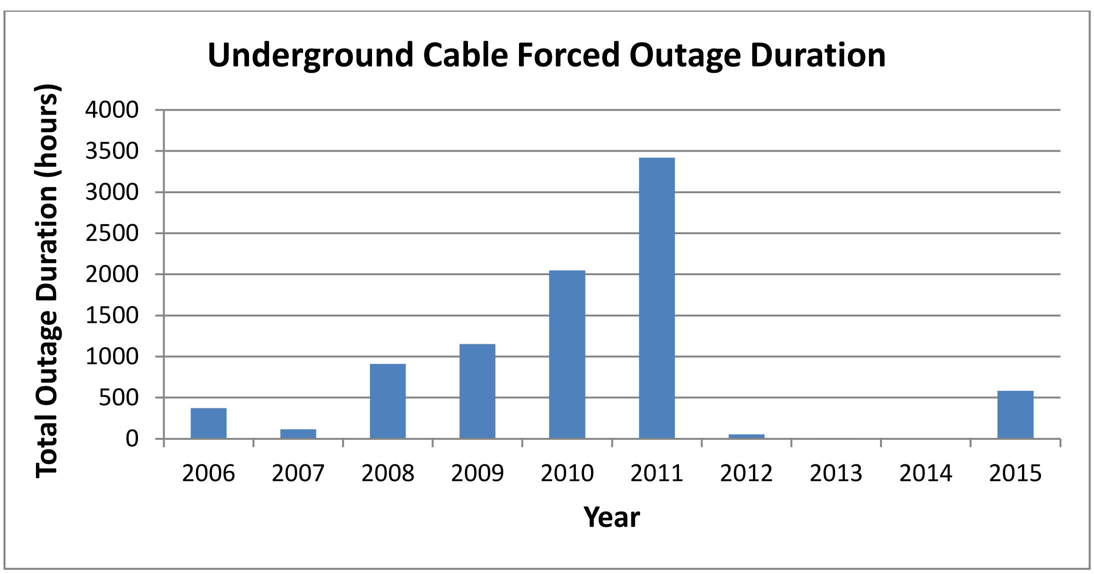


Figure 47: Duration of Forced Outages due to Underground Cable Failures

The forced outage statistics depicted in Figure 47 and 48 are for failures that were significant enough to require the circuit to be forced out of service. There are many other cases where equipment defects and cable leaks have occurred but were not severe enough to force the circuit from service, but instead were addressed under a planned outage.

Condition

Hydro One assesses its underground cable fleet condition based on a variety of factors. This assessment is continuously reviewed and adjusted as new conditions are reported or factors are considered. Not all sections of a buried cable are accessible for maintenance inspections and diagnostics, but the inspections are generally representative of the entire cable system.

Based on the current assessment of the underground cable fleet condition, 4% of Hydro One's underground cable population is high risk, 22% fair risk, 73% low risk, and 1% need assessments.

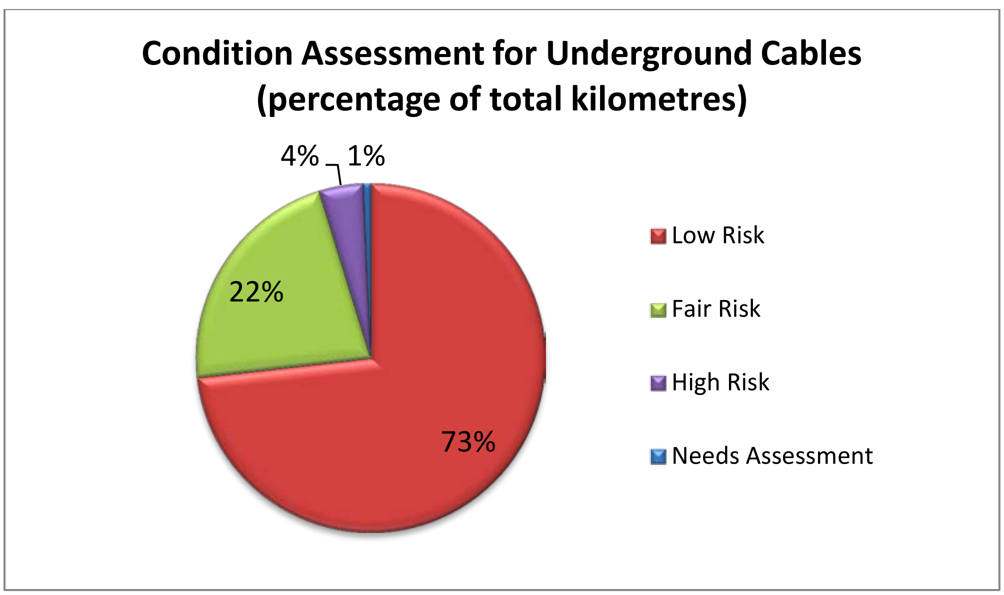


Figure 48: Underground Cable Fleet Condition Assessment

Other Influencing Factors

Other factors driving the increase in underground cable replacements are summarized below:

- Technical Obsolescence – There are some types of underground cables technology that are no longer available and supported by manufacturers. This is a significant factor for low pressure oil filled cables that rely on gravity feed oil reservoirs that are no longer available.
- Environmental Impacts – The failure of an underground cable can result in the leakage of oil into the surrounding area. In 2003, a downtown Toronto cable circuit (H3L) failed which resulted in 5,500 litres of oil spilling into the Don River. The failure was located and repaired, which took over a month to complete. When the circuit was returned to service, it failed again after only 2 months at another location, indicating the need to replace.
- Equipment Loading – Cables are located in major cities where loading has increased significantly since original installation impacting the aging process as well as the number of cable failures.
- Criticality – Underground cables are used to supply the load of major cities, thus a failure of the cable can result in significant impact to customers. In 2010, a downtown Toronto cable circuit (H2JK) failed, since the other supply circuit (K6J) was on a planned outage at the time, the failure of the cable caused all of the five delivery points at Strachan TS to go out of service. The longer term major risk was if the condition of these two circuits deteriorated to a level that was impractical to repair, then both circuits would have to be removed from service resulting in considerable strain and risk to the system for a prolonged period of time.

Table 13: Underground Cable Replacement

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

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

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

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

Witness: Chong Kiat Ng

Other Transformer Programs

- Replacement of station service transformers that have reached end of life. Station service transformers step down primary voltages, i.e., 230 kV, 115 kV, 44 kV, 27.6 kV or 13.8 kV to secondary voltages of 600V or 120V AC to supply station auxiliary equipment such as battery chargers, transformer cooling and tap changers, and station heaters.
- Installation of online monitoring and diagnostic equipment to provide real-time condition data that impacts both the day-to-day operation of the transformers and the longer term sustaining capital replacements.

3.3.3 Summary of Expenditures

The planned expenditure for 2015 and 2016 is $30.6 million and $75.3 million respectively. The 2015 expenditures are significantly less than previous years, whereas the 2016 expenditures are generally in line with historic spending in this program. This reduction in 2015 corresponds to an increase in 2015 spending in the Integrated DESN Investment category within the Station Re-investment program. Similar to the circuit breaker replacement program, the transformers identified in need of replacement that would have otherwise been completed within the power transformer replacement program are being completed as part of integrated station-level refurbishments. As demonstrated in Exhibit D1, Tab 2, Schedule 1, the total number of transformer replacements across the combination of all program categories is remaining generally consistent in the test years relative to bridge year.

A reduction in this program will delay the replacement of aged and degraded equipment as well as will result in maintaining a less than optimal spare inventory, resulting in increased risk exposure to reliability at both system stations and customer load delivery stations.

Planned capital investments in primary cable components and sub-systems vary from year to year depending on system needs. Table 20 outlines the planned projects for the test years. Additional details for these projects are provided in the Investment Summary Documents S56 and S57 in Exhibit D2, Tab 2, Schedule 3.

Table 20
Underground Cable Projects
($ Millions)

Ref #	Description	Test Years		Total Cost
		2015	2016	
S56	H2JK / K6J Cable Replacement	12.1	0.0	62.0
S57	H7L / H11L Cable Replacement	14.3	14.5	28.8
	Other Underground Cable Projects < $3M	1.8	0.6	
	Total	**28.1**	**15.1**	

Other underground cable projects include:

- Emergency repairs to the HVUG cable systems.
- Replacement of ring gaps associated with the cable bonding and grounding on the terminal ends of underground cables circuits. Studies have shown that due to rising fault currents at some stations the current devices are no longer adequate during system fault situations and could fail explosively.
- Replacement of sump pumps that control water levels in cable tunnels that accommodate underground cable circuits.
- Upgrades to the cathodic protection isolation devices on the underground pipe type cables which are critical to mitigate the risk of corrosion to the steel carrier pipes that contain the insulated conductors.

4.3.3 Summary of Expenditures

The planned expenditure for 2015 and 2016 is $28.1 million and $15.1 million respectively. The average spending in the test years is in line with the bridge year 2014, though year over year costs vary depending on the number and size of the underground cable replacement projects. However the test year expenditures represent a significant increase over the historic spending. This increase over historic years is required to replace a number of underground cable circuits that are in poor condition and are impacting the environment due to leakage of oil.

A reduction in this program will jeopardize the electrical supply reliability to the downtown areas of major centres in Ontario, as well as increase environmental risks associated with an increase in oil leaks from these aging cables.

INTERNAL AUDIT REPORT

INVESTMENT PLANNING

To:

Mike Penstone
Vice President, Planning

Distribution:

Carm Marcello	President and Chief Executive Officer
Sandy Struthers	Chief Operating Officer & EVP Strategic Planning
Ali Suleman	Acting Chief Financial Officer
Paul Brown	Director, Distribution Asset Management
Randy Church	Director, Network Connections & Development
Kathleen McCorriston	Manager, Investment Planning and Prioritization
Scott McLachlan	Director, Transmission Asset Management
Bing Young	Director, System Planning
Brad Bowness	Director, Project Management, E&CS
Mike Boland	Director, Station Services, Stations & Operating

Final Report Issued: January, 30, 2015 Auditor: Atul A. Solanki
Draft Report Issued: December 31, 2014
Report Number: 2014-29

EXECUTIVE SUMMARY

Hydro One has adopted an Asset Management model since its inception to separate accountability for asset and system investment decision making from the execution of work. The Planning Organization is accountable to produce an annual Investment Plan Proposal (IPP) detailing investments (and resulting work) required to develop and sustain asset and system capabilities over the next five years. The IPP is a major input to the Hydro One's Corporate Business Plan that is approved annually by its Board of Directors. The IPP also forms a basis for the Transmission and Distribution rate filing with the Ontario Energy Board. The IPP is put together based on the results of customer, asset and system need evaluation using criticality, performance, and condition as key factors. The plan goes through a risk-based optimization to ensure the maximization of corporate business values[1] (such as safety, reliability, customer satisfaction, shareholder value, etc.). The plan is further adjusted by Management to ensure that it is executable, meets financial objectives, and reduces plan risks to an acceptable level.

We are pleased to observe that the Planning organization is able to deliver an annual IPP on schedule. The introduction of support tools such as Asset Analytics (AA) and Asset Investment Planning (AIP) has resulted in timely availability of asset information for analysis as well as optimization of investment selection based on specified constraints. The Planning organization has a good mix of experienced and new planners, as well as managers, who bring varied perspectives. A recent move towards "station centric" sustainment investment planning is expected to improve planning and execution efficiencies. However, several key challenges remain to consistently determine, develop, optimize and release investments required to meet customer, asset and system needs.

Based on the specific areas reviewed, we conclude that controls are often ineffective and significant improvements are needed to ensure that a consistent investment planning process is used to produce a risk-based Investment Plan Proposal to address customer, asset and system needs.

Our conclusion is based on the following key observations:

- Ineffective governance and controls over the investment planning end-to-end process.
- Inconsistent identification, assessment, prioritization and action on asset and system needs.
- Lack of risk-based alternatives with a thorough cost-benefit analysis for most plans.
- Inefficient investment plan prioritization process that is not well-understood by the planners and service providers.
- Lengthy approval process that delays release of major investments.

Action plans have been developed by management to address the areas noted above and are summarized in the Summary of Actions (Appendix H). We would like to thank the management and staff in Planning, Engineering & Construction, and Stations for their assistance and open discussions during this review.

Atul A. Solanki, Audit Associate

[1] "Corporate business values" is the term used in the Asset Investment Planning (AIP) optimization process. These are actually the Corporate Strategic Objectives.

OBSERVATIONS AND RECOMMENDATIONS

The Investment Planning audit focused on the following five areas:

1. Effective governance structure and control environment over the "end-to-end" Investment Planning process
2. Appropriate identification and assessment of customer, asset and system needs requiring investment
3. Development of risk-based investment alternatives to meet the identified needs
4. Optimization of investment plans selecting alternatives that maximize corporate business values.
5. Timely release of sufficiently detailed investment plans for execution by the Service Providers.

A sample of 16 investments from the 2015-2019 Investment Plan Proposal (IPP) were selected for review during this audit.

The following are our observations and recommendations related to the above five areas.

1. Ineffective governance and controls

Background:

An effective governance structure and adequate control activities are a must for an organization to achieve its stated objectives while managing the risks it faces to a level that it is willing to accept. The governance and controls set the tone at the top regarding management's expectation of how its business activities are to be performed and an expected standard of conduct for the employees performing those activities. Management sets the control environment by developing, reviewing, approving and communicating appropriate policies, standards, processes, procedures and guidelines in sufficient details. Management ensures that appropriately qualified and trained employees are equipped with adequate tools to perform the tasks assigned to them. An effective governance structure and control environment also requires that adequate supervision, monitoring and quality assurance are in place to meet the organization's key deliverables.

Observations:

We are pleased to observe the following:

1.1 The Planning organization has been developed and released an increasing work program in recent years with a largest work program release of $2.8 billion (gross) for 2015. The 2015-2019 IPP was approved as part of the Hydro One Business Plan at the November 2014 Board meeting.

1.2 A recent reorganization combining the asset management and system development divisions into a single business unit has resulted in a management team of varied experience and background.

1.3 Monthly management reports are being put together to communicate work progress in each department and division.

1.4 An Approvals, Customers, Estimates, and Releases (ACER) review process has been put in place where executive, director and manager level monthly reviews occur between planning and executing lines of businesses to discuss and resolve issues related to large and complex plans (>$1 Million and/or customer impact) prior to their full release.

1.5 The majority of planners are experienced and knowledgeable about the customer, asset and system needs. In most cases, junior planners are teamed with senior planners for mentoring and knowledge transfer. The planners have tools such as Asset Analytics (AA), Asset Investment Planning (AIP), SAP and other databases to perform their assigned tasks.

1.6 AIP training is provided prior to start of the annual investment planning cycle. Detailed PowerPoint training presentations and job aids are posted on the SharePoint site.

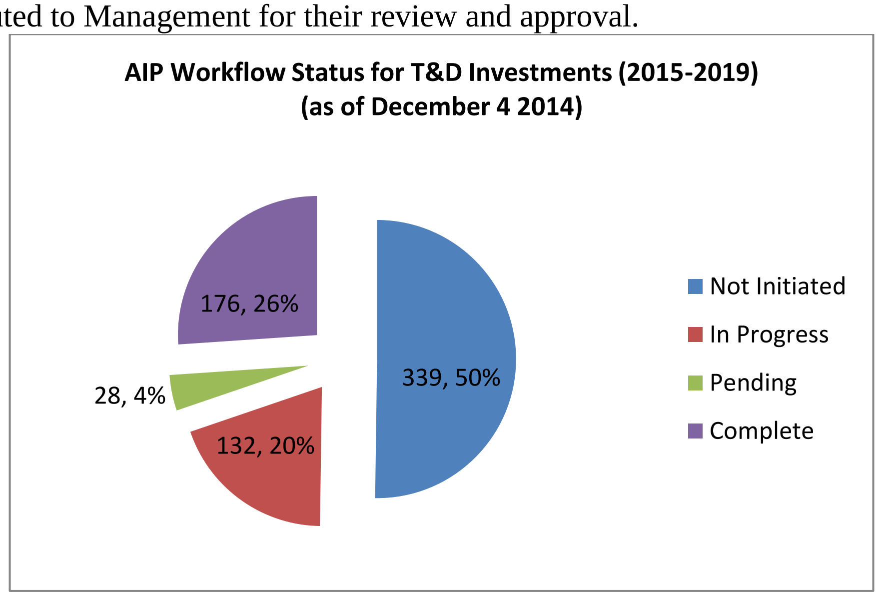
We also observed the following opportunities for improving controls:

1.7 There has been no recent and formal business risk assessment of the overall Planning business unit's objectives completed as per the Enterprise Risk Management Policy (SP0736).

1.8 Approximately 44 approved policies and directives are in place for planning and asset management. However, most of these documents are over 3 years old and do not have a review date. It is unclear if these policies are being followed by the planners as there were no references to any of these policies in the 16 investment planning documents that were reviewed during this audit. A key policy titled "*Asset Investment Planning Risk Assessment Corporate Operational Policy*" was developed in 2013 but was never approved by Management.

1.9 Approximately 363 business process models related to managing asset information and investments are documented in the ARIS Business Process modelling and management software, which is the official source of record for Hydro One business processes. The majority of these were developed during Cornerstone Phase 1 and 2 and have never been incorporated in the Hydro One Business Process Modelling Notation (H-BPMN). Only 42 process models have been mapped to process area "*01.02 Manage Asset Investments*" and "*01.03 Manage Asset Information*", which are the focus of this audit. Most of these process models are in "draft" form, have references to outdated process steps and work groups and have missing integration points with other business processes. Most planners are not aware of these process models and seldom follow them. Some departments have simplified versions of these processes in PowerPoint format for training and discussion purposes. Process clarification and guidelines are often communicated via e-mail or in training presentations.

1.10 There is no formally documented Quality Assurance process with related measures to assess the effectiveness of the "end-to-end" planning process. The "Investment Approval Process" within the training presentation indicated that all Investment plans (or ISR) prepared by an Investment Owner (Planner) were to be sent to the Driver Owner (Manager) for review and approval. All programs greater than $15M and all projects > $10M required additional review and approval by the Portfolio Owner (Director). These reviews and approvals were to occur through AIP workflows. The following is a summary of the AIP Workflow status for T&D investments where the Investment Summary Report (ISR) produced for each investment plan was to be routed to Management for their review and approval.



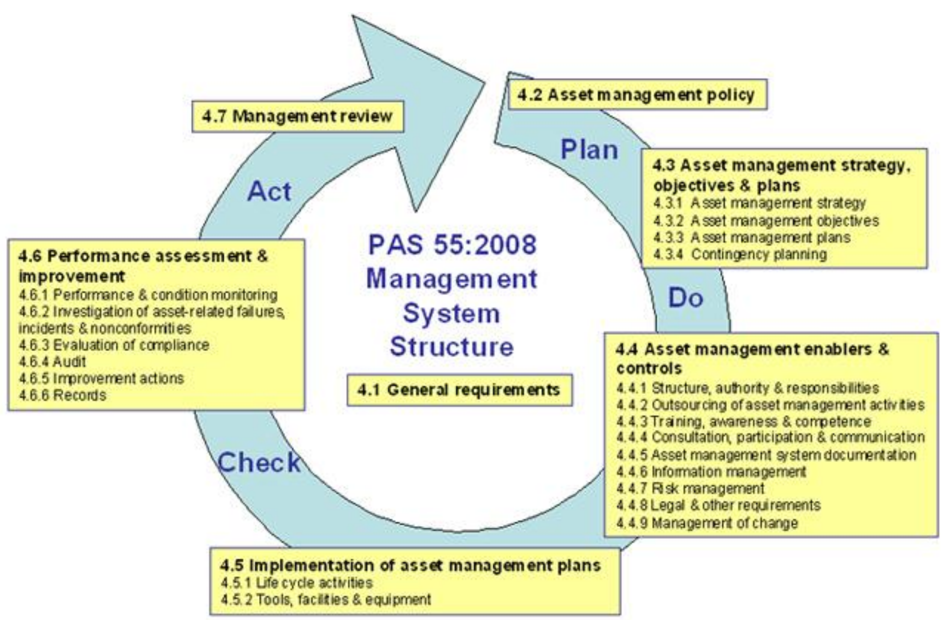
The above results show that half of the investments were never sent by planners to Management for review and approval. About 20% were sent for approval but were neither approved nor rejected by Management. Only the remaining 30% of the plans were either formally approved or rejected. Management has indicated that verbal reviews and approval did occur for all investments but the statuses were not updated in AIP due to time constraints. It was not possible to validate the quality of management reviews in the absence of appropriate documentation.

1.11 There is a lack of a clearly defined process and guidelines for the level of input to be sought by the planners and to be provided by the service providers during the investment plan development. For some plans, service provider input is only sought after an Investment Plan Proposal (IPP) has been put together. For other plans, service provider input is sought and incorporated during the early stages of plan development. Service providers have indicated a preference to be involved as early as possible during the plan development but this could lead to plans being influenced by the service providers' capability to execute rather than risk based customer, asset and system needs.

1.12 There is no formal training for the overall "end to end" planning process. However, there is informal training on use of tools. None of the training is tracked and refreshed as the process and tools evolve.

1.13 There is no formal lessons learned documentation for continuous process improvement. A Lessons Learned presentation was put together for discussion following completion of the 2013 planning cycle. However, it is unclear if any of these lessons were incorporated in the process that was followed during 2014 planning cycle.

