PROPOSED INCREMENTAL CAPITAL MODULE

Hydro One is requesting recovery for required capital under the Incremental Capital Module ("ICM"). Hydro One requires incremental revenue of $26 million in 2013 associated with required in service capital additions. Hydro One requests that a 2013 rate rider be established to recover this revenue requirement. The resulting average increase for customers, as a result of this rider, is approximately 2.3%. Hydro One will demonstrate that it has passed the Threshold Test that allows access to the ICM. Hydro One will also provide information on some of the issues related to the ICM and the approach that Hydro One has taken with this application. This approach is consistent with Hydro One's submission in the Renewed Regulatory Framework proceeding (EB-2010-0377, EB-2011-0043 and EB-2011-0004) filed with the Board on April 20, 2012.

Threshold Test:

The Board has provided a formula for the Threshold Value which determines whether or not a distributor is able to access the ICM. The Board's formula is as follows:

Threshold Value = 1 + (RB/d) * (g + PCI * (1 + g)) + 20%

Where:

RB = rate base included in base rates ($4,987 million)

d = depreciation expense included in base rates ($284 million)

g = distribution revenue change from load growth (-1.04%)

PCI = price cap index (0.88%)

The values for "RB" and "d" are the Board-approved amounts from Hydro One's EB-2009-0096 proceeding. The negative growth factor of 1.04% is calculated using the Board's approach. It is calculated as the percentage difference between Hydro One's 2011 approved revenue of $1,149 million and the 2010 revenue at 2011 rates of $1,161 million. The PCI of 0.88% has been specified by the Board for use in 2012 IRM applications and is calculated by subtracting the productivity factor of 0.72% and the stretch factor of 0.40% from the price escalator of 2.00% (note that the Board specified 2013 PCI should be issued and will be utilized when the Decision in this proceeding is put into effect). The resulting Threshold Value of 117% is applied to the depreciation expense included in base rates of $284 million to determine Hydro One's Capital Threshold of $332 million.

The Capital Threshold for Hydro One is $332 million while the in service capital requirement for 2013 is $644 million. Hydro One has passed the Threshold Test and is therefore able to access the ICM for its 2013 IRM application.

Types of Investment:

Hydro One has defined three categories of capital investment that make up the $644 million in required in-service additions: "Typical" capital spending; "Escalated Issue" capital spending; and "Non-typical" capital spending.

The first category is Typical capital spending which includes historically approved levels of sustainment, development and shared services and other spending. Sustainment spending includes categories such as wood pole replacements, transformer replacements, investments in distributing and regulating stations, repairing storm damage and the replacement of meters. Development spending includes categories such as new load connections, and upgrades and system capability reinforcement. Shared services and other spending includes information technology, fleet, and work and office equipment. Typical capital spending is reviewed in detail at Cost of Service ("COS") rebasing hearings and does not require detailed further review during the period of the IRM.

The second category is Escalated Issues capital spending. This category covers spending on typical categories but at a substantial increase over historically approved levels. The higher level of capital spending is required to address an identified escalated issue. For example, a distributor may require a substantial increase over historically approved levels to address a quality issue related to certain poles. This quality issue may relate to asset age or a manufacturer issue. Escalated Issue capital spending requires a more detailed review when introduced during the period of an IRM. This review covers the need and timing of the proposed level of spending. The Escalated Issue category of capital spending is further described in Exhibit B, Tab 2, Schedules 1 to 3.

The third category covers Non-typical capital spending for 2013. This category covers the cost to replace Hydro One's Customer Information System ("CIS"). Non-typical capital spending requires a full review by the Board when introduced during the IRM period. The Non-typical category of capital spending is further described in Exhibit B, Tab 3, Schedule 1.

Capital Recovery under ICM:

The current ICM provides a mechanism for recovering Escalated Issue and Non-typical capital spending during an IRM period. There is also a requirement to recover Typical capital spending, in excess of approved depreciation, during the period of an IRM. The Board's examination under the Renewed Regulatory Framework recognizes that one of the major challenges facing the sector today, and the most significant driver of costs, is the scale of capital spending expected over the next number of years to modernize the system and to provide for new demand. Table 1 calculates the amount of capital that Hydro One needs to recover through the ICM for Typical capital.

Table 1

Incremental Capital Required for Typical Capital Spending ($millions)

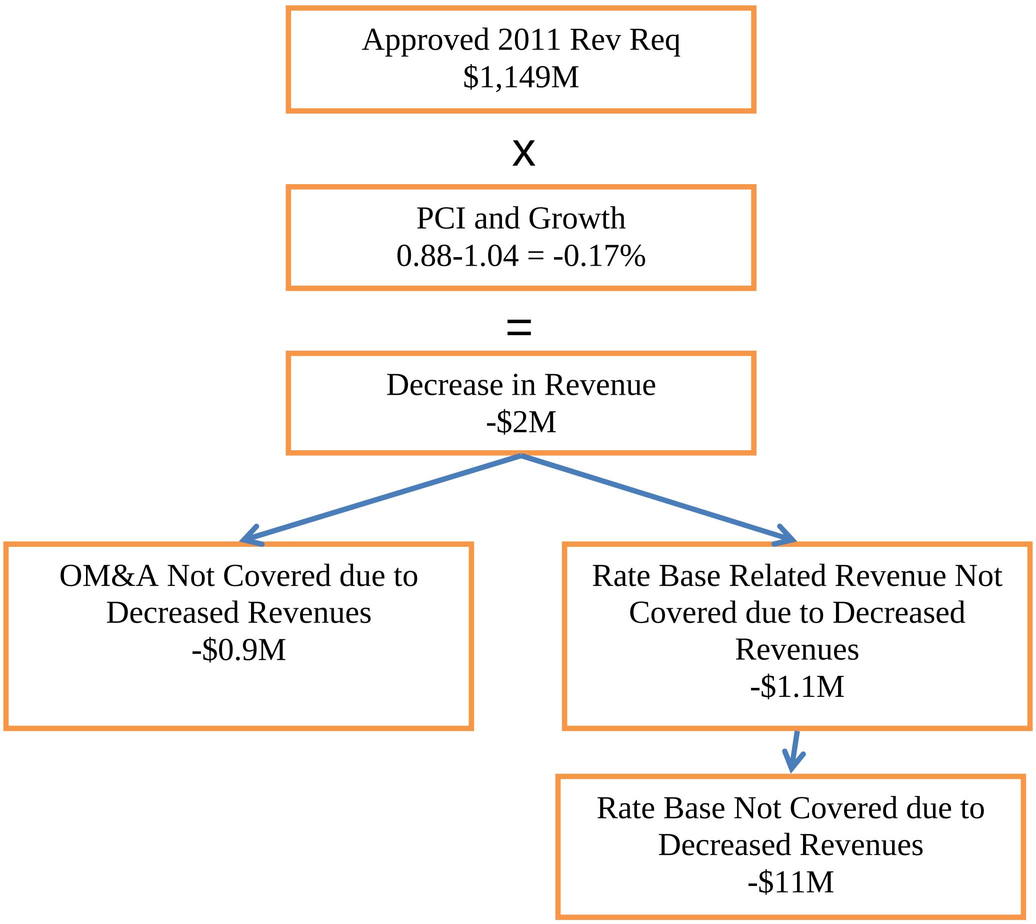
Line #		COS 2011	IRM 2013
1	Typical capital spending	$438	$414
2	Rate base impact of in-service capital		$414
3	Less rate base funded by depreciation		-$283
4	Add rate base no longer funded resulting from decrease in revenue		$11
5	Growth in rate base for Typical capital (line 2 + line 3 + line 4)		$142
6	Revenue required due to growth in rate base for Typical capital		$14

Line number 1 in Table 1 provides Hydro One's typical capital spending for 2013 of $414 million. To determine the growth in rate base for typical capital of $142 million one must deduct the approved rate base funded by the approved depreciation amount of $283 million and add back the $11 million in rate base that is no longer funded as a result of decreased revenues. The approved rate base funded by depreciation can be found in Hydro One's Board approved rate order for its EB-2009-0096 proceeding. Line 6 provides the revenue required due to growth in rate base for Typical capital of $14 million. The revenue required covers depreciation, cost of capital and taxes.

