

1                   **ASSET CONDITION ASSESSMENT AND ANALYSIS**

2  
3           **1.0 INTRODUCTION**

4  
5           This Schedule summarizes Hydro One Distribution’s Asset Condition Assessment  
6 (“ACA”) practices, processes and ACA findings for key distribution system components,  
7 equipment, and facilities. Hydro One Distribution’s ACA practices are based on previous  
8 studies carried out by Acres International (currently Hatch Energy), comparisons with  
9 other members in the electrical utility industry and expert opinion available within Hydro  
10 One. The practices are also based on a review of good utility practice.

11  
12           ACA is one of the tools used to detect and quantify the extent of asset degradation of  
13 distribution system equipment and to provide a means of estimating remaining asset life  
14 based on condition. The rate of change in asset condition over time helps identify  
15 deterioration trends. This information also helps establish maintenance, refurbishment or  
16 replacement requirements based on the asset’s ability to perform reliably. It must be  
17 recognized that the level of ongoing maintenance can have a pronounced effect on the life  
18 of some assets, and where this is the case, it is the ACA results that provide a barometer  
19 to assess the effectiveness of these maintenance programs, as well as identifying future  
20 end-of-life (“EOL”) replacement requirements.

21  
22           Hydro One Distribution monitors the condition of its assets through a number of  
23 activities that include targeted asset condition assessments, maintenance activities, EOL  
24 assessment studies and incident investigations. These techniques are used to identify  
25 assets whose performance could have serious negative impact on Hydro One’s business  
26 values and therefore require refurbishment or replacement, or in some cases, removal.  
27 The information is also used to decide on changes to maintenance practices when this is

1 the economical solution. ACA information is a significant factor in determining the  
2 priority of work requirements for Sustaining Capital and OM&A programs.

3  
4 **2.0 OVERVIEW**

5  
6 The effective and efficient operation of the asset management model requires accurate,  
7 timely and sufficient asset information for decision making purposes. This information is  
8 used to support investment decision and work prioritization processes by enabling the  
9 assessment of risks to the company's business values and performance targets discussed  
10 in Exhibit A, Tab 4, Schedule 1.

11  
12 The effective management of distribution assets requires the identification and optimum  
13 mitigation of risk to the business values. This is achieved by balancing lifecycle costs  
14 and the related asset performance. If the asset management focus were strictly on  
15 improving or maintaining asset condition without due consideration of the resultant risk  
16 mitigation, then the result would be unnecessarily high expenditure levels. A specific  
17 asset condition finding does not automatically prescribe a set course of action or its  
18 timing. Other considerations include operating conditions (e.g. loading levels), technical  
19 obsolescence, asset demographics, spare parts availability, asset performance (e.g. asset  
20 failure rates, reliability trends), environmental factors, financial implications and the long  
21 term strategy for managing a particular asset type.

22  
23 Recognizing that gathering detailed condition information on every individual asset and  
24 every "nut and bolt" is both practically infeasible and not required, distribution assets  
25 were grouped into 20 logical asset classes. These classes were prioritized and further  
26 grouped into three categories, Priority 1 ("P1"); Priority 2 ("P2"); and Priority 3 ("P3")  
27 based on their value to the business. These priorities determine the importance of  
28 acquiring condition information. The asset priority results are shown below.

1  
2  
3

**Figure 1: Prioritization of Assets**

Priority 1 (P1) <ul style="list-style-type: none"> <li>• High Value</li> <li>• High Risk</li> </ul>	Priority 2 (P2) <ul style="list-style-type: none"> <li>• Moderate Value</li> <li>• High Risk</li> </ul>	Priority 3 (P3) <ul style="list-style-type: none"> <li>• Low Value</li> <li>• Lower Risk</li> </ul>
Asset Class	Asset Class	Asset Class
Station Transformers	Station Reclosers & Breakers	Other Spares
Station Land Assessment & Remediation (Site Contamination)	Station HV Switches & Fuses	AC/DC Service Equipment
Overhead Line Sections	Station Sites and Structures	Feeder Protection (Switch/Fuse)
Wood Poles	Mobile Substations	Oil Containment
Right of Way (ROW) Vegetation	Transformer Spares	Switches – Lines
	Submarine Cables	Reclosers - Lines
	Underground Cables	Transformers - Lines
	PCBs – Stations	
	PCBs - Lines	

4

5 P1 assets represent the highest priority assets and are of high value (in terms of total  
 6 sustaining program expenditures) and high risk to the business. P2 assets are second in  
 7 priority with moderate program expenditures and high risk; and P3 assets are lowest in  
 8 priority with low program expenditures and lower risk to the business. For the high  
 9 value/high risk P1 assets, detailed asset condition assessments are carried out that involve  
 10 documenting asset description, demographics, condition criteria, and condition  
 11 assessment results. For P2 assets, in some cases detailed asset condition assessments are  
 12 carried out, but not to the same level of detail as with P1 assets, and in other cases, the  
 13 management of condition relies on routine or time based maintenance programs.

14

15 The P3 assets are managed to a great extent using routine programs (e.g. line patrols,  
 16 defect corrections, trouble call response) that collect the condition data necessary to  
 17 ensure assets are maintained to Hydro One Distribution’s standards. The routine

1 programs put in place for P3 assets use data to trigger asset management actions. For  
2 example, the distribution line transformers population is managed using line patrol  
3 observations (e.g. presence of corrosion, oil leaks, paint condition, pad placement and  
4 grading). P3 assets are not the focus of this exhibit.