1.14 At a high-level, the overall Investment planning process does seem to be aligned with the PAS55:2008 specification for the optimized management of physical assets with its "plan, do, check and act" phases as detailed below. However, significant opportunities exist to define an appropriate asset management strategy & objectives, implement appropriate enablers and controls, monitor performance and practice continuous improvement.



Source: Key Features of PAS55:2008, http://pas55.net/features.asp

Risks: R

- Lack of well-defined, communicated and understood policies, standards, processes, procedures and guidelines could lead to inconsistent decision making leading to poorly defined investment plans that are unable to adequately address the asset and system risks and needs.
- Inadequate specification of accountabilities, training and suitable tools would lead to staff performing their assigned duties on a best effort basis leading to poor quality output and resulting rework.
- Insufficient monitoring of process effectiveness and quality assurance of process outputs would lead to an increased risk of errors and degradation of output quality.
- Lack of continuous improvement through lessons learned would lead to inefficient processes that will have a lower chance of being adopted by the users.

Recommendations:
We recommend that Management:

1.1 Perform a formal risk assessment as per ERM Policy (SP0736) on an annual basis to ensure that business risks facing the planning organization are identified and mitigating actions are developed and tracked. (related to Observation 1.7)

1.2 Develop, review and approve sufficiently detailed policies, standards, procedures and guidelines to ensure a consistent risk-based approach to planning and decision making. This would require a review of the existing governance documents and ARIS process models for their accuracy and validity. Management has informed us that a Policy Review project is currently underway to consolidate policy and directive documents. (related to Observations 1.8 and 1.9)

1.3 Clarify the timing and level of input to be sought by the planners from the service providers as they develop their plans. (related to Observation 1.11)

1.4 Implement a formalized Quality Assurance process and related performance measures to assess the effectiveness of the end-to-end planning process. This would include quality expectations for plans being prepared by the planners and the quality of reviews and feedback being given by management prior to approving those plans. (related to Observation 1.10)

1.5 Formalize and track all process and tool related training being given to planners in their Learning Management System. Establish refresher training requirements whenever there are significant changes in process and tools. (related to Observation 1.12)

1.6 Document and communicate lessons learned after each planning cycle and use them for continuous improvement of the planning process. (related to Observation 1.13)

Management Response:
All recommendations have been agreed to by Mike Penstone, VP Planning. They are assigned for action as follows:

1.1 Randy Church, Director, Network Connections and Development
1.2 Luis Marti, Director, Reliability Studies, Strategies and Compliance
1.3 Kathleen McCorriston, Manager, AM Processes & Tools
1.4 Scott McLachlan, Director, Transmission Asset Management
1.5 Mike Penstone, VP Planning
1.6 Kathleen McCorriston, Manager, AM Processes & Tools

Proposed Action Plan: *(Accountable Manager, above in Management Response)*

1.1 Planning will work with ERM Group to conduct a risk workshop to identify risks in achieving the planning business objectives.

1.2 Conduct a review of processes, procedures, standards and guidelines to determine the need, effectiveness, currency and to ensure they are aligned with and support the Corporate Operational Policies. Establish a review cycle for these documents.

1.3 At the annual LOB kick off, AM Processes and Tools will identify and seek input from the service providers to obtain their feedback on ideal timing and level of input required. Planning will also be in attendance to ensure agreement and consistency in approach.

1.4 Quality expectations and the required metrics for the end-to-end process will be established and communicated by the Planning Organization.

1.5 The Planning Organization will assess all training requirements including the frequency of refresher training and mechanism for tracking training completion. We will develop an implementation plan that defines the accountabilities for creation and delivery of training material.

1.6 AM Processes & Tools will document and communicate lessons learned after the 2016-2020 planning cycle.

Completion Dates:

1.1 Q4, 2015
1.2 Q4, 2015
1.3 Q1, 2015
1.4 Q3, 2015
1.5 Q4, 2015
1.6 Q3, 2015

2. Inconsistent Customer, Asset & System Need Assessment

Background:
Hydro One's Transmission and Distribution (T&D) investment plans consist of four major categories of investments related to sustainment (maintain existing capability), development (add new capability to ensure secure and reliable supply), operation (operate and monitor assets and systems) and common corporate investments. For this audit, the focus was on T&D Station sustainment and development investments.

Key steps in investment planning process include:

i. the determination of investment needs from various stakeholders (including customers),
ii. collection and analysis of supporting data (e.g. asset data), and
iii. assessment of needs.

Sustainment investment needs are primarily identified using asset condition data collected during routine maintenance, inspections and testing, performance history, asset utilization, age, and criticality. Asset Analytics (AA) is a new tool available to planners to collect and analyze this data. An Overview of AA is provided in Appendix F. Development investment needs are primarily identified by system changes that include demand, performance, and configuration as well as changes to standards, codes and market rules. New customer connection requests as well as changes in Local Area Supplies and network transfer capabilities also result in development investment needs.

Both sustainment and development investment needs are assessed by focusing on mitigating risks associated with the likelihood and consequences of asset failures as well as maintaining T&D system performance and satisfying customer expectations.

Observations:

We are pleased to observe the following:

2.1 There has been a recent move towards "station centric" sustainment investments with a goal of bundling sustainment investments at a given transmission station every seven years.

2.2 The Potential Need (PN) notifications in SAP are being used by field staff to alert the planners of future asset sustainment needs. This requirement and related process is formally documented in HODS as "Potential Need (PN) Notification Administration Guide (SP1546)".

2.3 For transmission station refurbishment, a detailed "desk-side station assessment" listing all asset conditions and needs is being documented by the planner and discussed with the field staff.

We also observed the following opportunities for improving controls:

2.4 There is inconsistent documentation and tracking of asset and system needs for later follow-up. Most planners have their own spreadsheets in which they capture needs discovered during field visits, e-mail discussions with field service specialists or recommendations from maintenance technical services. Customer needs and manufacturers' recommendations are also tracked in various e-mails and documents. For most investments, there is no tie back of earlier identified needs to the investments being made. There is no consistent documentation showing which customer, asset and system needs were received, reviewed, accepted/rejected and actioned.

2.5 The PN Notification process outlined in SP1546 is not being consistently followed. In 2014, 307 PN notifications for TS assets were created and 273 (89%) of these have not yet been reviewed by the planners, while only 10 PN notifications were created for DS assets and none of them have been reviewed by the planners. According to the SP1546, "*Asset Management is responsible for assigning a PN notification to every planned replacement and refurbishment candidate in the current business plan*". There is no evidence to support that this has consistently occurred in 2014.

2.6 There is inconsistent use of AA data to assess individual asset needs. There are no documented procedures or guidelines on how to validate AA Risk Index data and translate them into asset needs. Most planners use the AA data as a starting point for further discussion with the service providers to confirm asset needs.

2.7 The AA data quality remains a concern. The quality of underlying data (accuracy, completeness and timely availability of recent data) being used from SAP and other databases for risk index calculations is unknown. It was noted that:

- Only 44% of DS and 51% of TS Supporting Factor data used for risk index calculation is considered "Normal". The remaining data are statistical calculations or default values.
- Percentage of assets with missing Asset Risk Index data (ARI = 0) is as follows:

AA Data Quality – Missing ARI						
ARI	**Condition**	**Demographics**	**Criticality**	**Economics**	**Utilization**	**Composite**
Distribution Station	54%	54%	10%	54%	70%	10%
Transmission	8%	8%	0%	7%	63%	0%

AA Data Quality – Missing ARI						
ARI	**Condition**	**Demographics**	**Criticality**	**Economics**	**Utilization**	**Composite**
Station						

- Gage TS, where major refurbishment is planned, currently shows a composite station level risk index as 27. According to the Risk Index guide, a risk index between 15 to 30 is considered "Good" condition. Dunneville TS, the reputedly the worst ranked station in the province, has a composite station level risk index of 36, which is on the better end of "Fair" condition scale of between 30 to 50.
- Breaker counter reading is one of the supporting factors used for the Utilization ARI calculation. The counter reading is supposed to be recorded twice a year during station inspections but the Aguasabon SS T1L1 breaker last had a counter reading of 292 recorded on August 7, 2012 in SAP. This data is obviously outdated and as a result the Utilization ARI for this breaker is suspect.

2.8 System development projects are based on area supply studies requiring power system historical data related to load flows, voltages, asset connectivity and statuses. These data are not available in AA.

2.9 There are no clearly documented asset strategies against which individual asset needs are assessed. However, work has recently started on developing Asset Strategy Documents for 30 key asset groups. These documents will detail key strategies in managing risks of a given asset group against which the individual asset needs will be assessed by the planners.

Risks: R Y

- Absence of a well-managed process to capture, review, assess, prioritize and action needs increases the risk of critical needs not being addressed in a timely fashion
- Absence of well-understood and quality asset information increases the risk of inadequate need assessment resulting in a less than optimal investment decision.
- Absence of clearly documented asset strategies increases the risk of inconsistent need assessment and investment decision.

Recommendations:

We recommend that Management:

2.1 Develop, implement and monitor an effective Need Identification Process. This may require review and enhancement of SP1546 to include both sustainment and development needs. This process should address a consistent mechanism for tracking details related to need identification, acceptance, review, prioritization, action as well as investment that has been made to meet the need. (related to Observations 2.4 and 2.5)

2.2 Develop detailed guidelines about how the planners should validate and use AA Risk Factors for the need assessment. (related to Observation 2.6)

2.3 Request an audit of Asset Analytics data sources and algorithms to confirm that quality data and appropriate calculation methods are used for calculating the six Asset Risk Indexes for individual assets as well as asset groups. (related to Observation 2.7)

2.4 Consider expanding the scope of the Asset Analytics tool to include up-to-date power system historical data such as load flows, connectivity, voltages, statuses, etc. (related to Observation 2.8)

2.5 Continue to develop sufficiently detailed Asset Strategy Documents for all asset groups and ensure that all future asset needs are assessed against these documented strategies. (related to Observation 2.9)

Management Response:
All recommendations have been agreed to by Mike Penstone, VP Planning. They are assigned for action as follows:

2.1 Scott McLachlan, Director, Transmission Asset Management
2.2 Scott McLachlan, Director, Transmission Asset Management
2.3 Randy Church, Director, Network Connections and Development
2.4 Bing Young, Director, System Planning
2.5 Scott McLachlan, Director, Transmission Asset Management

Proposed Action Plans: *(Accountable Manager, Title above in Management Response)*

2.1 This recommendation will be addressed as part of the overall Quality Assurance Process and metrics as outlined in Proposed Action Plan 1.4.
2.2 This recommendation will be addressed as part of the overall Quality Assurance Process and metrics as outlined in Proposed Action Plan 1.4.
2.3 SAP Data Audit on Asset and Maintenance data is already underway. The results of these audits will be used to address the underlying data issues in AA. Workshops with respective LOBs will be held regarding usability of existing algorithms.
2.4 AM Process and Tools will request ISD to add audit recommendation to corporate application roadmap. Key requirement is to have access to NMS information.
2.5 We will continue to develop Asset Strategy Documents.

Completion Dates:

2.1 Q3, 2015
2.2 Q3, 2015
2.3 Q4, 2015
2.4 Q1, 2015
2.5 Q4, 2015

3. Lack of Investment Alternatives

Background:
Developing investment alternatives is the next step required in the Investment Planning process and it is guided by the results from the need assessment. Work bundling opportunities among several programs are also explored while developing alternatives. Some programs are demand driven (such as service upgrades, trouble calls, studies, storm damage, etc.) and have only one alternative that is included in the plan based on historical averages of funding. Projects that are already under execution also have only one alternative. Most other projects and programs should have more than one alternative with varying risks and benefits to allow selection of the best alternative during optimization process. Project alternatives can shift in time, while program alternatives can have varying levels of accomplishments.

For program work, four levels of alternatives are considered as follows:

1. Vulnerable – Minimal short-term funding to meet regulatory and safety risks
2. Intermediate (1..n) – Varying levels of risk exposures with increased funding above vulnerable level
3. Asset Optimal – Balancing point where asset lifecycle costs are minimized. This would be an ideal level of funding.

4. Accelerated – Exceeds asset optimal funding in order to mitigate an oncoming “bow wave” of asset needs.

Further detail on these alternatives is included in Appendix F.

Program work cost is unit priced while project work cost is based on the planner’s estimate based on similar projects, budgetary estimate or detailed estimate from the service provider (where available).

The need, objectives, accomplishments, costs and risk assessment for each alternative is documented in the AIP tool by the planners and an Investment Summary Report (ISR) is produced for each investment. Management performs a quality assurance review of the ISR to ensure that a clear and compelling justification is made for each alternative along with uniform use of the risk assessment model.

Observation:

We are pleased to observe the following:

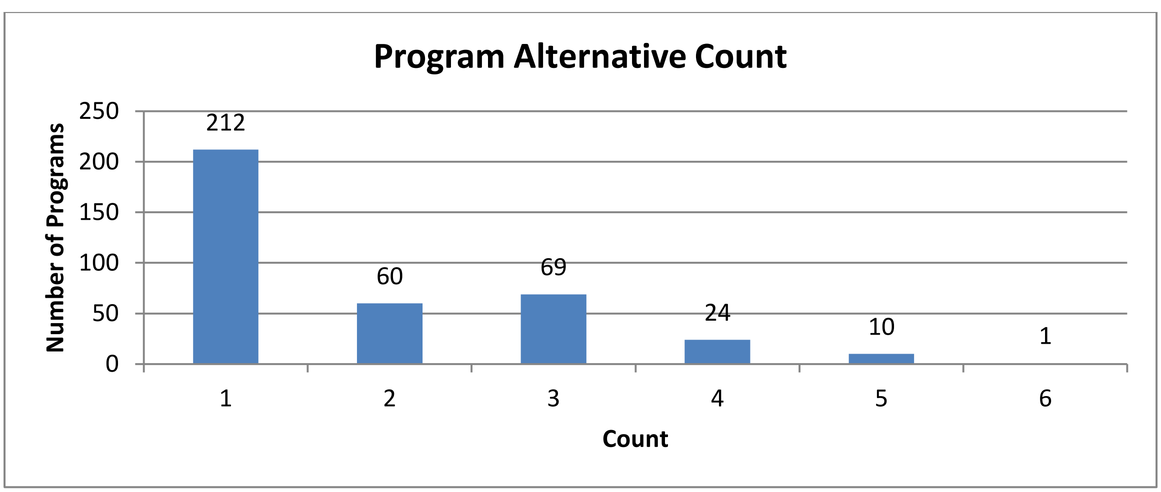
3.1 Investment values were calculated based on a weighted average of 8 corporate business values as follows: Safety (17%), Reliability (17%), Customer Satisfaction (13%), Productivity (13%), Financial Benefit (13%), Employees (9%), Environment (9%) and Shareholder value (9%).

3.2 Baseline and alternative risks for each investment are being evaluated using a sufficiently detailed and a standardized risk matrix based on 6 levels of probability and 9 levels of consequence.

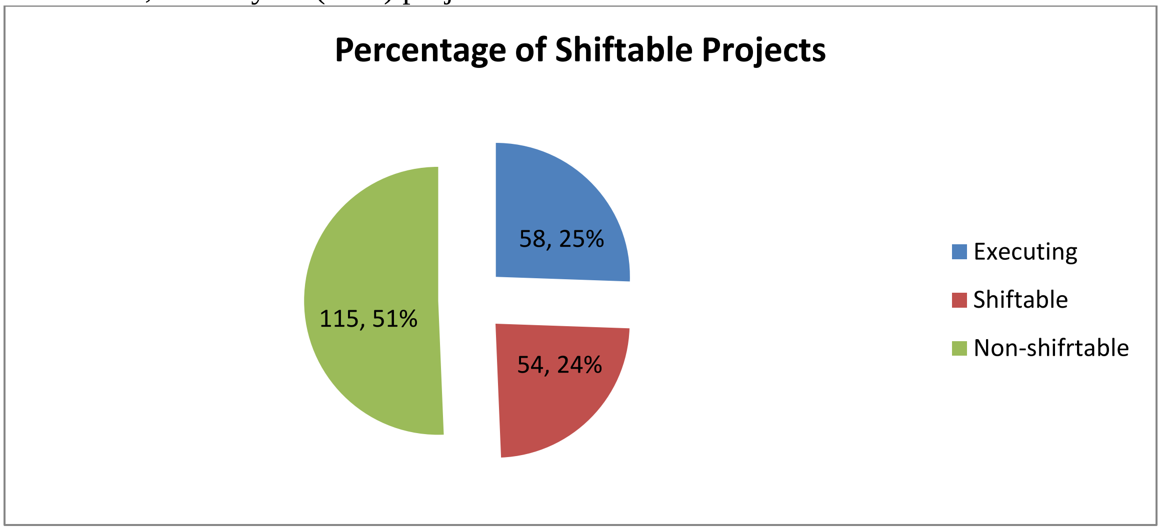
3.3 A risk consequence table was provided to the planners to guide their selection of the appropriate consequence for each corporate business value. A spreadsheet based tool was also developed to guide the planners in determining consequence ratings through a series of questions. Job aids related to risk assessment for each corporate value were also provided and posted on the SharePoint site for planners’ use.

We also observed the following opportunities for improving controls:

3.4 For the AIP optimization to be effective, projects should be shiftable in time and programs should have more than one alternative. There are 675 plans for Transmission and Distribution drivers in the 2015-2019 IPP with 448 Programs and 227 Projects. Of the 448 programs, 50 programs are demand driven and 22 programs are already under execution so these are required to have only a single alternative. The remaining 376 are under short term planning and should have had more than one alternative specified. However, 212 (56%) have only one alternative specified. The following is the alternative count for these programs.



Of the 227 projects, 58 are under execution and are not shiftable. The remaining 169 should all be shiftable, but only 54 (24%) projects were identified as shiftable in time.



From the above analysis, it can be concluded that projects and programs do not have sufficient alternatives defined to allow optimal selection of best available alternative.

3.5 Baseline and alternative risks assessed for most investments are mostly subjective with no (or very little) quantitative data to support the assigned probability and consequence for the risks. Although informal guidelines were provided on how to translate AA risk factors into corporate risks, this was not done for most investments. Most planners have indicated that the current risk matrix is confusing and that the provided guidelines are subjective. The provided training and job aid explained the risk matrix but it did not specify how the planners should rank risks (i.e. pick a specific box in the risk matrix). It was left up to the management reviews of risk assessment to ensure that risk ranking is consistent across all investments.

3.6 There was no risk assessment done for transmission system development plans as all of these plans are non-discretionary.

3.7 Sample investments having single alternatives lack appropriate justification documented in the Investment Summary Report.

3.8 There is very little documentation of management quality assurance review of investment plans (including risk assessments). Management has indicated that these type of reviews have occurred with verbal feedback being provided to planners in most cases. Please refer to related observation 1.10.

3.9 Some of the unit prices being used for program work are outdated or incorrect. As an example, unit prices for TS maintenance work do not include material cost while the unit prices for DS maintenance work do include material cost. The 2015 PCB Retro fill program is considered "underfunded" by the service provider because the outdated 2013 unit prices were used in determining the funding level.

3.10 There is inconsistent engagement with internal service providers during the development of alternatives. Some investment plans have significant engagement with service providers to confirm start date, in-service date, accomplishment levels, resources or cash flow based on sufficiently detailed estimates provided by the service provider. Most other plans are based on planner's estimates and desired schedule. The service providers have indicated a preference to be involved much earlier during the investment plan development. Please refer to related observation 1.11.

3.11 There are insufficient documented details on coordination of plans among sustainment and development groups as well as identification of any bundling opportunities between transmission and distribution work.

3.12 There are insufficient details on how the individual plans align with the regulatory filing.

3.13 There is a lack of details for placeholder investments having significant value. The placeholder investments are used for projects that are expected but have very little scope defined. The value of these placeholder investments is based on historical trends and future forecasts. There are 37 placeholder investments in the IPP totalling $914M (Gross) over the 2015-2019 planning period. Service providers are concerned about providing accurate forecasts for these placeholder investments that have no or very little defined scope.

Risks: R Y

- Lack of available alternatives increases the risk of less than optimal investment plans.
- Inadequate assessment of baseline and alternative risk could result in incorrect risk values being assigned to the alternative.
- Incorrect assumptions related to the timing and costs of investment could result in less than optimal cash flow requirements.
- Undue influence by the service provider during the planning process increases the risk of plans being made based on the service provider’s ability to execute rather than on asset needs.