Figure 1 provides the derivation of the rate base which is no longer funded as a result of decreased revenues.

Figure 1

Derivation of Rate Base No Longer Funded due to Decreased Revenues



To determine the Rate Base adjustment required as a result of decreased revenues one must start with the 2011 approved revenue requirement of $1,149 million and apply the PCI plus growth percentage. The PCI of 0.88% plus the negative growth of 1.04% [1] results in negative 0.17% to be applied to the approved revenue requirement. The resulting decrease in revenue of $2 million is apportioned to OM&A and Rate Base based on the percentage of OM&A and rate base related revenues that make up the approved revenue requirement. This results in rate base related revenue requirement not covered

[1] The supporting calculations for PCI and negative growth can be found on page 1 of this Exhibit.

due to decreased revenues of $1.1 million. This in turn results in rate base not covered due to decreased revenues of $11 million. As a result of the decrease in revenues, $11 million in rate base is no longer recovered in approved rates.

ICM Issues:

It is critical that Hydro One recover Typical, Escalated Issue and Non-typical capital spending during the period of an IRM. Hydro One is not in a position, due to credit rating issues, to invest in rate base for which there is no cost recovery. Any negative impact to Hydro One's credit rating would result in borrowing challenges and increased borrowing costs for our customers. In order to avoid any negative credit rating impacts, Hydro One must maintain its earnings metrics including rate of return. Adding to this pressure, Hydro One was recently downgraded by Moody's by one notch. Also, Standard and Poors has revised Hydro One's outlook from stable to negative. These reports are filed at Exhibit A, Tab 6, Schedule 1, Attachments 1 & 2.

An unintended outcome of not being in a position to invest in rate base for which there is no return is lower reliability as Hydro One would have less ability to replace or refurbish assets prior to breakdown. A common industry term for this is the "harvesting" of assets. Another unintended outcome is not replacing or refurbishing assets when it is economically beneficial to do so. Planning for replacement and refurbishment and executing the plan is less costly than simply replacing or refurbishing assets when they break. The harvesting of assets would certainly result in increased contract and employee labour costs as Hydro One would be unable to levelize work based on the most efficient use of resources.

Finally, recovery of Typical, Escalated Issue and Non-typical capital spending during the period of an IRM avoids step increases in rates at COS rebasing hearings. This is particularly important given the capital intensive nature of the electricity distribution business and the pressing need for Hydro One to renew and modernize its system to meet the needs of its customers.

Hydro One's Approach:

In this application, Hydro One requests the approval of a rate rider based on the full capital program for in-service additions in 2013 based on a review of forecast changes to rate base.

Hydro One will apply the 2013 Board approved cost of capital in determining the revenue requirement when it is available, as outlined in Exhibit B, Tab 1, Schedule 2. Hydro One believes that this is appropriate because the new investments should earn returns that are consistent with the anticipated returns during the period of the investment. This treatment results in a lower return than would be realized if Hydro One applied the 2011 Board approved cost of capital as specified at page 11 in Chapter 3 of the Filing Requirements for Transmission and Distribution Applications dated June 22, 2011.

The extent of the capital investment review is determined by the nature of the investments that are driving the change in rate base. Typical capital spending is reviewed in detail at COS rebasing hearings and should not require detailed review during the period of the IRM. The Typical category is very familiar to stakeholders. The general level and type of Typical capital spending continues during the IRM period. This is similar to the treatment of OM&A costs during an IRM period.

For Hydro One, Typical capital includes the capital spending approved in the most recent COS application (i.e. net of any OEB directed reductions) less all capital spending associated with renewable generation and smart grid investments as spending in these areas is recovered through rate riders and deferral accounts. Table 2 shows the Typical capital spending for the historic, base and IRM years.

Table 2
Summary of Typical Capital
($ Million)

	Historic			Base Year	IRM Year
	2008	2009	2010	2011	2013
TOTAL	**435.3**	**455.5**	**430.5**	**437.6**	**451.9**

The amount of revenue requirement that a utility requires to recover its capital investments in a particular year results from the in-service capital additions in the year, not the capital expenditures in the year as some projects require several years before they are completed. The in-service capital additions in the year are added to rate base and therefore are included for recovery in rates. The in-service capital additions in 2013 for the Typical capital are $414 million.

The Escalated Issue category includes increased spending on stations, pole replacements and the capital contribution for a transmission station to address pressing issues. Hydro One has filed three years of historic investment information to establish the typical spending pattern for these types of investments. Detailed age and asset condition information has been provided to defend Hydro One's spending to address the Escalated Issues. The evidence is detailed and is consistent with the high quality of evidence that has been filed in previous COS filings for these types of program investments.

Finally, the Non-typical category includes spending to replace Hydro One's current Customer Information System. Hydro One has provided detailed evidence that is consistent with the high quality evidence that has been filed in previous COS filings for this type of project investment.

In summary, Hydro One requests recovery of Typical, Escalated Issue and Non-typical in-service capital additions as outlined in the following table.

Table 3

Typical, Escalated Issue and Non-Typical Investment Recovery

Line #	(All $ in millions)	2013 Capital	Associated ICM Revenue	% Distribution Rate Impact
1	Typical	$414	$14	1.2%
2	Escalated Issue	$75	$6	0.5%
3	Non-typical	$155	$7	0.6%
4	Total in service additions	$644	$26	2.3%

The revenue increase required for each category is provided in the second last column and the associated rate impact for a typical customer is provided in the last column. The derivation of the required revenue associated with Typical in service capital is $14 million and the supporting calculation is contained in Table 1 of Exhibit B, Tab 1, Schedule 2. The derivation of the required revenue associated with Escalated Issue and Non-typical in service capital is also provided in the same exhibit.

In summary, Hydro One has met the Threshold Test for the ICM and is requesting an associated increase in revenue requirement of $26 million to recover required expenditures on Typical, Escalated Issue and Non-typical capital. Hydro One proposes that this required increase in revenues be recovered through a 2013 approved rate rider as detailed in Exhibit E1, Tab 2, Schedule 1.

