EB-2013-0416

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 distribution of electricity as of January 1, 2015.

SCHOOL ENERGY COALITION CROSS-EXAMINATION COMPENDIUM (Panel 3)

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TABLE 1

Summary of Distribution Capital Expenditures ($ Million)

Description	Historic						Bridge	Test				
	2010	2010 Approved	2011	2011 Approved	2012	2013	2014	2015	2016	2017	2018	2019
Sustaining	314.0	289.0	274.2	246.9	261.8	323.2	286.4	308.2	335.2	359.7	380.4	383.5
Development	162.9	185.0	157.1	202.5	185.9	192.1	200.2	223.3	206.3	207.7	183.5	199.1
Operations	1.2	8.0	1.3	11.2	2.7	3.6	5.1	9.4	18.8	7.0	7.0	4.2
Customer Service Capital	18.4	21.0	30.1	49.9	43.1	6.4	22.9	22.6	9.9	3.9	0.0	0.0
Corporate Common Costs & Other Capital	93.2	114.0*	133.0	64.6*	142.5	111.7	109.9	85.4	84.5	83.1	84.2	82.3
TOTAL	**589.7**	**617.0**	**595.7**	**575.1**	**636.0**	**637.0**	**624.5**	**648.9**	**654.7**	**661.4**	**655.1**	**669.1**

*The envelope reduction to Capital from the OEB Decision was not spread across the work program areas but was included in Other Capital

Table 1
Summary of Distribution OM&A Budget
($ Millions)

Description	Historical Years						Bridge Year	Test Years				
	2010	2010 Approved	2011	2011 Approved	2012	2013	2014	2015	2016	2017	2018	2019
Sustaining	305.9	315.2	317.1	337.5	307.9	335.7	320.4	329.5	374.4	380.1	363.2	358.1
Development	12.3	11.7	15.8	12.0	14.7	11.1	18.4	15.4	17.7	17.0	17.4	17.8
Operations	18.5	20.2	18.1	20.9	21.0	22.0	30.4	30.2	34.4	34.8	42.2	41.0
Customer Services	114.7	117.2	113.3	113.4	116.7	148.6	133.7	117.9	116.3	114.7	113.5	115.4
Common Corporate Costs and Other OM&A	94.9	50.9*	85.5	46.5*	88.6	88.8	73.8	66.7	62.5	62.4	62.4	62.3
Property Taxes & Rights Payments	4.6	4.7	4.6	4.8	4.5	4.4	4.6	4.7	4.9	5.0	5.2	5.4
TOTAL	**550.9**	**520.0**	**554.4**	**535.0**	**553.4**	**610.6**	**581.3**	**564.3**	**610.2**	**614.0**	**603.9**	**600.0**

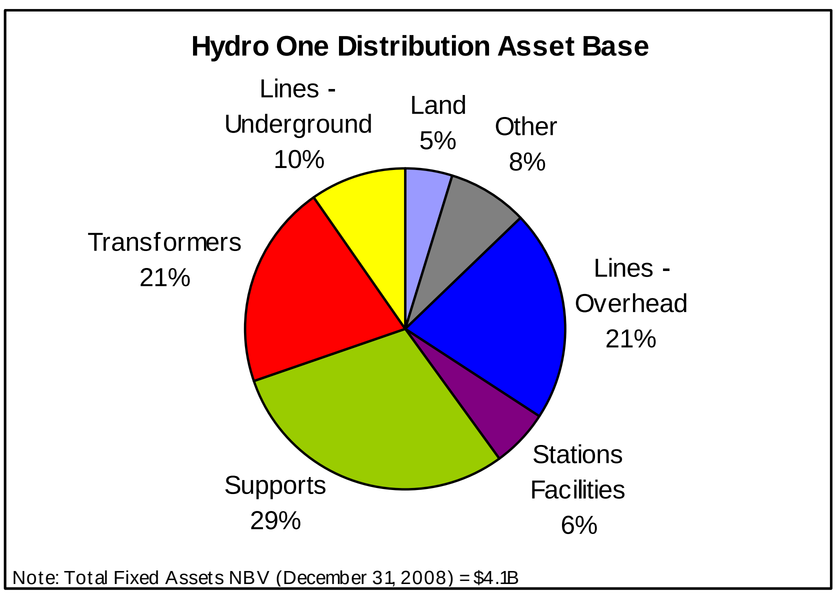
* The envelope reduction to OM&A from the OEB Decision was not spread across the work program areas but was included in other OM&A.

DISTRIBUTION ASSETS

1.0 INTRODUCTION

At Dec. 31, 2008, Hydro One Distribution managed $4.1 billion of distribution net fixed assets to provide the safe and reliable delivery of electricity, from transmission and generation systems, to approximately 1.2 million customers across the Province of Ontario. The assets consist of about 120,200 circuit kilometers of distribution line, 1005 distributing stations (including 77 regulating stations). The major power system components include; conductors, switches, transformers, insulators, reactors, capacitors, connecting hardware, associated protection and control equipment, foundations, grounding systems and revenue meters. The functional breakout of Hydro One Distribution's asset base is shown in Figure 1 below.

Figure 1



2.0 KEY CHARACTERISTICS OF THE DISTRIBUTION SYSTEM

Hydro One Distribution operates in a large service territory characterized by low customer densities. The distribution system has been designed and is operated to industry standards. The system is mainly radial in design, with very little redundancy in supply to customers, which is consistent with rural utilities. Due to this configuration, most component failures require immediate repair to restore service.

Almost exclusively, with the exception of voltage transformation at 88 high voltage distribution stations ("HVDSs"), Hydro One Distribution's power system assets are operated at voltages below 50kV, and all of Hydro One Distribution customers are supplied at voltages below 50 kV.

The key characteristics of Hydro One Distribution's system as of December 31, 2008 are shown in Table 1 below.

Table 1

Hydro One Distribution System Assets		
Customers	Distribution	1,193,000
	Large Users > 5 MW	47
	Embedded LDCs	32
Fixed Assets (NBV YE2008)		$4.1 Billion
Distribution Operating Centre		1
Distribution System Voltages (kV)		44 , 27.6 , 25 , 22 , 13.8 , 12.48 , 8.32, 4.16
Overhead Subtransmission Feeders		24,700 km
Overhead Primary Distribution Feeders		95,500 km
Underground Cable & Submarine Cable (included in the above kilometer figures)		6,600 km
Secondary Distribution Feeders		49,000 km
Poles (line supports)		1.7 million
Distribution Stations		928
Regulating Stations		77
Station Transformers and Regulators		1,460
Pole-mount & Pad-mount Transformers		485,000

Table 4.1: Summary of Priority 1 (P1) ACA Results

Asset	ACA Results		
	"Poor" or "Very Poor"	"Fair"	"Good" or "Very Good"
Stations			
Transformers	15%	14%	71%
Land Assessment & Remediation (LAR)	3%	0%	97%*
Lines			
Distribution Line Sections	-	-	-
Wood Poles	5%	2%	93%
ROW Vegetation Management	35%	33%	32%

* Includes sites that are contaminated but that have been addressed through remediation activities, or present low environmental risks. The low risk contaminated sites are included in the “good to very good” category as there are no plans in place for further remediation in the foreseeable future based on site specific risk assessments.

A consistent approach has been used in developing asset condition assessment results so that the meaning of the categories is generally understood across the asset classes. It must be recognized that condition ratings in the table above represent a snapshot in time and may not include factors that may accelerate deterioration or increase the percentage of assets which are in a deteriorated state in the future. These factors include changing demographics (a large number of assets reaching the critical stage where degradation accelerates, as is the case with wood poles), degree of damage caused by failures of sub-systems (as may be the case with transformers where a fault may shorten the life of a transformer), or environmental factors that may be influenced by changes in regulations (e.g. new PCB legislation). The categories developed are:

- “Very Poor” and “Poor” condition assets are high risk and will require replacement, refurbishment or other remedial action within the next 5 years to correct significant deterioration. The exception is for rights-of-way vegetation as explained below.
- “Fair” condition assets have experienced noticeable deterioration but should survive another 5 years with regular maintenance, and future work will be based on subsequent risk assessments.

- "Good" to "Very Good" Condition assets are currently at a lower risk than the other categories.

As noted above, Rights-of-Way vegetation does not fall into the time frames noted, as conditions change more rapidly for vegetation than with other asset classes. The more suitable descriptions for rights-of-way vegetation are: "Very Poor" and "Poor" category relates to feeders that will require maintenance within 2 years; "Fair" which relates to rights-of-way that may require maintenance in 3 to 4 years depending on further analysis; and "Good" to "Very Good" which relates to rights-of-way that have been recently (i.e. within 3 years) maintained or those that will not require attention within the next 4 years.

The following sections provide details on the key asset groups and highlight ACA results based on information and observations gathered up to December 31, 2008.

4.1.1 Distribution Station Transformers

The condition of station transformers is assessed using the following methods:

- Dissolved Gas in oil Analysis ("DGA") and Standard Oil Tests involve withdrawing a sample of oil from a transformer with follow-up laboratory analysis to determine quantities and type of gas in the oil and the condition of the oil. The results provide an indication concerning the degradation of oil and insulating material. The analysis techniques used are the Key Gas method that is defined in IEEE C57.104 and the Rogers Ratio method.

- Furan (ASTM D-5837) testing is an additional oil test that provides information regarding the condition of the paper insulation in the core of the transformer.

Asset Analytics Risk Factors

hydro one

6 risk factors are colour coded on a red to blue scale to give a visual representation of asset risk. Risk factors for a given asset are calculated relative to assets of the same type.

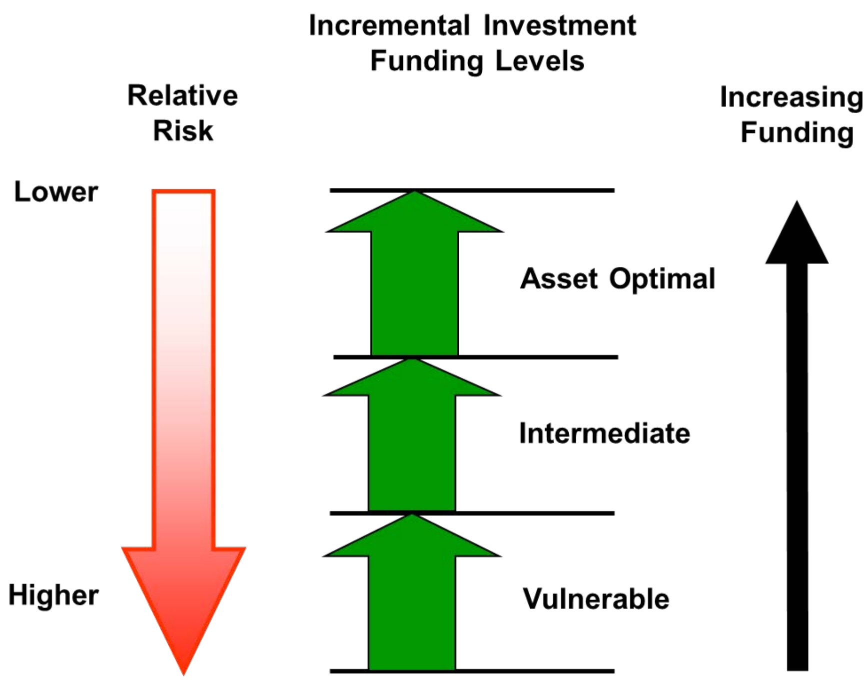
1. **Condition Risk** reflects probability of failure due to the degradation of condition over time.
2. **Demographic Risk** reflects the probability of failure based on a particular make, manufacturer, and/or vintage of an asset.
3. **Economics Risk** reflects the economic evaluation of the ongoing costs to operate an asset.
4. **Performance Risk** reflects the historical performance of an asset.
5. **Utilization Risk** reflects the deterioration rate of assets that are highly utilized.
6. **Criticality Risk** represents the impact that an asset's failure has on the distribution system, specifically, the number, type and size of impacted customers.

Asset Analytics

In the short term, the investment required to mitigate risk to a prudent residual level, may not be achievable, because of factors such as shortages of critical work execution resources or financial constraints put in place to mitigate the impact to the customer bill. As a result, a lower investment plan may need to be undertaken over the short term while additional resources are secured and brought to bear on the overall investment requirement.

This approach is illustrated in Figure 1.

Figure 1
Accomplishment Levels versus Risk



As demonstrated in Figure 1, there are three investment funding levels, described in this section.