Recommendations:

We recommend that Management:

3.1 Require the planners to define more than one alternative for non-demand driven programs and time shift-able projects. Management should also ensure that appropriate justification is documented and reviewed for plans having only a single alternative. (related to Observation 3.4)

3.2 Simplify the risk assessment matrix and provide suitable training and guideline to planners to perform an effective risk assessment. Specific focus should be on using quantative data from AA and other systems to determine/support appropriate probability and consequence on the established risk matrix. (related to Observations 3.5, 3.6 and 3.7)

3.3 Increase quality assurance reviews and feedback to planners on the quality of their alternatives and risk assessment to ensure uniformity of plans and related risk assessment. (related to Observation 3.8)

3.4 Review and confirm the Unit Price Catalog with the service providers prior to the start of each planning cycle to ensure that the most current unit prices are being used to determine the funding level for the program work. (related to Observation 3.9)

3.5 Define and communicate the required level of engagement with the service provider when investment plans are being developed to ensure that plans are based on asset needs rather than executability by the service providers. Please refer to related Recommendation 1.3. (related to Observation 3.10)

3.6 Require the planners to electronically attach/link supporting data (such as those from AA) and related documentation for each alternative risks assessment to their ISR in AIP. (related to Observations 3.11, 3,12 and 3.13)

Management Response:
All recommendations have been agreed to by Mike Penstone, VP Planning. They are assigned for action as follows:

3.1 Scott McLachlan, Director, Transmission Asset Management
3.2 Scott McLachlan, Director, Transmission Asset Management
3.3 Scott McLachlan, Director, Transmission Asset Management
3.4 Chong Ng, Project Development
3.5 Kathleen McCorriston, AM Processes & Tools
3.6 Scott McLachlan, Director, Transmission Asset Management

Proposed Action Plans: *(Accountable Manager, Title above in Management Response)*

3.1 We will define the framework for investments including the expectations outlining the definition and governance of programs and projects and requirements for program alternatives and time shift-able projects. Document and communicate these requirements.
3.2 We will improve the guidance on the use of the risk assessment matrix through the provision of practical examples.
3.3 This recommendation will be addressed as part of the overall Quality Assurance Process and metrics as outlined in Proposed Action Plan 1.4.
3.4 We will establish a process to ensure costs included in the investment plans are agreed upon between Planning and Operations (executing LOBs).
3.5 This recommendation will be addressed as part of the Proposed Action Plan 1.3 related to the timing and level of input to be sought from LOBs.
3.6 This recommendation will be addressed as part of the overall Quality Assurance Process and metrics as outlined in Proposed Action Plan 1.4.

Completion Dates:
3.1 Q3, 2015
3.2 Q4, 2016
3.3 Q3, 2015
3.4 Q4, 2015
3.5 Q1, 2015
3.6 Q3, 2015

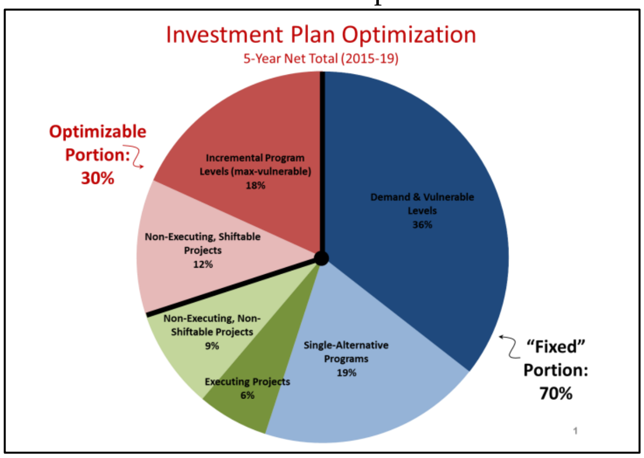
4. Inefficient Investment Plan Optimization

Background:
Hydro One uses an Asset Investment Planning (AIP) tool for risk-based optimization to ensure that selected investments will result in the maximization of corporate business values. During each planning cycle, the AIP tool is set up with appropriate investment master data from SAP (such as driver, LOB, Appropriation Request Number, etc.), historical and forecast finance data, corporate value function and other constraints. The risk assessment, costs, schedule and accomplishments for each investment alternative is then input by the planners in to the AIP tool. Once all input is completed, the optimization process starts during which the AIP tool selects the best of the several alternatives of each investment based on the timing of investments that will maximize risk mitigation and financial benefits while satisfying pre-determined constraints and dependencies. The aggregation of work programs and projects selected from available alternatives during the optimization process yields the preliminary Investment Plan Proposal (IPP).

An enterprise engagement takes place whereby each line of business (planning, executing and finance) is represented at review meetings to discuss the preliminary IPP. Management discretion is used to adjust the IPP to ensure that appropriate resources are available to execute the plan, financial and regulatory objectives are met, and the level of risk imposed by the plan is acceptable.

Observations:
We are pleased to observe the following:
4.1 For the 2015-2019 Investment planning, a detailed schedule was developed and communicated to ensure that the optimization process and IPP review was completed by end of June 2014. The planned tasks on this schedule were completed on time and a weekly workflow status report was issued to management to indicate progress.
4.2 A detailed procedure exists for set up of the AIP tool at the start of the prioritization process.

We also observed the following opportunities for improving controls:
4.3 Only 30% of the plans in 2015-2019 IPP were optimizable within AIP.



Source: Director Review June 2 v2.pptx from Kathleen Kerr

4.4 The AIP tool was only available for a limited time resulting in planners having insufficient time for thorough documentation of their plans and management having insufficient time to review those plans in detail. The planned and actual schedule dates for the 2015-2019 planning cycle were as follows:

Event	Planned	Actual
LOB approval of Unit Price Catalog	April 11	No official signoff was received
Setup of AIP Tool Complete	April 11	April 11
AIP open for Planner Input	April 14	April 14
Investment Approval Workflow Submission deadline	May 9	May 9 – Workflow status reports were issued weekly to Management
Investment approval deadline	May 16	May 20 – Extra weekend was given for management review and approval
Start of Optimization	May 20	May 20
Optimization results review (Prelim. IPP)	June 2	June 2
LOB and Stakeholder review and input	June 13	June 13
IPP adjustments complete	June 30	July 4

Planners were given 4 weeks to complete their input into AIP and management was given 1 week to review it. As of May 15, one day before the plan approval deadline, only 49% of the plans had workflow initiated for review and approval by management. Please refer to related observation 1.10.

4.5 Manual workarounds are in place to update AIP data from SAP and other systems. Spreadsheet based tools are being used for data uploads. These uploads are based on a snapshot of available data from the originating system (such as SAP) and they became stale as soon as the snapshot is taken since the originating system is continually updated. As an example, forecast costs and in-service date changes are continually being updated in SAP by the service providers, but these changes are not reflected in AIP once the snapshot of data is taken from SAP and uploaded to AIP.

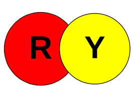
4.6 Enterprise engagement is occurring at the director level and above with a focus on comparison with previous year's plan to identify what has changed and discuss why. A line by line review is only occurring for major / complex plans. The LOB engagement for 2015-2019 IPP occurred over a four day period from June 9 to 13, but the service providers have indicated that they need more time to review each investment line item in IPP in sufficient detail with their project and program managers to ensure that the IPP can be executed as planned.

4.7 Adjustments and changes to the optimized IPP are logged in a spreadsheet based change log. This change log does not seem to capture all changes. As an example, total gross funding has significantly changed for DS preventive and corrective maintenance, TS preventive maintenance, P&C Maintenance and P&C NOEA support, but these changes are not logged in the change log. Service providers have also indicated that some of their project and program specific input was incorporated while others was not. They have also indicated that there was a lack of communication about why some input related to in-service date and cash flow changes was not accepted.

4.8 It is unclear what changes to the optimized plan would require the plan to be run through the optimization process again. The IPP, once optimized, is simply adjusted based on changes recommended during the enterprise engagement reviews. The resulting adjusted IPP may not be a fully optimized plan. It was noted that the preliminary IPP was adjusted and re-issued to LOBs approximately 10 times before being finalized.

4.9 It is unclear how multi-year in-service additions are being treated in the IPP. In all cases, the "station centric" multi-year programs are being shown as in-serviced in the final year of the program. The reality is that these programs are in-serviced each year as the work progresses.

Risks:



- An insufficient number of optimizable plans defeat the benefits of overall plan optimization.
- Insufficient time to provide quality input to the optimization process and to review the results of the optimization process increases the risk of having less than optimal plan.
- Inadequate communication around changes to the optimized plan increases the risk of diminishing the plan's credibility and less acceptance of the plan by its users.

Recommendations:

We recommend that Management:

4.1 Increase the number of investments that are optimizable. (related to Observation 4.3) Please refer to related Recommendation 3.1.

4.2 Make the AIP tool available year around to allow the planners to input and update their plans and risk assessments throughout the year. Management has indicated that plans are already underway to upgrade the AIP tool to allow this to occur in 2015. (related to Observation 4.4)

4.3 Consider AIP tool integration with other systems and tools such as AA (for asset risk factors), SAP (for AR and driver related data), BPC (Business Process Consolidation, for LOB forecast and accomplishment data) and UPC (Unit price catalog, for unit price data) to ensure that information in AIP is kept up-to-date with other systems. (related to Observation 4.5)

4.4 Increase the enterprise engagement period to allow a detailed line by line review of unreleased work in the IPP by the project and program managers who will be executing the plan. This will allow better feedback on cash flows and in-service dates from the service providers based on the established scope. (related to Observation 4.6)

4.5 Implement a formal change log to document all recommended changes. This should also include appropriate review, approval and incorporation of changes with appropriate communication back to the requestor of the change. (related to Observation 4.7)

4.6 Determine and document which types of changes to the individual plans require the IPP to be run through the optimization process again to ensure that the resulting plan remains optimal. (related to Observation 4.8)

Management Response:

All recommendations have been agreed to by Mike Penstone, VP Planning. They are assigned for action as follows:

4.1 Scott McLachlan, Director, Asset Management)
4.2 Kathleen McCorriston, Manager, AM Processes and Tools
4.3 Kathleen McCorriston, Manager, AM Processes and Tools
4.4 Kathleen McCorriston, Manager, AM Processes and Tools
4.5 Kathleen McCorriston, Manager, AM Processes and Tools
4.6 Kathleen McCorriston, Manager, AM Processes and Tools

Proposed Action Plans: *(Accountable Manager, Title above in Management Response)*

4.1 This recommendation will be addressed as part of the action plan for recommendation 3.1.
4.2 This recommendation will be addressed upon implementation of AIP tool upgrade.
4.3 AM Process and Tools will request ISD to add audit recommendation to corporate application roadmap.
4.4 Enterprise Engagement period will be revised and incorporated into the revised schedule for the 2016-2020 planning cycle.
4.5 All changes will be recorded in the accomplishment file change log and/or documented in the meeting minutes.
4.6 AM Process & Tools will document conditions and requirement for the IPP to be run through the optimization process again into the Investment Optimization Management Procedure.

Completion Dates:

4.1 Q3, 2015
4.2 Q3, 2015
4.3 Q3, 2015
4.4 Q3, 2015
4.5 Q1, 2015 – COMPLETED
4.6 Q2, 2015

5. Lengthy Investment Plan Approval and Release Process

Background:
After the completion of IPP prioritization and review/adjustment by Senior Management, the adjusted IPP is included in the Corporate Business Plan for approval by the Hydro One Board of Directors. Subsequently, individual investments are then released to the service provider for execution. Programs work is approved at Board level and released annually while project work is released after a review and approval of Business Case Summary (BCS) by the appropriate Organization Authority Register (OAR) authorities.

The planners ensure that BCS showing cash flow based on detailed estimates, start date and in-service date as agreed with the service providers and customers (if required) is prepared and approved by appropriate OAR authorities prior to releasing funds to the service provider through SAP.

In May 2013, changes to the project/program definition and approval limits were implemented as per recommendations by Finance and approval of the Executive Committee (EC). A key change was to apply the interpretation of "program" to include component replacement/refurbishment, including bundling of such work. This resulted in a number of "station centric" bundled programs (often referred to as "projam" because they have a scope and schedule similar to project work but are funded through approved programs using unit pricing) of significant value being approved at a director level using Station Investment Capital Approval (SICA) even though the value of the "projam" exceeded the director level OAR authority.

Observation:
We are pleased to observe the following:

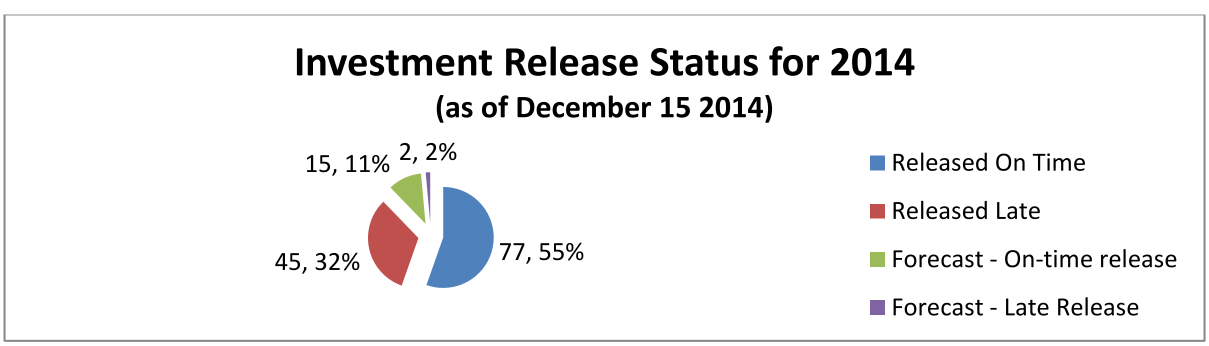
5.1 The approval and release process has not changed over the last several years. Appropriate training presentations, templates and job aids are available to planners for development of the BCS and directing it to the appropriate OAR authority.

5.2 87% of 2015 and 46% of 2016 transmission capital work program have already been released to Engineering and Construction.

We also observed the following opportunities for improving controls:

5.3 A requirement has been put in place recently to treat all "projam" greater than $20M as projects requiring an approved BCS by the appropriate OAR authority prior to release. However, it is unclear how the remaining "projam" investments will be approved and progress will be monitored.

5.4 100 projects and 39 "station centric" programs were scheduled to be released in 2014 using a BCS or SICA. The following is a summary of their release statuses as of December 15 2014.



From the above analysis, we conclude that release dates are often optimistic.

5.5 Of the 45 projects that were released late in 2014, only one had its in-service date pushed back due to late release. The service providers are concerned about the timing of work release as they can't execute the work without a release. They have requested that changes in the release date need to be tied to changes in the in-service date to ensure that it will be met.

5.6 The primary cause for a delayed release is a delay in availability of detailed estimates.

5.7 A BCS requiring board approval goes through a series of reviews at director, VP, SVP/COO/CFO, President/EC and BT Committee of the Board. All these reviews require timely submission of information and if there are any questions or concerns raised during the review, the process is delayed. A detailed "Investment Review Schedule" showing earliest and latest submission dates for approval at specific committee or board meeting date is available to planners. It shows that, in most cases, the review and approval process needs to start a minimum of 6 to 8 weeks ahead of the Board meeting date.

Risks: R Y

- Delayed release of investments increases the risk of not meeting the approved in-service date.
- Lengthy review and approval process of BCS requiring Board Approval increases the risk of delayed release.

Recommendations:

We recommend that Management:

5.1 Clarify the approval requirement and progress monitoring for "projam" investments. Review the project and program approval process with specific focus on shortening the approval timeline. This may include appropriate escalation triggers as well as clarification of requirement for timely review / approval. (related to Observation 5.7)

5.2 Ensure that realistic release dates are considered by the planners as they develop their plans. (related to Observation 5.4, 5.5 and 5.6)

Management Response:

All recommendations have been agreed to by Mike Penstone, VP Planning. They are assigned for action as follows:

5.1 Mike Penstone, VP Planning

5.2 Scott McLachlan, Director, Transmission Asset Management

Proposed Action Plans: *(Accountable Manager, Title above in Management Response)*

5.1 This will be incorporated into annual review of OAR.

5.2 This recommendation will be addressed as part of the action plan for recommendation 1.4.

Completion Dates:

5.1 Q3, 2015

5.2 Q3, 2015

SUMMARY OF ACTIONS

(R) #	Observations	Risk	Recommendations (R)	Action Plan	Accountability	Completion Date
1. Governance and Controls						
1.1	There has been no recent and formal business risk assessment of the overall Planning business unit's objectives completed as per the Enterprise Risk Management Policy (SP0736).	M	Perform a formal risk assessment as per ERM Policy (SP0736) on an annual basis to ensure that business risks facing the planning organization are identified and mitigating actions are developed and tracked.	Planning will work with ERM Group to conduct a risk workshop to identify risks in achieving the planning business objectives.	Randy Church, Director, Network Connections and Development	Q4, 2015
1.2	Policies, processes, procedures, standards and guidelines are missing, incomplete, outdated or not being used consistently	H	Develop, review and approve sufficiently detailed policies, standards, procedures and guidelines to ensure a consistent risk-based approach to planning and decision making. This would require a review of the existing governance documents and ARIS process models for their accuracy and validity. Management has informed us that a Policy Review project is currently underway to consolidate policy and directive documents.	Conduct a review of processes, procedures, standards and guidelines to determine the need, effectiveness, currency and to ensure they are aligned with and support the Corporate Operational Policies. Establish a review cycle for these documents.	Luis Marti, Director, Reliability Studies, Strategies and Compliance	Q4, 2015
1.3 3.5	There is a lack of a clearly defined process and guidelines for the level of input to be sought by the planners and to be provided by the service providers during the	M	Clarify the timing and level of input to be sought by the planners from the service providers as they develop their plans.	At the annual LOB kick off, AM Processes and Tools will identify and seek input from the service providers to obtain their feedback on ideal timing and level of input required.	Kathleen McCorriston, Manager, AM Process & Tools	Q1, 2015

	Observations	Risk	Recommendations	Action Plan	Accountability	Completion Date
	investment plan development. There is inconsistent engagement with internal service providers during the development of alternatives.		Define and communicate the required level of engagement with the service provider when investment plans are being developed to ensure that plans are based on asset needs rather than executability by the service providers.	Planning will also be in attendance to ensure agreement and consistency in approach.		
1.4 2.1 2.2 3.3 3.6 5.2	There is no formally documented Quality Assurance process with related measures to assess the effectiveness of the "end-to-end" planning process.	H	Implement a formalized Quality Assurance process and related performance measures to assess the effectiveness of the "end-to-end" planning process. This would include: • a Need identification and tracking process • guidelines on use and validation of AA data to assess needs and risks • QA reviews of Investment Summary Reports and feedback to planners • Supporting document availability and review, and • realistic investment release dates	Quality expectations and the required metrics for the end-to-end process will be established and communicated by the Planning Organization.	Scott McLachlan, Director, Transmission Asset Management	Q3, 2015
1.5	There is no formal training for the overall "end to end" planning process. However, there is informal training on use of tools. None of the training is tracked and refreshed as the process and tools evolve.	M	Formalize and track all process and tool related training being given to planners in their Learning Management System. Establish refresher training requirements whenever there are significant changes in process and tools.	The Planning Organization will assess all training requirements including the frequency of refresher training and mechanism for tracking training completion. We will develop an implementation plan that defines the accountabilities	Mike Penstone, VP Planning	Q4, 2015

	Observations	Risk	Recommendations	Action Plan	Accountability	Completion Date
				for creation and delivery of training material.		
1.6	There is no formal lessons learned documentation for continuous process improvement.	M	Document and communicate lessons learned after each planning cycle and use them for continuous improvement of the planning process.	AM Processes & Tools will document and communicate lessons learned after the 2016-2020 planning cycle.	Kathleen McCorriston, Manager, AM Process & Tools	Q3, 2015
2. Customer, Asset and System Need Assessment						
2.3	The AA data quality remains a concern. The quality of underlying data (accuracy, completeness and timely availability of recent data) being used from SAP and other databases for risk index calculations is unknown.	H	Request an audit of Asset Analytics data sources and algorithms to confirm that quality data and appropriate calculation methods are used for calculating the six Asset Risk Indexes for individual assets as well as asset groups.	SAP Data Audit on Asset and Maintenance data is already underway. The results of these audits will be used to address the underlying data issues in AA. Workshops with respective LOBs will be held regarding usability of existing algorithms.	Randy Church, Director, Network Connections and Development	Q4, 2015
2.4	System development projects are based on area supply studies requiring power system historical data related to load flows, voltages, asset connectivity and statuses. These data are not available in AA.	M	Consider expanding the scope of the Asset Analytics tool to include up-to-date power system historical data such as load flows, connectivity, voltages, statuses, etc.	AM Process and Tools will request ISD to add audit recommendation to corporate application roadmap. Key requirement is to have access to NMS information.	Bing Young, Director, System Planning	Q1, 2015

	Observations	Risk	Recommendations	Action Plan	Accountability	Completion Date
2.5	There are no clearly documented asset strategies against which individual asset needs are assessed. However, work has recently started on developing Asset Strategy Documents for 30 key asset groups.	M	Continue to develop sufficiently detailed Asset Strategy Documents for all asset groups and ensure that all future asset needs are assessed against these documented strategies.	We will continue to develop Asset Strategy Documents.	Scott McLachlan, Director, Transmission Asset Management	Q4, 2016
3. Investment Alternatives						
3.1 4.1	For the AIP optimization to be effective, projects should be shiftable in time and programs should have more than one alternative. Only 30% of the plans in 2015-2019 IPP were optimizable within AIP.	H	Increase the numbers of investments that are optimizable by requiring the planners to define more than one alternative for non-demand driven programs and time shift-able projects. Management should also ensure that appropriate justification is documented and reviewed for plans having only a single alternative.	We will define the framework for investments including the expectations outlining the definition and governance of programs and projects and requirements for program alternatives and time shift-able projects. Document and communicate these requirements.	Scott McLachlan, Director, Transmission Asset Management	Q3, 2015
3.2	The current risk matrix is confusing and that the provided guidelines are subjective.	M	Simplify the risk assessment matrix and provide suitable training and guideline to planners to perform an effective risk assessment. Specific focus should be on using quantative data from AA and other systems to determine/support appropriate probability and consequence on the established risk matrix.	We will improve the guidance on the use of the risk assessment matrix through the provision of practical examples.	Scott McLachlan, Director, Transmission Asset Management	Q4, 2016