CALCULATION OF INCREMENTAL CAPITAL MODULE REVENUE REQUIREMENT

1.0 OVERVIEW

In calculating the revenue requirement for the proposed ICM introduced in Exhibit B, Tab 1, Schedule 1, the methodology applied is generally consistent with Board requirements as outlined in Chapter 3 of “the Filing Requirements for Transmission and Distribution Applications”, dated June 22, 2011. The attached Table 1 provides the calculations made to determine the revenue requirement for Typical, Escalated Issue and Non-typical capital; the latter two categories are discussed in detail in Exhibit B, Tabs 2 and 3 respectively. An overview of the methodology and parameters applied to determine the revenue requirement follows below.

Hydro One Distribution is proposing to allocate the revenue requirement associated with the incremental capital expenditures eligible for cost recovery on the basis of distribution revenue. Hydro One Distribution proposes to recover this amount by means of a variable rate rider, as outlined in Exhibit E1, Tab 2, Schedule 1, Attachment 1, which will remain in effect until Hydro One Distribution’s next cost of service application.

2.0 DISCUSSION

Full Year Rule for In Service Additions

The revenue requirement calculations are consistent with Board direction that the half-year rule for in-service additions not be applied. The Board determined that the half-year rule should not apply so as not build a deficiency for the subsequent years of the IRM plan term. Consequently all calculations including depreciation, return on capital as well as the CCA claim in determining the income tax are based on the full year in-service addition assumption.

However one exception has been made in the case of the Non-Typical capital CIS project. The CCA claim used in the tax calculation is based upon the half-year rule in order to smooth this impact over the 2013 and 2014 years. This results in rate smoothing as well as process efficiency. Specifically, the resulting $6.8 million of incremental revenue requirement results in a 0.6% rate increase in 2013. Alternatively, if the full CCA claim for CIS were factored in in 2013, rather than the half-year rule, the incremental revenue requirement which would result would be -$19.8 million or a rate decrease of 1.7%. In this case, in order to recover a fair and equitable return on this necessary investment, Hydro One would re-submit the project in the 2014 IRM test year, seeking full recovery of the required $32.28 million revenue requirement in that year, resulting in an incremental 4.6% rate increase. Calculation details of this alternative approach are provided in Table 2. Hydro One believes that its recommended approach of applying the half year rule on the CCA calculation benefits the rate payer through rate smoothing (a single incremental rate increase of 0.6% in 2013; versus a rate decrease of 1.7% in 2013 followed by an incremental 4.6% rate increase in 2014); and benefits the Board through the process efficiency of having to consider the CIS project in only one IRM proceeding rather than two.

Depreciation and CCA

Appropriate depreciation rates and CCA rates were used for each program or project. For Typical capital, a depreciation rate of 3.5% and CCA rate of 8% was applied. In the case of the Escalated Issue projects/ programs, depreciation rates of about 2% and CCA rates of 8% per year were utilized. In the case of the Non-Typical capital CIS project, the appropriate depreciation rate is 10.5% whereas the CCA rate is 100%.

Capital Structure

Hydro One Distribution’s deemed capital structure for rate making purposes is 60% debt and 40% common equity. This capital structure was approved by the Board as part of its

Decision With Reasons in EB-2009-0096. This is consistent with the Board's report on the cost of capital: see the Report of the Board on the Cost of Capital for Ontario's Regulated Utilities dated December 11, 2009 (EB-2009-0084). The 60% debt component is comprised of 4% deemed short term debt and 56% long term debt.

Cost of Capital Parameters

In terms of the cost of capital parameters applied, consistent with Exhibit B, Tab 1, Schedule 1, these were derived on a more recent consensus forecast than the Board approved rates for 2011 in EB-2009-0096, resulting in a lower cost of capital.

Specifically, a return on equity rate of 9.16% was applied. This is based on the Board's formulaic approach in the Report of the Board (EB-2009-0084). The return on equity calculation is based on the February 2012 Consensus Forecast (12 month out), as well as Bank of Canada data and the change in the spread of A-rated Utility Bond Yields during February. Hydro One assumes that the return on equity for 2013 will be updated in accordance with the December 11, 2009 Cost of Capital Report, upon the final decision in this case. For rates effective January 1, 2013, the Board would determine the ROE for Hydro One Distribution based on the September 2012 Consensus Forecasts and Bank of Canada data which would be available in October 2012.

The deemed short-term rate assumed is 2.01% for 2013 using the February 2012 Global Insight Forecast plus a spread of 91 bps, which is based on the spread contained in the Cost of Capital Parameter Updates for 2012 Cost of Service Applications for Rates Effective January 1, 2012, dated November 10, 2011. Hydro One assumes that the deemed short term debt rate for 2013 will be updated in accordance with the December 11, 2009 Cost of Capital Report, upon the final decision in this case. Specifically, for rates effective January 1, 2013, the Board would determine the deemed short term debt rate based on the September 2012 Bank of Canada data which would be available in October 2012 plus the average spread obtained by Board Staff in 2012.

The long term debt rate is calculated to be 4.94% for 2013. The long term debt rate is calculated as the weighted average rate on embedded debt, new debt and forecast debt planned to be issued in 2012, and 2013. As discussed in this exhibit, forecast interest rates will be updated consistent with the methodology used for the return on common equity and deemed short term interest rate.

Table 1
CALCULATION OF 2013 ICM REVENUE REQUIREMENT

Project / Program		**Typical Capital**		**Escalated Issue Capital**							**Non-Typical Capital**	**Total**
		Miscellaneous		**Commerce Way TS Capital Contribution**		**Distributing & Regulating Stations**		**Wood Pole Replacement**	**Subtotal Escalated Issue Capital**		**CIS**	
In Service Addition		142		9.2		42.63		22.86	74.69		155.40	372.09
Average Rate Base (no half year)		139.52		9.11		42.21		22.64	73.96		147.22	360.69
Depreciation	3.50%	4.97	2.0%	0.19	2.0%	0.84	1.9%	0.44	1.47	10.5%	16.36	22.80
Return on Debt (blended)		3.97		0.26		1.20		0.64	2.11		4.19	10.28
Return on Equity		5.11		0.33		1.55		0.83	2.71		5.39	13.22
Tax		(0.36)		(0.07)		(0.35)		(0.19)	(0.61)		(19.15)	(20.12)
Total Incremental Revenue Requirement		***13.70***		***0.71***		***3.24***		***1.72***	***5.67***		***6.80***	***26.17***
Tax Calculation												
Return		4.75		0.26		1.20		0.64			(13.76)	
Add: Depreciation		4.97		0.19		0.84		0.44			16.36	
less: CCA		(11.13)		(0.73)		(3.40)		(1.82)			(77.70)	
		(1.40)		(0.29)		(1.36)		(0.74)			(75.10)	
Tax rate		25.50%		25.50%		25.50%		25.50%			25.50%	
		(0.36)		(0.07)		(0.35)		(0.19)			(19.15)	
CCA		139.52		9.20		42.63		22.86			155.40	
half year		-		-		-		-			(77.70)	
UCC		139.52		9.20		42.63		22.86			77.70	
CCA claimed	8%	11.13	8%	0.73	8%	3.40	8%	1.82		100%	77.70	

Cost of Capital	***2013***
Return on Long-term debt	4.94%
Return on Short-term debt	2.01%
Return on Debt (blended)	4.75%
Return on Equity	9.16%