5

### 6 **3.0 THE ACA PROCESS**

7

8 Hydro One Distribution carries out asset condition assessments using an approach that is  
9 based on the ACA objectives, prioritizes assets, and develops criteria to be used for  
10 assessing the condition of its distribution assets. Hydro One Distribution assesses the  
11 condition of its assets through inspections, testing, and preventative maintenance  
12 activities, making improvements to its data collection process and carrying out special  
13 condition surveys. Valuable asset condition information may also be obtained through  
14 incident investigations and special end-of-life studies for specific assets, when required.

15

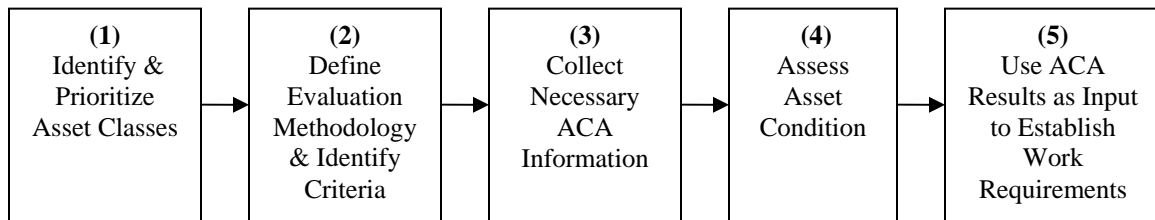
16 An outline of the steps involved in the asset condition assessment process is illustrated in  
17 Figure 1 below.

18

19

**Figure 2: General ACA Process**

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21

22

23 The major steps in the ACA process as depicted in Figure 1 are:

24

- 1 1. Identify asset classes and prioritize them (i.e. P1, P2, P3) based on the value the  
2 assets represent to the business, which in turn determines the importance of acquiring  
3 condition information.  
4
- 5 2. Define the asset information needed to determine and evaluate asset condition against  
6 predefined condition indicators based on failure mode analysis and expected results  
7 or specifications for higher priority asset classes.  
8
- 9 3. Collect the necessary asset condition information. Define the measurements, and  
10 coordinate and schedule the necessary work to collect relevant asset condition  
11 information that will enable the development of appropriate work programs or  
12 projects to respond to condition deficiencies and mitigate risks. This information may  
13 be obtained through regular testing, surveys, inspections or studies.  
14
- 15 4. Analyze the asset condition and performance information to identify population  
16 condition, performance trends and high risks and impacts of asset condition on  
17 meeting business objectives, including service quality standards.  
18
- 19 5. Use the asset condition assessment results to support detailed Sustaining and  
20 Development Capital and OM&A programs and projects. ACA information is a  
21 critical input to determine the level of work required in conjunction with other factors  
22 such as equipment performance, environmental considerations, availability of spares  
23 and customer reliability.

### 24 25 **3.1 Asset Condition in Comparison to Asset Defects**

26  
27 The ACA process is intended to measure asset degradation, the criticality of the  
28 degradation, and the remaining asset life. When considering ACA, it is important to

1 understand the differences between defect management and regular maintenance versus  
2 long term asset degradation and asset condition assessment. Defects are usually well  
3 defined and associated with failed or defective components which make up an asset and  
4 affect the operation and reliability of the asset well before end-of-life. These do not  
5 normally affect the life of the asset itself, if detected early and corrected. Defects are  
6 routinely identified during inspection and dealt with by maintenance activities to repair or  
7 replace failed components and thereby ensure continued reliable operation of the asset.

8  
9 Long term degradation is generally less well defined and is not easily determined by  
10 routine visual inspection. The asset condition assessment's purpose is to detect and  
11 quantify long-term degradation and provide some means of quantifying remaining asset  
12 life. This includes identifying assets that have a high risk of failure or are at end-of-life,  
13 and which will require major capital expenditure to refurbish, replace or eliminate  
14 altogether.

15

## 16 **4.0 ASSET CONDITION SUMMARY AND RESULTS**

17

18 The following sections highlight the prioritized asset classes that Hydro One Distribution  
19 uses and provides the most recent set of summarized ACA results for the two highest  
20 priority asset classes.

21

### 22 **4.1 Detailed ACA Results for P1 Assets**

23

24 The application of the ACA process to each asset quantifies the proportion of the assets  
25 that will require work through planned sustaining and development programs. A  
26 summary of the P1 asset conditions based on data collected up to the end of 2008 are  
27 shown in Table 4.1 below.

28

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

Asset	ACA Results		
	"Poor" or "Very Poor"	"Fair"	"Good" or "Very Good"
<b>Stations</b>			
Transformers	15%	14%	71%
Land Assessment & Remediation (LAR)	3%	0%	97%*
<b>Lines</b>			
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.

- 1 • “Good” to “Very Good” Condition assets are currently at a lower risk than the other  
2 categories.

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

11  
12 The following sections provide details on the key asset groups and highlight ACA results  
13 based on information and observations gathered up to December 31, 2008.

14  
15 4.1.1 Distribution Station Transformers

16  
17 The condition of station transformers is assessed using the following methods:

- 18  
19 • Dissolved Gas in oil Analysis (“DGA”) and Standard Oil Tests involve withdrawing  
20 a sample of oil from a transformer with follow-up laboratory analysis to determine  
21 quantities and type of gas in the oil and the condition of the oil. The results provide  
22 an indication concerning the degradation of oil and insulating material. The analysis  
23 techniques used are the Key Gas method that is defined in IEEE C57.104 and the  
24 Rogers Ratio method.  
25  
26 • Furan (ASTM D-5837) testing is an additional oil test that provides information  
27 regarding the condition of the paper insulation in the core of the transformer.