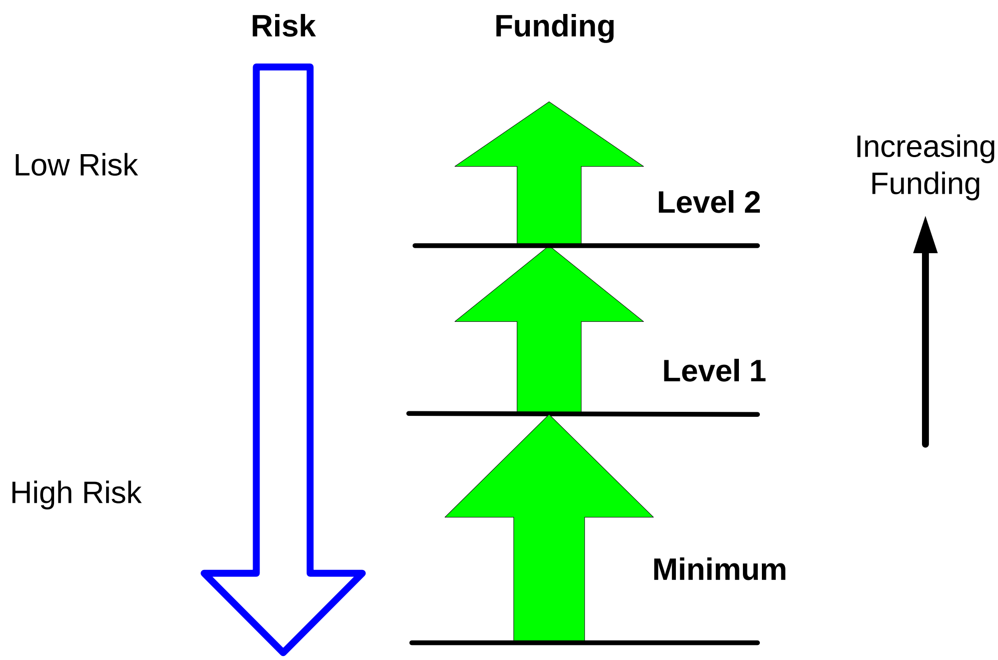
"Vulnerable" Investment Level: (previously entitled Deteriorating) – This level of investment is tolerable for only brief periods and exposes the company to possible risk of asset failure. Under this level of funding, asset maintenance and/or replacement needs are not fully met and the future performance of the asset is uncertain. This level of investment includes non-discretionary investments required to ensure regulatory compliance and safety in the short term. The Vulnerable Level of investment is neither a sustainable level of investment nor a desirable target level of investment and the residual risk at the end of the five year planning period is just outside the "red zone" shown in Table 3.

"Intermediate" Investment Level (previously entitled Maintaining): This level of investment represents materially less risk exposure and materially more cost than "Vulnerable" but remains below "Asset Optimal". Under this level of funding, asset performance and risk are held at current levels. Where appropriate there may be several intermediate investment levels to provide appropriate granularity between the Vulnerable and Asset Optimal alternatives.

"Asset Optimal" Investment Level (previously entitled Optimized): This level of investment represents a balancing point where total lifecycle costs of the asset are minimized and risk is low. This level of investment will ensure customer and asset needs are fully met and there is a high degree of confidence that the assets will perform as aligned with the Corporate Strategy.

The approach is illustrated in Figure 1 below.

Figure 1
Accomplishment Levels versus Risk



The accomplishment levels are established and evaluated for a period of five years to allow for, among other things the long-term management of resources. However, short-term constraints, such as scheduling of skilled staff, availability of materials, or availability of outages, are also considered when establishing the levels of work that are undertaken.

Minimum Levels of investment, as illustrated in Figure 1, are those required to avoid unacceptable risk. The Minimum Level of investment is neither a sustainable level of investment nor a desirable target level of investment. The Minimum Level is an extreme lower level boundary condition used for investment planning purposes. This level is used as a foundation upon which additional investments at higher levels are layered with the objective of mitigating risk to a prudent residual level.

DISTRIBUTION ASSET INVESTMENT OVERVIEW

1.0 INTRODUCTION

This exhibit summarizes the results of the Asset Risk Assessment process introduced in Exhibit A, Tab 17, Schedule 7. For major distribution station and distribution line asset types, various risk factors are considered. A summarized view of the key distribution assets and their primary risk factors are provided below. This information supports the development of the test year Sustaining OM&A and Capital expenditures submitted in Exhibit C1, Tab 2, Schedule 2 and Exhibit D1, Tab 3, Schedule 2 respectively.

2.0 ASSET RISK ANALYSIS SUMMARY

Hydro One Distribution's assets are generally grouped into "Stations" and "Lines" assets. This grouping facilitates the risk assessment of the assets. The asset risk assessments for the key assets in each group are provided below.

2.1 DISTRIBUTION STATION ASSETS

2.1.1 <u>Transformers</u>

Transformers comprise the single largest component of Hydro One Distribution's station asset base. Hydro One Distribution owns and operates 1,214 distribution station transformers.

Figure 1: Picture of a Station Transformer

Distribution transformers convert a high level voltage (typically 115kV, 44kV, or 27.6kV) to a lower distribution voltage (typically 27.6, 25, 13.8, 12.47, 8.32 and 4.16 kV). Regulating transformers are also included in this asset group. The number of transformers by primary voltage is outlined in Table 1.

Table 1: Transformer by Voltage Level

Primary Voltage Level	***Number of Transformers***
230 kV	1
115 kV	130
44 kV	781
27.6 kV	238
< 27.6 kV	64

Hydro One Distribution's asset strategy for transformers is to mitigate the risk of failures through proactive replacement. Opportunities to integrate transformer replacements with other work required at a distribution station are considered in order to improve work efficiency and minimize customer outages. The strategy also focuses on installing new transformers rather than refurbished transformers when proven more economical in order to sustain a reliable electricity supply to Hydro One customers.

<u>Demographics</u>

One of the indicators of the degradation of transformers is their age. The age distribution of transformers owned by Hydro One Distribution is shown in Figure 2.

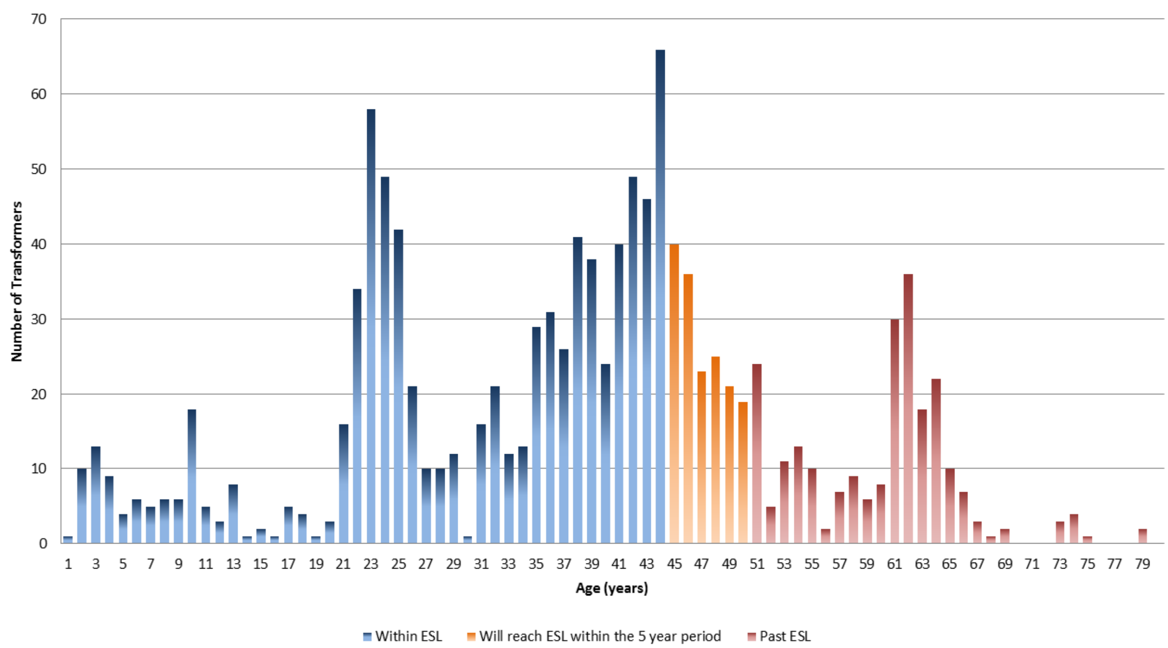


Figure 2: Demographics of the Distribution Transformers

Hydro One Distribution utilizes an expected service life of 50 years for its distribution station transformers. As depicted in Figure 2, the average age of the transformer fleet is 38 years. Currently 19% of the transformer population is beyond its expected service life, with an additional 10% to reach its expected service life in the next 5 years. While not all of these transformers require immediate replacement, they do pose a potential risk to the system and customer reliability and are prioritized in the Transformer Replacement and Station Refurbishment programs. The long term management of the high number of transformers reaching their expected service life requires increased funding as described in Exhibit D1, Tab 3, Schedule 2.

Condition

The condition of a transformer is one of the leading predictive indicators of its reliability. The internal components degrade as a function of time, as well as other influencing factors such as transformer loading, switching and lightning surges, moisture contamination, and paper insulation ageing. Degradation of the paper insulation in the transformer windings causes it to lose its tensile strength and excessive moisture trapped in the insulation of the transformer winding can weaken its condition causing premature failures. Since the degradation of transformer insulation is irreversible, replacement is the only viable solution.

Hydro One Distribution assesses a transformer's condition primarily on transformer oil and moisture test results by applying industry standard diagnostic testing such as: Dissolved Gas Analysis, Standard Oil, Furan, and Moisture Content. The condition of the transformer bushings, control cabinets, transformer tanks, tap-changer compartments, and cooling systems are also assessed during preventive maintenance. Historically, only the oil sample results for the transformer main tanks were used as a proxy for the transformer condition. However starting in 2013, Hydro One Distribution started to include oil sample results for all oil filled compartments in transformers, including the tap-changer selector and diverter compartments as well as bushings, into its transformer condition evaluations. The inclusion of tap-changer condition is very important in the evaluation since transformer tap-changer failures require the transformer to be removed from service.

Based on results gathered, approximately 24% of distribution station transformer condition assessments fall into the high risk category. Figure 3 illustrates which component of the transformer is the main contributing factor to the condition of these high risk distribution station transformers.

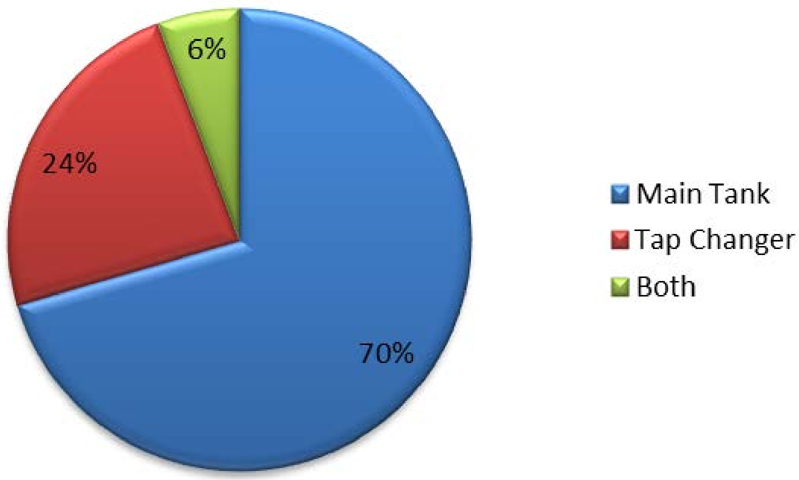


Figure 3: High Risk Transformers

These units are at a higher risk of failure compared to the transformer population and should be considered for replacement, refurbishment or other remedial action in order to correct significant deterioration or deficiencies to prevent failures and reduce impacts to Hydro One Distribution's customers.

The condition of the transformer is continually evaluated based on routine inspections and oil sampling and it is expected more transformers will gradually deteriorate into the high risk of failure category over the next 5 years as the transformer population continues to age. There are also events that can cause damage that is not easily detected and can lead to rapid deterioration of condition. These events that can lead to a more rapid deterioration include electrical failures of components, faults occurring from animal contact or lightning, mechanical failure caused by movement of internal windings, or failures caused by malfunctioning cooling systems.

<u>Performance</u>

Distribution station transformer failures are highly impactive since a large number of customers are supplied by these stations. Service restoration following a transformer failure usually requires a mobile unit substation to be temporarily installed while the unit is replaced to minimize customer interruption which would otherwise be lengthy.

Diagnostic and oil test results have helped to identify transformers in failing condition; allowing Hydro One Distribution to proactively remove the transformer thereby avoiding a major failure, however it is not possible to eliminate all risks of major failures.

The total number of failures varies from year to year; however, the number of major transformer failures (Class 1) combined with the number of major failures avoided by proactively removing transformers from service (Class 3) has been trending higher as can be seen in Figure 4 below.

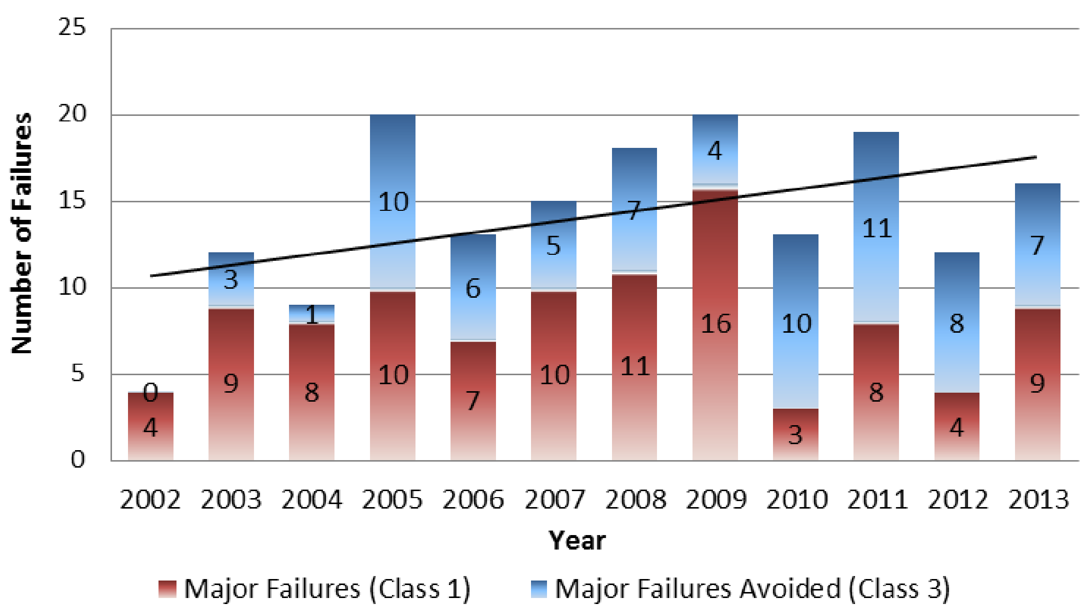


Figure 4: Failures of Station Transformers

With the approaching bow wave of transformers at and beyond their expected service life, the probability of failure trend is expected to increase over the next 5 years as transformer condition continues to degrade with age.