Table 2
CIS Full Year CCA Revenue Requirement Scenario

	2013		2014	
In Service Addition		155.40		139.04
Average Rate Base (no half year)		147.22		130.86
Depreciation	10.5%	16.36	10.5%	16.36
Return on Debt (blended)	4.75%	4.19	4.70%	3.69
Return on Equity	9.16%	5.39	9.44%	4.94
Tax	25.50%	(45.74)	25.50%	7.29
Total Incremental Revenue Requirement		**(19.80)**		**32.28**
Incremental Rate Impact		**-1.7%**		**4.6%**
Tax Calculation				
Return		(40.35)		12.23
Add: Depreciation		16.36		16.36
less: CCA		(155.40)		-
		(179.39)		28.59
Tax rate		25.50%		25.50%
Tax		(45.74)		7.29
CCA		155.40		-
				-
UCC		155.40		-
CCA claimed	100%	155.40		-

ESCALATED ISSUE CAPITAL - CAPITAL CONTRIBUTIONS

1.0 OVERVIEW

Hydro One Distribution is requesting approval to recover the incremental capital costs of the $9.2 million capital contribution to be made to Hydro One Transmission for the Commerce Way Transformer Station ("Commerce Way TS") as part of its 2013 ICM request. This expenditure falls under the Escalated Issue category of capital investment.

1.1 Project Need

Hydro One Distribution and Woodstock Hydro ("WH") requested that Hydro One Transmission provide additional transformation and line capacity to address existing overloads and load growth in the Woodstock area. Woodstock TS exceeded its summer capacity of 82.9 MW during 2006 to 2010. The peak overload of 9 MW occurred in August 2006. Expected load growth resulting from the Toyota Woodstock plant and associated industry in the area will compound the loading issues at Woodstock TS. By 2016, WH and Hydro One Distribution are forecasting 60 MW of load growth beyond the summer capacity of 82.9 MW at Woodstock TS. Not proceeding with the construction of the new Commerce Way TS would result in continued deficiency in the transformation capacity in the Woodstock area. The need and prudence of the Commerce Way TS has been approved by the Board in Hydro One's leave-to-construct proceeding (EB-2009-0079) and Hydro One Transmission's 2011/2012 rates proceeding (EB-2010-0002) respectively.

1.2 Project Description

Hydro One Transmission will design, construct, own and operate the new Commerce Way TS which consists of two transformers (115/27.6 kV, 50/83 MVA) and eight 27.6

kV feeder positions. Supply will be provided by rebuilding about 4 km of single circuit line tap will connect the station to the rebuilt B8W line. In its Leave to Construct decision (EB-2009-0079), the Board granted approval for the B8W rebuild as an end-of-life replacement, the new station and line tap, and inclusion of telecom facilities associated with Woodstock Area Transmission Reinforcement project.

The available capacity of the new station will be split 50-50 between Hydro One Distribution and WH based on the forecast load growth of both LDC's over a 25 year planning horizon. Capital contributions have been determined by conducting an economic evaluation as per Section 6.3 of the Transmission System Code (TSC). A capital contribution of $9.2 M is required from Hydro One Distribution.

On March 22, 2012, in its Decision and Order in Woodstock Hydro's 2012 IRM application (EB-2011-0207), the Board approved WH's request to seek recovery of its $4.4 million in support of its Capital Contribution to Commerce Way TS. The cost contribution from Hydro One Distribution is higher than Woodstock Hydro because the revenues from WH's forecasted loads are greater than revenues from Hydro One Distribution's forecasted loads. WH plans to utilize its share more quickly than Hydro One Distribution.

The proposed in-service date of Commerce Way TS is December 2012 and Hydro One Distribution has agreed to payment terms for the total Capital Contribution of $9.2 million to Hydro One Transmission in 2013.

ESCALATED ISSUE CAPITAL - DISTRIBUTION AND REGULATING STATIONS

1.0 INTRODUCTION

Hydro One Networks has 1,002 distributing and regulating station facilities, which are used for the delivery of power, voltage transformation and switching. Due to the configuration of Hydro One's distribution system, most distribution stations have no redundancy. When a failure occurs, the result is an outage to some or all customers supplied from the station. Over 70% of distribution stations are in rural areas throughout the province, meaning even in ideal conditions it can take several hours to mobilize equipment and restore power.

Although asset age is not the only indicator, it does provide a useful measure for determining capital and OM&A investment needs. Of Hydro One's 1,002 distribution and regulating stations, 25% are beyond their expected service life of 50 years, with an additional 25% between 40 and 50 years old. This aged plant requires significantly increased capital re-investment on an ongoing basis to ensure that the existing risk profile does not deteriorate. If the current capital reinvestment for distribution stations is not significantly increased, the volume of station assets that are beyond their expected service life will become unmanageable over a period of time. The result will be a degrading level of performance to customers, increasing safety risks to the public and employees, and escalating OM&A costs.

Hydro One has continuously learned from available condition assessment information. Over the past several years, success in maintaining the reliability of the station fleet has been achieved through a greater dependency on maintenance of distribution station assets. This is not viewed to be sustainable or prudent from a long-term perspective, as an increasing number of assets are beyond a point which makes them technically or economically maintainable compared with the alternative of replacement.

Using updated asset information and through the development of new Asset Analytic tools, Hydro One is applying a longer-term view of investment needs and is proposing a capital expenditures increase in 2013 to sustain the safe and reliable operation of distribution stations in a long-term cost effective manner.

Station facilities contain many of the following components: power transformers, instrument transformers, reclosers, fuses, disconnect switches, bus, insulators, power cables, support structures, cable terminators, surge arrestors, station service supplies, grounding systems, fences, and buildings.

Stations Sustaining Capital funding covers capital investments required to replace these existing assets located within distribution and regulating stations and is categorized as per the following programs:

- Station Refurbishment Program, which funds the capital investments to replace several station assets that have reached end of expected service life or pose a safety or environmental risk.
- Transformer Spares and Replacements, which funds the purchase of operating spare transformers to support the in-service population of transformers, as well as the planned replacement of existing transformers within stations.
- Mobile Unit Substation ("MUS") Program, which funds the renewal of the fleet of MUSs used to provide backup support in the event of failures and to allow continuity of service to customers as planned work is completed.
- Other Station Component Replacements and Demand Programs, which funds the planned and demand replacement of individual components within the stations.

Required funding for 2013, along with the spending levels for the base and historical years are provided in Table 1 for each of these categories.

Table 1
Stations Capital ($ Millions)

Description	**Historic Years**		**Base Year**	**IRM Year**
	2009	**2010**	**2011**	**2013**
	Actual	Actual	OEB approved	
Station Refurbishments	2.8	2.7	3.2	29.0
Transformer Spares and Replacements	1.0	3.9	4.1	20.3
MUS Reinvestment	1.5	1.0	2.8	3.2
Other Station Component Replacements and Demand Programs	9.9	6.1	5.2	5.4
Total	**15.2**	**13.7**	**15.3**	**57.9**

The Stations Capital investment required for these programs in 2013 is an increase of $42.6 million over the Board approved level in 2011. The required increases in cost over the 2011 base year are in the two areas: Station Refurbishments and Transformer Spares and Replacements. Information in the remainder of this exhibit will outline the requirements for these two areas. The existing refurbishment rate of 4 stations per year needs to be increased to 32 stations per year. The existing replacement rate of 6 transformers per year needs to be increased to 36 transformers per year.