1 Degradation of paper causes it to lose its tensile strength and results in release of  
2 furans.

- 3 • Moisture Content (ASTM D-1533) is a test used to determine that amount of water  
4 present within the transformer. This water can be found in the cellulose insulation of  
5 the transformer winding. Excessive moisture trapped in cellulose insulation can  
6 undermine the condition of transformer windings causing premature failures.
- 7 • Bushings, control cabinets, transformer tanks and cooling systems are inspected  
8 visually.

9

10 Hydro One Distribution makes use of proactive measures and diagnostic methods and  
11 tools such as those noted above to facilitate early detection of deteriorating transformer  
12 condition and incipient failure to detect the remaining life of these costly assets. Based  
13 on results gathered, about 15% of distribution station transformers fall in the “Poor” to  
14 “Very Poor” range and are at a high risk of failure. These units will need to be replaced  
15 or remediated. These transformers will be proactively taken out of service should their  
16 condition deteriorate further to prevent failures and reduce impacts to Hydro One  
17 Distribution’s customers.

18

19 At this time, 85% of in-service transformers are in “Fair” to “Good” or “Very Good”  
20 condition, but this could change quickly if they are not maintained in an ongoing and  
21 prudent manner. Events that can lead to rapid deterioration include electrical failures of  
22 components or faults occurring from animal contact, lightning, contamination of  
23 equipment; mechanical failure caused by movement of internal windings; or failures  
24 caused by malfunctioning cooling systems. These failures can cause damage that is not  
25 easily detected and can lead to rapid deterioration of condition. As a result, station  
26 transformers can move from the “Fair” and “Good” categories into the “Poor” category  
27 very rapidly due to normal wear and exposure.

28

1 It should be noted that the above condition results are based on a refined approach to  
2 transformer ACA that was not developed in prior years. This approach was adopted in  
3 2008 in response to findings on Hydro One Transmission transformers with relation to  
4 the correlation of condition ratings and failures. In particular, a subset of Transmission  
5 station transformers had experienced 3 catastrophic failures that were not predicted by  
6 ACA results. A review of the transformer ACA methodology with the particular  
7 transformer manufacturer resulted in the refinements adopted. Had these refinements  
8 been developed and adopted previously, station transformer ACA results submitted  
9 during previous proceedings would have been as follows:

10  
11 **Table 4.2: Summary of Distribution Transformer Health Indices**  
12

<b>Classification</b>	<b>ACA Result</b>	
	<b>2007</b>	<b>2009</b>
Very Poor & Poor	11%	15%
Fair	15%	14%
Good & Very Good	74%	71%
	<b>100%</b>	<b>100%</b>

13  
14 Analysis of the historic results indicates that the condition of the entire population of  
15 transformers has been deteriorating as greater percentages of “Good” and “Very Good”  
16 transformers have moved into the fair and poor categories. During this timeframe, Hydro  
17 One Distribution has continued to focus on maintenance and diagnostic activities as  
18 discussed in Sustaining OM&A Exhibit C1, Tab 2, Schedule 2 and has demonstrated that  
19 investments are well directed based on reductions in the number of transformer failures.  
20 Furthermore, improvements made recently in assessing the condition of these costly and  
21 critical assets will improve our ability to manage the life cycle cost and reliability,  
22 reducing the impacts of aging on this class of assets. The reduction in transformer  
23 failures from 2004 to 2008 is highlighted in Table 4.3.

1                   **Table 4.3: Summary of Distribution Transformer Failures 2004 to 2008**  
2

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

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

10  
11    4.1.2    Site Contamination – Land Assessment & Remediation

12  
13    Hydro One Distribution assesses the environmental condition of Distribution Stations by  
14    examining soil, ground water and the surface run off from a site. Soil contamination is  
15    determined by the laboratory analysis of soil samples. Soil samples can be obtained from  
16    shallow open excavations or by drilling to gain samples at various depths. Ground water  
17    quality is determined by the laboratory analysis of ground water samples taken from  
18    monitoring wells that are installed on station property or adjacent property. Surface  
19    water runoff quality is determined by the laboratory analysis of runoff water samples  
20    taken by automated sampling devices. The results of these lab tests are then compared to  
21    contaminant levels permitted in provincial and federal regulations.

1 The chemical contaminants that exist on some sites were as a result of oil leaks and spills  
2 from equipment, or from previous industry accepted applications of certain long lasting  
3 chemicals (e.g. wood preservatives, herbicides) that complied with environmental  
4 regulations at the time that they were used. The primary contaminants of concern are:

- 5
- 6 • Arsenic (“AS”) – From arsenic trioxide, a registered herbicide at the time, used for  
7 total vegetation control within Distribution Stations from the 1950s until about 1965
  - 8 • Total Petroleum Hydrocarbons (“TPH”) - From leaked or spilled transformer  
9 insulating oil
  - 10 • Polychlorinated Biphenols (“PCBs”) – From leaked or spilled transformer insulating  
11 oil
  - 12 • Pentachlorophenol (“PCP”) – From treated wood poles

13

14 Hydro One Distribution has assessed all distribution station sites for site contamination  
15 and found that about 45% contained some degree of contamination, and of those, 3% still  
16 require remediation to ensure the contaminants do not present any threat to humans and  
17 the surrounding environment.

18

19 Remediation activities are scheduled using a risk based ranking system that focuses on  
20 high risk sites and on mitigating the risk of off-property impacts related to human and  
21 ecological exposure. Medium risk sites, are those containing some degree of  
22 contamination that is unlikely to migrate off-site but the risks are high enough to warrant  
23 sampling and monitoring on an ongoing basis. The remaining sites may contain some  
24 degree of contamination, but the risk of off site contamination or negative human health  
25 impacts is very low, or samples do not show any significant levels of arsenic, PCBs or  
26 TPH.