	Observations	Risk	Recommendations	Action Plan	Accountability	Completion Date
3.4	Some of the unit prices being used for program work are outdated or incorrect.	M	Review and confirm the Unit Price Catalog with the service providers prior to the start of each planning cycle to ensure that the most current unit prices are being used to determine the funding level for the program work.	We will establish a process to ensure costs included in the investment plans are agreed upon between Planning and Operations (executing LOBs).	Chong Ng, Director, Project Development	Q4, 2015
4. Investment Plan Optimization						
4.2	The AIP tool was only available for a limited time resulting in planners having insufficient time for thorough documentation of their plans and management having insufficient time to review those plans in detail.	M	Make the AIP tool available year around to allow the planners to input and update their plans and risk assessments throughout the year. Management has indicated that plans are already underway to upgrade the AIP tool to allow this to occur in 2015.	This recommendation will be addressed upon implementation of AIP tool upgrade.	Kathleen McCorriston, Manager, AM Process & Tools	Q3, 2015
4.3	Manual workarounds are in place to update AIP data from SAP and other systems.	L	Consider AIP tool integration with other systems and tools such as AA (for asset risk factors), SAP (for AR and driver related data), BPC (Business Process Consolidation, for LOB forecast and accomplishment data) and UPC (Unit price catalog, for unit price data) to ensure that information in AIP is kept up-to-date with other systems.	AM Process and Tools will request ISD to add audit recommendation to corporate application roadmap.	Kathleen McCorriston, Manager, AM Process & Tools	Q3, 2015

	Observations	Risk	Recommendations	Action Plan	Accountability	Completion Date
4.4	Enterprise engagement is occurring at the director level and above with a focus on comparison with previous year's plan to identify what has changed and discuss why. A line by line review is only occurring for major / complex plans. The LOB engagement for 2015-2019 IPP occurred over a four day period from June 9 to 13, but the service providers have indicated that	H	Increase the enterprise engagement period to allow a detailed line by line review of unreleased work in the IPP by the project and program managers who will be executing the plan. This will allow better feedback on cash flows and in-service dates from the service providers based on the established scope.	Enterprise Engagement period will be revised and incorporated into the revised schedule for the 2016-2020 planning cycle.	Kathleen McCorriston, Manager, AM Process & Tools	Q3, 2015
	they need more time to review each investment line item in IPP in sufficient detail with their project and program managers to ensure that the IPP can be executed as planned.					
4.5	Adjustments and changes to the optimized IPP are logged in a spreadsheet based change log. This change log does not seem to capture all changes.	M	Implement a formal change log to document all recommended changes. This should also include appropriate review, approval and incorporation of changes with appropriate communication back to the requestor of the change.	All changes will be recorded in the accomplishment file change log and/or documented in the meeting minutes.	Kathleen McCorriston, Manager, AM Process & Tools	Q1, 2015 Complete

	Observations	Risk	Recommendations	Action Plan	Accountability	Completion Date
4.6	It is unclear what changes to the optimized plan would require the plan to be run through the optimization process again. The IPP, once optimized, is simply adjusted based on changes recommended during the enterprise engagement reviews. The resulting adjusted IPP may not be a fully optimized plan. It was noted that the preliminary IPP was adjusted and re-issued to LOBs approximately 10 times before being finalized.	M	Determine and document which types of changes to the individual plans require the IPP to be run through the optimization process again to ensure that the resulting plan remains optimal.	AM Process & Tools will document conditions and requirement for the IPP to be run through the optimization process again into the Investment Optimization Management Procedure.	Kathleen McCorriston, Manager, AM Process & Tools	Q2, 2015
5. Investment Plan Approval and Release						
5.1	A requirement has been put in place recently to treat all “projam” greater than $20M as projects requiring an approved BCS by the appropriate OAR authority prior to release. However, it is unclear how the remaining “projam” investments will be approved and progress will be monitored.	H	Clarify the approval requirement and progress monitoring for “projam” investments. Review the project and program approval process with specific focus on shortening the approval timeline. This may include appropriate escalation triggers as well as clarification of requirement for timely review / approval.	This will be incorporated into annual review of OAR.	Mike Penstone, VP Planning	Q3, 2015

Chapter 3

Section

3.06 Hydro One—Management of Electricity Transmission and Distribution Assets

1.0 Background

1.1 Overview

Hydro One Inc., one of the largest electricity delivery systems in North America, has three key reportable segments:

- **Transmission**: Hydro One Networks Inc. transmits electricity through its 29,000-kilometre high-voltage transmission network that sends electricity from power generators to approximately 90 large industrial customers and 47 of the 71 local distribution companies (LDCs), or utilities, in Ontario, as well as to Hydro One's local distribution business;
- **Distribution**: Hydro One Networks Inc. also delivers and sells electricity to residential and industrial customers through its 123,000-kilometre low-voltage distribution system that serves as the LDC for about 1.4 million customers mostly in smaller municipalities and rural areas throughout the province and serving 28% of all customers in Ontario. (This is different than most other distributors, which typically service larger urban and surrounding areas. Hydro One has an average of 11 customers for each kilometre of distribution line, whereas the average for the four largest LDCs in Ontario is 51.) It also sends electricity to the remaining 24 smaller LDCs not directly serviced by the transmission network; and
- **Telecommunications**: Hydro One Telecom Inc. manages a telecommunications system that allows Hydro One to monitor and remotely operate its transmission system equipment. Telecommunications services are also sold to large resellers and corporate users.

The Ontario electricity grid is a network of power generators and consumers connected by high-voltage transmission towers and lines and low-voltage distribution lines. Hydro One owns and operates 96% of the province's electricity transmission system, with the remaining 4% being owned by four private-sector corporations. The transmission system collects electricity from generators and sends it via high-voltage transmission towers and lines to transformer stations, where the electricity is converted to a lower voltage and then travels from the transformer station to an LDC or a large industrial client.

LDCs own and operate the low-voltage lines that distribute or deliver power to homes and businesses. As of December 31, 2014, there were 71 LDCs across the province that were mainly owned by the municipalities they service, in addition to Hydro One Networks distribution system operations (for the rest of this report, we refer to 72 LDCs because we include Hydro One Networks as an LDC). This includes Hydro One Brampton Networks Inc., a wholly owned subsidiary of Hydro One Inc., which operates as a standalone LDC serving the City of Brampton area. In addition, Hydro One Remote Communities Inc. operates standalone generation and distribution systems for 21 remote northern Ontario communities serving 3,500 customers.

Figure 1 shows the organization and the roles and responsibilities of key entities, including Hydro One, involved in the electricity system in Ontario, covering policy formulation, planning, generation, pricing, regulation, transmission and distribution. (See **Section 3.05** of this year's Annual Report for our audit of the Ministry of Energy's Electricity Power System Planning.)

Hydro One's mandate is to be a safe, reliable and cost-effective transmitter and distributor of electricity. The corporation is subject to direction from its sole shareholder, the government of Ontario, and operates in accordance with governing legislation and regulations, particularly the *Electricity Act, 1998*. The board of directors is responsible for the stewardship of the company and supervision of management.

Hydro One's transmission and distribution businesses are licensed and regulated by the Ontario Energy Board (OEB) under the authority of the *Ontario Energy Board Act, 1998*. The OEB sets transmission and distribution rates and issues licences to Hydro One for both systems.

Hydro One is bound by the terms of its transmission and distribution licences, as well as the requirements of the Transmission System Code and Distribution System Code, both issued by the OEB. The codes provide the minimum conditions a transmitter or distributor must meet in carrying out its obligation to operate and maintain each system.

Hydro One's earnings are principally generated from its regulated transmission and distribution businesses. For the year ending December 31, 2014, Hydro One's total revenues were $6.548 billion, and its operating and other costs were $5.801 billion, resulting in a net income of $747 million. Hydro One's transmission, distribution and telecommunication net fixed assets were valued at about $16.2 billion. At the end of 2014, Hydro One had 5,500 permanent staff and had employed 2,100 temporary workers during the year. The temporary workers are mainly seasonal, working from April to October on construction projects and to supplement Hydro One lines and forestry groups.

1.2 Transmission System

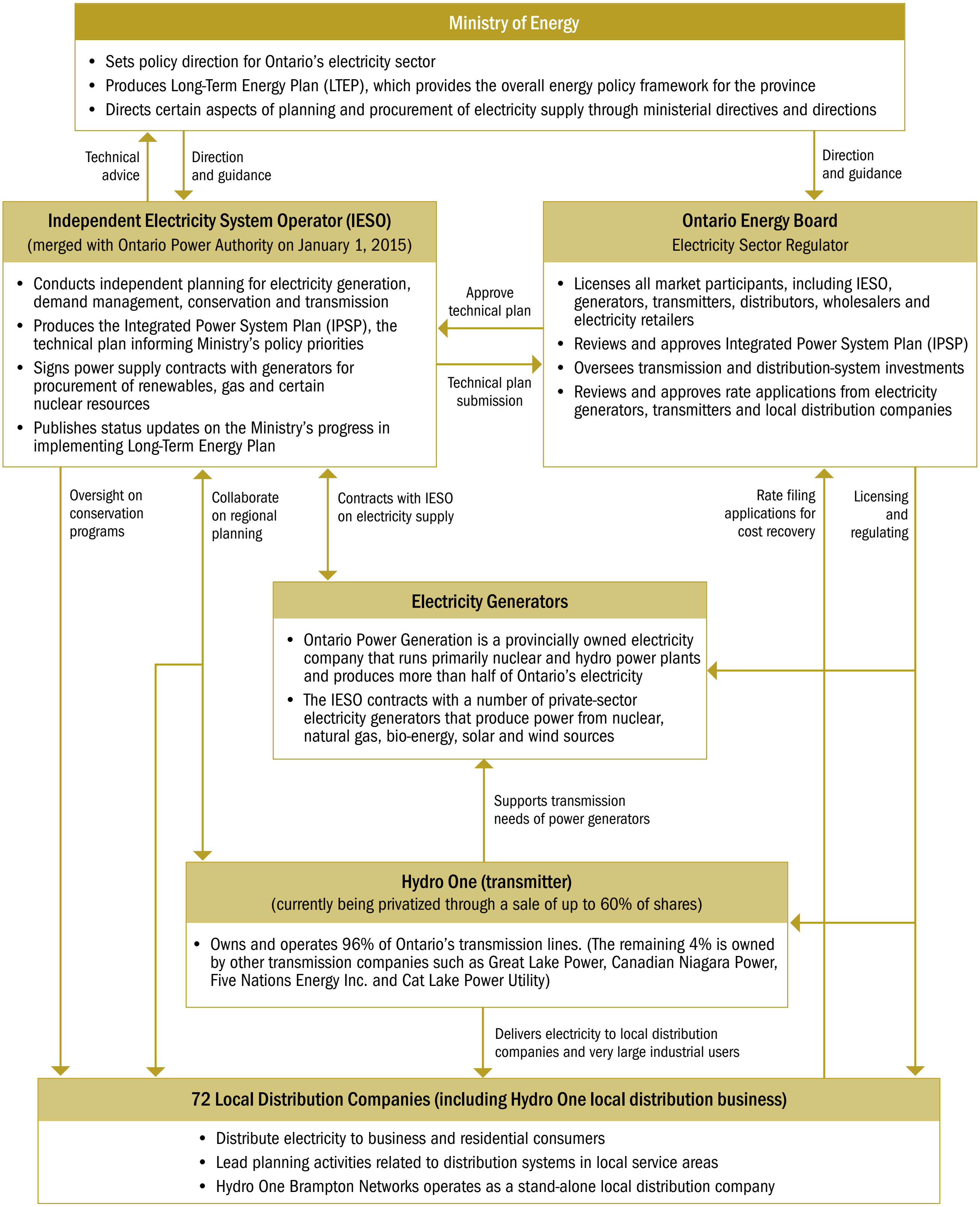
Hydro One's transmission system had net tangible capital assets (for example, lines, towers and transformer stations) valued at $9.3 billion as of December 31, 2014. The transmission system operates over long distances and links electricity generating facilities to LDCs and end-user transmission customers, such as mines, automobile manufacturing facilities and petro-chemical plants via transmission towers and lines connected to transformer stations. The transmission system is linked to five adjoining jurisdictions: Quebec, Manitoba, New York, Michigan and Minnesota. These interconnections are designed to facilitate the transfer of electricity between Ontario and other jurisdictions.

High-voltage transmission towers and lines operate at 500,000 volts, 230,000 volts and 115,000 volts. Almost all lines are overhead, as opposed to underground. Key components of high-voltage transmission lines include the lines, overhead conductors, steel support structures (towers) and grounding systems. Hydro One owns and operates 299 transformer stations that contain 722 power transformers, 4,604 power circuit breakers and 14,000 switches, along with protection and control equipment. There is also physical infrastructure, such as buildings, roads and security fences within a station's boundaries.

Unplanned power outages on the transmission system are primarily caused by weather, particularly lightning strikes, and by equipment failures. Approximately 70% of the delivery points (which receive over 85% of all electricity) on Hydro One's

Figure 1: Roles and Responsibilities of Key Entities Involved in the Electricity System in Ontario

Prepared by the Office of the Auditor General of Ontario



transmission system are multi-circuit delivery points, meaning they have more than one line available to provide power to customers along that line. The remainder of the transmission system features single-circuit delivery points. Where there are multiple transmission towers and lines connected to a customer, a power outage on one line will not disrupt the power supply to a customer because the other operational line still provides electricity.

(Please see the **Appendix** at the end of this report for a glossary of terms we have used.)

Hydro One must adhere to reliability standards established by the North American Electricity Reliability Corporation (NERC). NERC's mission is to ensure the overall reliability of the bulk electricity system in North America. As the North American transmission system is interconnected, its utilities share a common set of standards that govern the reliability of their operations. Working with the continent's approximately 1,400 bulk electricity transmitters, including Hydro One, NERC establishes and monitors these standards.

The transmission system is monitored, controlled and managed centrally by the Ontario Grid Control Centre (Control Centre) in Barrie. The Control Centre monitors the system around the clock electronically, responds to alarms caused by equipment, and can restore, divert and interrupt power transmission remotely. The Control Centre also authorizes all planned outages (such as when maintenance needs to be performed on transmission system equipment), and it dispatches repair crews to deal with unplanned outages.

Total transmission revenues for Hydro One in 2014 were $1.6 billion. Transmission revenue is based on the transmission tariffs set by the OEB, for which Hydro One makes rate applications every two years. The tariff is designed to recover from large industrial customers and LDCs enough revenue to support Hydro One's costs to operate and maintain the transmission system.

1.3 Distribution System

Hydro One's distribution system spans 75% of Ontario geographically and serves 28% of the province's customers. It serves approximately 1.4 million retail customers, 44 large industrial users and 24 smaller LDCs. Hydro One is the largest LDC in Ontario by both number of customers served and geographic area covered.

The distribution system's net tangible capital assets are valued at $5.9 billion. The system is composed of 123,000 kilometres of distribution lines that operate below 50,000 volts, 1.6 million wooden poles, 500,000 pole-top transformers and approximately 1,200 distribution stations. Distribution stations typically include equipment such as transformers, switches and protection and control equipment, and may include buildings, roads and security fences. From 2012 to 2014, Hydro One installed at a cost of $660 million approximately 1.2 million smart meters, which allows it to remotely receive individual customers' usage data over its telecommunications system.

The Control Centre is also responsible for overseeing the distribution system. However, the system is generally not equipped to monitor service electronically for outages. When a power outage occurs, the Control Centre receives service disruption calls from its customers, and it dispatches local work crews throughout the province to repair service. Unplanned power outages on the distribution system are often due to fallen trees and branches (31%), equipment failure (25%)and miscellaneous incidents such as accidents involving motor vehicles or wildlife (27%). On the other hand, outages on the transmission system, which feeds electricity to the distribution system, cause less than 1% of outages on the distribution system. In addition, planned outages for maintenance work account for 17% of outages.

Total revenue for the distribution business was approximately $4.9 billion in 2014. Similar to the transmission system, distribution revenue is based on distribution tariffs set by the OEB, which are based on separate rate applications that Hydro One submits, typically covering periods of one to three years.

1.4 Telecommunications System

Hydro One's high-speed telecommunications system throughout its transmission and distribution networks had net tangible capital assets of $541 million. The system is used to provide telecommunications for the monitoring, protection and control equipment of Hydro One's transmission system, as well as for corporate data and voice networks and smart meter operations for its distribution system. The system allows the Control Centre to receive real-time data on the performance of the transmission system and operate transmission protection equipment remotely. Use of the telecommunications system is also sold to telecommunications carriers and commercial customers, which in 2014 generated revenues of $57 million.

1.5 Privatization of Hydro One Inc. and Sale of Hydro One Brampton Networks Inc.

The government passed the *Building Ontario Up Act* in June 2015 to permit the sale of up to 60% of the province's common shares in Hydro One. The government announced plans for the fiscal year ending March 31, 2016, to release an initial public offering of approximately 15% of the common shares in Hydro One. The legislation requires the province to retain at least 40% the common shares in Hydro One, and no other single shareholder would be allowed to hold more than 10% of the total equity. In April 2015, the Premier's Advisory Council on Government Assets estimated Hydro One's valuation at $13.5 to $15 billion; using this estimate, selling 60% of Hydro One could bring up to $9 billion to the province, the sole shareholder.

Effective December 4, 2015, the *Building Ontario Up Act* also removed the ability of the Office of the Auditor General to conduct and report on value-for-money audits on the operations of Hydro One Inc. As a result, this audit of Hydro One's management of electricity transmission and distribution assets, which commenced prior to the tabling of the *Building Ontario Up Act*, will be the last value-for-money audit released by the Office.

The government is also proceeding with the sale of Hydro One Brampton Networks, expected to bring the province about $607 million, net of any price adjustments. In April 2015, the government announced that it had agreed to an unsolicited offer by three other LDCs, Enersource Corporation, Powerstream Holdings Inc. and Horizon Holdings Inc., to form a merger with Hydro One Brampton Networks.

On August 31, 2015, Hydro One declared a dividend transferring all its shares in Hydro One Brampton Networks to the province. The sale was still in progress as of September 2015 and subject to approval of the local municipalities that own the other LDCs and the Ontario Energy Board.

2.0 Audit Objective and Scope

Our audit objective was to assess whether Hydro One had adequate systems and procedures in place to manage and maintain its transmission and distribution assets efficiently and cost-effectively in accordance with relevant Hydro One policies and regulatory requirements, and to ensure the system was reliable for its customers.

Senior Hydro One management reviewed and agreed to our audit objective and criteria.

Our audit work included interviews with Hydro One management and staff, as well as review and analysis of relevant files, asset databases and other IT systems, policies and procedures, and Hydro One's transmission and distribution regulatory filings to the Ontario Energy Board.

Our work was primarily conducted at Hydro One's head office in Toronto. However, we also visited several transmission and distribution stations, the Ontario Grid Control Centre in Barrie and the Central Maintenance Shop in Pickering. During our visits we interviewed operations staff and we also held discussions with several key staff responsible for vegetation management throughout the province. We also met with representatives from the Association of Major Power Consumers in Ontario, the Canadian Electricity Association, and the Ontario Society of Professional Engineers. We reviewed past Hydro One Internal Audit reports, which also contained findings consistent with our own report.

The scope of our work did not include Hydro One Brampton Networks, which is managed and operated as a standalone LDC and is separate from Hydro One Networks, its distribution system. This audit also did not cover the government's recent decisions to privatize Hydro One Inc. and sell Hydro One Brampton Networks; both of these transactions had not been fully executed at the time our field work was completed in July 2015. We also did not cover Hydro One Remote Communities because its communities are not connected to Ontario's electricity grid.

Our audit fieldwork was conducted from January to July 2015, and we primarily focused on Hydro One activities over the three calendar years from 2012 to 2014.

3.0 Summary

Hydro One's mandate is to be a safe, reliable and cost-effective transmitter and distributor of electricity. Hydro One's customers instead have a power system for which reliability is worsening while costs are increasing. Customers are experiencing more frequent power outages, largely due to an asset management program that is not effective or timely in maintaining assets or replacing aging equipment, and an untimely vegetation-management program that has not been effectively reducing the number of outages caused by trees.