The expenditures are required for increased asset replacement to manage demographic pressures and the asset condition of the aged station infrastructure as Hydro One approaches the “bow wave” of required re-investment work that can be seen in the age profiles. Increased capital reinvestment starting in 2013 will maintain the current risk levels, and allow the stabilization of OM&A expenditures over a 10-year time period that would otherwise have to increase as the station infrastructure ages.

To facilitate the increased expenditures in Distribution Sustainment capital, Hydro One is developing a new standard, the integrated modular distribution station (iMDS). In part due to the development of the new standard, Hydro One will have increased capabilities to deliver the growing Sustaining capital program in 2013 and beyond.

Delays in addressing the age and condition of distribution stations through Sustaining capital expenditures will result in further compounding of risk which will require further increases to capital and OM&A expenditures to allow the safe and reliable operation of the distribution stations.

2.0 STATION REFURBISHMENTS PROGRAM

2.1 Introduction

The Station Refurbishment Program addresses assets that are beyond their expected service life and exhibit conditions or design deficiencies that result in safety and customer supply reliability risks. Older stations typically contain a number of components that meet these criteria at about the same time. As such, efficiency gains are achieved by replacing all such components within the station as part of the same project. The refurbishment of the station will allow it to function as originally designed - restoring performance, improving safety and maintainability, and reducing maintenance costs. This program also contributes to greater customer satisfaction due to fewer planned outages, and reduced risk of unplanned outages that can occur when one or more system elements fail.

A typical station refurbishment would include the replacement of the existing transformer, station's fence and ground grid, low and high voltage structure, reclosers, metal-clad breakers, associated ancillary equipment, concrete structures and provision for load transfer and back-up capability. As a result, assets are brought to current safety and equipment standards, and are compatible with future modernization of the distribution system. These refurbishments basically return stations to "like new" conditions.

An example of the type of equipment that makes up a distribution station and will need to be refurbished is shown in Figure 1. This is a picture of a relatively new station.

Figure 1: The equipment associated with a distribution station

2.2 Demographics

Hydro One uses a normal expected service life of 50 years for distribution stations. Hydro One has 1,002 distribution stations that vary in age up to 92 years old. Figure 1 provides the current demographics of the distribution stations.

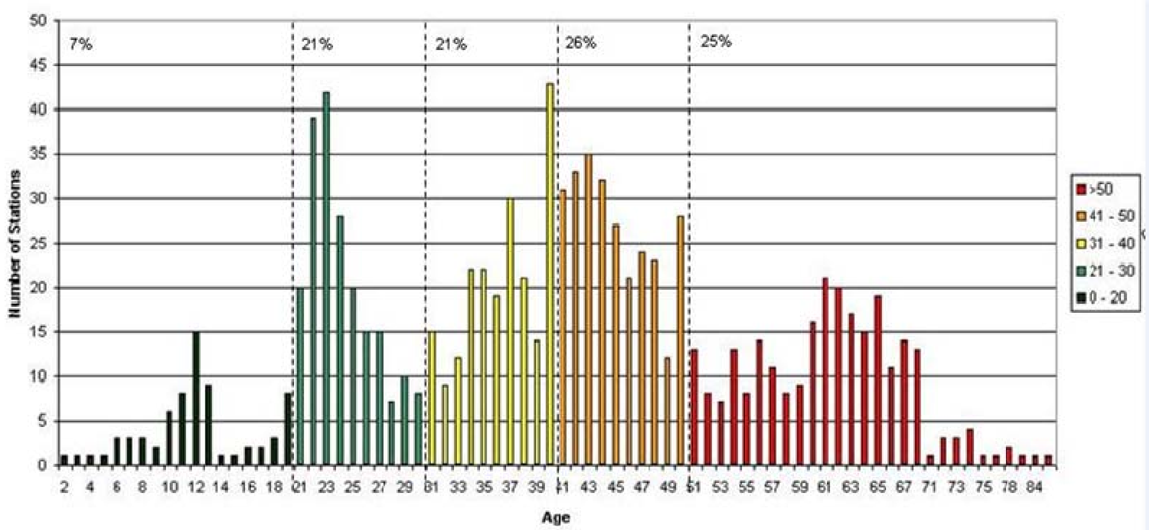


Figure 2: Current demographics of Hydro One Distribution Stations

25% of distribution stations are currently over 50 years old and in another ten years 51% of the transformer fleet will be over 50 years old. It is imperative Hydro One refurbishes distribution stations at a greatly increased rate when compared to historic levels to maintain reliability and safety risks in a cost effective manner.

Figure 3 shows a 10 year planning outlook based on the existing replacement rate (4 stations per year, 0.4% of the fleet) and the proposed replacement rate of 32 stations per year respectively. At the current replacement rate, by 2023, more than half of Hydro One's distribution stations will be beyond their expected service life; double the number today. At the proposed investment level, the number of stations beyond their expected service life will remain generally constant over the next 10 years.

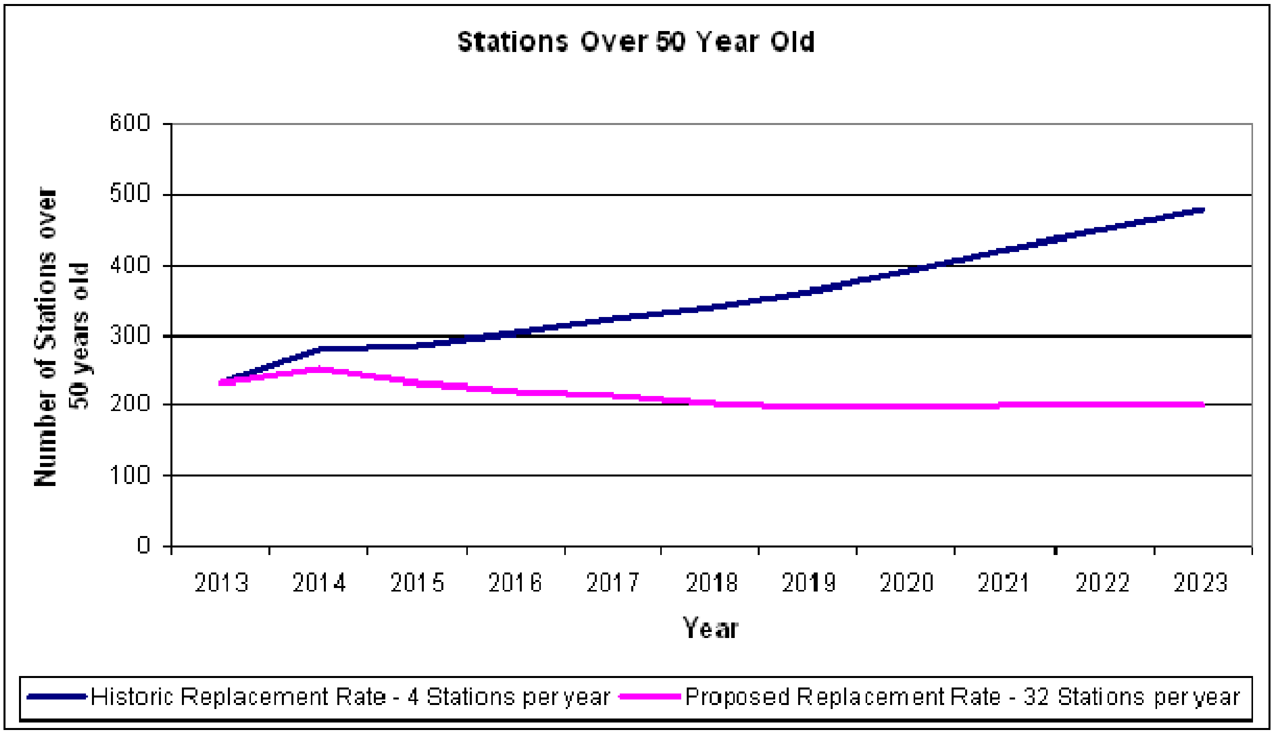


Figure 3: Distribution station demographics assuming existing station refurbishment rate of 4 per year and proposed rate of 32 per year

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.