Replacement of failed transformers takes longer to complete, is more costly, and is more impactive to customer supply when compared to replacements under planned situations. These factors along with the ageing demographics and the degrading condition of the transformer population highlight the need to increase the number of transformer replacements in order to maintain an acceptable level of risk.

Other Influencing Factors

- Distribution stations are primarily located in rural areas of the province and lack redundancy. This configuration can result in lengthy outages to all customers supplied from the station in case of transformer failure.

- Environment Canada regulations require all oil-filled equipment to be tested for PCB contamination and equipment not meeting the requirements must be removed from service by 2025.

- Spill containment systems are required in stations where there is high environmental risk of oil being released from the site, in adherence to the Ministry of Environment's *Environmental Protection Act*.

- Noise complaints from customers dwelling in proximity to distribution stations, where noise levels exceed acceptable limits must be reduced through transformer replacements or through the installation of sound barriers in order to be compliant with Ministry of Environment regulations.

<u>Trends and Impacts</u>

Historically, an average of 7 transformers have been replaced on a planned basis annually. At this historic rate of replacement, the percentage of transformers beyond their expected service life will increase to 29% by 2020 and to 45% by 2025 as depicted in Figure 5. These demographic projections do not take into account the condition of the transformers.

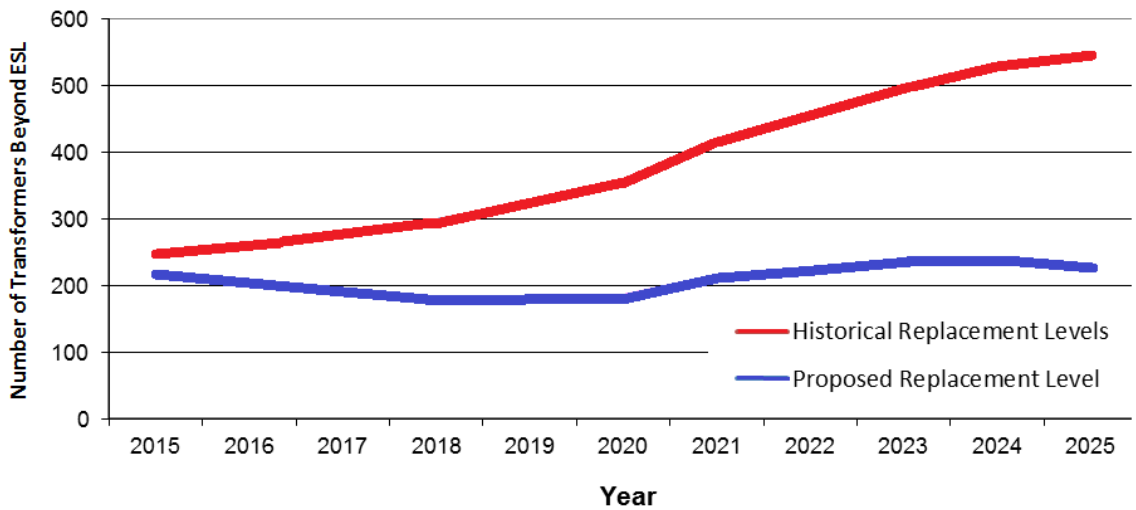


Figure 5: Projection of Transformers Beyond Expected Service Life

As can be seen in Figure 5, a proposed replacement rate of 36 transformers a year will allow the percentage of transformers beyond their expected service life of 50 years to remain relatively constant over the next 10 years assuming that the oldest transformers are the first to be replaced. Replacement candidates will be prioritized not only by their age, but by other risk factors including condition, performance, economics, utilization and criticality. These will be replaced under the Station Refurbishment, Transformer Replacement and Demand Work programs as described in Exhibit D1, Tab 3, Schedule 2.

If less than 36 transformers are replaced per year, the transformer demographics will continue to deteriorate, with the number of transformers beyond their expected service

Table 4.3: Summary of Distribution Transformer Failures 2004 to 2008

Year	Number of Transformer Failures (Forced Outages)
2004	37
2005	32
2006	25
2007	23
2008	21

To sustain the performance improvements in light of the deteriorating station transformer condition, Hydro One Distribution is proposing the maintenance and capital stations programs as detailed in Sustaining OM&A Exhibit C1, Tab 2, Schedule 2 and Sustaining Capital Exhibit D1, Tab 3, Schedule 2. These programs provide appropriate funds to effectively manage the life cycle of these costly assets and will address those transformers identified to be at high risk over the next 5 year period.

4.1.2 Site Contamination – Land Assessment & Remediation

Hydro One Distribution assesses the environmental condition of Distribution Stations by examining soil, ground water and the surface run off from a site. Soil contamination is determined by the laboratory analysis of soil samples. Soil samples can be obtained from shallow open excavations or by drilling to gain samples at various depths. Ground water quality is determined by the laboratory analysis of ground water samples taken from monitoring wells that are installed on station property or adjacent property. Surface water runoff quality is determined by the laboratory analysis of runoff water samples taken by automated sampling devices. The results of these lab tests are then compared to contaminant levels permitted in provincial and federal regulations.

the distribution system, these customer interruptions can last 8-16 hours or more until such time as a temporary supply (MUS or otherwise) is installed.

Because of the degrading fleet condition and compounding demographic pressures, this negative trend will continue if the replacement rate of transformers is not increased significantly from historic levels.

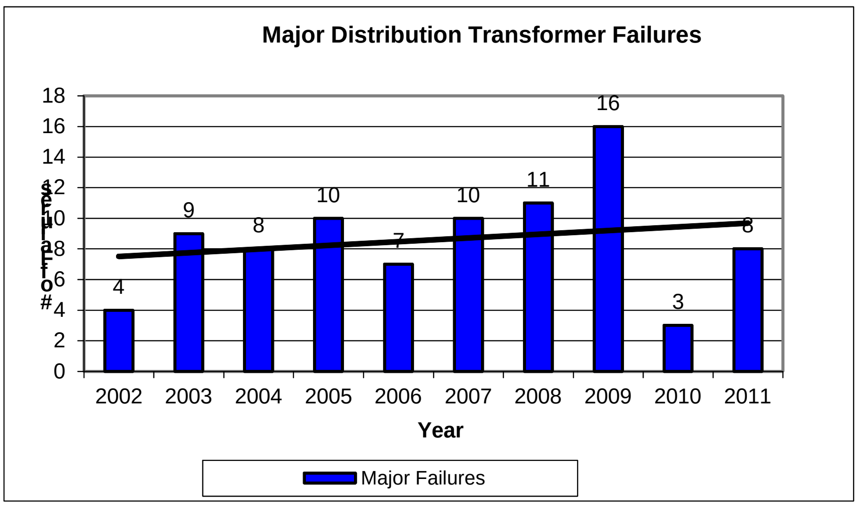


Figure 16 - Major Distribution Station Transformer Failures

3.6 Other Influencing Factors

Other factors driving the increase in transformer replacements include:

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

today. At the proposed investment level, the number of stations beyond their expected service life will remain generally constant over the next 10 years.

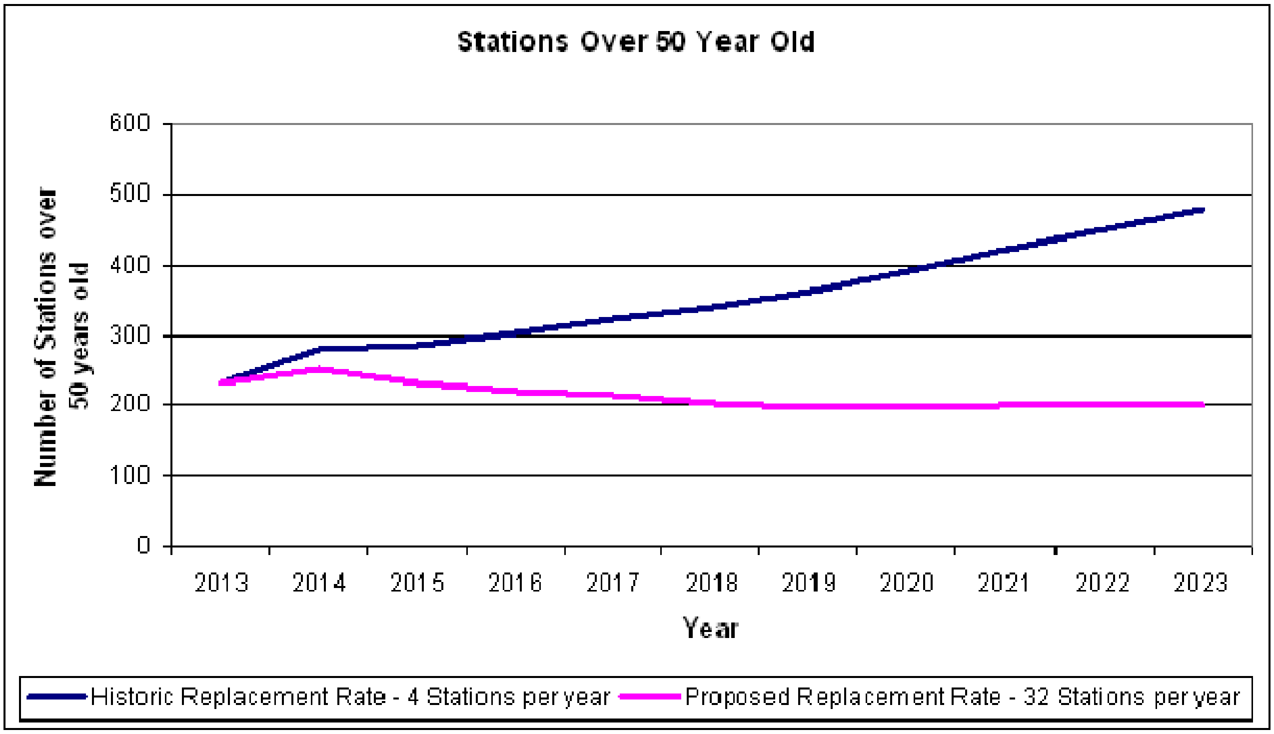


Figure 3: Distribution station demographics assuming existing station refurbishment rate of 4 per year and proposed rate of 32 per year

2.3 Condition of Assets

Hydro One performs ongoing routine inspections of station infrastructure and collects asset condition information such as visual inspections, counter readings on reclosers and tapchangers, and transformer diagnostic information through non-invasive oil sampling. This information identifies issues that need to be mitigated on either a demand or planned basis through either capital or OM&A programs.

Hydro One Distribution – Investment Summary Document

Sustaining Capital – Stations

Investment Name: Transformer Spares and Replacements Program
Work Execution Period: January 2015 to December 2019
Primary Outcome: Operational Effectiveness

Objective:
To manage the ageing demographic and deteriorating condition of the transformer assets through planned replacements and continued management of a strategic spare inventory to support the in-service distribution transformer population.

Need:
Transformers comprise the single largest component of Hydro One Distribution's station asset base. Hydro One Distribution owns and operates 1,214 distribution station transformers. As outlined in Exhibit D1, Tab 2, Schedule 1, the demographics of the distribution station transformer asset base is ageing and currently 19% of the transformers are beyond their expected service life. Over the next five years an additional 10% of the transformers will exceed the expected transformer service life. Transformers approaching their expected service life are prone to demonstrating signs of degradation including: leaks from failing/worn gaskets and fittings, deteriorating winding insulation, degrading insulating oil due to contaminants, or worn tapchanger parts. Approximately 24% of the distribution station transformers condition assessments fall into the high risk category. Other influencing factors are noise level requirements and environmental impact of leaking oil-filled transformers.

Transformer replacements under failure conditions are expensive, take a longer time to complete as compared to planned replacements and also place pressure on the mobile unit substation ("MUS") fleet resulting in the deferral of planned work.

Alternatives:
<u>Alternative 1: "Do Nothing"</u>
Wait for transformers to fail while in service and replace them on a reactive basis with spare transformers, at a premium cost and with increased safety risks. Eventually the strategic spare inventory will become depleted, and with a limited number of MUS's to by-pass failed transformers there would come a point at which customers will sustain lengthy outages.

Alternative 2: "Status Quo"
Continue replacement of transformers at historical average rate of replacement. At this rate, the percentage of transformers beyond their expected service life will increase from 19% to 29% by the year 2020. This alternative is not sustainable; as the asset base continues to age the likelihood of failures will increase resulting in reduced customer reliability.

Alternative 3: "Increased Rate" (Recommended)
Replace transformers at a rate that balances the asset needs. At this rate, the percentage of transformers beyond their expected service life will be maintained.