1 The plan that is being implemented under the Land Assessment and Remediation  
2 (“LAR”) program is highlighted under the Stations program in the Sustaining OM&A  
3 Exhibit C1, Tab 2, Schedule 2.

4  
5 4.1.3 Distribution Overhead Line Sections  
6

7 Hydro One Distribution does not conduct asset condition assessments on Overhead Lines  
8 Sections in the same manner as other P1 assets. This particular asset is considered  
9 unique compared to other P1 assets as it consists of a grouping of diverse overhead line  
10 components (e.g. conductor, insulators and wood poles) each of which have very  
11 different characteristics, condition deterioration factors, and maintenance requirements.  
12 It is for this reason, and the fact that it would be extremely costly to collect ACA  
13 information system wide on all of the lower level components that comprise a line  
14 section, that Table 4.1 above does not contain a percentage breakdown for Overhead  
15 Lines Sections.

16  
17 The most practical and cost-effective approach for assessing the condition of distribution  
18 line sections is to collect relevant information on individual components that make up the  
19 line section. The information is obtained through:

- 20
- 21 • pole assessment and line patrol activities as outlined in Sustaining OM&A Exhibit  
22 C1, Tab 2, Schedule 2, which provides information on defects and condition of wood  
23 poles.
  - 24 • a business process whereby field staff report suspect conditions that require more  
25 detailed assessments.
  - 26 • reliability information indicating poor performance of a feeder or section.
- 27

1 When a critical mass of components reaches end-of-life, such that it is more cost-  
2 effective to refurbish an entire line section than to replace components individually, then  
3 a Line (Refurbishment) Project is undertaken. Projects propose in this application are  
4 described in Sustaining Capital Exhibit D1, Tab 3, Schedule 2.

5

6 As noted above, it is cost prohibitive to collect asset condition information on all  
7 distribution line sections, nor is it necessary, as many of the line sections are in good  
8 condition. The process noted above is considered to be the most practical and cost  
9 effective means to manage the condition of these assets.

10

#### 11 4.1.4 Wood Poles

12

13 Information used for determining the condition of wood poles is gathered from pole  
14 inspections and tests. Visual inspections identify numerous defects such as split tops,  
15 leaning poles, lightning damage, broken poles, wood pecker damage, rodent damage,  
16 shell rot, fire damage, insect infestation and other mechanical damage. The number and  
17 severity of these defects is used to assess condition. In addition, sounding tests using a  
18 hammer are employed to detect the presence of hollow areas in the pole, shell separation,  
19 or external decay. Poles that appear to have internal rot are further tested using a drill test  
20 that measures the shell thickness (amount of wood in good condition in the outer area of a  
21 pole).

22

23 Based on inspection and test results accumulated up to the end of 2008, Hydro One  
24 Distribution estimates that approximately 5% of the wood poles in the system are in  
25 “Poor” to “Very Poor” condition. The exact locations of these poles are identified during  
26 the normal course of the inspection cycle. Once identified, poles that are found to be in  
27 very poor condition are replaced in an expedient manner and those found to be in poor  
28 condition are replaced as part of the Wood Pole Structure Replacement Program

1 described in Exhibit D1, Tab 3, Schedule 2. The finding that approximately 5% of poles  
2 are at risk supports the need to maintain pole assessment plans proposed in Sustaining  
3 OM&A Exhibit C1, Tab 2, Schedule 2 and to fund pole replacements at levels proposed  
4 in Sustaining Capital Exhibit D1, Tab 3, Schedule 2.

5

6 ACA results have also been analyzed in relation to Hydro One Distribution's wood pole  
7 demographics. Figure 3 below, indicates the percentage of poles that required  
8 replacement (i.e. "Poor" or "Very Poor" condition) relative to their age based on the  
9 latest inspection and testing data.