In addition to the routine station inspections, Hydro One conducted a survey of all its distribution stations over 2010 and 2011 to gather additional supplementary asset and condition information. The resulting additional asset information reinforces the need for increasing capital investment to maintain safe and reliable distribution stations.

Degraded transformer condition continues to be one of the primary requirements for distribution station reinvestment, and specific information is provided later within this exhibit.

An area which was previously lacking complete and consistent condition information was the station structures and their foundations, which the 2010/11 survey provided. These structures support equipment such as the buswork, insulators, reclosers as well as concrete foundations for transformers. The resulting assessment is that 110 of the stations structures (11%) are in a condition that puts them at risk of failure. Stations with structures in poor condition pose a health and safety risk for employees as structures support energized exposed electrical equipment which is at risk of collapse. Customers will also be impacted with unplanned outages occurring more often than normal.

Figures 4 through 9 show some of the typical issues found that require permanent solutions through station refurbishments.

Figure 4 – Tube and Clamp Structure broken; supporting live overhead equipment

Figure 5 – Crumbling Concrete structure; supporting oil filled power transformer

Figure 6 – Cracked Concrete foundation structure with live overhead equipment

Figure 7 – Rotten Wooden Cross arm supporting live overhead equipment

Figure 8 – 4” Deep Crack in Wood Supporting Structure

Figure 9 – Heavily Damaged Wood Supporting Structure

2.4 Performance and Impacts of Maintaining the Status Quo

While the majority of customer interruptions on the distribution system are caused by events on the distribution lines outside of stations, events at stations can be very significant because the events impact all customers supplied from the station. These outages are typically long duration (8 hours or more) and can have safety and environmental consequences. Depending on the type of event they often require engineered solutions to permanently resolve.

The most pronounced Distribution Station equipment failures are associated with transformers and metal-clad breakers. On average, there are 9 major transformer failures and 22 transformer component failures per year representing 3.1% of the fleet (additional transformer information is provided in section 3.0 of this exhibit). 78 stations or 8 % of the fleet contain metalclad breakers beyond their expected service life, which are prone to failure, and are technically obsolete without spare parts support. Until recently, there has been an average of one metalclad breaker failure per year however the failure rate is increasing as there were five failures in 2011.

Batteries and chargers are other important assets in the distributing stations. Although lower cost to resolve, they can contribute to outages and safety risks because of their requirement to provide continuous backup power supply to ensure protective devices within some stations operate when required when the main power supply is not available. Figure 10 shows battery and charger failures over the past four years. The failure trend with this particular asset is increasing and will be mitigated through proposed funding level increases.

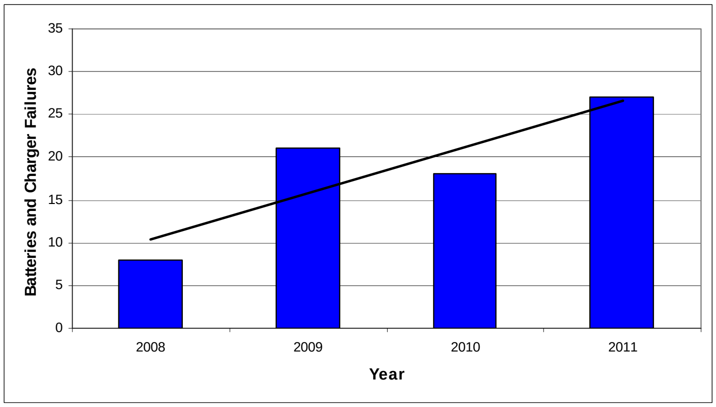


Figure 10: Battery and Charger Failures

The increased number of station refurbishments are required to reduce the risks associated with failures (unplanned customer outages) that impact schools, emergency services, industrial customers, shipping lanes, residential customers, native reserves and LDCs. The replacement of all end-of-life assets at a station bundled under a single project will also reduce the number of planned customer outages.

Given the condition ratings established during the survey conducted in 2010 and 2011, as well as from general maintenance programs, failure trends will continue to increase as too many assets are aging and falling into “poor” or “very poor” condition categories. The performance levels of Hydro One’s distribution station assets will decline unless a significant increase in station refurbishments takes place starting in 2013 and in the following years.

2.5 Program Strategy to Address the Situation

In addition to the on-going component replacements in historic years, additional integrated station refurbishments will allow for the complete rebuild or replacement to address the significant number of stations with multiple assets in poor condition in the most efficient manner. The additional capital expenditures will help contain OM&A expenditures that would otherwise have to increase in future as the demographic and asset condition pressures continue to compound.

The strategy for the Distribution Station Refurbishment Program is to address stations that are at a high risk of failure as determined by asset health. Stations are prioritized based on the impact of failure on key factors including customer, safety and environmental risks. Station refurbishment candidates are driven by condition, criticality, demographics, and technical obsolescence. Information is provided by analytic tools, survey information, field maintenance reporting, customer requirements and employee safety.

There are also some new and developing considerations for Sustaining distribution stations that will be factored into the refurbishment planning:

- Distributed generation connections may drive the advancement of Sustaining capital investments to replace equipment that does not meet the functional requirements (i.e. transformers with reverse power flow capability).
- Due to urban growth, residential housing has moved next to and around many of Hydro One’s Distribution stations which were previously in rural settings. To meet MOE noise limits, new transformers built with lower dBA levels are often required to prevent the installation of costly sound barriers.

- To meet the ESA Regulation 22/04 requirements, modifications and or replacement of any electrical asset at a distribution or regulating station must be engineered and brought up to acceptable current standards.

To facilitate the necessary increased accomplishment levels while improving productivity, reliability, and safety, Hydro One is developing a new standard for prefabricated integrated modular distribution stations (iMDS). The iMDS is going to be designed, engineered, manufactured off-site and commissioned by an external vendor. The iMDS is expected to be very efficient to install and will minimize resource requirements, outage duration and cost. It will also offer safety, environmental and reliability benefits when compared to standard distribution station design and construction. The implementation of the iMDS will help Hydro One to realize its accomplishment goals for station refurbishments in 2013 and beyond.

2.6 Impact of Increased Sustaining Capital on Sustaining OM&A

With degrading asset condition due to the aging infrastructure, continuing at historic capital reinvestment levels of 4 per year will undoubtedly result in increases in future OM&A for additional preventive and corrective maintenance and equipment refurbishment instead of replacement. An integral part of Hydro One's proposed increased Sustaining capital investment is to contain the required future OM&A expenditures for distribution stations at or below historic levels.