Investment Description:
This program mitigates the risks associated with the transformer assets through planned replacement and the sustainment of spare inventory.

Transformer Replacements
The replacement of transformers is based on asset risk assessment which considers: equipment reaching the end of its expected service life, degrading condition, and deteriorating performance. Consideration is also given to transformers that produce noise which triggers customer complaints. The transformers planned for replacement over the five year period are outlined below.

Year	Transformer
2015	Brighton DS #2 - T1
	Fiddlers Green DS - T1
	Ottonabee DS - T1
	Rockland East DS - T1
	Vandeleur DS - T1
	Walkerton DS #2 – T1
2016	Clearwater Bay DS - T1
	Madawaska DS - T1
	Oil Springs DS - T1
	Owen Sound DS #2 - T1
	Rockland East DS - T2
	Wiarton RS - R2
2017	Anderdon DS - T1
	Blind River DS - T1
	Clarksburg DS - T1
	Colbourne DS #2 - T1
	Dresden DS - T1
	Wardsville DS - T1

Year	Transformer
2018	Belmont DS - T1
	Chatham Harwick DS - T1
	Duff DS - T1
	Rugby DS - T1
	Seaforth DS - T1
	Woodland Beach DS - T1
2019	Commanda DS - T1
	Drummond DS – T1
	Lebel DS - T1
	Millington DS - T1
	Whitedog DS - T2
	Young Jct RS - R1

These planned transformer replacements are limited to cases where no other assets at the station require replacement. If other assets at the station are at the end of their expected service life and in failing condition, then the work is bundled into an integrated Station Refurbishment project as outlined in Investment Summary Document S7 in Exhibit D2, Tab 2, Schedule 3.

Transformer Spares

Strategic spare transformers are required to be used as replacements for failed units or to aid in the avoidance of a major failure. The yearly candidates of strategic spares purchased are dependent on which categories of spare transformers are deployed each year under failing and failed conditions. The number of major transformer failures combined with the number of major failures avoided is on average 15 per year. Taking into consideration the failure rate along with the ageing and degrading condition of the in-service transformer population, the number of strategic spares required over the test years are outlined in the table below.

Year	2015	2016	2017	2018	2019
Number of Spare Purchases	26	27	26	31	32

Result:

The transformer spares and replacement program will result in:

- Addressing the ageing demographic issues,
- Reducing the risk of lengthy equipment outages, and
- Maintaining customer supply reliability.

Costs:

($M)	2015	2016	2017	2018	2019	Total
Capital* and Minor Fixed Assets (A)	18.0	18.4	17.9	21.2	21.6	97.0
Operations, Maintenance & Administration and Removals (B)	0.1	0.1	0.1	0.1	0.1	0.5
Gross Investment Cost (A+B)	18.1	18.5	18.0	21.3	21.7	97.5
Recoverable (C)	-	-	-	-	-	-
Net Investment Cost (A+C)	18.0	18.4	17.9	21.2	21.6	97.0

*Includes Overhead at current rates. No Allowance for Funds During Construction is charged due to monthly capitalization.

Investment Category:

System Access	System Renewal	System Service	General Plant
0%	100%	0%	0%

OEB Renewed Regulatory Framework Outcome Summary:

Customer Focus	• Improve customer interruption time by maintaining an adequate level of spare transformers.
Operational Effectiveness	• Maintain customer supply reliability by replacing ageing and degrading transformers.
Public Policy Responsiveness	• Comply with the Distribution Rate Handbook by maintaining the service reliability indicators through sustaining an adequate level of spare transformers to minimize interruption time and by replacing ageing and degrading transformers prior to failure event.
Financial Performance	• Cost savings are recognized when transformers are replaced proactively rather than reactively; as failed transformers take longer to replace making it more costly.

Ontario Energy Board (Board Staff) INTERROGATORY #61

Issue 3.3 Has Hydro One proposed sufficient, sustainable productivity improvements for the 2015-2019 period, and have those proposals been adequately supported, for example, by benchmarking?

Interrogatory

Reference: Exhibit D1/Tab3/Schedule 2/p.19

Hydro One indicates that it will utilise a new prefabricated integrated modular station that is more cost effective.

a) How much more cost effective is this method compared to earlier methods of station refurbishment? What are the efficiency gains with this method?
b) Please file any information Hydro One used to determine that the prefabricated modular station is more efficient than previous practices.
c) Did Hydro One benchmark its costs against other distributors to ensure best practices were being followed?
d) Please file a capital cost per station table from 2010 to 2019.

Response

a) It is too early in the pilot project to quantify efficiencies gained. This pilot project is still underway and Hydro One is in the process of determining lessons learned and the strategy going forward.

b) As outline in Exhibit D1, Tab 3, Schedule 2, the prefabricated modular station is more cost effective in urban areas where space is limited. The cost efficiency Hydro One is referring to is the efficiencies resulting from the small footprint of the iMDS design compared to the traditional distribution layout which would result in having to relocate distribution stations or purchase additional land to enlarge the station.

Further efficiencies Hydro One expects to gain are related to prefabrication of the iMDS by an external vendor. The external vendor will purchase, assemble and commission station equipment which translates to shorter in-service time.

c) No.

d) The following table provides the actual cost of station refurbishment completed over the 2010 to 2013 period.

Year	Stations	Actual Cost
2010	Metcalfe DS	$0.2M
	North Shore DS	$2.2M
2011	Smooth Rock Falls DS	$1.1M
	Thorold South DS	$0.6M
2012	Calabogie DS	$0.5M
	Lindsay Durham West DS	$3.0M
	Sioux Narrows DS	$2.9M
2013	Bobcaygeon Boyd DS	$1.0M
	Chesley Hawkins DS	$0.5M
	Currie DS	$1.8M
	Dundalk Victoria DS	$1.0M
	Elginfield RS	$0.4M
	Espanola DS	$0.6M
	Havelock Industrial DS	$1.7M
	Huntsville RS	$2.0M
	Iroquois Dam DS	$2.7M
	Madawaska DS	$0.8M
	Matachewan DS	$1.4M
	Meaford DS #2	$2.5M
	Noelville DS	$1.7M

The following table provides the station refurbishments planned for the 2014 to 2019 period along with the corresponding forecast cost for each station refurbishment period. The average forecast cost for each station is approximately $1 million.

Year	Stations			Forecast Cost
2014	Abitibi Canyon DS	Highgate DS	Pelee Island DS	**$26.1M**
	Aguasabon DS	Kemble DS	Post Creek DS	
	Appin DS	Kenogami DS	Red Lake DS	
	Barwick DS	Kirkland Lake Woods DS	Shining Tree DS	
	Bobcaygeon Duke DS	Larder Lake DS	St. Williams DS	
	Brockville Parkdale DS	Longlac West DS	Tilbury Peltier DS	
	Cache Bay DS	Lucan Market DS	Trenton Bay DS	
	Campbellford Industrial DS	Madsen DS	Trenton Frankford DS	
	Crow River DS	Maxville George DS	Welland Effingham DS	
	Emsdale DS	Nestor Falls DS	Wilsonville DS	
	Essex DS	Oxley DS		

Year	Stations			Forecast Cost
2015	Abbey DS	Dorchester DS	Perrault Falls DS	$34.6M
	Alexander Kenyon West DS	Exeter DS#2	Plattsville DS	
	Berwick DS	Forest Jefferson DS	Princeton DS	
	Blenheim DS	Geraldton South DS	Russell DS	
	Bolsover DS	Haliburton DS	St. Thomas DS	
	Brigden DS	Kemptville Van Buren DS	Stouffville 10th Line DS	
	Brockville Park DS	Kingsville Pulford DS	Tara DS	
	Brockville Water DS	Kirkland Lake Goodfish	Tralee DS	
	Carleton Place	Lindsay Eglinton DS	Trenton McAuley DS	
	Chatham Raleigh DS	Little Current DS	Wainfleet DS	
	Corbeil DS	Marathon DS	Warkworth DS	
	Deep River DS	Merlin DS	Wyoming Churchill DS	
2016	Adams Point DS	Fenelon Falls Elliot DS	Newport DS	$39.0M
	Bismark DS	Gorrie DS	Nipigon DS	
	Bobcaygeon Ann DS	Gravenhurst DS	Pointe Au Baril DS	
	Carp DS	Guthrie DS	Port Lambton DS	
	Consecon DS	Holland Landing DS	Precious Corners DS	
	Craigleith DS	Horsey Bay DS	Shannonville DS	
	Crozier DS	Kirkland Lake DS #1	Sutton Base Line #1 DS	
	Devlin DS	Longlac East DS	Thorold Turner DS	
	Dover Centre DS	McGregor DS	Vanastra DS	
	Dundas Sydenham DS	Meaford Louisa DS	Wallaceburg DS	
	Elk Lake DS	Meaford Thompson DS	Waupoos DS	
	Elliot Lake DS	Mountain Chute DS	Wingham DS	
	Elora Union DS	New Liskard Halibton DS		
2017	Arnprior Airport DS	Deseronto DS	Perth DS	$40.0M
	Arnprior Elgin DS	Drumbo DS	Perth North DS	
	Arnprior McLachlin DS	Firth Corners DS	Pinelands DS	
	Aspdin DS	Galetta DS	Rockland DS	
	Athens DS	Hawley DS	Smithfield DS	
	Black Corners DS	Kemptville West DS	Sturgeon Falls DS	
	Brockville Cedar DS	Killaloe DS	Thamesville North DS	
	Brockville Schofield DS	Manitouwadge DS #1	Trenton McNichol DS	
	Cameron DS	Marthaville DS	Wartburg DS	
	Clarence DS	Meaford Vincent DS	Welcome DS	
	Collins Bay DS	Milford DS	Whitney DS	
	Corunna DS	Monkton DS	Yarmouth Centre DS	
	Cumberland DS	Owen Sound 12 St E DS		

Year	Stations			Forecast Cost
2018	Alexander DS	Forest Jura DS	Owen Sound 2 Ave E DS	**$44.5M**
	Battersea DS	Glengarry DS	Pleasant Point DS	
	Beaumaris DS	Haycroft DS	Red Rock DS	
	Bolton Hardwick DS	Horningmill DS	Ridgetown Palmer DS	
	Cedar Mills DS	Jones Road DS	Ripley DS	
	Clayton DS	Joyceville DS	Rock Mills DS	
	Creemore DS	Kennisis Lake DS	Roseville DS	
	Dack DS	Kleinburg DS	Rylston DS	
	Deleware DS	Lagoon City DS	Sam Lake DS	
	DorcasBay DS	Madoc Madawaska DS	Shedden DS	
	Dunchurch DS	McCrimmon DS	Shelburne Andrew DS	
	Erin DS	Merrikville DS	Snelgrove DS	
	Fenelon Falls DS	Mindemoya DS	Wiarton Claude DS	
	Flynn Corners DS	Owen Sound 12 St W DS		
2019	Aberfoyle DS	Golden Valley DS	Punkidoodles Corners DS	**$45.2M**
	Addison DS	Huntsville DS	Ruthven DS	
	Alexandria Margaret DS	Kerwood DS	Sharon DS	
	Blythswood DS	Keswick DS	Sleeman DS	
	Bondhead DS	Lanark DS	Smith Falls DS	
	Buckhorn DS	North Brook DS	Taylor Kidd DS	
	Carleton Place Francis DS	Omemee DS	Thedford DS	
	Chatham Raleigh RS	Osgood DS	Vankleek Terry Fox DS	
	Chesterville Bran DS	Ospringe DS	Vienna DS	
	Cobalt DS	Oxford Mill DS	Virginiatown DS	
	Dunedin DS	Park Road DS	Wanup DS	
	Emo DS	Picton Barker DS	Wellington Wharf DS	
	Farlain Lake DS	Pinegrove DS	Wooler DS	
	Fonthill RS	Prospect DS		

Power Workers Union (PWU) INTERROGATORY #6

Issue 3.2 **Is the level of planned capital expenditures appropriate for the period 2015-2019 and is the rationale for the planning and pacing choices appropriate and adequately explained?**

Interrogatory

Reference: **(a) Exh D1, Tab 2, Schedule 1. Distribution Asset Investment Overview.**
(b) Exh D1, Tab 3, Schedule 2, Page 19.

Ref (b) states:

> **The strategy is to address stations that are at a high risk of failure as determined by the asset risk assessment and prioritized based on the impact of failure of key factors including customer, safety and environmental risks.**

(c) Exh D2, Tab 2, Schedule 3, Reference #: S-07. Hydro One Distribution – Investment Summary Document Sustaining Capital – Stations

a) Please provide the current demographics of Hydro One Distribution Stations.

b) Please list Hydro One Distribution Stations that were replaced/refurbished in 2010, 2011, 2012 and 2013 historical years and projected for the 2014 bridge year.

c) Please provide the rate (share in total distribution stations) of stations replaced/refurbished for 2012, 2013 historical years and 2014 bridge year.