10

11 **Figure 3: Wood Pole Inspection & Testing Results Relative to Pole Age**

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13

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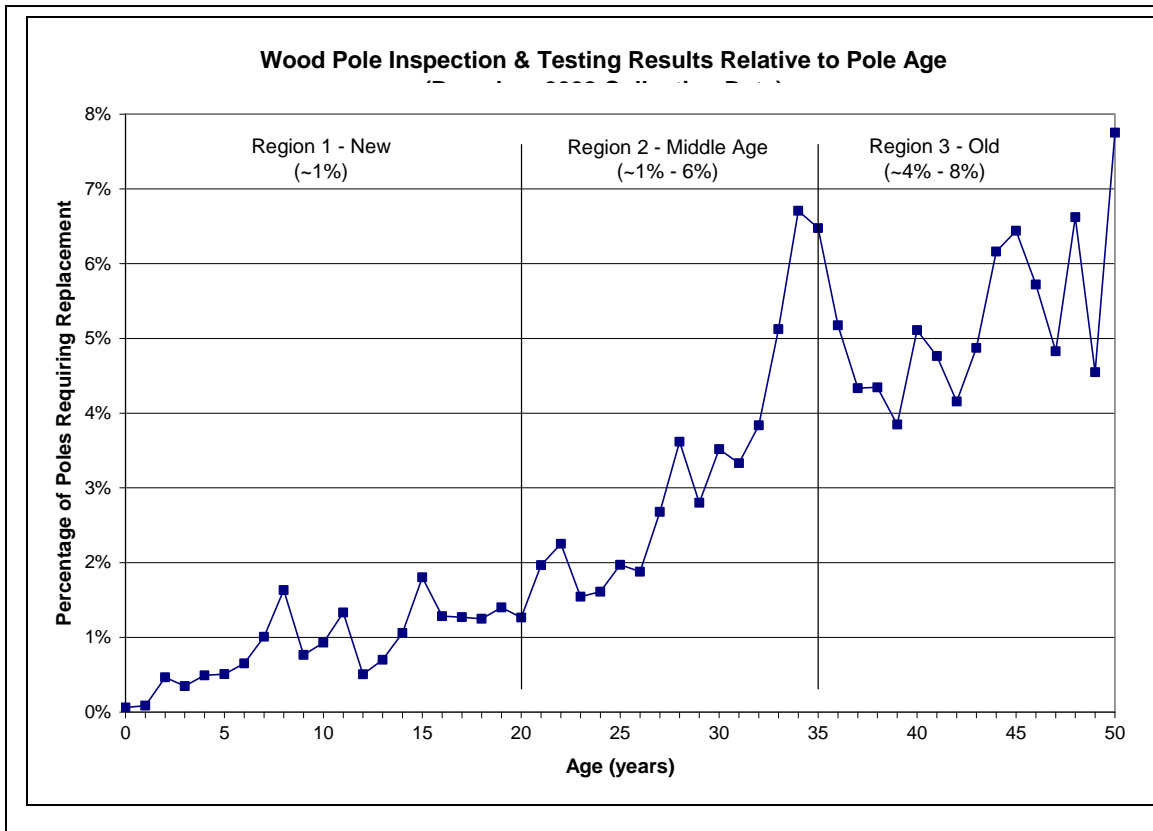
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**Figure 4: Hydro One Distribution Wood Pole Demographics**

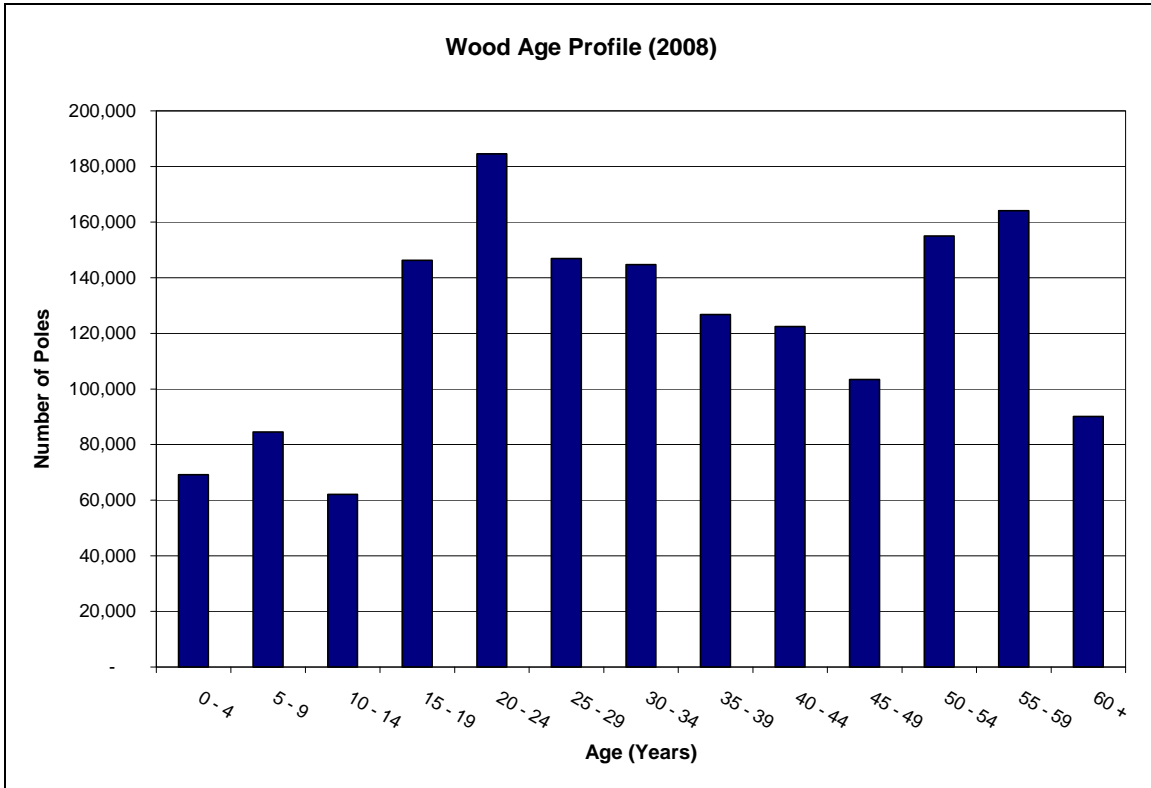


Figure 4 above is a representation of Hydro One Distribution's wood pole demographics and of particular interest is the large number of poles that are currently between 20 and 24 years of age. These poles have just started to move through Region 2 illustrated in Figure 3, where the replacement rates increase rapidly from approximately 1% to 4% over the next 10 years. In the past, the number of poles per year that have entered this Region has been about 25,000 to 35,000, but over the next 10 years the number will increase to as much as 45,000, thereby increasing the number of poles expected to be found at end-of-life. This information indicates that in the future one can expect an increasing number of pole replacements.