Some of the more significant areas we noted for improvement in transmission reliability included:

- **Transmission system reliability has deteriorated**: Hydro One's transmission system reliability has worsened for the five years from 2010 to 2014. Outages are lasting 30% longer and occurring 24% more frequently. In the same period, Hydro One's spending to operate the transmission system and replace assets that are old or in poor condition increased by 31%. While Hydro One's overall transmission system reliability compares favourably to other Canadian electricity transmitters, it has worsened in comparison to U.S. transmitters.
- **Equipment outages increasing, backlog of preventive maintenance growing**: Hydro One has a growing backlog of preventive maintenance orders to be performed on its transmission system equipment, and this lack of maintenance led to equipment failures. The backlog of preventive maintenance orders for transmission station equipment increased by 47%, from 3,211 orders as of 2012 to 4,730 orders as of 2014. At the same time, the number of equipment outages on the transmission system increased by 7%, from 2,010 in 2012 to 2,147 in 2014. The cost to clear the backlog of preventive maintenance work orders has grown 36%, from $6.1 million as of December 31, 2012, to $8.3 million as of December 31, 2014.
- **Hydro One not replacing very high-risk assets, contrary to its rate applications**: We found Hydro One was not replacing assets it determined were in very poor condition and at very high risk of failing, and it used these assets in successive rate applications to the Ontario Energy Board to justify and receive rate increases. Power transformers that are identified as being in very poor condition should be replaced at the earliest time possible; however, Hydro One replaced only four of the 18 power transformers it deemed to be in very poor condition in its 2013-2014

application used to obtain rate increases, and instead replaced other old transformers rated in better condition. These transformers are at a higher risk to fail, and we found two power transformers rated as being in very poor condition that failed and resulted in outages to customers lasting 200 minutes in 2013 and 220 minutes in 2015. Hydro One's transmission system rate application for the two-year period 2015-2016 listed 34 power transformers as rated "very high risk" for failure; however, the application did not indicate that Hydro One was planning to replace only eight of these over this period. In choosing not to use the additional funds from rate increases approved by the OEB to replace 26 transformers in very poor condition, Hydro One will have to seek $148 million again in the future to carry out the overdue replacement.

- **Significant transmission assets that are beyond their expected service life still in use**: Hydro One's risk of power failures can increase if it does not have an effective program for replacing transmission assets that have exceeded their planned useful service life. The number of key transmission assets, such as transformers, circuit breakers, and wood poles, in service beyond their normal replacement date ranged from 8% to 26% for all types of assets in service. Replacing these assets will eventually cost Hydro One an estimated $4.472 billion, or over 600% more than its $621-million capital sustainment expenditure for 2014.
- **Funding requests made to Ontario Energy Board not supported by reliable data**: The asset condition ratings provided by Hydro One in its 2013-2014 and 2015-2016 rate applications to the OEB were inaccurate and contained errors because of unreliable internal systems for reporting on the condition of assets. We found that 27 of the 41 transformers replaced in 2013 or 2014 had been wrongly identified in the rate applications as being in good or very good condition, yet Hydro One had plans at the time to replace several of these transformers due to their old age or poor condition. Similarly, we noted that 24 of the 43 transformers inaccurately reported in the 2015-2016 rate application as having a low or very low risk of failure were already scheduled to be replaced during this period.
- **Asset Analytics System not accurately considering all factors related to asset replacement decisions**: Key information is often not included, or incorrectly weighted, in the Asset Analytics system, Hydro One's new asset investment planning IT system implemented in 2012 to replace older systems. As a result, assets that need replacing are not being accurately identified. We found that the Asset Analytics database does not incorporate qualitative factors, such as technological or manufacturer obsolescence information, known asset defects and health and safety concerns. For example, oil leaks are one of the leading reasons for replacing a transformer. However, this information has only a minor impact in Asset Analytics for determining the risk of the asset failing and the need to replace it. In its reporting to OEB, Hydro One assigns oil leaks an impact on a transformer's condition rating of only 15% in determining whether an asset is classified as being in very good to very poor condition overall.
- **Limited security for electronic devices increases risk of power outages**: Hydro One's approach to ensuring proper security over transmission system electronic devices did not ensure a robust, high level of security for all of its electronic devices. Only certain devices in its transmission system receive higher levels of security in order for it to meet North American Electricity Reliability Corporation (NERC) standards for the bulk electricity system, which includes those major transmission lines and transformer stations that are linked to other states and provinces.

Hydro One is required to apply NERC standards related to electronic devices to only 18% of its transmission stations, and only to critical devices, which make up less than 17% of the electronic devices at these stations. All other electronic devices that are used for transmission within Ontario and don't impact the bulk electricity system are covered by Hydro One's weaker security policy, which was not applied consistently to devices. This increases the risk of service disruptions for Ontario customers due to sabotage, vandalism, software viruses and unauthorized or unintentional changes to device software or controls.

Some of the more significant areas we noted for improvement in distribution reliability are as follows:

- **Distribution reliability poor and costs have increased**: Hydro One's distribution system has consistently been one of the least reliable among large Canadian electricity distributors between 2010 and 2014. The average duration of outages reported by members of the Canadian Electricity Association (CEA) between 2010 and 2014 was about 59% less than Hydro One over the same period, while average frequency of outages among CEA members was 30% lower. In a scorecard published by the Ontario Energy Board in 2014, Hydro One was ranked worst and second worst of all distributors in Ontario for duration and frequency of outages in 2013. Over the same period, spending increased by 18% to operate and maintain the distribution system or replace assets that were old or in poor condition.
- **Hydro One not clearing vegetation (forestry) around distribution system in timely way, thus increasing the risk of outages and system reliability**: The top reason for distribution system outages from 2010 to 2014 was broken lines caused by fallen trees or tree limbs. A key factor in this was that Hydro One operates on a 9.5-year vegetation-management cycle, while the average such cycle for 14 of Hydro One's peer utilities was 3.8 years. Hydro One's own analysis indicates that by not operating on a vegetation-management cycle similar to its peers, the vegetation-management work it did in 2014 cost $84 million more than it would have under a four-year vegetation management cycle and customers would have experienced fewer outages caused by trees, and, therefore, had 36 minutes less in total outage time for the year.
- **Improper prioritization of vegetation-management work resulted in more tree-caused outages**: The system used by Hydro One to designate distribution lines for vegetation management does not put priority on those areas where tree-related outages have caused disruptions. We found examples where vegetation management was performed on distribution lines that had had few tree-caused outages, at the expense of distribution lines that had had significantly more tree-caused outages. This resulted in the number of tree-caused outages increasing by 5% from 2010 to 2014 (from 7,747 in 2010 to 8,129 in 2014), while vegetation management spending increased by 14% over the same period ($161 million in 2010 to $183 million in 2014).
- **Asset Analytics ratings information for distribution assets is incomplete and unreliable**: As of July 2015, Hydro One's Asset Analytics system, a key tool in making replacement decisions, had incomplete and unreliable data for distribution assets. We found that three years after the implementation of the Asset Analytics database, it contained incomplete or erroneous data for distribution system assets. For example:
    - there was limited data available to evaluate all 152 distribution station breakers; and
    - 14 distribution station power transformers that are under 10 years old were mistakenly

assigned age scores of 100, which would be past the 40-year expected service life of such transformers.

- **Significant distribution assets that are beyond their expected service life still in use**: Hydro One increases the risk of power failures by not replacing distribution system assets that have exceeded their planned useful service life. Hydro One's planned service life for wood poles is 62 years, but 202,000 poles, or 13% of the total, were older than that. Replacing these poles will eventually cost $1.76 billion. Only about 12,000 poles are replaced each year, much less than the number needed to address the risk of poles falling and much less than the number that are in service beyond their expected service life. In addition, it will eventually cost another $158 million to replace the 243 station transformers beyond their 50-year expected service life.
- **Smart meters not used to proactively identify power outages**: Hydro One installed 1.2 million smart meters on its distribution system at a cost of $660 million, yet it has not implemented the related software and capabilities to improve its response times to power outages. Currently, smart meters are used by Hydro One predominantly for billing purposes and not to remotely identify the location of power outages in the distribution system before a customer calls to report an outage. Such information from smart meters would make dispatching of work crews timelier and more efficient, leading to improved customer service and cost savings.

Some of the other significant areas we noted for improvement pertaining to both the transmission and distribution systems are as follows:

- **Excessive number of spare transformers in storage**: Hydro One did not have a cost-effective strategy for ensuring it had an appropriate number of spare transformers on hand, resulting in it having too many spare transformers in storage. While typically only about 10 transformers fail annually, Hydro One had 200 spare transformers—60 transmission transformers and 140 distribution transformers—valued at around $80 million in storage at the Central Maintenance Shop in Pickering. Thirty-five of these transformers had been in storage for at least 10 years. Hydro One itself estimates that by standardizing transformers and improving forecasting, it could reduce the number of spare transformers by up to 35% and save up to $20 million over the next 10 years. We estimate this savings could be much higher with better management, ranging from $50-$70 million.
- **Power quality issues are not corrected proactively**: Major transmission and distribution customers are concerned about the quality of their power, such as having stable voltage levels, but Hydro One addresses power quality issues only if customers complain. Hydro One has received 150 power quality complaints from 90 large industrial transmission customers alone since 2009. To measure fluctuations and assess the frequency and location of power quality events, Hydro One has installed 138 power quality meters across its transmission and distribution systems since 2010. However, Hydro One is not monitoring and analyzing the data from these meters to improve system reliability for its customers unless a customer first calls to complain.
- **Weak management oversight processes over capital project costs**: While Hydro One spent over $1 billion annually from 2012 to 2014 on capital projects to sustain its transmission and distribution systems, we noted it had weak oversight processes to minimize projects costs. For instance, up to 55% of projects costs are internal charges, since Hydro One primarily uses its own employees to carry out construction projects; however, it does not regularly analyze or benchmark its internal costs to industry standards to assess whether they are reasonable.

We also found that all capital project estimates used for approving projects included on average a 20% contingency charge allowance and an 8% escalation charge allowance, which gave Hydro One staff little incentive to complete a project at its original project cost estimate, or develop more accurate cost estimates for projects. We asked Hydro One management to prepare a report that compared the original project approval, including allowances, with the actual project costs for all projects completed for the years 2013 to 2015. The report we received in June 2015 was incomplete, and only included 61 of the 105 projects approved for over $1 million. Using the incomplete report, we estimate Hydro One spent on average 22% more than the original project cost estimates and used the allowances to complete these projects. This amounted to a total of $150 million more spent on the projects than the original project cost estimates.

Given that the Office of the Auditor General will no longer have jurisdiction over Hydro One as of December 4, 2015, we have made the following recommendation, requesting that the Ontario Energy Board take the observations we have made in this report into consideration during its regulatory processes:

- That the Ontario Energy Board, on behalf of electricity ratepayers in Ontario, as part of its regulatory oversight of Hydro One, review this report, the recommendations, and future actions taken by Hydro One to improve the reliability and cost-effectiveness of its transmission and distribution systems.

This report contains 17 recommendations to Hydro One, consisting of 37 actions, to address the findings noted during this audit.

OVERALL ONTARIO ENERGY BOARD RESPONSE

As part of its regulatory regime, the Ontario Energy Board (OEB) uses processes to hold all utilities, including Hydro One, to a high standard of efficiency and effectiveness. The recommendations made by the Auditor General in this report are useful in further supporting our efforts and in holding Hydro One accountable for prudently managing its resources and improving its service.

The OEB is committed to using all key information available for its deliberations and decision-making processes, and will, as appropriate, consider the areas of improvement identified by the Auditor General in future as it exercises its regulatory functions to ensure that Hydro One undertakes appropriate planning and investing, and optimal maintenance of its systems, and that it benchmarks itself against external comparators.

The report highlights a number of areas where Hydro One can improve the quality of its planning and the cost-effectiveness of its execution of those plans. The OEB likewise places a high priority on delivering value to electricity customers for the rates they pay. In 2012, the OEB developed the renewed regulatory framework for electricity (RRFE) distributors, which places a focus on rigorous asset management and capital planning in support of cost-efficient operations. The framework prescribes use of industry benchmarking to ensure improvement in cost performance and contains high expectations of continuous improvement to increase the productivity of operations. Utilities are expected to engage with their customers to understand their needs and preferences and to focus on the achievement of outcomes that take their priorities into account.

In its evaluation of Hydro One's most recent rate-rebasing application (EB-2013-0416), the first such application that it filed under the OEB's renewed framework, the OEB identified certain deficits: among other things, it concluded that Hydro One Networks Inc.'s distribution investment planning does not yet appear to be properly aligned with the actual condition of its assets; that its vegetation management does not show sufficient efficiencies or productivity improvements; and that its productivity commitments do not show the company to have a strong enough orientation toward continuous improvement.

Consequently, the OEB has already secured Hydro One's commitment to measure and report on many of the areas that the Auditor General's report has highlighted in its audit recommendations. In fact, in light of its concerns as to whether Hydro One's distribution investment priorities had been optimized, in Hydro One's last rate application, the OEB approved only three years of a proposed capital spending plan rather than the five years Hydro One requested, and indicated that further approvals will be contingent on the quality of Hydro One's supporting evidence.

The OEB decision in this application took further steps to ensure that Hydro One addresses shortcomings in its planning and benchmarking, many of which intersect directly with the recommendations of the Auditor General. Specifically, the OEB has ordered or otherwise secured Hydro One's commitment, among other things, to:

- conduct external benchmarking on the unit costs of its distribution pole replacement and station refurbishment plans;
- consider external review of its distribution system planning;
- report on achieved in-service investments relative to plan;
- undertake a total factor productivity study of Hydro One's own productivity, including data from 2002 and following years at a minimum; and
- explore best practices in vegetation management, considering changes in labour mix and innovation opportunities, as well as conduct a trend analysis of the vegetation management program showing year-over-year variations in unit costs.

Similar focus has also fallen on Hydro One's transmission business. As part of its most recent transmission rate application (EB-2014-0140), Hydro One has committed to benchmark its transmission cost performance relative to similar companies. The OEB is also working toward the implementation of the RRFE framework for transmission in Ontario as part of its continued commitment to ensure that the owners and operators of electricity networks in Ontario provide reliable, cost-effective service at rates that represent good value to customers.

OVERALL HYDRO ONE RESPONSE

Managing Hydro One's massive and complex transmission and distribution system requires considerable engineering expertise and dynamic asset management strategies that result in timely and disciplined investments to maintain or improve reliability and optimize equipment performance and cost. The Company recognizes there is always room to do better in this regard, so it makes continuous improvement a primary consideration in all of its asset plans and strategies.

Hydro One has strengthened the oversight of the Company and its operations. Internal Audit, reporting directly to the Audit Committee of the independent Board of Directors, will review this report and will oversee the Company's implementation of the recommendations where Hydro One believes they enhance reliability while balancing service and cost.

Hydro One's transmission and distribution businesses are regulated by the Ontario Energy Board (OEB), and the Company must comply with the conditions of service within the transmission and distribution system codes as part of its license. Hydro One places a high priority on its obligation to provide the OEB with complete, accurate and supportable evidence in its rate applications. Additionally, the Company acts on the recommendations and direction of the OEB as outlined in successive rate decisions.

Going forward, Hydro One is focused on delivering improved business performance and superior customer service as the Company prudently invests in Ontario's electricity transmission and distribution infrastructure. The Company will continue to do so while balancing service with cost.

Hydro One appreciates the work of the Auditor General and her staff, and the opportunity to respond to the findings within the audit. The recommendations provided as a result of this audit are being carefully considered as the Company moves forward.

4.0 Detailed Audit Observations

4.1 Transmission System

4.1.1 System Reliability Worsened from 2010 to 2014

Hydro One's transmission system customers expect their system to be reliable. However, we found that the system became less reliable from 2010 to 2014, with longer and more frequent outages. Hydro One's overall transmission system reliability compares favourably to other Canadian electricity transmitters; however, its reliability has worsened compared to U.S. transmitters.

Transmission system reliability is measured by two main metrics: the duration of outages and the frequency of outages. The System Average Interruption Duration Index (SAIDI) (average duration of outages) measures the average number of minutes per year each delivery point on the transmission system has experienced an outage, while the System Average Interruption Frequency Index (SAIFI) (average frequency of outages) measures the average number of outages per delivery point per year.

Hydro One measures system reliability separately for areas that are serviced by single-circuit delivery points, where a customer has only one line delivering electricity, and multi-circuit delivery points, where a customer has multiple towers and lines delivering electricity. Transmission outages are less likely to occur in areas that have multiple towers and lines since electricity can be supplied uninterrupted using an alternative line should one become out of service. Hydro One publicly reports on the performance of its transmission system based only on its areas serviced by multi-circuit delivery points, which cover over 85% of the electricity it delivers.

The difference in reliability between areas serviced by single or multiple lines was significant. As shown in **Figure 2**, single-circuit areas averaged 217.5 minutes in outages per year from 2010 to 2014, and the number of minutes varied significantly between years. In comparison, multi-circuit areas averaged 9.9 minutes in outages per year. Similarly, the number of outages averaged 3.22 per year per delivery point for the single-circuit transmission system compared to only 0.31 per year for the multi-circuit transmission system.

We found 47% of transmission outages from 2010 to 2014 occurred in Northern Ontario, even though this is where fewer than 20% of Hydro One's delivery points are located. In Northern Ontario, 86% of the delivery points are single circuit supplied. As it is costly to build additional towers and lines, Hydro One does not attempt to convert rural single-circuit delivery points that serve fewer, or smaller, customers to multi-circuit delivery points because it does not consider it cost effective to do so, even if it would improve system reliability for these customers.

For multi-circuit areas of the transmission system, Hydro One's reliability performance has deteriorated significantly since 2010. **Figure 2** shows that average duration of outages and average frequency of outages worsened (increased) by

Figure 2: Hydro One Transmission System Outages, 2010–2014
Source of data: Hydro One

	2010	2011[1]	2012	2013	2014[2]	Five-year Average	% Change Between 2010 and 2014
Multi-circuit Delivery Points							
SAIDI (minutes per delivery point)	9.1	8.9	6.8	12.9	11.8	9.9	30
SAIFI (outages per delivery point)	0.29	0.33	0.28	0.30	0.36	0.31	24
Unplanned outages	176	203	175	189	228	194	30
Single-circuit Delivery Points							
SAIDI (minutes per delivery point)	165.2	410.0	224.9	192.4	95.2	217.5	–42
SAIFI (outages per delivery point)	2.99	3.25	3.59	3.55	2.73	3.22	-9
Unplanned outages	820	851	947	945	737	860	–10

1. Hydro One indicated that 2011 was an extraordinary year for power outages for areas serviced by single-circuit delivery points because of forest fires in northern Ontario. Forest-fire-triggered outages accounted for 234 minutes out of the total 410 minutes incurred during that year.
2. Hydro One indicated that 2014 performance improved significantly for power outages for areas serviced by single-circuit delivery points primarily because of relatively less adverse weather during the year.

approximately 30% and 24% respectively from 2010 to 2014, and unplanned outages increased by 30%. Hydro One's records indicate this deterioration in reliability is primarily due to an increase in the number of unplanned outages, such as those caused by equipment failure or weather, that occurred at the same time as planned outages for such work as refurbishing or replacing aging transmission system assets, which temporarily rendered the alternate lines inoperative. If the alternate lines had been in operation at the time, those customers would likely not have experienced outages. These types of outages increased by 27% from 2010 to 2014 (from 74 outages in 2010 to 94 outages in 2014).

Despite the fact that Hydro One's recent transmission system reliability has worsened, it still compares favourably to other Canadian transmitters. The Canadian Electricity Association (CEA) collects information on the system reliability of Canadian electrical transmitters. Annually from 2010 to 2014, Hydro One's average duration and frequency of outages were generally better than the CEA average each year.

4.1.2 Transmission System Reliability is Poor Compared to the U.S.

As part of the bulk electricity system in North America, Hydro One's transmission system is integrated with transmitters in the United States. Hydro One participates in an annual transmission system reliability benchmarking study with transmitters in the United States, and the results indicate the reliability of Hydro One's system was generally worse than other transmitters. Other provinces' transmitters that are also on the bulk electricity system do not participate in these studies.

The study compares various metrics, including the average frequency and duration of outages, of a transmitter's entire system. In the 2011 report, based on outage data from 2006 to 2010, Hydro One's average duration and frequency of outages ranked only 21st and 22nd respectively out of the 25 participants. Similarly, in the 2015 study, based on outage data from 2010 to 2014, Hydro One was ranked only 10th and 13th for the average duration and frequency of outages out of 14 participants, and both averages were higher (worse) than the scores from the 2011 report.

The study also compares the reliability of only the portion of each transmitter's system that is part of the bulk electricity system. In the 2011 report, Hydro One's average duration of outages for its bulk electricity system was ranked 21st out of 24, and in the 2015 report, it ranked only 12th out of 14. In the 2011 report, Hydro One's average frequency of outages for its bulk electricity system was ranked only 21st out of 24, and in the 2015 report, it ranked only 13th out of 14.

4.1.3 Transmission System Availability Has Worsened from 2006 to 2014 Compared to Other Provincial and U.S. Transmitters

Comparison to Other Provincial Utilities

The Canadian Electricity Association (CEA) collects data from and reports to its provincial utility members on an availability metric for their transmission systems. The metric identifies how often electricity was unavailable, in system minutes, on the transmission system.

The CEA's data shows that Hydro One's availability is generally better than the CEA average of other provincial transmitters, with Hydro One unavailability at 16.4 system minutes compared to the CEA's average of 19.5 minutes using the average unavailability during the period 2010-2014.

Nevertheless, Hydro One's availability has worsened over time. While the CEA's 2011 report found that from 2006 to 2010, Hydro One's unavailability was 14.6 system minutes on average per year, this increased to 16.4 system minutes on average per year in the 2015 report, which reports on data from 2010 to 2014. While Hydro One's unavailability increased by 12% between the 2011 and 2015 reports, the CEA average unavailability decreased slightly during the same period, from 20.2 system minutes to 19.5 system minutes.

Transmission system availability is impacted by both planned and unplanned outages. It appears that Hydro One may have had more scheduled outages due to increased spending for maintenance, repairs and improvements, and therefore availability was negatively impacted when primary or back-up lines were shut down.