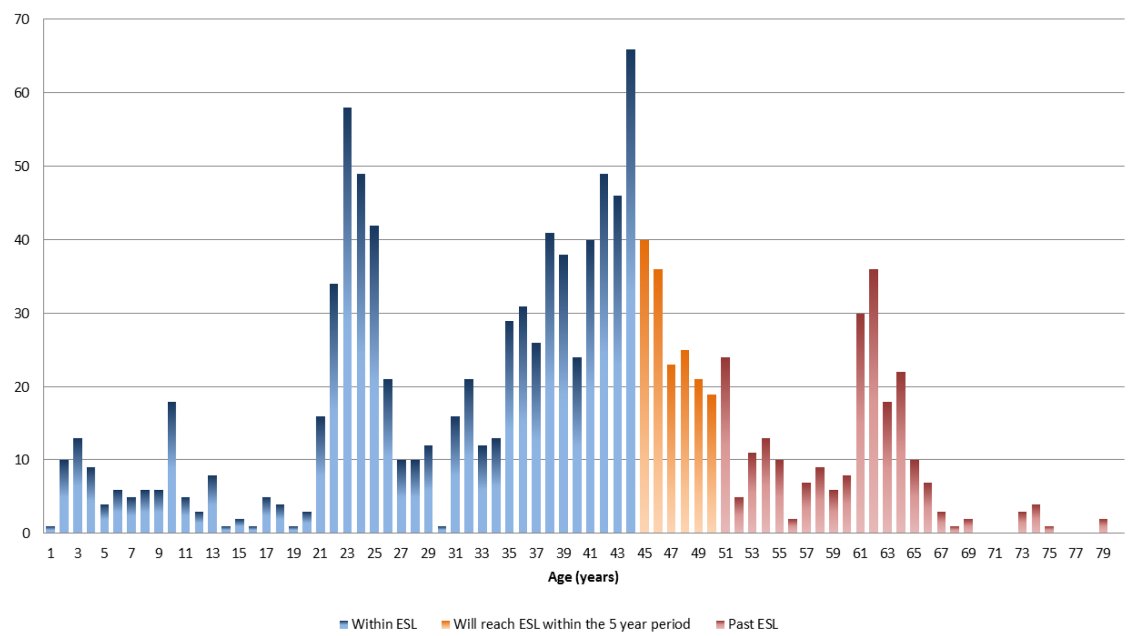
d) How many stations are currently at a high risk of failure?

e) How many stations would be at a high risk of failure by 2020 assuming Hydro One's proposed stations refurbishments over the test period 2015-2019 are accomplished?

f) How many stations would be in a high risk of failure by 2020 assuming historical replacement or refurbishment rates are maintained?

Response

a) Hydro One's distribution stations consist of many components including but not limited to power transformers, disconnect switches, bus, insulators, fuses, support structures, reclosers, fences, grounding systems, instrument devices. Using the most critical component of a distribution station, station transformers, as a proxy for the station age below is the current demographics of Hydro One's distribution stations.



b) Please see response to Exhibit I, Tab 3.03, Schedule 1 Staff 61 for a listing of Distribution Stations that underwent major capital upgrades in the 2010 to 2013 period, as well as the distribution stations planned for completion in 2014.

c) The following table represents the rate of distribution stations (compared to the total station population) that underwent major capital upgrades in the 2010 to 2013 and the ones planned for completion in 2014.

Year	**2012**	**2013**	**2014**
Number of Station Upgrades	3	14	32
Percentage of Population	0.3%	1.4%	3.2%

d) Approximately 27% of the distribution stations are currently at high risk of failure.

e) Assuming that Hydro One's proposed station refurbishments over the test period of 2015 to 2019 are accomplished, it is expected that by 2020 the number of high risk stations will remain at approximately 27% of distribution station.

f) Assuming that historical refurbishment rate (average of 5 stations per year) are maintained over the 2015 to 2019 period, it is expected that by 2020 the number of stations that will be high risk will increase by the number of stations in the proposed plan that will not be refurbished and account for approximately 44% of the distribution station population.

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #26

Issue 3.2 Is the level of planned capital expenditures appropriate for the period 2015-2019 and is the rationale for the planning and pacing choices appropriate and adequately explained?

Interrogatory

Reference: Exhibit D1/Tab 2/Schedule 1/p.11

Preamble: Historically, an average of 7 transformers have been replaced on a planned basis annually.

a) Please provide the average number of transformers replaced on a failure basis annually.

Response

The average number of transformers replaced on a failure basis annually is 11 units.

> way toward aligning Hydro One's costs with other comparable companies."[5]

The Board concludes that a comparable reduction is warranted for the distribution business. Hydro One has shown (for the categories presented) that it has controlled wage escalation better than some of the other Ontario Hydro successor companies. However, compensation costs remain excessive in comparison to market indicators. The evidence indicates that Hydro One's main competition for labour comes from within Ontario and the Board regulates most of those other entities. It would be unacceptable for the Board to, in effect, fuel that wage competition by incorporating ever rising wage levels (over and above market related levels) into rates. Hydro One has indicated that a reduction of $9 million would be comparable to the Board's finding in the transmission decision. The Board has already established an overall OM&A envelope and will not order this as a specific reduction. However, the Board would observe that compensation costs, including growth in headcount, are one of the areas in which Hydro One must take further action to control expenditure increases.

3.3 VEGETATION MANAGEMENT

Hydro One's vegetation management program manages clearances to energized equipment to maintain reliability, manage safety hazards posed by trees, manage plant species to permit maintenance and restoration of power, and minimize environmental, ecological and social impacts. Vegetation management accounts for about 40% of the Sustaining budget in 2010. In 2008, actual spending was $118 million, increasing to $136 million in 2009, dropping slightly to $133 million in 2010 and growing to $145 million in 2011.

Hydro One's evidence indicated that the 2010 and 2011 spending requirements are based on continuing to reduce the vegetation management cycle so that a 7-year cycle can begin in 2011. Line clearing accomplishments in 2007 and 2008 were performed at about an 8-year cycle. Hydro One's evidence was that a reduction to a 7-year cycle would require a 14% increase in expenditures in 2010 and a 24% increase in 2011 in comparison to the 2007 and 2008 period.

PWU supported the proposal and submitted that the increased spending is required, will improve Hydro One's performance, and will control costs in the long-term.

[5] EB-2008-0272 Decision with Reasons, May 28, 2008, p. 31

AMPCO, VECC, CME, and SEC all argued that the vegetation management costs should be reduced by maintaining an 8-year cycle rather than moving to a 7-year cycle. Two primary reasons were cited: the need to control spending at this time and a lack of strong evidence supporting the benefits of moving to a 7-year cycle. Intervenors were also of the view that the activity was not being conducted as efficiently as possible.

AMPCO submitted that the evidence does not show improved reliability even though there have been increases in vegetation management spending since 2006. AMPCO accepted that there may be some benefits from moving to a 7-year cycle, but submitted that Hydro One had not provided sufficient evidence to support a decision to move beyond an 8-year cycle at this time. AMPCO urged the Board to direct Hydro One to continue on the 8-year cycle and provide evidence in its next application as to whether its projections of improved service quality are being realized. SEC also recommended staying with the 8-year cycle until evidence is provided that a shorter cycle is warranted and the benefits to ratepayers are determined.

VECC submitted that Hydro One is focusing too much on labour hours and not enough on overall cost efficiency and that an overall cost efficiency focus could lead to achieving more than an 8-year cycle for the same level of expenditure. In AMPCO's view, the Vegetation Management Study shows that the actual per unit cost for Hydro One to treat a tree was more than double that of other utilities. AMPCO submitted that the Board should direct Hydro One to undertake a study to determine whether it is prudent and cost effective to continue to execute their vegetation management program in-house.

Hydro One responded that its evidence, including the Vegetation Management Study, supported the move to a 7-year cycle. Hydro One maintained that the benefits of a shorter cycle do not seem to be in doubt and that reducing these costs in the short term would lead to increased costs in the longer term.

BOARD FINDINGS

The Board concludes that this is an area where spending deferrals or reductions may well be warranted. The analysis suggests that there are net benefits from moving to a 7-year cycle. However, the actual benefits of moving to an 8-year cycle have yet to be demonstrated on Hydro One's system. The Board understands the lag involved between increased spending levels for vegetation management and reduced future expenditures on trouble calls, but it would be appropriate to perform some analysis of actual results at the 8-year cycle before embarking on the significant expense associated with moving to the 7-year cycle.

The evidence also suggests that Hydro One's efficiency level for this activity could be enhanced whatever the cycle length. The significant expenditures associated with moving to the 7-year cycle should be supported by a thorough demonstration that Hydro One has investigated all potential efficiency improvements for this work, for example, greater outsourcing.

The evidence indicates that if Hydro One were to maintain spending at the 8-year cycle level, OM&A could be reduced by about $17 million in 2010 and $28 million in 2011. The Board has already established an overall OM&A envelope and will not order a specific incremental reduction for this item. However, vegetation management is one of the areas where expenditure reductions should be achievable.

1. Asset planners determine a list of investments for the various investment categories based on the assumption that no constraints exist. After a series of challenges the list of investments is finalized.

2. This list undergoes a prioritization process resulting in a portfolio of individual investments that together make up a preliminary Investment Plan.

3. The preliminary Investment Plan is reviewed by senior management who may further modify it based on various considerations.

4. The end result is a prioritized Investment Plan proposal, which is recommended to the Hydro One Board of Directors for approval as part of the Corporation's business plan.

Hydro One's prioritization process considers risk mitigation against the dimensions of a set of business values to select the proposed levels of investment. The process incorporates a probability/severity-of-outcome risk matrix to determine the impact ratings for each business value. The Probability scale ranges from Remote to Very Likely and the Severity of Outcome scale ranges from Minor to Worst Case. The accomplishment levels are established and evaluated for a period of five years. The lowest level of investment is referred to as Minimum Level. Minimum Levels of investment are those required to avoid unacceptable risk within the five-year planning period.

The following issues are addressed in this chapter:

- Overall Capital Expenditures
- Distribution System Code Interpretation
- Allowance for Funds Used During Construction
- Working Capital Allowance

4.1 OVERALL CAPITAL EXPENDITURES

Capital expenditures, excluding the direct Green Energy Plan expenditures, are forecast to increase by 22% between 2009 and 2010. The level in 2011 is projected to be slightly lower than in 2010, but still 21% higher than 2009. The arguments generally focused on the overall level of the proposed capital expenditures.

Hydro One argued that aside from the Green Energy Plan investments the capital budget has not increased considerably and that the increases are primarily driven by Green Energy Plan related activity. PWU supported the capital expenditure budget and noted that if Hydro One does not undertake increased sustaining work now and into the future, the system will be left with a population of assets that is too old and in very poor condition. PWU submitted that replacing assets under those circumstances could be prohibitively costly.

Board staff noted that Minimum Level funding by definition is intended to mitigate unacceptable risk and questioned whether certain capital programs could be deferred in light of the significant increases proposed in the application. Board staff also noted the significant decline in the cost escalators as updated since the initial application.

CME submitted that the Board should reduce Hydro One's budget to the Minimum Level. VECC submitted that the Board should reduce the work plan by limiting capital expenditures to near the Minimum Level. VECC proposed a 10% reduction to the 2010 capital budget and 5% reduction to the 2011 budget. VECC argued that as Minimum Level spending culminates in unacceptable risk after 5 years, it is appropriate for Hydro One to be restricted to Minimum Level spending for the two test years as a rate impact mitigation measure.

VECC also submitted that before the capital budget is reduced to near Minimum Level, it should first be adjusted for the reduction in the cost escalator for construction. VECC noted that the cost escalator had been significantly reduced from applied-for levels and estimated the impact would be a reduction of 2% to the budget.

SEC argued that Hydro One should prioritize its capital expenditures within an overall envelope, including the Green Energy Plan. SEC submitted that the distribution capital budget should be $460 million in 2010.

CCC submitted that spending should be capped at $415.5 million in 2010. This level is the average for the period 2006 through 2009. CCC proposed that the level for 2011 be set at $423.8 million which is a 2% increase over the level proposed for 2010. CCC also submitted that there should be an asymmetric variance account to capture any underspending.

Hydro One responded that the proposed work plan is based on asset condition information and no party challenged that information. In Hydro One's view, arguments that call for a reduction to the work plan are inconsistent given the uncontested asset condition information. Hydro One also noted that while there was an overall decrease in system demand, the evidence demonstrated that there are pockets of the Province where demand is increasing and Hydro One is obligated to respond to new customer connections.

BOARD FINDINGS

The Board concludes that in light of the significant increased expenditures associated with the Green Energy Plan, there should be significant efforts to contain spending in other areas of the distribution business. The Board acknowledges that spending at the Minimum Level may not be appropriate over the longer term, but it is appropriate to consider limiting spending to this level during this period of accelerated Green Energy Plan expenditures. The Minimum Level for 2010 is $487 million and for 2011 it is $505 million. However, this analysis was driven off a base level of spending which included the portion of the Green Energy Plan spending which is proposed to be recovered directly from Hydro One's ratepayers. As a result, since Green Energy Plan spending is considered separately in this decision, the Minimum Level for the rest of the distribution business is likely somewhat lower than these levels. In addition, it is also clear that inflation and cost escalation factors are lower than the levels incorporated into the Minimum Level budget.

In the OM&A section of this decision the Board has laid out in detail the basis for its envelope approach. The Board will adopt the same approach for capital expenditures for the same reasons. The Board acknowledges that there are areas of work driven by asset condition (for example, wood pole replacement) and regulatory obligations (for example, customer connections). However, given the very significant expenditure plans associated with connecting renewable generation and implementing smart grid technologies, it is incumbent upon Hydro One to manage and prioritize the balance of its expenditures in order to moderate the overall impact on customers. This may involve reducing the level of work. For example, the budget for Transport and Work Equipment, though driven by the Green Energy Plan, is likely over-stated given more realistic estimates of the magnitude and timing of that program. Prioritizing may also lead to the deferment of certain projects. The large increases in expenditures in the area of Facilities and Real Estate suggest this may be an area where project deferrals are in order. However, as with OM&A, the Board will not make project-specific reductions or disallowances; in the Board's view it is appropriate for Hydro One to make those decisions.