1 In addition to challenges with demographics, Hydro One Distribution has become aware  
2 of a potential problem with a particular subset of its red pine poles that have been  
3 installed between 1997 and 2004. In recent years, a number of these relatively young  
4 poles have failed under storm conditions and failure analyses have indicated that  
5 premature rot was the root cause. Further analysis on these poles has indicated that 13%  
6 of those sampled are showing advanced stages of internal rot or are vulnerable to pest  
7 damage (e.g. ants, woodpeckers). The 13% statistic does not compare favorably with the  
8 fact that poles of this age typically require replacement at a 1% rate. Currently, the poles  
9 of concern make up approximately 55,000 of the total 1.7 million poles that are in-  
10 service. These poles are showing a high degree of deterioration, which increases safety  
11 risks for joint use partners and Hydro One Distribution staff that have to work on these  
12 poles under difficult conditions (e.g. storms, power restoration). Managing these  
13 situations introduces complexities that require added processes and training thereby  
14 increasing overall costs. As a result, systemic problems of this type need to be addressed  
15 in a proactive manner. Based on the risks and condition findings, 50% of the red pine  
16 poles are in the “Very Poor to Poor” category of the ACA results and will require  
17 replacement over the next 5 years.

18  
19  
20 The Red Pine Pole issue along with the leading indicators discussed above (i.e.  
21 demographics and expected future replacement rates), and the results from the current  
22 pole assessment program, support the need to replace those poles found to be substandard  
23 under the pole replacement program. The numbers of poles requiring replacement in  
24 future years will increase and the pole replacement program will need to be expanded to  
25 continue to manage safety and reliability risks associated with sub-standard poles.

1   4.1.5   Rights-of-Way Vegetation

2

3   Vegetation asset condition assessments are undertaken by collecting data on various  
4   vegetation parameters including tree clearances (i.e. percentage of trees within 1m of the  
5   conductor), overhang (i.e. percentage of trees overhanging the conductor), danger trees  
6   (i.e. diseased or dead trees), tree densities, average brush height, and average brush  
7   density (i.e. stems per line span). This information is combined to yield asset condition  
8   assessment results for feeders and is used to prioritize line clearing and brush control  
9   programs.

10

11   Assessment of vegetation conditions identify that about 35% (36,000 km) of rights-of-  
12   way are in the “Very Poor” and “Poor” category and are at risk and require clearance  
13   work within the next two years. The increase in the percentage of rights-of-way in this  
14   category (about 4%) over the last two years is primarily attributed to the effect of lower  
15   accomplishment levels achieved during 2005 and 2006. Volumes in those years were  
16   low due to the need to redirect resources during 2006 in response to the unusually high  
17   number of storms, and the 2005 labour disruption. The effect of those accomplishment  
18   levels was that feeders that were previously in the “Fair” category have deteriorated. In  
19   more recent years (i.e. 2007 and 2008), accomplishments were higher (e.g. approximately  
20   12,200 kms of line clearing were accomplished in each year) and this drove a 2%  
21   increase in “Good” rights-of-way from 30% as of the end of 2006, to 32% as of the end  
22   of 2008.

23

24   ACA results and the performance of specific feeders are the primary inputs that are used  
25   to schedule line clearing and brush control work on overhead lines. For Hydro One  
26   Distribution, the condition of rights of way is of great concern, as vegetation caused  
27   interruptions are the single greatest contributor to unreliability, as illustrated in Exhibit A,  
28   Tab 3, Schedule 1, and Exhibit C1, Tab 2, Schedule 2.

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The projected accomplishment over the 2009 to 2010 two-year period will not fully address the “Poor” and “Very Poor” locations. These conditions will slowly improve over the next few years, but will not be fully addressed until a shorter vegetation maintenance cycle is fully implemented.

## **4.2 ACA results for P2 Assets**

The following sections provide ACA information for P2 assets. It is recognized that P2 assets are of lower priority, and as a result, detailed analysis is not carried out to the same extent as with P1 assets. In a number of cases it may not be cost effective or practical to acquire the necessary information to support detailed ACA analysis, in which case maintenance processes and reliability indicators are used to manage the assets. This is further discussed in each of the asset groups below.

### **4.2.1 Station Reclosers**

Hydro One Distribution currently manages approximately 6,000 distribution station reclosers consisting of single-phase and three-phase units, and about 160 circuit breakers. These pieces of equipment are currently on a six-year maintenance interval for refurbishment or replacement and amount to 1,000 units per year. Due to the comprehensive maintenance program, separate detailed asset condition assessments are not completed for station reclosers and breaker assets. The condition of these assets is monitored through reliability and performance data and information gathered during the ongoing maintenance program funded under the Stations Program in Exhibit C1, Tab 2, Schedule 2.

1    4.2.2   High Voltage Fuses

2

3    There are approximately 1,000 3-phase sets of High Voltage fuses installed on the Hydro  
4    One Distribution system. The cost effective method of collecting ACA information on  
5    this asset group is to inspect these devices during regular station maintenance activities.  
6    Devices that are found to be in substandard condition are replaced in an expedient  
7    manner under the Station Program in Exhibit C1, Tab 2, Schedule 2.

8

9    4.2.3   Station Sites and Structures

10

11   Based on ongoing inspections carried out during regular maintenance and asset condition  
12   assessment findings, stations that require significant improvements to site facilities are  
13   completed as part of the station refurbishment work described in Exhibit D1, Tab 3,  
14   Schedule 2. This work includes, as appropriate, the refurbishment or replacement of  
15   fences, high voltage and low voltage structures, buildings, yards and roads. The first  
16   phase of the assessment is completed during the regular station inspections and if  
17   required, a more detailed assessment is made to establish the condition of stations  
18   structures (e.g. wood poles, steel structures), building envelope and roof, etc. The  
19   refurbishment plans in Capital Sustaining Exhibit D1, Tab 3, Schedule 2 will address  
20   those sites that have been identified to be in poor condition.