There is a decreasing trend in historic maintenance dollars as Hydro One continues to shift from a time based maintenance schedule to a more condition based maintenance philosophy. With increasing Sustaining capital expenditures starting in 2013 and as more distribution stations are refurbished and transformers are replaced with new units, the need for transformer refurbishments going forward will decrease over the next 10 years.

Corrective maintenance is forecast to be contained at 2013 levels as aging infrastructure is offset with increased capital investment.

2.7 Summary of Required Capital Expenditures

The 2013 spending requirement for this program is $29.0 million; this is a significant increase over historic years. This increase is to address the number of station assets that have exceeded their expected service life and are in degraded condition. With improved asset information and application of a longer term outlook, it is clear that historical Sustaining capital is not sufficient to cost effectively maintain distribution stations in a safe and reliable state. Hydro One's proposed step change will set in motion a volume of work that is required to prevent the existing risk levels from deteriorating over the next 10 year period.

Funding levels below the proposed $29.0 million in 2013 for the station refurbishment program will result in increased safety risks, decreased reliability to our customers, increase in the risk of failures and an asset base where the condition pressures are compounding due to the number of stations beyond the end of their expected service life. Future Sustaining capital requirements will compound and put upward pressure on OM&A that will be required to adequately manage the risk.

3.0 TRANSFORMER SPARES AND REPLACEMENT PROGRAM

3.1 Introduction

Transformers in the Hydro One distribution system consist of nine possible primary voltages. High voltage distribution transformers convert voltages of 230 kV or 115 kV to a lower distribution voltage of less than 50 kV for customer supply. Low voltage distribution transformers range in primary voltages of 44 kV, 27.6 kV, 25 kV, 13.8 kV, 12.47 kV, 8.32 kV and 4.16 kV, with secondary voltages that range between 27.6 kV and 600 V. Other transformers included in this group are regulating transformers. Grounding transformers and station service transformers are not included.

The Transformer Spares and Replacement program is designed to upgrade Hydro One's distribution transformer spare population, as well as replace a number of transformers each year under either planned or demand / failure conditions. This category does not include the transformers purchased and installed as part of the Station Refurbishment program described above.

Table 2 summarizes the transformers planned for replacement in 2013.

Table 2

	# in 2013	$ in 2013
Transformer Spares and Replacement program	**35**	**$ 20.3M**
Operating Spare Purchases	23	$ 13.3M
Planned Replacements	6	$ 3.5M
Demand Replacements	6	$ 3.5M
Station Refurbishment Program		
24 of 32 stations planned for refurbishment include transformer replacements	24	
Total Sustaining Capital Transformer Replacements	**36** (6+6+ 24)	

3.2 Operating Spare Purchases

The Distribution operating spare complement is currently below the defined requirement, and the requested funding for 2013 will allow for the purchase of required spares.

A significant portion of Hydro One's existing operating spare pool for distribution transformers is comprised of used transformers, some of which would require refurbishment prior to being deployed. Refurbishments are typically completed under OM&A programs. New transformers have a longer expected service life than refurbished transformers, as some life has already been consumed from the refurbished transformer when previously in use. Hydro One will continue to renew the operating spare pool through purchase of new transformers in 2013. This will reduce the dependency on refurbished transformers which have shown to have a shorter life expectancy, sometimes requiring replacement within 5-10 years after being deployed from the operating spare pool. This is not a cost effective approach as the design, labour and equipment costs are incurred twice in a short time span. A renewed operating spare pool will better support the in-service fleet in response to the condition and demographic pressures.

3.3 Demographics

Hydro One has used a normal expected service life of 50 years for station power transformers installed in distribution & regulating stations. Replacement of transformers in unacceptable condition or those that have met or exceeded their expected service life is required to ensure the system maintains an acceptable level of performance in a safe and cost-effective manner. There are approximately 1,212 distribution transformers that vary in age up to approximately 78 years old. Figure 11 and Table 3 provide the demographics of the fleet.

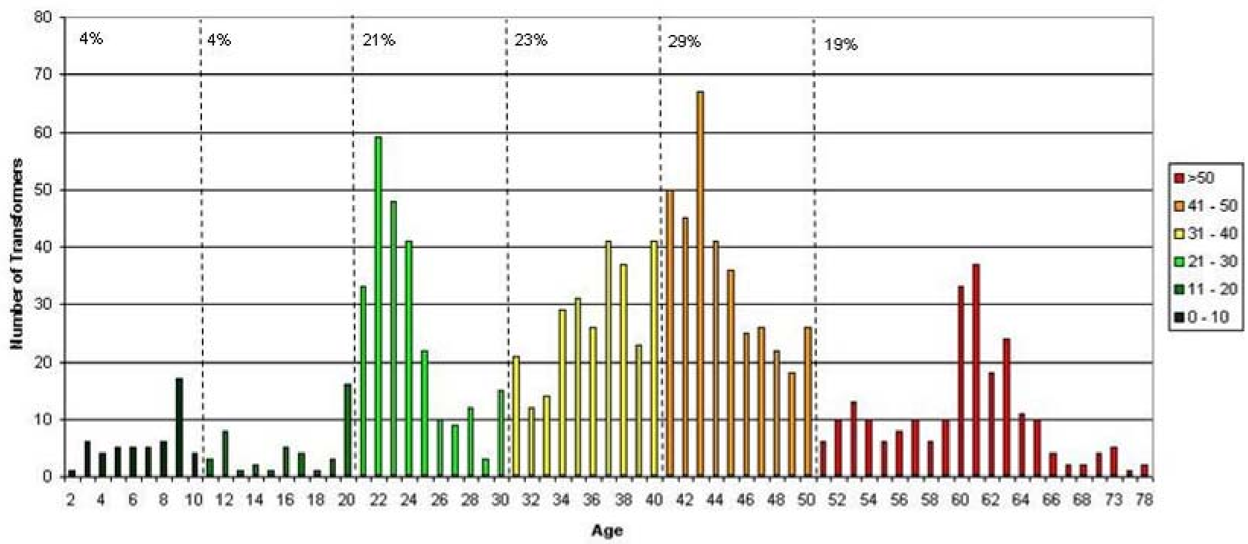


Figure 11: Current demographics of Hydro One Distribution Transformers

Table 3: Current demographics of Hydro One Distribution Transformers

Power Transformers								
		Voltage Level (kV)						
		< 27.6	27.6	44	115	230	Total	%
Age Group (years)	0 - 10	3	14	31	5	0	53	4%
	11 - 20	6	23	10	5	0	44	4%
	21 - 30	3	24	193	32	0	252	21%
	31 - 40	7	25	205	38	0	275	23%
	41 - 50	29	75	223	28	1	356	29%
	>50	21	81	113	17	0	232	19%
	Total	69	242	775	125	1	1212	100%
	%	6%	20%	64%	10%	0%	100%	

The rate of planned transformer replacements over the last 10 years has averaged 6 per year or 0.5% of the fleet per year. 19% of distribution transformers are currently over 50 years old and in another 10 years 48% of the fleet will be over 50 years old. It is imperative Hydro One replaces distribution transformers at a greatly increased rate when compared to historic levels.