Comparison to U.S. Transmitters

The transmission system reliability benchmarking study Hydro One participates in with transmitters in the United States indicates that the unavailability of Hydro One's system is higher than other participating transmitters.

The study compares an overall Transmission Availability Composite Score (TACS), which measures the availability of electricity (how often transmission customers had electricity available for their use compared to how often they desired electricity). In the 2011 report, based on outage data from 2006 to 2010, Hydro One's TACS ranked it 23rd out of 25 participants. Similarly, in the 2015 study, based on outage data from 2010 to 2014 from 14 participants, Hydro One scored worse than it had in 2011 and placed last, including being behind the two transmitters that had a worse TACS than Hydro One in 2011.

On the other hand, Hydro One's availability for only the portion of each transmitter's system that is part of the bulk electricity system has improved compared to others U.S. transmitters surveyed. While Hydro One's system availability decreased (worsened) between the 2011 and 2015 reports, Hydro One's overall ranking improved from 13th of 24 in the 2011 report to fourth of 14 in the 2015.

We asked Hydro One management why U.S. transmitters generally have more reliable systems, and were advised that they typically have shorter distances to deliver electricity than Hydro One, and that Ontario's geography is larger and more challenging to service. However, no detailed analysis was available that studied these reasons or how to overcome the differences.

RECOMMENDATION 1

To ensure the reliable operation of the transmission system and to reduce the number of power outages experienced by customers, Hydro One should:

- set multi-year targets and timetables for reducing the frequency and duration of power outages that would lead to it having a system reliability and availability that compares favourably to other utilities in North America, establish an action plan and strategy for achieving these targets, and regularly report publicly on its efforts to achieve these targets;

- set targets and timetables, and cost-effective action plans, to improve the poor performance of its single-circuit transmission system; and
- more thoroughly analyze outage data on both its single- and multi-circuit systems to correct the main issues that are contributing to the system's declining reliability.

HYDRO ONE RESPONSE

Hydro One agrees with the Auditor General's recommendation and has started setting multi-year reliability targets in its 2015 Corporate Scorecard. The 2015 Corporate Scorecard included both 2015 and 2019 targets to signal the Company's drive to continuous improvement.

Hydro One will continue to make reliability a key priority by reducing the number of planned outages. It will do so by combining planned maintenance activities undertaken during the outage. This will reduce the risk of customer interruptions.

Hydro One's single circuit delivery points, by design, are not as reliable as delivery points served by multiple circuits. Single-circuit delivery point reliability has increased over the 2010–14 time horizon, as shown by the improved SAIDI and SAIFI results and lower unplanned outages.

Hydro One does respond to customer requests to improve reliability, providing the customer is prepared to pay the costs of the necessary investments in accordance with the Ontario Energy Board's (OEB's) Transmission System Code (TSC). The TSC requires affected customers to consent to pay their respective shares of the cost of the additional circuit. Customers have generally not provided such consent in Ontario, where such costs tend to be high due to low customer density and long lines.

Hydro One will continue to analyze outage data to identify issues relating to reliability. Hydro One carries out investments to improve customer reliability in accordance with the Customer Delivery Point Performance Standard issued by the OEB. This standard sets out thresholds for inadequate performance and appropriate funding levels based on minimum improvement levels and size of the customer load. The investments balance costs and benefits, and consider the degree of the improvement and the size of the load that is impacted.

Hydro One will undertake network expansions to provide redundant supplies and improve reliability to electrical areas that serve multiple customers when electricity demand in the area meets the criteria established by the Independent Electricity System Operator's Ontario Resource Transmission Assessment Criteria standard. The objective of the standard is to balance cost, customer benefit and ratepayer impacts.

4.1.4 Growing Backlog of Preventive Maintenance on Equipment Reduced System Reliability

A lack of preventive maintenance can lead to a shorter expected service life of equipment and premature equipment failure, which is the second-most common cause of outages (16% of all outages from 2010 to 2014). We found that the growth in the backlog of preventive maintenance on transmission system equipment from 2012 to 2014 likely contributed to an increase in the number of equipment outages on the transmission system. The backlog increased by 47%, from 3,211 orders as of 2012 to 4,730 orders as of 2014. During the same period, the total number of equipment outages on the transmission system increased by 7%, from 2,010 instances in 2012 to 2,147 instances in 2014.

Almost half (48%) of the preventive maintenance backlog in 2014 relates to the two most critical assets within a transmission station—transformers and circuit breakers. The backlog of preventive maintenance for these assets increased by 320% and 393%, respectively, from 2012 to 2014. During the same period, the increase in the number of transformer and circuit breaker outages on the transmission system increased by approximately 14% and 36%, respectively. We identified instances where a key piece of equipment for the transmission system failed that had backlogged preventive maintenance work.

Hydro One advised us that the backlog exists because it does not have sufficient staff available to perform all scheduled maintenance. The situation has worsened since 2012 as maintenance staff have been assigned to complete capital projects to repair or refurbish Hydro One's aging transmission system. We estimate from the preventive maintenance work orders in the backlog that the cost to clear the backlog has grown 36%, from $6.1 million as of December 31, 2012, to $8.3 million as of December 31, 2014. We believe that an $8.3-million backlog should have been manageable and eliminated long ago by Hydro One, given their multi-billion dollar annual operating budgets; instead, it is growing and impacting system reliability.

RECOMMENDATION 2

To ensure that Hydro One has an effective preventive maintenance program for all its critical transmission system assets to ensure they operate reliably and their expected service life is not shortened, Hydro One should:

- establish a timetable that eliminates its growing preventive maintenance backlog as soon as possible; and
- improve its oversight of preventive maintenance programs to ensure maintenance is completed as required and on time.

HYDRO ONE RESPONSE

Hydro One agrees that more diligence is required to ensure that the records contained in its management information system are reflective of actual outstanding maintenance. Consistent with industry practice, Hydro One maintains a catalogue of planned maintenance work that may have completion dates that extend well into the future. These maintenance orders are released well in advance of required completion dates to allow Hydro One to bundle work effectively (thus avoiding the need for multiple planned outages). Reducing the number and duration of planned outages reduces the risk of customer interruptions.

All critical preventative maintenance is completed when required. Maintenance activities that need to comply with industry standards are confirmed through Hydro One's Internal Compliance Program.

Hydro One will continue to prioritize work to enhance reliability and optimize work efficiency, while at the same time balancing service and cost.

4.1.5 Hydro One Not Replacing Transmission Assets that Are at Very High Risk of Failure

We found that the assets that Hydro One replaced or planned to replace from 2013 to 2016 were not the ones that it reported to be in very poor condition and at very high risk of failure in its bi-annual transmission rate applications to the Ontario Energy Board (OEB). In its rate application for 2013-2014, Hydro One stated that it had a program to replace power transformers and circuit breakers that had reached the end of their useful service lives, which was determined by evidence including the condition and age of the asset and its operating history. The rate application noted that the condition of an asset is the main indicator of its risk of failing, and that replacing assets that are in poor condition as soon as possible is key to maintaining the reliability of the system.

Based on Hydro One's report of its aging and deteriorating transmission transformers, as presented in its rate applications, the OEB approved increased capital sustainment funding for the period 2013 to 2016. As a result, Hydro One's transmission transformer replacement spending increased to more than $280 million over the two years 2013 and 2014 from $180 million over 2011 and 2012. Hydro One also planned to spend about $225 million on transformer replacements over 2015 and 2016.

In its 2013-2014 transmission rate application filed in May 2012, Hydro One reported that 18 of its 719 power transformers as of December 2011 were rated as being in very poor condition and at a very high risk of failure. Most of these 18 power transformers were at or past their expected service life of 40 to 60 years, with their average age being over 60 years.

However, as **Figure 3** shows, Hydro One replaced only four of the 18 power transformers deemed to be in very poor condition in 2013 and 2014, and replaced 37 other old power transformers, including 14 rated as being in very good condition and 13 in good condition. Of the four power transformers in very poor condition that were replaced, one failed prior to its replacement in 2013, causing a major power outage of 200 minutes on September 12, 2013, in an eastern Ontario town. One of the remaining 14 power transformers rated as being in very poor condition that was not replaced also failed in 2015, causing a major outage of 220 minutes on February 13, 2015, affecting customers in Toronto.

In its 2015-2016 transmission rates application filed in June 2014, indicating it wanted to replace 43 transformers, Hydro One informed the OEB that it now had 34 power transformers deemed as being at very high risk of failure. The application did not state that the 34 transformers included 13 that had been identified in the previous rate application as being in very poor condition, but had not yet been replaced. However, information for 2015-2016 provided to us by Hydro One indicated that of the 43 transformers it indicated it wanted to replace, it planned to replace only eight of the 34 in very poor condition. By not replacing 26 transformers in very poor condition, even though the OEB approved rate increases to fund these replacements, Hydro One will have to seek $148 million again in the future for their eventual overdue replacement.

Similarly, as **Figure 3** shows, Hydro One did not replace circuit breakers during 2013 and 2014 in accordance with the condition ratings it submitted to the OEB. While 153 circuit breakers were replaced at a cost of $123 million, only one of the 16 circuit breakers reported as being in very poor condition was replaced, and 63% of breakers replaced were in fair, good or very good condition. In addition, Hydro One's planned replacement lists for 2015-2016 indicate that the 85 circuit breakers

Chapter 3 • VFM Section 3.06

Figure 3: Condition Ratings and Replacements of Transformers and Circuit Breakers

Source of data: Hydro One

	Condition Rating					
	Very Good	Good	Fair	Poor	Very Poor	Total
Transformers						
# as of December 2011*	374	203	68	56	18	**719**
# replaced in 2013–2014	14	13	6	4	4	**41**
Circuit Breakers						
# as of December 2011*	908	1,715	975	648	16	**4,262**
# replaced in 2013–2014	12	50	34	56	1	**153**

* This is the number reported in Hydro One's transmission rate application for 2013/14 filed with the Ontario Energy Board in May 2012.

to be replaced will include only 21 that were rated as having a high or very high risk of failure.

We asked Hydro One asset management staff why assets in very poor condition were not replaced while others in reportedly better condition were. We were advised that Hydro One generally does not rely solely on reports from its Asset Analytic system (discussed later in **Section 4.1.6**) to decide which transmission assets to replace. Instead, asset management staff prepare a business case for assets that cost more than $20 million and need replacing, and a shorter project execution summary for all other replacements. These reports consider factors not covered by Asset Analytics, such as health and safety issues, and an onsite inspection of the asset is made. However, we found that Hydro One did not use the results of this more in-depth process for its rate applications to the OEB, instead using the unreliable information from Asset Analytics.

Nevertheless, we confirmed with Hydro One that those assets reported to the OEB as being in very poor condition and very high risk during rate applications between 2013 and 2016 were accurately reported and in need of replacement as soon as possible. This still leaves us questioning decisions made by Hydro One asset management staff on how they prioritize transmission assets for replacement when assets known to be in very poor condition and very high risk are not replaced. We also question why they continue to report inaccurate information to justify rate increases in their applications to the OEB.

Transmission Assets in Service Beyond Their Expected Life Increases Risk of Power Outages

Hydro One increases the risk of power failures because it does not have an effective program for replacing transmission assets that have exceeded their planned useful service life. **Figure 4** shows the percentages of Hydro One's key transmission assets that are in service beyond their expected service life and the estimated replacement cost that Hydro One will incur to replace these assets. The number of key transmission assets in service beyond their normal replacement date ranged from 8% to 26% of all assets in service. Replacing these assets will cost Hydro One an estimated $4.472 billion, or over 600% higher than its $621 million capital sustainment expenditure for 2014.

For transformers and circuit breakers, Hydro One acknowledged in its June 2014 rate application for

Figure 4: Transmission Assets in Use Beyond Their Expected Service Life, as of June 2014

Source of data: Hydro One

Asset	# or Distance Covered as of June 2014	Years of Expected Service Life	% Assets in Use in June 2014 That Were Beyond Their Expected Service Life	Estimated Cost to Replace Assets That Were Beyond Their Expected Service Life ($ million)
Stations				
Transformer	722	40, 50 or 60*	24	988
Circuit breaker	4,604	40 or 55*	8	325
Protection system	12,135	20, 25 or 45*	17	224
Lines				
Overhead conductor and hardware	30,000 km	70	19	1,908
Wood pole structure	42,000	50	26	378
Steel structure	50,000	80 to 100*	21	397
Underground cable	290 km	50	16	252
Total				**4,472**

* There are different types of this asset, each with different years of expected service life.

2015-2016 that its transformer and circuit breaker reliability lagged behind Canadian Electricity Association (CEA) averages for 33 large utilities.

In addition, we noted that the expected service life that Hydro One sets for its transformers exceeds the average expected service life used by other CEA member utilities. Hydro One sets its expected service life at 40 to 60 years depending on the type of transformer, while the CEA average is 40 years.

RECOMMENDATION 3

To reduce the risk of equipment failures that can cause major power outages on the transmission system, Hydro One should:

- ensure that its asset replacement program targets assets that have the highest risk of failure, especially those rated as being in very poor condition;
- reassess its practice of replacing assets that are rated as being in good condition before replacing assets in very poor condition; and
- replace assets that have exceeded their planned useful service life.

HYDRO ONE RESPONSE

Hydro One agrees that an asset in good condition should not be replaced before an asset in poor condition unless justified by one or more additional factors in the asset replacement process (for example, customer requirements, inadequate capacity, known manufacturer defect and so on).

Hydro One's asset replacement program is supported by asset condition information, detailed engineering assessments and a prioritization process to manage risks (safety, reliability) and achieve execution efficiency (outage availability, resources, bundling with other work).

Hydro One considers equipment condition and defects as a leading indicator of major equipment performance.

Other factors that inform the decision to replace an asset include equipment obsolescence, criticality, utilization, maintenance costs, performance and demographics. The Company does not replace assets that, while old, are in good working condition.

RECOMMENDATION 4

Hydro One should ensure that its applications for rate increases to the Ontario Energy Board provide accurate information on its asset replacement activities, including whether it actually replaced assets in poor condition that were cited in previous applications and whether the same assets in poor condition are being resubmitted to obtain further or duplicate rate increases in current applications.

HYDRO ONE RESPONSE

Information about transformer age and condition, filed with the Ontario Energy Board as part of rate filings, is intended to establish overall fleet condition. This information alone is insufficient to establish plans for individual transformer replacements. Rather, it informs the investment plan and helps determine the size of the program.

Hydro One exercises discretion, based upon specific information and circumstances, in selecting, prioritizing and adjusting the timing (including deferral) of capital work. Consequently, a proposed investment can appear in subsequent rate applications.

In future rate submissions, Hydro One will provide evidence of what it accomplished relative to the previously filed /approved rate application.

4.1.6 Information Systems on Asset Condition Not Reliable

The system Hydro One uses to record the condition of transmission assets contained erroneous and incomplete information, and did not adequately support Hydro One staff decisions on when to replace assets. Hydro One also used unreliable information from its systems to report asset condition and age on OEB rate applications to justify its requests for rate increases. The OEB considers and approves rate increases for Hydro One to charge its customers based on this information for the period covered by the application. If the information is inaccurate, OEB cannot adequately assess Hydro One's need for replacement assets, and accurately approve rate changes, either decreases or increases, to meet Hydro One's needs and be fair to its customers.

Inaccurate Information Provided to OEB in Rate Applications

The condition ratings provided by Hydro One in its rate applications to the OEB for the periods 2013-2014 and 2015-2016 were inaccurate and contained errors. As **Figure 3** shows, we found that 27 of the 41 transformers replaced in 2013 or 2014 had been identified in the rate applications as being in good or very good condition, yet Hydro One had plans at the time to replace several of these transformers due to their old age or poor condition. Similarly, we noted that 24 of the 43 transformers reported in the rate applications for 2015-2016 as having a low or very low risk of failure were already scheduled to be replaced during this period. The main reason Hydro One reported inaccurate asset condition and age to OEB is because it uses information from its unreliable internal systems.

Asset Analytics System Incomplete and Inaccurate

Hydro One maintains information on its transmission assets and scheduled maintenance primarily on its asset inventory module as part of its financial system. In 2012, Hydro One began using a new investment planning information technology system called Asset Analytics. Using data from Hydro One databases, including the financial system, Asset Analytics applies six factors to evaluate the condition of the asset and assess the risk of it failing: age of the asset; its condition; the amount spent on repairs on it; how much it is used compared to its capacity; its performance reliability based on unplanned outages; and its importance based on the number of customers it serves. Asset Analytics weighs all six factors for each asset type to generate a composite risk score that tells Hydro One which assets are at high risk of failing and should be considered for replacement.

We noted Asset Analytics was incomplete or inaccurate for a number of reasons:

- There are a number of key factors that are not recorded and considered by the system, including technological or manufacturer obsolescence information, known defects in the assets, environmental impact and health and safety concerns.
- The system does not properly weigh the risk posed by certain conditions that may shorten the life of the asset. For example, oil leaks are one of the leading reasons for replacing a transformer; however, the detection of a leak accounts for only about 15% of the transformer's condition rating and only 3.75% of the transformer's composite score.
- In 2013, a report by Hydro One's internal auditors found that 21% of notifications of defective equipment recorded by maintenance staff did not accurately identify the transmission asset that had the deficiency. For example, field staff may have discovered and recorded a transformer oil leak at a transmission station, but failed to record which specific transformer at the station was defective. As a result, the database could not be updated for the specific asset. The problem still existed in 2015; for the period January 1 to May 30, 2015, our testing noted that 13% of defective equipment notifications did not accurately identify the specific piece of equipment that was defective.

While we discussed earlier in **Section 4.1.5** that Hydro One's asset management staff generally do not rely on Asset Analytics for accurate asset condition reporting, Hydro One still uses the system's unreliable information to report to the OEB in its rate applications on asset condition to justify its requests for rate increases.

RECOMMENDATION 5

To ensure Hydro One is replacing assets that are at the highest risk of failure as determined through accurate asset condition ratings, Hydro One should:

- enhance its Asset Analytics system to include information on all key factors that affect asset investment decisions, including those related to technological/manufacturer obsolescence, known defects, environmental impact and health and safety;
- review and adjust current weighting assigned to risk factors in Asset Analytics to more accurately reflect their impact of asset condition and risk of failure;
- make changes to its Asset Analytics system and procedures so that updates to its data are complete, timely and accurate;
- conduct a comprehensive review of the data quality in Asset Analytics to update any incomplete or erroneous information on its assets and to ensure the information can support its asset replacement decision-making process; and
- investigate why known deficiencies in the reliability of the Asset Analytics system, such as those found two years earlier by internal audits, have not been corrected by management in a timely manner.

HYDRO ONE RESPONSE

Hydro One acknowledges that Asset Analytics data and algorithms continue to be developed and improved.

A data remediation project is under way to address the data gaps. In addition, data input and the change control process, along with data population and data quality dashboard metrics, will ensure data is populated in a complete, timely and accurate manner.

Hydro One has always intended to revisit the risk factors algorithms once a suitable post-deployment time period elapsed to provide enough results for the comprehensive review.

Hydro One intends to add health and safety and obsolescence factors to the tool.

Hydro One is addressing any outstanding internal audit recommendations regarding the Asset Analytics tool.

RECOMMENDATION 6

Hydro One should ensure that its applications to the Ontario Energy Board for rate increases include accurate assessments of the condition of its assets.

HYDRO ONE RESPONSE

Hydro One places a high priority on its obligation to provide the Ontario Energy Board with complete, accurate and supportable evidence in its rate applications.

The Company agrees that there is an opportunity to continuously enhance the quality and quantity of data in the Assets Analytics tool and has, for some time, been working toward this goal. The Asset Analytics tool represents only one input into the asset planning process and cannot replace decisions made by qualified engineers in conjunction with physical inspections.

A project is under way to address data improvement in the Asset Analytics tool with a focus on the transmission data to support the upcoming rate application. Its functionality will also be reviewed in 2016 to identify improvement opportunities.

4.1.7 Overall Spending to Maintain and Operate the Transmission System Has Increased, but Reliability Has Deteriorated

Hydro One's overall increased spending to maintain and operate the transmission system from 2010 to 2014 did not result in improved system reliability.

Costs related to the transmission system can be broken down into three main categories:

- Capital sustainment: refurbishment or replacement of components of the system to allow it to function as originally designed;
- Capital development: construction of new stations or lines, as well as upgrades to existing stations or lines to increase their capacity or capability; and
- Operations, Maintenance & Administration (OM&A): day-to-day costs related to operating the system.

Of the three cost categories, capital sustainment spending is expected to have the biggest overall impact on improving system reliability, followed by OM&A. Capital sustainment and OM&A spending are at the discretion of Hydro One. As shown in **Figure 5**, transmission capital sustainment spending increased by 74% from 2010 to 2014 ($356 million to $621 million) while OM&A decreased slightly ($421 million to $400 million). Overall spending in these two categories increased by $244 million (31%) from 2010 to 2014.

Decisions for Hydro One's capital development work generally involves either the Independent Electricity System Operator, government, Ontario Energy Board and/or customers, which may direct or help inform Hydro One where and when to increase transmission capacity by building new or replacing transmission lines and transformer stations. The addition of newer assets and upgrades also help to improve reliability. From 2010 to 2014, capital development spending decreased by 75% (from $523 million to $132 million).