21

22   4.2.4   Mobile Substations

23

24   Mobile substations are comprised of a trailer and distribution equipment such as  
25   transformers, switches, fuses or reclosers as well as ancillary electrical systems. Trailers  
26   are inspected on a regular basis as required by the Ministry of Transportation and  
27   electrical equipment is inspected in detail on an annual basis. Inspection standards for  
28   the related electrical equipment are identical to that of a distribution station, but more

1 frequent, as these assets are relied upon during emergency situations. Any significant  
2 defects are logged and immediate plans are made to correct these. Minor defects are  
3 corrected as part of the Stations Program in Exhibit C1, Tab 2, Schedule 2.

4  
5 Hydro One Distribution currently has a fleet of 28 mobile substations and as discussed in  
6 Sustaining Capital Exhibit D1, Tab 3, Schedule 2, investments are required to refurbish  
7 and grow the fleet to accommodate the increased need for PCB testing and to maintain  
8 adequate levels of station maintenance activities.

9  
10 4.2.5 Transformer Spares

11  
12 Hydro One Distribution has 1,460 in-service transformers and regulators, ranging in size  
13 from 0.5 to 40 MVA in approximately 70 different categories. A complement of spare  
14 transformers is required in order to respond to approximately 20 to 40 failures and service  
15 removals. The majority of spare transformers are stored in a central location and are  
16 inspected on an annual basis to ensure that they are serviceable when required. Primary  
17 activities include the visual inspections of main components (i.e., bushings, cabinets,  
18 tanks and cooling systems). The visual inspection standards for spare transformers are  
19 identical to that of in-service units, and if required oil samples are taken and analyzed.  
20 Spare transformers are maintained in a serviceable condition, such that they are available  
21 for deployment if required.

22  
23 A comprehensive transformer spare complement strategy has been developed to ensure  
24 the correct number and types of spares are available. Additional details are provided in  
25 Sustaining Capital, Exhibit D1, Tab 3, Schedule 2.

1 4.2.6 PCBs - Stations

2 Polychlorinated Biphenyls (“PCBs”) are organic compounds used in insulating oils up  
3 until the late 1970’s when they became a banned substance due to the fact that they are  
4 resistant to environmental degradation and have detrimental human health and  
5 environmental impacts. In 2008, new federal PCB regulations were enacted that mandate  
6 the retirement of PCB contaminated oils and equipment that contains oil with PCB levels  
7 above 500 ppm by 2009 and 50 ppm by 2025.

8  
9 The new regulations have a significant impact on Hydro One Distribution stations assets  
10 as approximately 80% were placed in service prior to 1985 and as a result may be  
11 vulnerable to PCB contamination in excess of 50 ppm. Of this subset, between 5% and  
12 10% is estimated to exceed allowable PCB limits. These estimates are based on historic  
13 PCB testing at stations that was focused on equipment with larger oil volumes (e.g.  
14 transformer volumes) but also included some equipment with smaller volumes such as  
15 bushings and instrument transformers.

16  
17 Currently, over 60% of station transformers have been tested and approximately 7% of  
18 volumes tested have been found to exceed 50 ppm of PCBs. For bushings, approximately  
19 20% have been tested and approximately 9% have been found to exceed 50 ppm. For  
20 instrument transformers, over a third have been tested and approximately 6% has been  
21 found to exceed the 50 ppm threshold. For all equipment, less than 1% of the units tested  
22 has insulation oil with PCBs in excess of 500 ppm.

23  
24 Station units that have not been tested to date and that were manufactured prior to 1985  
25 are the focus of current station maintenance programs as discussed in Sustaining OM&A,  
26 Exhibit C1, Tab 2, Schedule 2. Testing requires station outages and mobile substation  
27 (MUS) installations to avoid lengthy and unacceptable customer outages. This is a very  
28 time consuming and costly procedure and it is limited by Hydro One Distribution’s

1 current MUS fleet availability. At this time, Hydro One Distribution has determined that  
2 MUS and resource availability is not sufficient to meet the 2009 regulation requirements  
3 (i.e. test all units and retire those with PCBs in excess of 500 ppm) and has  
4 communicated this to Environment Canada. It is currently seeking an extension to the  
5 2009 deadline.

6  
7 As discussed in Sustaining OM&A Exhibit C1, Tab 2, Schedule 2, Hydro One  
8 Distribution is proposing to test equipment such that contaminated units can be identified,  
9 retrofilled, or replaced on a planned basis to meet the legislative deadline.

10  
11 4.2.7 PCBs – Lines

12  
13 Some oil-filled distribution lines components also contain PCBs. The new regulations  
14 have a significant impact on Hydro One Distribution given that the lines system is  
15 composed of 440,000 pole mounted transformers, 45,000 pad-mounted transformers, and  
16 2,300 capacitors, among other equipment. The transformers are the largest concern and  
17 Hydro One Distribution's experience has been that approximately 10% of units that were  
18 manufactured prior to 1985 may contain insulating oil that exceeds the 50 ppm threshold.  
19 This experience is based on PCB tests that were conducted between 1997 and 2003.

20  
21 Demographic information indicates that approximately 240,000 pole mounted  
22 transformers on the lines system were manufactured prior to 1985 and that 24,000 (i.e.  
23 10%) of those are expected to exceed the PCB threshold. For pad-mounted transformers,  
24 demographic information indicates that in excess of 6,000 units were manufactured prior  
25 to 1985 and that approximately 600 of those units will exceed the PCB threshold.