The Board finds that capital expenditures for 2010 and 2011 will be reduced to $500 million in each year. This level remains above the Minimum Level and represents a significant increase over historical levels. Given the significant reduction from the proposed level, the Board concludes that a variance account is not required. As indicated above, the Green Energy Plan is addressed separately in this decision.

4.2 DISTRIBUTION SYSTEM CODE

During the proceeding VECC's counsel raised two issues with respect to Hydro One's interpretation of certain sections of the Distribution System Code ("DSC"). The first dealt with the types of activities that were considered "enhancements" versus "expansions" for the purpose of applying the cost recovery provisions of the DSC to load and non-renewable generation customers. The second issue dealt with Hydro One's interpretation of section 3.3.4 of the DSC which addressed the implementation period for changes to the DSC.

Hydro One provided a list of the types of investment activities it considers to be "enhancements" as opposed to "expansions" for the purpose of applying the cost recovery provisions of the DSC. At the hearing, Counsel for VECC noted that three activities on the list of enhancement activities (increasing the size of distribution station transformers, re-conductoring lines and modifications to voltage regulating equipment) are categorized as expansion activities in section 3.2.30 of the DSC. Hydro One clarified its position and indicated that its categorization of what is enhancement and what is expansion varies depending upon whether the activity arises as a result of the connection of a particular customer or group of customers or whether the activity is part of its overall distribution system plan. Hydro One noted that if the Board finds that the activities it has interpreted to be enhancements are in fact expansions, the impact would be a reduction of $2 million per year to the connections budget.

VECC submitted that the DSC clearly lays out the definition of enhancement and expansion activities and that Hydro One should align its approach with the DSC. VECC however acknowledged that under the DSC the cost recovery treatment for certain activities changes depending on whether they are in or out of a distributor's system plan and this may have the same effect as Hydro One's approach.

To address the risks associated with an aging fleet with a deteriorating condition, incremental levels of accomplishment are developed for the multi-year plan. Table 2 illustrates the Distribution Station Transformer Replacement example.

Table 2:
Distribution Transformer Replacement Levels

	Avg # Replacements per year	Avg % Replacements per year	# Replaced (over 5 yr plan)
Vulnerable	22	1.8%	110
Intermediate	29	2.4%	145
Asset Optimal	36	3.0%	180

The **Asset Optimal Level** is currently being proposed to address aged transformers and allow for the sustainment of the condition, demographics and reliability of the transformer fleet. At this replacement rate, the percentage of transformers beyond their expected service life will slightly decrease from 19% to 15% by year 2020, but if maintained for the next five years, will increase back to 19% by year 2025. These percentages were calculated with the assumption that the oldest transformer is next in-line to be replaced; these percentages may be higher as candidates for replacement are not solely based on demographics. This level of funding will address many of the transformers in poor and very poor condition, maintain or enhance customer reliability and reduce corrective maintenance.

The **Intermediate Level** would result in 35 fewer transformers replacements over the five years than the Asset Optimal Level of investment. At this rate of replacement, the percentage of transformers beyond their expected service life will slightly decrease from

19% to 18% by year 2020, but will increase to 25% by year 2025. The number of transformers that are at high risk is expected to increase, but not as rapidly as at the Vulnerable funding level. Reliability is also still expected to decrease as this accomplishment rate will still not keep pace with the aging demographics.

The **Vulnerable Level** would result in about 70 fewer transformers being replaced over the five years than the Asset Optimal Level of investment. At this rate of replacement, the percentage of transformers beyond their expected service life will increase from 19% to 22% by year 2020, and to 31% by year 2025. A refurbishment deficiency of this magnitude would increase the number of transformers that are high risk and reliability would decrease as this accomplishment rate will not keep pace with the aging demographics and resulting deterioration of condition.

The Vulnerable Level of investment will maintain a level of unacceptable risk over the five year planning horizon. Prolonged funding at the Vulnerable level is not sustainable and does not conform to good utility practice as refurbishment activities will not keep pace with asset condition requirements.

The risk-based prioritization process is used by Hydro One to quantify risks, and to identify the appropriate level of investments that will ensure the achievement of customer commitments, maintain safety and reliability while minimizing customer bill increases.

Reducing investments to the Vulnerable Level of investment over the planning period can create longer term sustainability issues, resulting in higher long-term customer costs. If the accomplishments fall below a certain level in a given area, meeting the appropriate safety, regulatory and/or legal requirements may be at risk.

Hydro One Distribution – Investment Summary Document

Sustaining Capital – Stations

Investment Name: Station Refurbishments
Work Execution Period: January 2015 to December 2019
Primary Outcome: Operational Effectiveness

Objective:
To refurbish an entire distribution station or part of a distribution station to address assets approaching the end of their expected service life that have a high risk of failure.

Need:
As outlined in Exhibit D1, Tab 2, Schedule 1, distribution station assets are ageing and a number of components are near the end of their expected service life. There are also concerns with the condition of the distribution station assets, including rotting high and low voltage wood structures, failing tube and clamp structures, deteriorated transformers, obsolete or faulty station equipment, fence and grounding systems.

Many assets reaching the end of their projected service life also coincide with poor reliability performance. Station failures could occur with lengthy customer outages realized.

Some other factors contributing to the need for the refurbishment of a station are: loading requirements, lack of mobile unit substation connection facilities, obsolete equipment, customer issues, operational problems, environmental spill risk mitigation, and safety issues or a combination of all of these factors.

Alternatives:
Alternative 1: "Do Nothing"
Wait for components to fail while in service and replace them on a reactive basis, at a premium cost and with increased safety risks.

Alternative 2: "Individual Component Replacements"
Replace individual defective assets in distribution stations on a component basis. While this type of replacement is performed in some cases, it is not ideal. Individual component replacements do not allow efficiencies associated with the integrated replacement of a number of components at once.

Alternative 3: "Station Refurbishment" (Recommended)
Refurbish entire stations or parts of a station to current Hydro One Distribution standards in order to improve the reliability of the distribution system. The refurbishment of the station will result in reduced costs and will extend the life of the station.

Investment Description:
Distribution station assets deteriorate over time and should be replaced as they reach their expected end of service life. Stations are identified and prioritized for refurbishment based on asset risk assessments. Through station refurbishment a higher reliability is obtained by the installation of new equipment and other infrastructure.

The refurbishment will address: aged transformers and structures, defective equipment, site or property issues, customer issues, safety concerns, environmental compliance, and operational issues. The stations will be refurbished to comply with present standards. Noise assessments are completed for station refurbishments that require the replacement of the transformer. If the noise of the transformer is an issue; a new transformer with lower noise levels will be installed. Landscaping, low profile designs, and wood fences are also incorporated into the station design where sites are located in urban areas.

Each station refurbishment will vary in size and scope. The average capital investment for each station refurbishment is below $1 million. The station refurbishments planned over the five year period are outlined below.

Year	Stations		
2015	Abbey DS	Dorchester DS	Perrault Falls DS
	Alexander Kenyon West DS	Exeter DS#2	Plattsville DS
	Berwick DS	Forest Jefferson DS	Princeton DS
	Blenheim DS	Geraldton South DS	Russell DS
	Bolsover DS	Haliburton DS	St. Thomas DS
	Brigden DS	Kemptville Van Buren DS	Stouffville 10th Line DS
	Brockville Park DS	Kingsville Pulford DS	Tara DS
	Brockville Water DS	Kirkland Lake Goodfish	Tralee DS
	Carleton Place	Lindsay Eglinton DS	Trenton McAuley DS
	Chatham Raleigh DS	Little Current DS	Wainfleet DS
	Corbeil DS	Marathon DS	Warkworth DS
	Deep River DS	Merlin DS	Wyoming Churchill DS

Year	Stations		
2016	Adams Point DS	Fenelon Falls Elliot DS	Newport DS
	Bismark DS	Gorrie DS	Nipigon DS
	Bobcaygeon Ann DS	Gravenhurst DS	Pointe Au Baril DS
	Carp DS	Guthrie DS	Port Lambton DS
	Consecon DS	Holland Landing DS	Precious Corners DS
	Craigleith DS	Horsey Bay DS	Shannonville DS
	Crozier DS	Kirkland Lake DS #1	Sutton Base Line #1 DS
	Devlin DS	Longlac East DS	Thorold Turner DS
	Dover Centre DS	McGregor DS	Vanastra DS
	Dundas Sydenham DS	Meaford Louisa DS	Wallaceburg DS
	Elk Lake DS	Meaford Thompson DS	Waupoos DS
	Elliot Lake DS	Mountain Chute DS	Wingham DS
	Elora Union DS	New Liskard Halibton DS	
2017	Arnprior Airport DS	Deseronto DS	Perth DS
	Arnprior Elgin DS	Drumbo DS	Perth North DS
	Arnprior McLachlin DS	Firth Corners DS	Pinelands DS
	Aspdin DS	Galetta DS	Rockland DS
	Athens DS	Hawley DS	Smithfield DS
	Black Corners DS	Kemptville West DS	Sturgeon Falls DS
	Brockville Cedar DS	Killaloe DS	Thamesville North DS
	Brockville Schofield DS	Manitouwadge DS #1	Trenton McNichol DS
	Cameron DS	Marthaville DS	Wartburg DS
	Clarence DS	Meaford Vincent DS	Welcome DS
	Collins Bay DS	Milford DS	Whitney DS
	Corunna DS	Monkton DS	Yarmouth Centre DS
	Cumberland DS	Owen Sound 12 St E DS	
2018	Alexander DS	Forest Jura DS	Owen Sound 2 Ave E DS
	Battersea DS	Glengarry DS	Pleasant Point DS
	Beaumaris DS	Haycroft DS	Red Rock DS
	Bolton Hardwick DS	Horningmill DS	Ridgetown Palmer DS
	Cedar Mills DS	Jones Road DS	Ripley DS
	Clayton DS	Joyceville DS	Rock Mills DS
	Creemore DS	Kennisis Lake DS	Roseville DS
	Dack DS	Kleinburg DS	Rylston DS
	Deleware DS	Lagoon City DS	Sam Lake DS
	DorcasBay DS	Madoc Madawaska DS	Shedden DS
	Dunchurch DS	McCrimmon DS	Shelburne Andrew DS
	Erin DS	Merrikville DS	Snelgrove DS
	Fenelon Falls DS	Mindemoya DS	Wiarton Claude DS
	Flynn Corners DS	Owen Sound 12 St W DS	

Year	Stations		
2019	Aberfoyle DS	Golden Valley DS	Punkidoodles Corners DS
	Addison DS	Huntsville DS	Ruthven DS
	Alexandria Margaret DS	Kerwood DS	Sharon DS
	Blythswood DS	Keswick DS	Sleeman DS
	Bondhead DS	Lanark DS	Smith Falls DS
	Buckhorn DS	North Brook DS	Taylor Kidd DS
	Carleton Place Francis DS	Omemee DS	Thedford DS
	Chatham Raleigh RS	Osgood DS	Vankleek Terry Fox DS
	Chesterville Bran DS	Ospringe DS	Vienna DS
	Cobalt DS	Oxford Mill DS	Virginiatown DS
	Dunedin DS	Park Road DS	Wanup DS
	Emo DS	Picton Barker DS	Wellington Wharf DS
	Farlain Lake DS	Pinegrove DS	Wooler DS
	Fonthill RS	Prospect DS	

Result:

Station refurbishments will result in:

- Addressing the ageing and degrading condition of distribution stations in a cost-effective manner,
- Ensuring the safe and reliable operation of the distribution system, and
- Reducing the risk of lengthy equipment outages caused by equipment failure or malfunction.

Costs:

($M)	2015	2016	2017	2018	2019	Total
Capital* and Minor Fixed Assets (A)	34.6	39.0	40.0	44.5	45.2	203.3
Operations, Maintenance & Administration and Removals (B)	2.4	2.6	2.7	2.9	3.0	13.6
Gross Investment Cost (A+B)	37.0	41.6	42.7	47.4	48.2	216.9
Recoverable (C)	-	-	-	-	-	-
Net Investment Cost (A+C)	34.6	39.0	40.0	44.5	45.2	203.3

*Includes Overhead at current rates. No Allowance for Funds During Construction is charged due to monthly capitalization.

Investment Category:

System Access	System Renewal	System Service	General Plant
0%	100%	0%	0%

OEB Renewed Regulatory Framework Outcome Summary:

Customer Focus	• Reduce the number of planned outages at distribution stations that impact customer supply with the integrated approach to station refurbishments.
Operational Effectiveness	• Maintain safe operation and reliability of the distribution station by addressing all ageing and degrading equipment in an integrated manner.
Public Policy Responsiveness	• Comply with the Distribution Rate Handbook by maintaining the service reliability indicators by upgrading ageing and degrading equipment prior to failure.
Financial Performance	• Cost savings are recognized when all ageing and degrading components within the station are replaced as part of the same project.