However, the spending did not improve the reliability of the system. As shown earlier in **Figure 2**, the average frequency of outages of Hydro One's multi-circuit transmission system (covering 85% of electricity usage) increased 24% over this period. This was primarily due to an increase in the number of unplanned outages, such as those caused by equipment failure or weather, that occur at the same time as planned outages to replace aging transmission system assets. Some improvement was noted in the frequency of outages for all other areas covered by single circuit lines.

Hydro One Does Not Perform Cost Benchmarking against Comparable Utilities

Hydro One has acknowledged that its transmission cost measures can be benchmarked against those of other utilities, but it has not attempted to do so since 2009.

Until 2009, the Canadian Electricity Association (CEA) annually compared costs of all major Canadian transmitters. Thirteen types of costs were compared, including total cost incurred per energy transmitted (in megawatt hours) and per peak capacity (highest demand period measured in megawatt hours), and total OM&A costs per kilometre of transmission line and per transmission asset. The CEA's results from 2009 indicated that Hydro One spent less in eight categories and more in five categories than the CEA average, and that its system reliability ratings were better than the CEA average. The annual benchmarking study was discontinued by the CEA's board of directors because it was concerned that the data was being used by provincial regulators to set transmission rates.

Figure 5: Transmission System Costs, 2010–2014

Source of data: Hydro One

Cost	2010 ($ million)	2011 ($ million)	2012 ($ million)	2013 ($ million)	2014 ($ million)	% Change Between 2010 and 2014
Transmission operating, maintenance and administrative	421	415	415	388	400	–5
Transmission capital sustainment	356	333	389	480	621	74
Total	**777**	**748**	**804**	**868**	**1,021**	
Overall percentage increase						**31**

We compared Hydro One's 2014 costs with the 2009 costs for the same 13 types of costs, and noted that its costs have increased in 12 categories, ranging from 2% to 82% over the period. The only cost type that decreased was in spending on OM&A, by 15%, which is a concern due to the number of assets it has in use that were beyond their expected service life (see **Figure 4**).

In its recent rate applications to the OEB, Hydro One included a study by a consultant it hired that compared Hydro One's staff compensation levels (i.e., salary, incentives and benefits) to those of other regulated transmission and distribution utilities in North America. In the 2013 study, Hydro One's staff compensation levels were found to be 10% higher than the median of other utilities. This was an improvement from the 2008 and 2011 studies, which showed Hydro One's compensation being 17% and 13% higher, respectively.

The OEB has recognized the need for comparison of Hydro One's costs with other similar transmitters. As part of the OEB's January 2015 decision to award Hydro One a transmission system rate increase for 2015-16, Hydro One agreed to complete an independent transmission cost benchmarking comparison study, and to provide it to the OEB in spring 2016 as part of its next rate application for 2017-2018. The study is to "provide a high level set of benchmarks and comparisons of Total Cost (defined as Capital and OM&A) and Business Performance (generally defined as service delivery effectiveness and efficiency) for Hydro One among North American peer organizations."

RECOMMENDATION 7

To ensure that its maintenance expenditures on the transmission system are cost-effective, and activities produce more timely improvements to the reliability of the transmission system, Hydro One should conduct:

- an assessment of its past maintenance expenditures and activities to determine what changes and improvements can be made to more effectively focus its efforts on the critical factors that improve system reliability and how its planned maintenance and capital improvements work can be completed with less risk of service disruption;
- benchmark cost assessments with other similar North American transmitters to compare its results with those that have reasonable expenditures and that maintain reliability; and
- a study of other leading cost-effective transmitters and consider implementing their best practices to quickly improve Hydro One's reliability and improve its costs.

HYDRO ONE RESPONSE

Hydro One will conduct an assessment of its past maintenance expenditures and activities, with a focus on critical factors and contributors to the transmission reliability measure.

Consistent with a recent Ontario Energy Board decision, Hydro One is undertaking a total cost benchmarking review for transmission.

4.1.8 Weak Security over Electronic Devices Increases the Risk of Unauthorized Use

We found that the security Hydro One has in place for most of the electronic devices on its transmission system is weak. The devices include the electronic controls for transformers, circuit breakers and reclosure equipment, as well as the controls for physical security and access to stations. Effective security is key to preventing sabotage, vandalism, software viruses, and unauthorized or unintentional changes to device software or controls, all of which can disrupt service or cause power outages that could impact hundreds to possible millions of customers, shut down businesses, government services, and transportation and communications networks. As well, if protection equipment is disabled, a system component could become overloaded and damaged or destroyed.

Hydro One manages security risk by adhering to Hydro One policies, one of which uses standards

School Energy Coalition (SEC) INTERROGATORY #010

Reference:

With respect to the 2015 Auditor General of Ontario Chapter 3 Report, "Hydro One – Management of Electricity Transmission and Distribution Assets".

Interrogatory:

a. Please provide a chart showing each Auditor General recommendation and all sub-recommendations, Hydro One's specific response to those recommendations (and each sub-recommendation), and the status of implementation of the recommendation.

b. If the recommendation or sub-recommendation asks for Hydro One to set a target/timetable, provide a report, create an action plan, or anything similar, please provide it.

Response:

a) Please see Exhibit I, Tab 1, Schedule 2.

b) Hydro One has not committed to any timetables or targets.

Witness: Mike Penstone

INTERNAL AUDIT REPORT

Transmission Lines
Preventive Maintenance Optimization

To:

Mike Penstone
Vice President, Planning

Distribution:

Mayo Schmidt	President & Chief Executive Officer
Michael Vels	Chief Financial Officer
Frank D'Andrea	Vice President & Chief Risk Officer
Chong Kiat Ng	Director, Transmission Asset Management
Walter Kloostra	Manager, Transmission Lines Asset Sustainment & Secondary Land Use

Final Report Issued: April 7, 2016
Draft Report Issued: January 8, 2016
Report Number: 2015-33

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

EXECUTIVE SUMMARY

Preventive Maintenance programs are in place for Hydro One Networks' transmission and distribution system assets to ensure safe and reliable operation of these systems while meeting regulatory maintenance requirements for these assets. The Planning Organization is accountable for developing and funding Preventive Maintenance Optimization (PMO) programs for transmission and distribution assets, ensuring cost-effective preventive maintenance is performed on the right equipment at the right time to maintain system functions. The PMO programs include periodic visual inspections, diagnostic testing, as well as intrusive inspections and maintenance (such as cleaning, lubrication and worn out parts replacements) based on observed test results and asset conditions.

The primary objective of this audit was to provide assurance that the governance and controls within the Planning organization are effective for the development and management of PMO programs. This area was audited in 2003 with specific focus on end-to-end preventive maintenance processes. Due to resource limitations within Transmission Asset Management – Stations at the present time, our audit focused on transmission lines and distribution stations, as well as lines PMO programs for this interim report. Separate audit reports were produced for Transmission and Distribution business areas. *This* report focuses on PMO in the transmission business. We suggested to management that the observations and recommendations within this report also be considered for application to the Transmission Stations PMO program.

Our work included:

- Interviews with management and planners within both the Planning organization and the Forestry division to determine effectiveness of existing controls.
- Review of governance documents related to maintenance planning (strategies, policies, processes, procedures, training, etc.).
- Review of the annual maintenance plans developed for 2013, 2014 and 2015, including cost and accomplishment variance reports as well as maintenance plans setup in SAP.
- Review of the regulatory maintenance compliance reporting for transmission line right-of-way (ROW) maintenance.

We noted that the following success factors were in place:

- The PMO program mandate and accountabilities are well-understood within the Planning organization.
- High-level PMO program strategy and policy documentation are in place.
- Annual PMO programs are developed and released to the service providers for execution as per agreed investment planning schedule.
- There is on-time regulatory compliance reporting for transmission line ROW maintenance.
- Formal reports are available on demand from work management system (SAP) for PMO program variance monitoring. They are used by management for program redirection.
- Communication between Planning and Service Providers for PMO program development, work execution and technical support has recently improved over that of previous years, driven by management's efforts.

We have discussed our observations with management throughout the audit. The recommendations we made, which management has accepted and for which action plans have been developed include:

- Ensure details for overhead lines, underground cable and right-of-way maintenance among various PMO investment planning documents are consistent and up to date.

- Update and approve the PMO planning process to ensure consistency across all asset types; then ensure that appropriate process training and/or knowledge transfer is in place for new planners.
- Document risk-based asset strategies that detail what maintenance needs to be performed at what interval and for which reasons, along with the risks for delaying maintenance. This strategy can then be applied for consistent identification of risk-based alternatives for vulnerable, intermediate, optimal or accelerated investment funding levels.
- Perform an annual review of the maintenance strategy for further optimization opportunities based on observed asset performance and condition, selection of optimal maintenance task and frequency, and work bundling opportunities with other work programs (such as asset replacement).
- Ensure that the annual maintenance plan has supporting data for risk based prioritization of investment alternatives, accurate unit price based costs, and appropriately documented input and agreements on plan executability.
- Ensure that regulatory maintenance compliance reporting is performed directly from SAP where cost and accomplishment are tracked, rather than from an off-line spreadsheet.
- Develop an appropriate process and accountabilities for defining new assets and their maintenance plans in SAP along with creation of maintenance work orders that are consistent with the agreed annual maintenance plan.
- Ensure appropriate tracking of management redirection actions based on observed program costs and accomplishments variances.
- Ensure consistent reporting, analysis and use of asset condition data to determine any revision or adjustment to annual maintenance plans.

Based on the specific areas reviewed as of December 1, 2015, we concluded that some control improvements are needed to ensure that the Preventive Maintenance Optimization program is able to plan and release cost-effective asset maintenance plans.

Management has developed action plans to mitigate the identified risks and address our recommendations, as summarized in Attachment "A" of this report. Additional details are available upon request.

We would like to thank the management and staff in the Planning organization and Forestry division for their assistance and open discussions during this review.

ATTACHMENT A

OBSERVATIONS, RECOMMENDATIONS AND MANAGEMENT ACTIONS

(R) #	Observations	Risk[1]	Recommendations	Action Plan	Accountability	Completion Date
1.0 Governance						
1.1	Governance documents are developed, reviewed, approved and communicated by Management to set the expectations around how Transmission Line Preventive Maintenance Optimization (TL PMO) planning work is to be performed. We observed the following deficiencies in the existing governance documents for overhead lines, rights-of-way and underground cable maintenance planning: • Asset-specific strategy documents were not in place at the time of the audit, however we were advised by management that they are currently being developed. • Asset Planning documents for overhead lines and underground cables have not been updated since 2013. They are required to be reviewed and updated annually during each planning cycle. • Investment Summary Reports are missing details of risks and accomplishment levels. • Scope of Work documents have minimal and inconsistent details of work accomplishment and reporting requirements. • Work Standard Documents are in place	M	Ensure completeness and consistency of details within various PMO investment planning documents across all asset types such as asset strategies, planning documents, investment summary reports, scopes of work and work standard documents.	The format of planning documents will be reviewed for content consistency. Templates will be developed and posted to the Tx AM Lines SharePoint site for use by the Planners.	Walter Kloostra, Manager, Transmission Lines Asset Sustainment & Secondary Land Use	Q4 2016

[1] Residual Risk levels applied are described in the Legend that follows this table (Page 11).

(R) #	Observations	Risk[1]	Recommendations	Action Plan	Accountability	Completion Date
	for underground cables, but not for overhead lines and rights-of-way. ***Risk:*** *Poorly defined, inconsistent or missing governance documents increase the risk of confusion around strategy, policy, risk-analysis as well as work plan, execution and reporting requirements.*					
1.2	Appropriate work process and related training are required for consistent and efficient execution of work. We found that a detailed asset life-cycle management process is in place, but the planners were not aware of it. Management informed us that a process is being developed specifically for maintenance planning. Planners are currently following their own program-specific planning process based on their experience and understanding of what needs to be done. All three planners for overhead lines, rights-of-way and underground cable maintenance have been in their position for less than two years with little, or no initial or ongoing knowledge transfer or process training. ***Risk:*** *Lack of well-defined, communicated and understood work process and related training could lead to poorly defined maintenance programs that are unable to address asset and system needs.*	M	Update and approve the Maintenance Planning process to ensure consistency across all asset types and ensure that appropriate maintenance planning process training and/or knowledge transfer is in place for new planners.	The Transmission AM draft maintenance planning process will be stakeholdered and finalized.	CK Ng, Director, Transmission Asset Management	Q4 2016

(R) #	Observations	Risk[1]	Recommendations	Action Plan	Accountability	Completion Date
1.3	A risk assessment record for the Transmission Lines asset maintenance planning process does not exist. ***Risk:*** *Missing business risk assessment and mitigating actions could lead to the business being exposed to unacceptable levels of business risks.*	L	Perform a formal risk assessment of the Maintenance Planning process in accordance with Hydro One's Enterprise Risk Management framework	Maintenance planning risks will be assessed with the process and asset strategy being updated as required.	CK Ng, Director, Transmission Asset Management	Q4 2016
2.0 Preventive Maintenance Strategy						
2.1	High-level maintenance strategies identified in Hydro One Network's regulatory submissions are being followed, however the planners are continuing with these existing high-level strategies without adequate knowledge of how they were developed, or what needs to be monitored to ensure their effectiveness. Planners have informed us that the current strategies were developed based on industry best practices at the time, but they are unaware of any recent changes or evolution of those industry best practices. Example: the right-of-way maintenance is primarily driven by NERC regulatory requirement, which while prescribing a minimum standard for all of North America, may not necessarily be optimal in all Hydro One situations. ***Risk:*** *The absence of a well-defined asset maintenance strategy would result in less than optimal maintenance planning.*	H	Document risk-based, asset-specific maintenance strategies that detail what maintenance tasks need to be performed and how often, criteria to identify opportunities and associated risk of delaying maintenance. This strategy can then be applied for consistent identification of risk-based investment alternatives (vulnerable, intermediate, optimal or accelerated).	Asset strategy documents have been developed and will be reviewed to ensure inclusion of asset-specific maintenance planning strategies.	Walter Kloostra, Manager, Transmission Lines Asset Sustainment & Secondary Land Use	Q4 2016

(R) #	Observations	Risk[1]	Recommendations	Action Plan	Accountability	Completion Date
2.2	Currently there is a limited review of existing maintenance plans with focus on which maintenance could be delayed rather than which maintenance plans could be eliminated or have their frequencies adjusted. There is a limited review of asset performance and condition data to determine whether to delay or bring forward planned maintenance. The annual maintenance plan is based on the planners' subjective understanding of asset criticality, last maintenance date and service provider's input on work executability. Exploration of work bundling opportunities at the maintenance planning level is limited or non-existent. Instead, most work bundling is done by the service provider at the work execution level. ***Risk:*** *Inadequate periodic review and adjustment of maintenance strategy would lead to less than optimal maintenance plan. Not identifying work bundling at the planning stage can limit work and equipment outage bundling opportunities.*	M	Perform an annual review of the asset specific maintenance strategies for further optimization opportunities: • Identify, collect and analyze key asset performance and condition information to validate that maintenance plans are optimal. • Delay or reduce maintenance of non-critical assets to determine optimal maintenance tasks and frequency. • Identify and implement maintenance bundling opportunities with other work programs.	a) Maintenance strategy documents will be reviewed annually for further optimization opportunities as per the Asset Strategy document referred to in 2.1 above. b) Existing collaboration with the TSOG process will be enhanced to investigate and consider outage bundling opportunities for planned PM work.	Walter Kloostra, Manager, Transmission Lines Asset Sustainment & Secondary Land Use	Q4 2016
3.0 Annual Maintenance Plan						
3.1	Planners are required to develop risk-based alternatives for prioritizing maintenance investments. The planners' risk assessments for various maintenance investment alternatives are mostly subjective with no consistency in using asset performance or condition data to support their risk evaluation. Available funding levels are the primary factors for	M	Clearly document supporting data and/or planner judgments that are used for risk-based prioritization of various funding levels along with asset-specific planned accomplishments for each funding level.	AIP risk assessments will be reviewed with the intent to capture supporting data and any qualitative information used for risk assessment.	Walter Kloostra, Manager, Transmission Lines Asset Sustainment & Secondary Land Use	Q4 2016

(R) #	Observations	Risk[1]	Recommendations	Action Plan	Accountability	Completion Date
	risk assessment rather than asset condition or performance data. Example: A 10% cut in right-of-way maintenance funding level necessitated corresponding cuts in planned accomplishments. ***Risk:*** *Inadequate assessment of baseline and alternative risks could lead to high-risk assets not being maintained at appropriate intervals.*					
3.2	Unit costs being used for the 2016 to 2020 business plan are inconsistent with the agreed Unit Price Catalog. Planners have indicated that they have informal discussion and agreement with the service provider on the unit prices, accomplishment levels and resulting funding levels. ***Risk:*** *Use of incorrect or outdated unit prices could lead to the maintenance investment plan being underfunded for specified number of accomplishments.*	M	Ensure that the unit costs being used to determine funding levels are as per current Unit Price Catalog agreed with the service providers.	a) The planners will document in AIP any changes to unit prices that they have agreed with the service providers and inform Investment Management of these changes. b) Investment Management will update the UPC with newly revised unit prices when advised by either the planners or service providers.	a) Walter Kloostra, Manager, Transmission Lines Asset Sustainment & Secondary Land Use b) Kevin Mancherjee, Manager, Investment Management	Q4 2016
4.0 Asset and Maintenance Plan Setup in SAP						
4.1	NERC compliance reporting for Right-of-Way regulatory maintenance is managed by the service provider in an off-line spreadsheet using periodic data download	H	Ensure that NERC impactive circuits and their vegetation maintenance accomplishments are tracked and reported from SAP,	a) A formal report from FMS will be developed for regulatory reporting	Tom Jackson, Director, Forestry Services	Q4 2016

(R) #	Observations	Risk[1]	Recommendations	Action Plan	Accountability	Completion Date
	from the Forestry Management System (FMS). ***Risk:*** *Reliance on off-line manual tracking of maintenance accomplishments for regulatory reporting increases the risks of errors and omissions.*		which is the official source for maintenance costs and accomplishments tracking.	purposes replacing the manual spreadsheet based report. b) FMS will be used instead of SAP for accomplishment reporting as FMS is the system being used by the Service Providers for accomplishment tracking.		
4.2	The planners are accountable to create appropriate work orders in SAP for each asset to execute the planned work program. The process and accountabilities for ensuring that appropriate maintenance work orders are created for new assets is unclear. For right-of-way maintenance, the service provider creates required work orders in SAP to execute the agreed work program but there is no planner validation to ensure that appropriate work orders are created and used by the service provider. ***Risk:*** *Missing assets and work orders in SAP could lead to planned maintenance not being performed on specific assets.*	H	Develop a process and clarify accountabilities to ensure that appropriate Work Orders are created in SAP to monitor the annual work accomplishments.	Tx Lines AM will document a process and accountabilities for work orders released in SAP, and monitor with monthly reporting.	Walter Kloostra, Manager, Transmission Lines Asset Sustainment & Secondary Land Use	Q4 2016
5.0 Variance Monitoring and Change Management						
5.1	Planners currently do not document results of their monthly variance discussions with the service providers or any redirection decisions that are made during these discussions for later implementation and	M	Ensure that discussions and decisions resulting from monthly variance monitoring meetings are documented and action items are monitored for completion. This	Meeting minutes from quarterly meeting with the service provider will be documented.	Walter Kloostra, Manager, Transmission Lines Asset	Q3 2016

(R) #	Observations	Risk[1]	Recommendations	Action Plan	Accountability	Completion Date
	monitoring. ***Risk:*** *Missing or poor documentation of redirection decisions can lead to confusion around which maintenance should be delayed or deferred.*		includes changes resulting from funding reductions and ability to execute the work (maintenance unit swapping).		Sustainment & Secondary Land Use	
5.2	The "PP-177 Schedules A&C Gross Report" from SAP is used to monitor accomplishments and maintenance costs. The 2015 PP-177 report for Overhead lines has budget accomplishments listed as zero resulting in no variance monitoring for planned monthly and annual accomplishments. ***Risk:*** *Errors and omissions in variance reports can lead to incorrect management redirection decisions based on observed variances.*	M	Ensure that Overhead Line accomplishment budget is identified in the PP-177 Report (currently missing).	Tx Lines AM will ensure that service providers report on the Statistical Key Factor (SKF) in each quarterly meeting (related 5.1).	Walter Kloostra, Manager, Transmission Lines Asset Sustainment & Secondary Land Use	Q3 2016
5.3	There is no planning issue log to capture and track timely resolution of various process and data issues raised during maintenance planning and monitoring phases. ***Risk:*** *Absence of timely identification and resolution of planning issues could lead to delays or cost overruns in maintenance plan development and execution.*	M	Develop and maintain a planning issue log to capture and resolve various process and data issues raised during planning and execution discussions on a timely basis.	Tx Lines AM to implement a planning issue log to identify issues and track actions to resolution.	Walter Kloostra, Manager, Transmission Lines Asset Sustainment & Secondary Land Use	Q3 2016

(R) #	Observations	Risk[1]	Recommendations	Action Plan	Accountability	Completion Date
6.0 Continuous Process Improvement						
6.1	Asset condition reports are a key input into determining asset risks and maintenance needs. Although asset conditions are being reported by the service providers in most cases, there is no evidence to indicate that recorded asset conditions are being actively used by the planners to revise / adjust asset maintenance plans. Planners have indicated that condition reports are primarily used for defect management and corrective maintenance. It was also noted that overhead lines and underground cable condition reporting is done in SAP while right-of-way condition reporting is done off-line in SharePoint spreadsheets. ***Risk:*** *Lack of maintenance review and adjustment based on reported asset condition can increase the risk of failure for rapidly deteriorating or aging assets.*	M	Ensure consistent reporting, analysis and use of asset condition reports for asset maintenance needs and adjustment.	Review and incorporate the requirement for consistent reporting, analysis and use of asset condition reports into the asset strategy document and into the maintenance planning process (see 1.2).	Walter Kloostra, Manager, Transmission Lines Asset Sustainment & Secondary Land Use	Q4 2016
6.2	Planners indicated that they obtain and incorporate best practices and new knowledge for the maintenance planning process, but it is unclear what knowledge has been gained and incorporated in the existing maintenance strategies. ***Risk:*** *Inability to incorporate industry best practices could result in less than optimal maintenance plans.*	L	Planners should continue to share their maintenance planning knowledge with their peers with a goal of identifying best-practice opportunities with other utilities and incorporating best-practices into existing processes and tools.	Tx Lines AM will document and incorporate best-practices into the asset strategy documents.	Walter Kloostra, Manager, Transmission Lines Asset Sustainment & Secondary Land Use	Q4 2016

(R) #	Observations	Risk[1]	Recommendations	Action Plan	Accountability	Completion Date
6.3	There are no active efforts to extract lessons learned from resolved planning issues. It is unclear how these issues and lessons are communicated and incorporated into the current process and future plans. ***Risk:*** *Lack of continuous improvement through lessons learned could lead to inefficient maintenance processes that will have a lower chance of being adopted by the users.*	L	Identify and extract lessons learned from various issues resolved during maintenance planning and execution. Ensure timely communication of these lessons learned and other stakeholder feedback among the planners for on-going process improvements.	Planning lessons learned during Quarterly meetings with service provider (see 5.1) will be documented.	Walter Kloostra, Manager, Transmission Lines Asset Sustainment & Secondary Land Use	Q2 2016

<u>LEGEND: RESIDUAL RISK CLASSIFICATION:</u>

RESIDUAL RISK[1] CLASSIFICATION	Assessment Indication
LOW: Unable to make year over year planning process and efficiency improvements.	L
MEDIUM: Unable to meet planned cost and accomplishment targets or address asset performance and condition issues through maintenance.	M
HIGH: Unable to identify assets and maintenance requirements, comply with regulatory requirements or increasing maintenance backlog.	H

OPPORTUNITIES FOR IMPROVEMENT
The following opportunity for improvement was identified during this audit and is provided to Management for their consideration (the anticipated LoB accountability is identified in parenthesis): Review the PMO process for Transmission Stations assets and take actions identified in this report for similar observations. (*CK Ng, Director, Transmission Asset Management*).