26  
27 As discussed in Sustaining OM&A Exhibit C1, Tab 2, Schedule 2 and Sustaining Capital  
28 Exhibit D1, Tab 3, Schedule 2, Hydro One Distribution is proposing to inspect and test

1 equipment such that contaminated units can be identified and replaced on a planned basis  
2 prior to the 2025 legislative deadline.

3

4 4.2.8 Submarine Cables

5

6 Hydro One Distribution's system contains about 2,300 km of submarine cable at  
7 approximately 5,000 locations across the Province. The maintenance activities for these  
8 assets involve a 6-year inspection, in accordance with the requirements of the  
9 Distribution System Code, and new Time Domain Reflectometry ("TDR") testing that  
10 will be implemented on a 12-year cycle over the longer term.

11

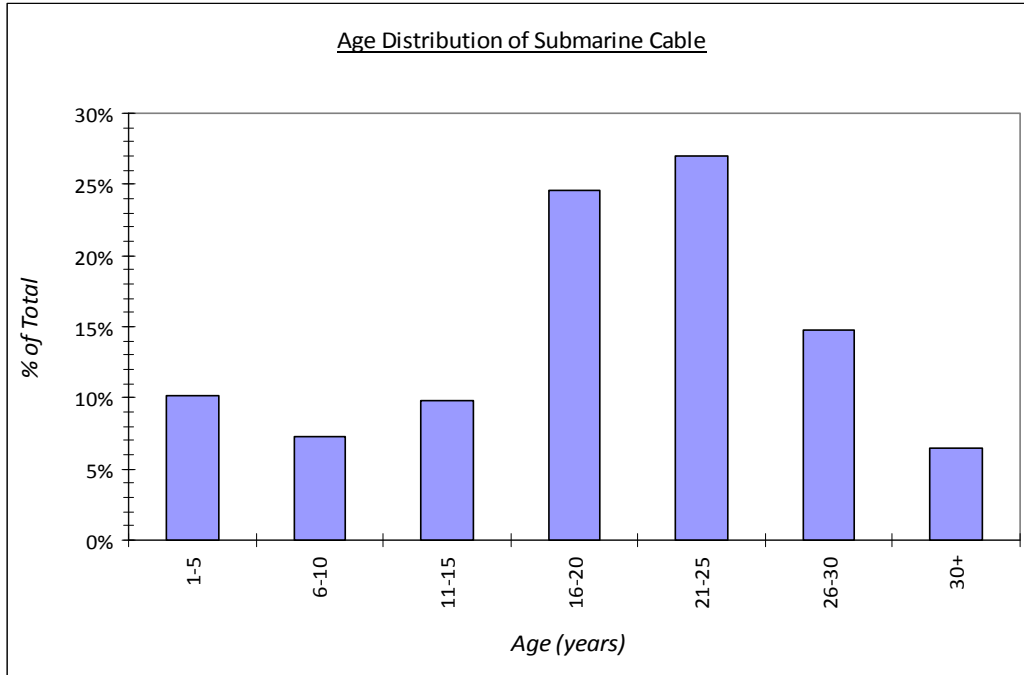
12 Inspections involve visual examination of the cable between the transformer and where it  
13 enters the water with particular emphasis at the edges of water bodies where cable armour  
14 wires (also acting as neutral wires) are susceptible to corrosion. Once corroded, these  
15 wires create a potential public safety hazard. To ensure accurate identification of  
16 corroded neutral wires, Hydro One Distribution implemented a new submarine cable  
17 testing program in 2008 that utilizes TDR testing.

18

19 The focus of the submarine cable TDR testing program is currently on older cables and  
20 the test results from the program's first year indicate that approximately 15% of cables  
21 tested are in need of refurbishment. Approximately three quarters of Hydro One  
22 Distribution's cables are older than 15 years as illustrated in Figure 5 below. The 15-year  
23 mark is noteworthy as Hydro One's experience has been that cables younger than 15  
24 years rarely require refurbishment

25

1 **Figure 5: Hydro One Distribution Submarine Cable Demographics**  
2



3  
4  
5 To address the corrosion of submarine cables and respond to the observed test results,  
6 Hydro One Distribution proposes to continue aggressively testing cables, as detailed in  
7 Sustaining OM&A Exhibit C1, Tab 2, Schedule 2, and to increase the numbers of  
8 planned refurbishments as detailed in Sustaining Capital Exhibit D1, Tab 3, Schedule 2.

9  
10 **4.2.9 Underground Cables**

11  
12 Hydro One Distribution's system contains about 4,300 km of underground cable. The  
13 maintenance activities for these assets involve a three-year inspection for urban circuits  
14 and a 6-year inspection for rural circuits in accordance with the requirements of the  
15 Distribution System Code.

1 For underground cables, the inspections involve visual examination of the components  
2 associated with the cable termination, pothead, elbows, cable riser and dip poles, pad-  
3 mounted transformers, and kiosks. For the large majority of cables, which are buried  
4 directly underground, no examination of cable or splices is undertaken. For a few cables  
5 that are in ducts, some examination of the external condition may be carried out for  
6 troublesome or critical circuits.

7

8 Hydro One Distribution's management practices for underground cables also include  
9 performance criteria: two failures within a section of cable would normally lead to the  
10 decision to replace the cable. The decision whether to repair or replace is made on  
11 condition information from a visual assessment and performance of the cable, and if  
12 deemed necessary, laboratory testing is carried out before decisions are made concerning  
13 replacement. The condition of these assets is managed on an ongoing basis from data  
14 gathered during inspections and performance monitoring. The underground cable system  
15 is relatively new and has not shown any significant deterioration trends.

16

17 Hydro One Distribution's program for managing distribution underground cables is  
18 generally consistent with the approach adopted by many other utilities for such cables.