Dx Investment Plan
- Vegetation Management

		Actual				Planned					
		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Line Clearing	Net Dollars ($M)	78.4	80.5	87.1	83.0	92.2	95.3	117.5	120.2	106.9	99.8
	Units	11,432	11,097	11,195	10,378	9,800	10,200	14,250	14,250	12,750	12,750
	Unit Price ($/km)	6,861	7,258	7,777	7,994	9,407	9,342	8,249	8,436	8,383	7,829
Brush Control	Net Dollars ($M)	34.8	31.2	34.7	35.6	31.4	31.6	42.8	42.8	38.3	37.0
	Units	12,980	11,426	11,557	10,448	9,800	10,200	14,250	14,250	12,750	12,750
	Unit Price ($/km)	2,683	2,727	3,000	3,403	3,200	3,100	3,000	3,000	3,000	2,900

Currently, Hydro One is on a 9.5 year cycle for line-clearing and brush control, rather than the targeted 8-year cycle, which will yield sustainable recurring cost efficiencies.

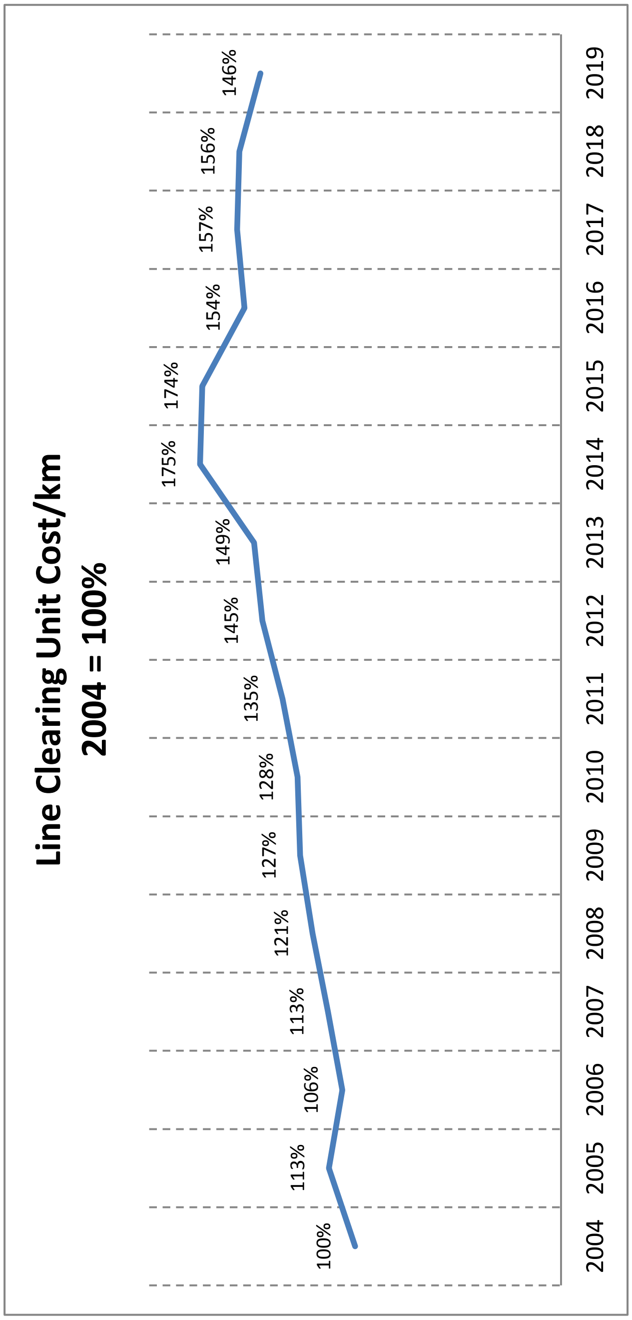
		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Clearing	Cost ($M)	55.6	52.9	50.6	74.1	78.7	88.3	78.4	80.5	87.1	83	92.2	95.3	117.5	120.2	106.9	99.8
	Units (km)	10,361	8,746	8,889	12,211	12,163	13,000	11,432	11,097	11,195	10,738	9,800	10,200	14,250	14,250	12,750	12,750
	Unit Price ($/km)	*$5,366*	*$6,048*	*$5,692*	*$6,068*	*$6,470*	*$6,792*	*$6,861*	*$7,258*	*$7,777*	*$7,994*	*$9,407*	*$9,342*	*$8,249*	*$8,436*	*$8,383*	*$7,829*
	2004=100%	100%	113%	106%	113%	121%	127%	128%	135%	145%	149%	175%	174%	154%	157%	156%	146%
Brush	Cost ($M)	19.6	21.1	25.2	26.9	25.8	31.3	34.8	31.2	34.7	35.6	31.4	31.6	42.8	42.8	38.3	37
	Units (km)	10,731	9,076	10,246	10,777	10,856	12,250	12,980	11,426	11,557	10,448	9,800	10,200	14,250	14,250	12,750	12,750
	Unit Price ($/km)	*$1,826*	*$2,325*	*$2,459*	*$2,496*	*$2,377*	*$2,555*	*$2,683*	*$2,727*	*$3,000*	*$3,403*	*$3,200*	*$3,100*	*$3,000*	*$3,000*	*$3,000*	*$2,900*

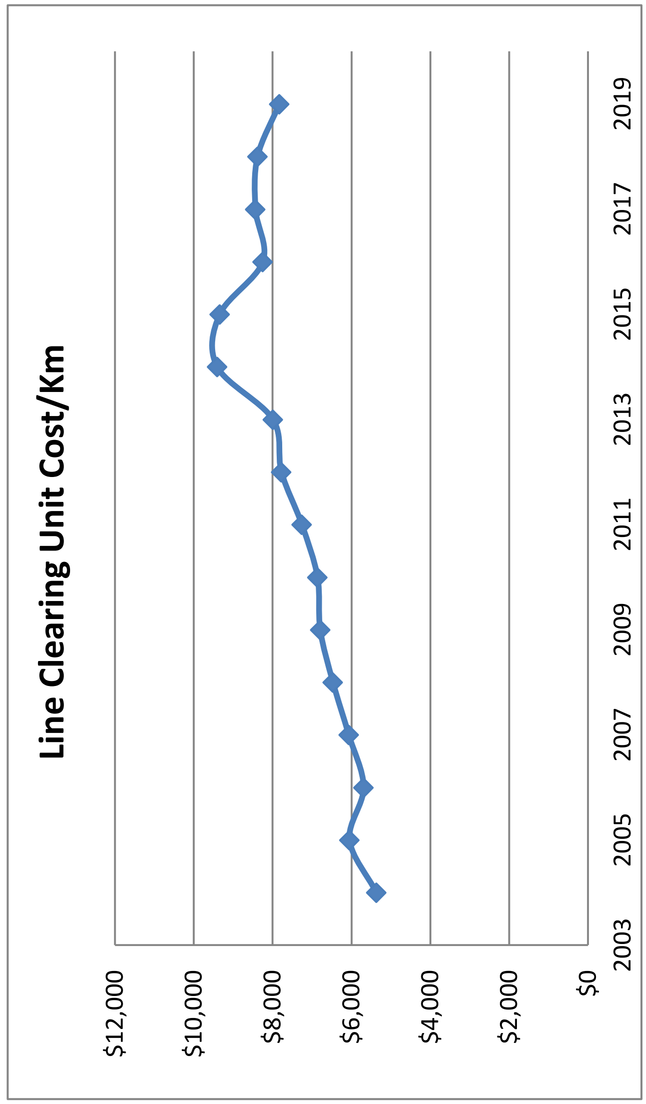
Source:

2010-2019 - Executive Panel Presentation (May 12, 2014) at p.10

2006-2009 - C1-2-2 -p.33 (EB-2009-0096/Staff IR 34 (EB-2009-0096)

2004-2005 - C1-2-2 -p.30 (EB-2007-0681)/ Staff IR 34 (EB-2009-0096)


Line Clearing Unit Cost/km
2004 = 100%
100%
113%
106%
113%
121%
127%
128%
135%
145%
149%
175%
174%
154%
157%
156%
146%
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019


Line Clearing Unit Cost/Km
$12,000
$10,000
$8,000
$6,000
$4,000
$2,000
$0
2003
2005
2007
2009
2011
2013
2015
2017
2019

2010-2011 Request versus Actuals

		2010 Request	2010 Actual	2011 Request	2011 Actual
Clearing	Cost ($M)	84	78.4	91.6	80.5
	Units (km)	13,500	11,432	14,300	11,097
	Unit Price ($/km)	$6,222	$6,861	$6,406	$7,258
Brush	Cost ($M)	33.3	34.8	36.2	31.2
	Units (km)	13,500	12,980	14,200	11,426
	Unit Price ($/km)	$2,467	$2,683	2,531	$2,727

Source:

2010-2011 Request - C1-2-2 Page 33 (EB-2009-0096)

2010-2011 Actuals - Executive Panel Presentiation (May 12, 2014) at p.10

Operations H3: Hydro One can reduce Forestry costs by outsourcing vegetation management activities

Findings

- In 2011 there were 1036 Forestry operator FTEs, which has grown at an average annual rate of 3.5% since 2006. Management indicated that due to workforce demographics, some hiring occurred to address the anticipated wave of retirements.
- 2011 vegetation management costs for Hydro One were approximately $145m, this translates into a Transmission cost of approximately $304/hectare and Distribution cost of $1178/km
- Analysis of the 2012 CN Utility Benchmarking report highlights that Hydro One has higher vegetation management costs than other report participants*:
  - Hydro One's cost per tree treated is $86/tree in comparison to the average of $53/tree and the next lowest cost peer company of $73/tree
  - The cost per labour hour for distribution routine maintenance was highest of all utilities at $86/hr
  - Compared to the closest peer in the report in terms of pole miles, Hydro One's cost per pole mile is 57% higher ($2,026 to $1,290) when adjusted for overhead vs. underground miles. This analysis implies a cost difference of approximately $44m based on the total overhead pole miles for Hydro One.
  - Hydro One's cost per customer is $102, which is nearly 2.5 times greater the next lowest cost peer company of $44 and significantly higher than the median cost per customer of $16.22
  - Although Hydro One serves an expansive territory, 69% of lines are accessible by roads or passable terrain, which is equal to the average of the utilities benchmarked in the report*. This implies that the cost disadvantage is not likely a result of more difficult terrain or line locations.
- Of the participating companies, only Hydro One used internal resources in all roles such as Forepersons, Qualified Arborists and Crew Leaders. On average, utilities reported outsourcing between 74 - 85% of these positions. Savings from outsourcing vegetation work is typically generated by lower overall staff costs and more efficient commercial business processes.
- Comparator analysis of a Provincial utility with 2m customers that outsources vegetation management shows Transmission costs of $267/hectare and distribution costs are $520/km, a difference of 14% and 56% respectively. This utility serves a slightly smaller transmission area (75k ha vs. 82k ha) and 40% smaller distribution area (58k km vs. 102k km) with more demanding vegetation characteristics.

Opportunity Assessment

- Hydro One has significantly higher vegetation management costs than peer utilities. The most significant difference between peer companies is the use of outsource suppliers.
- Based on our analysis, there is an incremental opportunity to reduce forestry costs by outsourcing vegetation management

There is an incremental opportunity for this hypothesis

Source: Management Interviews, department budgets, 2012 CN Utility Benchmarking report, KPMG Analysis

*CN Utility Benchmarking 2011-2012, Figure 5, Figure 15, Figure 77, Figure 10, Figure 167

UNDERTAKING - TCJ1.06

Undertaking

To provide the information with respect to any initiative in which, for any of the test-period years, there was a productivity savings amount of a million dollars or more

Response

In reference to savings found in Exhibit A, Tab 19, Schedule 1 and in Exhibit I, Tab 2.03, Schedule 6 VECC-42, the table below provides the information for any initiative containing productivity savings of seven and a half million dollars in any of the test years as agreed to during the technical conference. See page 102, lines 7 to 24 of the transcript. Also included is any initiative provided as an example in the pre-filed evidence with savings over one million dollars in a given test year.

The one million dollar threshold for all initiatives was once again requested however Hydro One did not agree to undertake to do that. See page 169, lines 16 to 28 and page 170, line 1 of the transcript.