SUMMARIES OF INTERNAL AUDIT REPORTS OF OM&A AND CAPITAL EXPENDITURES

Included in this Exhibit are Action Items pertaining to 2014 and 2015 Audit Reports.

Note: Risk Levels – Definitions

DEFINITION	
H	= High – Controls are Ineffective or need significant improvement.
M	= Medium – Controls Need Some Improvement
L	= Low – Controls are Good

Audit	Recommendation	Action Plan	Risk	Status of Action Plan
	and include all improvement opportunities identified during the inspections.			
Audit of Investment Planning #2014-29 January 30, 2015	**1.0 Governance and Controls**			
	1.1 Perform a formal risk assessment as per ERM Policy (SP0736) on an annual basis to ensure that business risks facing the planning organization are identified and mitigating actions are developed and tracked.	Planning will work with ERM Group to conduct a risk workshop to identify risks in achieving the planning business objectives.	M	**COMPLETE** – Q4,2015
Audit of Investment Planning #2014-29 January 30, 2015	1.2 Develop, review and approve sufficiently detailed policies, standards, procedures and guidelines to ensure a consistent risk-based approach to planning and decision making. This would require a review of the existing governance documents and ARIS process models for their accuracy and validity. Management has informed us that a Policy Review project is currently underway to consolidate policy and directive documents.	Conduct a review of processes, procedures, standards and guidelines to determine the need, effectiveness, currency and to ensure they are aligned with and support the Corporate Operational Policies. Establish a review cycle for these documents.	H	**COMPLETE** – Q4,2015 Addressed: • In order to have effective policies, we have incorporated into the Operational Policy Program the need of a Communication and Implementation Plan for all New and Reviewed Policies. In the past, the Plan was only required for New policies. • Included the Communication and Implementation Plan as part of policy development and review rather than the Plan being delivered post policy approval. This is indicated in the policy program milestones. • Reviewed Cycle – We are now stating “reviewed date” and “next review date” in HODS and on the policies.

Audit	Recommendation	Action Plan	Risk	Status of Action Plan
Audit of Investment Planning #2014-29 January 30, 2015	1.3 Clarify the timing and level of input to be sought by the planners from the service providers as they develop their plans. Define and communicate the required level of engagement with the service provider when investment plans are being developed to ensure that plans are based on asset needs rather than executability by the service providers.	At the annual LOB kick off, AM Processes and Tools will identify and seek input from the service providers to obtain their feedback on ideal timing and level of input required. Planning will also be in attendance to ensure agreement and consistency in approach.	M	**COMPLETE** – Q1, 2015
Audit of Investment Planning #2014-29 January 30, 2015	1.4 Implement a formalized Quality Assurance process and related performance measures to assess the effectiveness of the "end-to-end" planning process. This would include: • a Need identification and tracking process • guidelines on use and validation of AA data to assess needs and risks • QA reviews of Investment Summary Reports and feedback to planners • Supporting document availability and review, and • Realistic investment release dates.	Quality expectations and the required metrics for the end-to-end process will be established and communicated by the Planning Organization.	H	**COMPLETE** – Q4, 2015 End-to-end KPIs for the Investment Planning process have been developed and approved by the VP of Planning. Spreadsheet listing the KPIs is attached. Planning will received training on the KPIs through the Investment Planning Process training module.

Audit	Recommendation	Action Plan	Risk	Status of Action Plan
Audit of Investment Planning #2014-29 January 30, 2015	1.5 Formalize and track all process and tool related training being given to planners in their Learning Management System. Establish refresher training requirements whenever there are significant changes in process and tools.	The Planning Organization will assess all training requirements including the frequency of refresher training and mechanism for tracking training completion. We will develop an implementation plan that defines the accountabilities for creation and delivery of training material.	M	**COMPLETE** – Q4, 2015 Investment Planning Training has been finalized and scheduled. Currently the list of individuals requiring training is being updated by Managers and once completed the lists will be loaded into HOLMS for tracking.
Audit of Investment Planning #2014-29 January 30, 2015	1.6 Document and communicate lessons learned after each planning cycle and use them for continuous improvement of the planning process.	AM Processes & Tools will document and communicate lessons learned after the 2016-2020 planning cycle.	M	**COMPLETE** – Q3, 2015 Survey results and action plan associated with opportunities for improvement have been posted to IM SharePoint site.
Audit of Investment Planning #2014-29 January 30, 2015	**2. Customer, Asset and System Need Assessment**			
	2.3 Request an audit of Asset Analytics data sources and algorithms to confirm that quality data and appropriate calculation methods are used for calculating the six Asset Risk Indexes for individual assets as well as asset groups.	SAP Data Audit on Asset and Maintenance data is already underway. The results of these audits will be used to address the underlying data issues in AA. Workshops with respective LOBs will be held regarding usability of existing algorithms.	H	On Schedule. Revised date of completion is Q4, 2016. Preliminary workshops have been setup for Tx AM Planners input into revisiting existing AA algorithms and adding new risk factors. Work continues into Q4 on this.
Audit of Investment Planning #2014-29	2.4 Consider expanding the scope of the Asset Analytics tool to include up-to-date power system historical	AM Process and Tools will request ISD to add audit recommendation to corporate application roadmap. Key requirement is to have access to NMS	M	**COMPLETE** – Q1, 2015

Audit	Recommendation	Action Plan	Risk	Status of Action Plan
January 30, 2015	data such as load flows, connectivity, voltages, statuses, etc.	information.		
Audit of Investment Planning #2014-29 January 30, 2015	2.5 Continue to develop sufficiently detailed Asset Strategy Documents for all asset groups and ensure that all future asset needs are assessed against these documented strategies.	We will continue to develop Asset Strategy Documents.	M	Completion Date Q4, 2016. Schedule at risk due to Tx Rate Application and Business Planning work in Q2, and rate case defense in Q3 and Q4. Will reassess as we move closer to Q4.
Audit of Investment Planning #2014-29 January 30, 2015	**3. Investment Alternatives**			
	3.1 Increase the numbers of investments that are optimizable by requiring the planners to define more than one alternative for non-demand driven programs and time shift-able projects. Management should also ensure that appropriate justification is documented and reviewed for plans having only a single alternative.	We will define the framework for investments including the expectations outlining the definition and governance of programs and projects and requirements for program alternatives and time shift-able projects. Document and communicate these requirements.	H	**COMPLETE** – Q3, 2015 Review of Bus Plan will be done in Q4 to determine gaps areas in programs or investments without multiple alternatives.
Audit of Investment Planning #2014-29 January 30, 2015	3.2 Simplify the risk assessment matrix and provide suitable training and guideline to planners to perform an effective risk assessment. Specific focus should be on	We will improve the guidance on the use of the risk assessment matrix through the provision of practical examples.	M	**COMPLETE** – Q4, 2015.

Audit	Recommendation	Action Plan	Risk	Status of Action Plan
	using quantitative data from AA and other systems to determine/support appropriate probability and consequence on the established risk matrix.			
Audit of Investment Planning #2014-29 January 30, 2015	3.4 Review and confirm the Unit Price Catalogue with the service providers prior to the start of each planning cycle to ensure that the most current unit prices are being used to determine the funding level for the program work.	We will establish a process to ensure costs included in the investment plans are agreed upon between Planning and Operations (executing LOBs).	M	**COMPLETE** – Q4, 2015 The Investment Planning process has included a deadline for the Service Provider to provide a draft Unit Price Catalogue (UPC) and a deadline for the Asset Manager (Planners) to review and accept the UPC. This process and deadlines were communicated to the Director Level btw December 3rd and 9th, 2015.
Audit of Investment Planning #2014-29 January 30, 2015	**4. Investment Plan Optimization**			
	4.2 Make the AIP tool available year around to allow the planners to input and update their plans and risk assessments throughout the year. Management has indicated that plans are already underway to upgrade the AIP tool to allow this to occur in 2015.	This recommendation will be addressed upon implementation of AIP tool upgrade.	M	**COMPLETE** – Q3, 2015 The new version of the tool (v8.3) will provide more opportunities for sub-cost segment optimization to improve risk normalization within planning functions. However, it does not permit year round use by planners to input and update their plans throughout the year as originally envisioned. In order to have a constantly availability of the AIP, Hydro One would require two instances of the tool running in parallel. This would require two servers and a complex syncing processes and scripts that do not

Audit	Recommendation	Action Plan	Risk	Status of Action Plan
				currently exist and would be costly and difficult to implement. As such, the output of the investment planning process still requires a freeze period to tie to the financial models as part of the corporate business plan. The freeze period is between IRRC approval of the IPP and the Hydro One Board approval of the corporate business plan. Starting in 2016 the tool will be made available immediately after from Board approval in November, this will provide 6 additional months of availability. For the freeze period Planners are encouraged to continuously review the state of their assets, and assess system and customer needs. For projects, SAP and the ACER process is used to continuously update project/integrated program timing, expenditure projections, etc. Once AIP is available, planners can input the updated plans.
Audit of Investment Planning #2014-29 January 30, 2015	4.4 Increase the enterprise engagement period to allow a detailed line by line review of unreleased work in the IPP by the project and program managers who will be executing the plan. This will allow better feedback on cash flows and in-service	Enterprise Engagement period will be revised and incorporated into the revised schedule for the 2016-2020 planning cycle.	H	**COMPLETE** – Q2, 2015 The Enterprise Engagement period was extended as part of the 2016-20 Investment Planning Process and communicated as part of the Director Kick-off (Feb 20, 2015). Planning and the execution LOBs were encouraged to discuss preliminary plans,

Audit	Recommendation	Action Plan	Risk	Status of Action Plan
	dates from the service providers based on the established scope.			costs and risks associated with investments during the input period (Feb 1-March 30).
Audit of Investment Planning #2014-29 January 30, 2015	4.5 Implement a formal change log to document all recommended changes. This should also include appropriate review, approval and incorporation of changes with appropriate communication back to the requestor of the change.	All changes will be recorded in the accomplishment file change log and/or documented in the meeting minutes.	M	**COMPLETE**
Audit of Investment Planning #2014-29 January 30, 2015	4.6 Determine and document which types of changes to the individual plans require the IPP to be run through the optimization process again to ensure that the resulting plan remains optimal.	AM Process & Tools will document conditions and requirement for the IPP to be run through the optimization process again into the Investment Optimization Management Procedure.	M	**COMPLETE** – Q1, 2015
	5. Investment Plan Approval and Release			
Audit of Investment Planning #2014-29 January 30, 2015	5.1 Clarify the approval requirement and progress monitoring for "program" investments. Review the project and program approval process with specific focus on shortening the approval timeline. This may	This will be incorporated into annual review of OAR.	H	**COMPLETE** – Q4, 2015 All program investments are being converted to projects and will following the mature and robust processes already in place for project initial approvals and variances.

Audit	Recommendation	Action Plan	Risk	Status of Action Plan
	include appropriate escalation triggers as well as clarification of requirement for timely review / approval.			
Audit of Driver Safety #2014-30 January 21, 2015	**1.1 Corporate Level Strategic Direction and Accountabilities**			
	(a) Rationalize and assign overall accountability for the governance of an effective Driver Safety Management initiative, in accordance with Craft of Management principles, taking into account the observations and recommendations outlined in the remainder of this report. (b) Develop and define corporate level strategic direction for Driver Safety which clearly identifies accountabilities, initiatives, and objectives / targets, and cascades from the Hydro One Strategic Plan and Health and Safety Policy, to the LOB level, through the Networks' Health, Safety and Environment Management System. Communicate the Driver Safety direction and monitor its implementation.	(a) A Networks-level Driver Safety Program will be developed to address the Findings and Recommendations of this Audit. Health, Safety and Environment Division will take the lead role in facilitating the process, stakeholdering, and developing this Program. (b) A Networks-level Driver Safety Program will be developed to address the Findings and Recommendations of this Audit. Health, Safety and Environment Division will take the lead role in facilitating the process, stakeholdering, and developing this Program.	M	(a) **<u>COMPLETE</u>** – Q3, 2015 (b) **<u>COMPLETE</u>** – Q3, 2015

Audit	Recommendation	Action Plan	Risk	Status of Action Plan
Lines Preventive Maintenance Optimization #2015-33 April 7, 2016	Ensure completeness and consistency of details within various PMO investment planning documents across all asset types such as asset strategies, planning documents, investment summary reports, scopes of work and work standard documents.	The format of planning documents will be reviewed for content consistency. Templates will be developed and posted to the Tx AM Lines SharePoint site for use by the Planners.	M	**ONGOING** Documents under review
Transmission Lines Preventive Maintenance Optimization #2015-33 April 7, 2016	**1.2 Maintenance Planning Process**			
	Update and approve the Maintenance Planning process to ensure consistency across all asset types and ensure that appropriate maintenance planning process training and/or knowledge transfer is in place for new planners.	The Transmission AM draft maintenance planning process will be stakeholdered and finalized.	M	**ONGOING** Draft documents under review
Transmission Lines Preventive Maintenance Optimization #2015-33 April 7, 2016	**2.1 Maintenance Strategies**			
	Document risk-based, asset-specific maintenance strategies that detail what maintenance tasks need to be performed and how often, criteria to identify opportunities and associated risk of delaying maintenance. This strategy can then be applied for consistent identification of risk-based investment alternatives (vulnerable, intermediate,	Asset strategy documents have been developed and will be reviewed to ensure inclusion of asset- specific maintenance planning strategies.	H	**ONGOING** Asset strategy documents under review

Audit	Recommendation	Action Plan	Risk	Status of Action Plan
	optimal or accelerated).			
Transmission Lines Preventive Maintenance Optimization #2015-33 April 7, 2016	**2.2 Annual Review of Maintenance Strategies**			
	Perform an annual review of the asset specific maintenance strategies for further optimization opportunities: • Identify, collect and analyze key asset performance and condition information to validate that maintenance plans are optimal. • Delay or reduce maintenance of non-critical assets to determine optimal maintenance tasks and frequency. • Identify and implement maintenance bundling opportunities with other work programs.	(a) Maintenance strategy documents will be reviewed annually for further optimization opportunities as per the Asset Strategy document referred to in 2.1 above. (b) Existing collaboration with the TSOG process will be enhanced to investigate and consider outage bundling opportunities for planned PM work.	M	**ONGOING** Asset strategies under review
Transmission Lines Preventive Maintenance Optimization #2015-33 April 7, 2016	**3.1 Risk-based prioritization**			
	Clearly document supporting data and/or planner judgments that are used for risk-based prioritization of various funding levels along with asset-specific planned accomplishments for each funding level.	AIP risk assessments will be reviewed with the intent to capture supporting data and any qualitative information used for risk assessment.	M	**ONGOING** This year, AIP training focused on risk-assessment and AIP checklist were created whereby risk assessment was mandatory. All info is in AIP.
Transmission Lines Preventive Maintenance Optimization	**3.2 Unit Costs**			
	3.2 Ensure that the unit costs being used to determine funding levels are as per current	3.2 (a) The planners will document in AIP any changes to unit prices that they have agreed with the	M	**ONGOING** Each planner is documenting and storing in SharePoint/AIP and inform Investment

Audit	Recommendation	Action Plan	Risk	Status of Action Plan
#2015-33 April 7, 2016	Unit Price Catalogue agreed with the service providers.	service providers and inform Investment Management of these changes. 3.2 (b) Investment Management will update the UPC with newly revised unit prices when advised by either the planners or service providers.		Planning.
Transmission Lines Preventive Maintenance Optimization #2015-33 April 7, 2016	**4.1 Regulatory Maintenance**			
	4.1 Ensure that NERC impactive circuits and their vegetation maintenance accomplishments are tracked and reported from SAP, which is the official source for maintenance costs and accomplishments tracking.	4.1 (a) A formal report from FMS will be developed for regulatory reporting purposes replacing the manual spreadsheet based report. 4.1(b) FMS will be used instead of SAP for accomplishment reporting as FMS is the system being used by the Service Providers for accomplishment tracking.	H	**ONGOING** Work is continuing on developing an automated report. **COMPLETE** – Q1, 2016 SAP and FMS accomplishments are aligned.
Transmission Lines Preventive Maintenance Optimization #2015-33 April 7, 2016	**4.2 Monitoring of SAP Work Orders**			
	Develop a process and clarify accountabilities to ensure that appropriate Work Orders are created in SAP to monitor the annual work accomplishments.	Tx Lines AM will document a process and accountabilities for work orders released in SAP, and monitor with monthly reporting.	H	**ONGOING** Process and accountabilities are being documented for all TAM.
Transmission Lines Preventive Maintenance Optimization #2015-33 April 7, 2016	**5.1 Monthly Variance Review Meetings**			
	Ensure that discussions and decisions resulting from monthly variance monitoring meetings are documented and action items are monitored for	Meeting minutes from quarterly meeting with the service provider will be documented.	M	**ONGOING** Meeting minutes are being documented and stored on SharePoint site.

Audit	Recommendation	Action Plan	Risk	Status of Action Plan
	completion. This includes changes resulting from funding reductions and ability to execute the work (maintenance unit swapping).			
Transmission Lines Preventive Maintenance Optimization #2015-33 April 7, 2016	**5.2 Overhead Line Accomplishment Budget**			
	Ensure that Overhead Line accomplishment budget is identified in the PP-177 Report (currently missing).	Tx Lines AM will ensure that service providers report on the Statistical Key Factor (SKF) in each quarterly meeting.	M	**ONGOING** TxLines engaged service provider to ensure SKF is provided.
Transmission Lines Preventive Maintenance Optimization #2015-33 April 7, 2016	**5.3 Planning Issue Log**			
	Develop and maintain a planning issue log to capture and resolve various process and data issues raised during planning and execution discussions on a timely basis.	Tx Lines AM to implement a planning issue log to identify issues and track actions to resolution.	M	**ONGOING** Issue logs are being implemented and centralized.
Transmission Lines Preventive Maintenance Optimization #2015-33 April 7, 2016	**6.1 Use of Asset Condition Reports**			
	Ensure consistent reporting, analysis and use of asset condition reports for asset maintenance needs and adjustment.	Review and incorporate the requirement for consistent reporting, analysis and use of asset condition reports into the asset strategy document and into the maintenance planning process (see 1.2).	M	**ONGOING** Discussions taking place with planners for requirement. Strategies are being reviewed and will incorporated where applicable.
Inergi Services IT Contract Management Review #2015-35	**1. Service Level (SL) monitoring.**			
	Implement a periodic and independent validation of SL reports and supporting performance data submitted by	Our team is in the process of rolling out the VMWare IT Business Management (ITBM) tool. This tool will allow us to independently verify data provided by	M	**ON SCHEDULE** – Q4, 2016 Design in Progress - Validation check list template and verification rules being developed.