Initiative Name	Category	Reference	Explanation of Savings	Calculation Methodology	Projected Savings 2014-2019 - $M
Cornerstone Ph1, 2	Business Systems	Please refer to breakdown provided in TCJ1.1, as well as Exhibit A, Tab 19, Schedule 1.	Provided in referenced undertaking and in the productivity exhibit.	**Head Count Reduction savings:** was found by multiplying the standard cost of one regular employee by the number of staff that was reduced/not hired. **Application Rationalization savings:** is the cost of the applications (e.g. licensing) that were decommissioned. **Strategic Sourcing savings:** the difference between the market cost and the price paid as a result of bulk purchasing.	186.3
CIS	Business Transformations	Please refer to breakdown provided in TCJ1.1	Savings are related to Cornerstone Phase 4 - CIS	**Customer Care savings:** was found by multiplying the standard cost of one regular employee by the number of staff that was reduced/not hired. **IT savings:** is the savings from ongoing maintenance and upgrades of software as well new equipment that no longer needed to be purchased. **Finance savings:** savings are related to a reduced billing cycle and elimination of 13 day billing cycle, increasing cash flow.	109.2
Inergi Contract Extension	Back Office	Please refer to the rate filing for additional details, Exhibit A, Tab 19, Schedule 1. Back Office for 2014 and prior years relate solely to the Inergi Contract Extension initiative.	Provided in referenced exhibits.	Savings related to the Inergi Contract extension signed in 2009 for a five year period come from the reduced cost as a result of negotiations with Inergi. The contract expense is variable depending on the number of service requests and work that is asked of Inergi. To provide the basis for actual savings, the expected cost without renegotiation was subtracted from the actual contractual costs holding all variables equal, in order to find the savings.	23.3
Contract Replacement	Back Office	Please refer to the rate filing for additional details, Exhibit A, Tab 19, Schedule 1. Back Office for 2015 and later years relate solely to the Contract Replacement Initiative.	Provided in referenced exhibits.	Savings related to the Contract Replacement are forecasts for the new contract that is expected to begin in early 2015. The contract expense is variable depending on the number of service requests and work that is asked of Inergi. To provide the basis for forecasted savings, the forecasted expected cost using the old contract is subtracted from the forecasted contractual costs of the new contract holding all variables equal, in order to find the forecasted savings.	133.6
Advanced Distribution System (ADS) Phase 1	Business Transformations		The ADS will implement smart grid business capabilities allowing for increased efficiency and cost savings related to many different functions.	**Advanced Metering Infrastructure for Operations savings**: By using the smart meter to detect outages, operations will receive more and better points of data to predict outage location eliminating the additional costs of unnecessary service calls. **Load Transfer Studies savings:** studies will be conducted in house by HONI, reducing expenses and driving efficiency. **DMS - Generated Distribution Operating Maps savings**: decreased drafting requirements, savings are the labour hours saved multiplied by the standard labour rate. **Advanced Distribution System Phase 1 Release 2:** implementation of IEC 61850 will increase standardization, reduce redundant equipment and lower overall costs.	34.8

Usage of feller bunchers	Leveraging Technology	Please refer to the rate filing for additional details, Exhibit A, Tab 19, Schedule 1.	Provided in referenced exhibits.	Savings are found by calculating the cost per tree without the feller buncher, compared to cost per tree by using the feller buncher and then multiplying the difference by the number of trees the feller buncher was used on. Cost of equipment, maintenance and other feller buncher equipment costs were included in the calculation.	22.5
AA - Asset Analytics	Business Transformations	Please refer to the rate filing for additional details, Exhibit A, Tab 19, Schedule 1.	Provided in referenced exhibits.	**Tx Stations savings:** Identify and eliminate 'Poor Performing' Assets that prevent more costly unplanned equipment failure. **Dx Stations savings:** provide information to make better decisions on repair vs. replace, saving money on purchasing new equipment and reducing unplanned equipment failure. **Dx Lines savings:** provide information to make better decisions related to Vegetation Management, saving money on purchasing new equipment and reducing unplanned equipment failure.	24.0
Reduce Cables Locates	Staff Flexibility	Please refer to the rate filing for additional details, Exhibit A, Tab 19, Schedule 1.	Provided in referenced exhibits.	Savings are found by calculating the average unit cost per cable locate and multiplying it by the number of locates that have been reduced as a result of the initiative.	20.0
IMDS - Integrated Modular Distribution Station	Leveraging Technology	Please refer to the rate filing for additional details, Exhibit A, Tab 19, Schedule 1.	Provided in referenced exhibits.	During an extensive review of the costs associated with the installation of a new integrated modular distribution station compared to a standard station refurbishment, the decreased cost was found to be $500K per installation. The savings related to this initiative is the $500K multiplied by the number of IMDS installations that are in the investment plan each year.	17.0
Note: full listing of all initiatives including 2013-2019 savings can be found in Exhibit I, Tab 2.03, Schedule 6, page 2					
				Total Savings for 2014-2019 Provided Above:	**570.7**
				Total Dx Savings 2014-2019 Filed:	**728.8**
				Representation of Total Savings Filed:	**78.5%**

Figure 11: Picture of a Wood Pole

As shown in Table 6, Hydro One Distribution utilizes poles primarily made from wood, though concrete, steel and composite poles are used in specific situations.

Table 6: Pole by Material Type

Material	***Number of Poles***
Wood	1,550,000
Steel	6,000
Concrete	3,000
Composite	less than 1,000

As wood is the dominant pole material, and as wood exhibits the most variation in degradation over time, wood poles require careful management in order to mitigate the risk associated with their deterioration.

After analyzing Hydro One's major costs and interviewing many of their staff, 25 metrics have been suggested as candidates to measure productivity, which account for 22% of total O&M and Capex labor related costs. However, as with any measurement, the development of these metrics should be evaluated in the light of the cost to measure them, any potential negative effects they may create (e.g., adverse incentives for employees), and the ability to roll up these up to corporate scorecard measures.

#	Metric	Cost Coverage	% of total costs
1	Cost of brush control per km of line	$98M	4.6%
2	Cost per meter install	$82M	3.9%
3	Cost per pole set	$78M	3.7%
4	Cost per new service installed	$11M - $34M	1.1%
5	Cost per tower constructed	$13M - $26M	0.9%
6	Cost per tower foundation	$13M - $26M	0.9%
7	Cost per km of Tx line cleared (Capital)	$13M - $26M	0.9%
8	Cost per meter read	$22M	1.0%
9	Cost per upgrade	$14M	0.7%
10	Cost per km of transmission line refurbished	$14M	0.6%
11	Cost per insulator replaced	$8M - $13M	0.5%
12	Cost per cable locate	$12M	0.6%
13	Cost per km for line patrol	$6M - $10M	0.4%
14	Cost per breaker	$8M - $10M	0.4%
15	Cost per transformer	$9M	0.4%
16	Cost per RTU	$7M - $9M	0.4%
17	Cost per bill	$1M - $8M	0.2%
18	Cost per km of Tx line cleared (OM&A)	$7M	0.3%
19	Cost per protective device replacement	$2M - $5M	0.2%
20	Cost per Transformer Refurbishment	$4M	0.2%
21	Cost per service cancellation	$4M	0.2%
22	Cost per insulator inspection	$1M - $4M	0.1%
23	Cost per disconnect	$3M	0.2%
24	Cost per reconnect	$3M	0.2%
25	Cost per line inspection	$1M - $3M	0.1%
	Total	~$480M	~22%

UNDERTAKING - TCJ1.17

Undertaking

To provide a breakdown for 2009 to 2013 and a 2014 forecast with respect to investment summary document S13, using the same equipment categories as provided for the years 2015 to 2019.

Response

A full 5-year view of the data is not available for the programs requested. Data is provided for, where available, for the period 2011 to 2014 year-to-date.

Net Dollars ($M)	2011	2012	2013	2014 YTD
Sustainment Initiatives	19.9	24.4	22.5	16
Crossarms	1.2	1.4	1.6	0.6
Nest platforms	NA	0.1	0.2	0.1
Overhead Conductor	0.1	1.2	0.5	0.2
Regulators and Reclosers	0.3	1.8	0.5	0.2
Sentinel Lights	NA	0.9	1.5	0.4
Substandard Transformers	0.6	1.2	0.2	0.1
Switches	0.7	0.9	0.3	0.2
Submarine Cable	3.3	5.2	5.5	1.4

Units	2011	2012	2013	2014 YTD
Sustainment Initiatives (only large projects are counted)	13	13	11	13 (Planned)
Crossarms	1279	791	1028	326
Nest platforms	10	5	8	8
Overhead Conductor (meters of conductor)	NA	27303	18496	2285
Regulators and Reclosers	NA	32	19	5
Sentinel Lights	1410	1150	1468	790
Substandard Transformers	1	50	13	0
Switches	17	16	4	1
Submarine Cable (meters of cable, note that the average cable is approximately 330m in length)	NA	62155	62158	9672

Hydro One Distribution – Investment Summary Document

Sustaining Capital - Lines

Investment Name: Line Component Replacements Program
Work Execution Period: January 2015 to December 2019
Primary Outcome: Operational Effectiveness

Objective:
To manage the distribution overhead and underground line equipment through planned replacements to address end-of-life or defective equipment to ensure a r eliable and safe distribution system.

Need:
Hydro One's distribution system consists of approximately 120,000 circuit kilometers across the province. Line patrols and preventative maintenance programs are used to assess the condition of line equipment. These assessments have identified a number of distribution line components that are near the end of their expected service life. Additionally, there are a number of components that are substandard or that pose environmental risks. These components, which include crossarms, nest platforms, overhead conductor, regulators, reclosers, sentinel lights, substandard transformers, and switches, must be replaced or refurbished to mitigate their associated risks.

Alternatives:
Alternative 1: "Do Nothing"
Wait for the distribution line equipment to fail while in service and replace them on a reactive basis, at a premium cost and with increased safety risks.

Alternative 2: "Replace Assets" (Recommended)
Proactively replace distribution line equipment approaching end-of-life, demonstrating deteriorating condition or posing a safety risk to mitigate the risk of failure and ensure a safe and reliable distribution system.

Investment Description:
This program addresses the individual replacement or refurbishment of distribution line components when it is not economical to integrate the work into one of the large sustainment initiative projects. The program comprises the replacement of the following asset types:

Crossarms

Crossarms are fastened to poles to support insulators and conductors. As these components deteriorate with age, their risk of failure increases, posing increased safety risks to the public and Hydro One Distribution personnel, and impacting system reliability. By proactively addressing crossarms in poor condition, the risk of major crossarm failures can be greatly mitigated. The rate of replacement is approximately 2,500 crossarms per year, at a cost that ranges from $2.5 million to $2.7 million annually over the five year period.

Nest Platforms

Bird nests on distribution poles can potentially cause pole fires and damage equipment, impacting safety, asset condition, and system reliability. Nest platforms are constructed to allow bird nests to be relocated from distribution poles, while complying with environmental regulations protecting species at risk. The relocated nest platforms can be installed on existing poles, on taller poles, or on separate adjacent poles. The rate of relocation is approximately 30 nest platforms per year, at a cost that ranges from $240 thousand to $260 thousand annually over the five year period.

Overhead Conductor

Some types of overhead conductor have been found to pose increased safety risks requiring modified work practices. The presence of this conductor limits Hydro One Distribution's ability to work on poles and equipment, and can pose work issues for Joint Use Partners. Replacement is based on the location and joint use status of poles which support these conductor types. The cost ranges from $1.0 million to $1.1 million annually over the five year period.

Regulators and Reclosers

Regulators and Reclosers are integral components in the operation of the distribution system. Devices requiring replacement are those which are inoperable and where maintenance is not deemed feasible. Failed or inoperable regulators and reclosers can lead to disproportionately widespread and/or extended outage impacts. Proactively replacing or refurbishing these aged, deteriorated or defective assets can greatly reduce these risks. The rate of replacement is approximately 350 regulators or reclosers per year, at a cost that ranges from $3.0 million to $3.3 million annually over the five year period.

Sentinel Lights

Sentinel Lights are legacy equipment which provides dusk to dawn lighting for Hydro One Distribution customers. Hydro One Distribution is contractually obligated to maintain existing installations, which may include replacing failed fixtures or poles. This program also funds the removal of lights that are no longer required. The rate of replacement or removal is approximately 1,300 per year, at a cost that ranges from $370 thousand to $400 thousand annually over the five year period.

Substandard Transformers

Substandard Transformers are transformers which are housed in substandard enclosures. These include "Pole Transformer" units and "Transclosure" units. These transformers are in poor condition and provide inadequate operational clearances. As a result, any work on them can only be completed if they are taken out of service, which results in long outages. As these types of transformers are not currently part of Hydro One Distribution's standards, limited supplies of spare parts can also result in extended outages if they fail. This program funds the replacement of these substandard transformers. The rate of replacement is approximately 100 transformers per year, at a cost that ranges from $2.4 million to $2.6 million annually over the five year period.

Switches

Switches are integral components in the operation of the distribution system. Overhead Air Break and Load Break switches requiring replacement are those which have failed or have operational issues that cannot be feasibly repaired. Failed or inoperable switches can lead to reduced operational flexibility as well as disproportionately widespread and/or extended outage impacts. Proactively addressing these aged, deteriorated, or defective assets can greatly reduce these risks. The rate of replacement is approximately 60 switches per year, at a cost that ranges from $2.0 million to $2.2 million annually over the five year period.

Result:

The line component replacement program will result in:

- Mitigating safety risks of defective, substandard or deteriorated assets,
- Maintaining reliability of the distribution system, and
- Satisfying regulatory requirements.

Costs:

($M)	**2015**	**2016**	**2017**	**2018**	**2019**	**Total**
Capital* and Minor Fixed Assets (A)	11.6	11.8	12.1	12.3	12.6	60.4
Operations, Maintenance & Administration and Removals (B)	2.5	2.6	2.6	2.7	2.7	13.1
Gross Investment Cost (A+B)	14.1	14.4	14.7	15.0	15.3	73.5
Recoverable (C)	-	-	-	-	-	-
Net Investment Cost (A+C)	11.6	11.8	12.1	12.3	12.6	60.4

*Includes Overhead at current rates. No Allowance for Funds During Construction is charged due to monthly capitalization.

Investment Category:

System Access	System Renewal	System Service	General Plant
0%	100%	0%	0%

OEB Renewed Regulatory Framework Outcome Summary:

Customer Focus	• Reduce the number of potential interruptions to customers and mitigate potential safety hazards by proactively replacing defective, substandard or deteriorated distribution line components.
Operational Effectiveness	• Maintain customer supply reliability by replacing ageing and degrading distribution line components.
Public Policy Responsiveness	• Comply with the Distribution Rate Handbook by maintaining the service reliability indicators by replacing ageing and degrading distribution line components prior to failure. • Comply with the Distribution System Code requirement to ensure that appropriate follow up and corrective action is taken regarding problems identified during a line patrol.
Financial Performance	• Cost savings are recognized when distribution line components are replaced proactively rather than reactively; as failed components take longer to replace making it more costly.