Figure 12 illustrates a 10-year scenario of transformer fleet demographics based on historic replacement rates of 6 transformers per year and a 10-year scenario based on the proposed 2013 replacement rate of 36 transformers each year. At the historic replacement rate, almost half of the distribution transformers will be beyond their expected service life in 10 years; more than double the amount of transformers today. As illustrated in Figure 12, moving to the proposed 2013 replacement rate for 10 years will essentially maintain the proportion of transformers beyond 50 years of age.

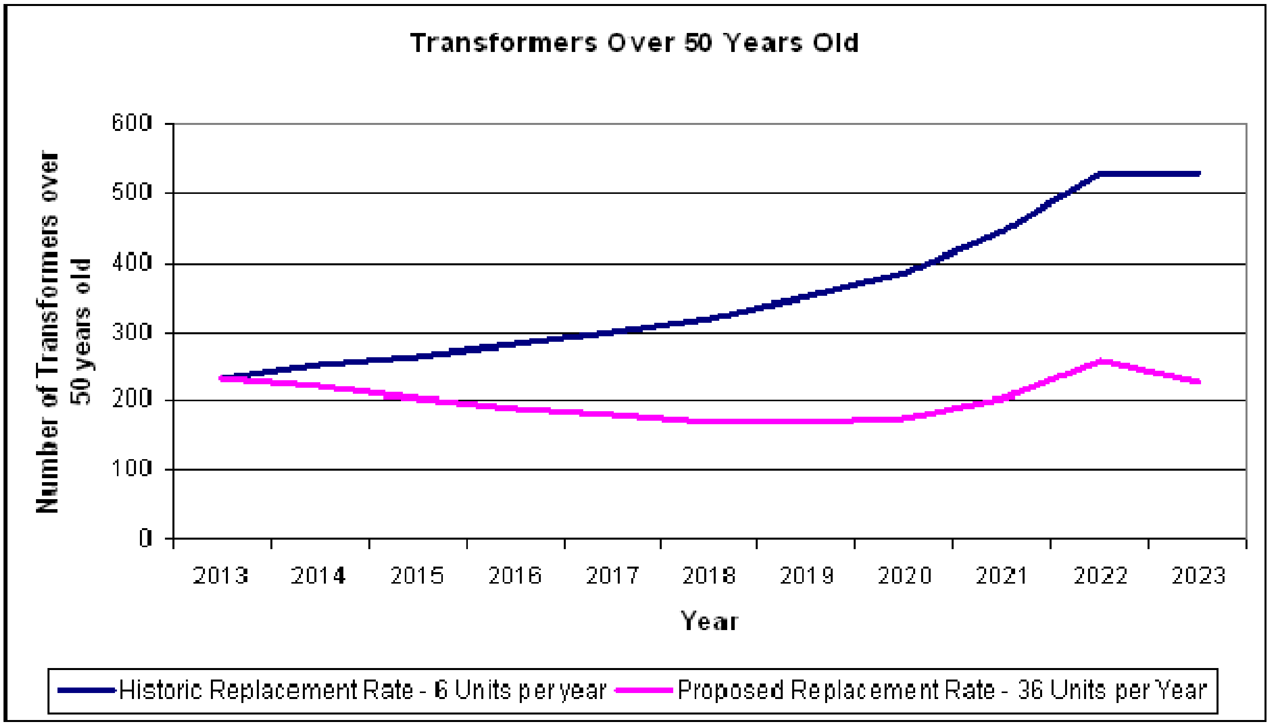


Figure 12: Distribution transformer demographics at the current rate of 6 replacements per year and at the proposed rate of 36 replacements per year

3.4 Condition of Assets

Transformer condition is an accurate leading indicator of equipment reliability. Condition assessment is primarily based on transformer oil testing (Dissolved Gas Analysis, furan, standard oil testing), Doble testing and general findings from maintenance programs. This information is gathered through routine maintenance programs triggered by time and/or asset condition. Industry standard oil testing is the primary criteria for assessing transformer condition. The internal components degrade as a function of time due to heat (from transformer loading), exposure to oxygen, and damaging acids in the insulating oil as a result of insulation aging. Degradation is irreversible and transformer replacement is the only economically viable solution. “Fair”, "Very Poor" and "Poor" condition categories indicate an increased risk of failure which in turn is an increased risk of customer outages.

Figure 13 shows an updated fleet-wide condition assessment of the in-service distribution transformers. According to the currently available information, 397 in-service transformers, or one third of the population of 1,212 transformers, are in a deteriorated condition that identifies them for replacement.

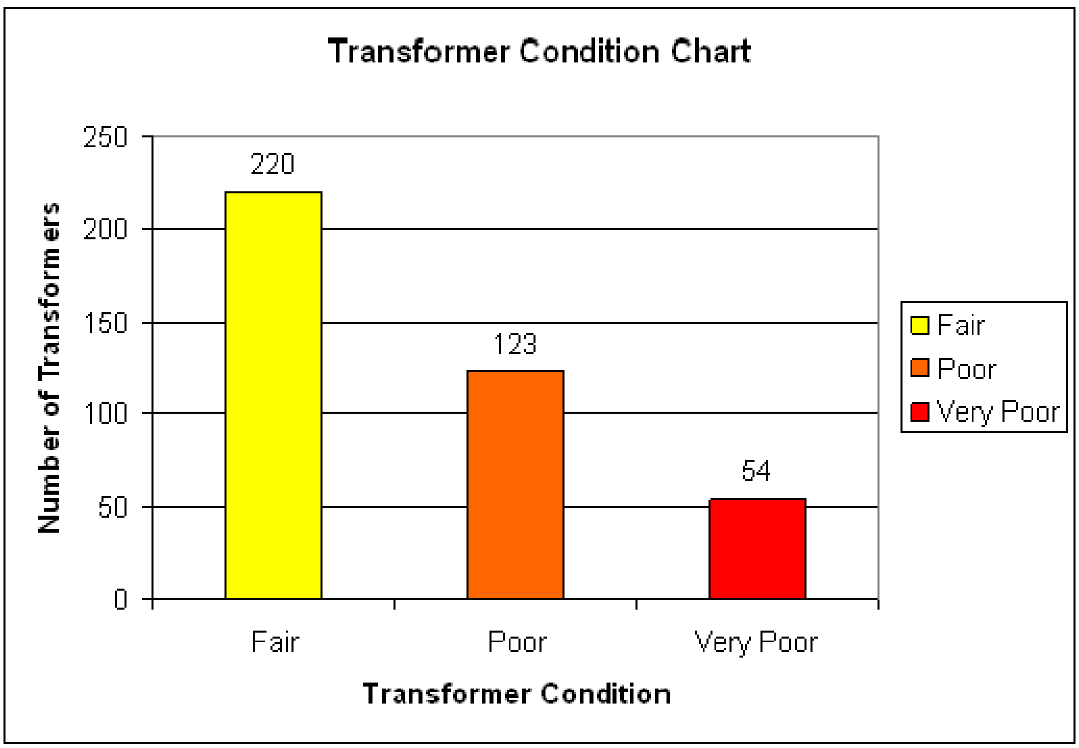


Figure 13 - Transformer Fleet Condition Assessment

With the compounding demographic pressure of the aging fleet, it can be expected that transformer fleet condition will continue to degrade. The primary inputs into transformer condition assessment measure irreversible damage or wear and these cannot be overcome in the long term with maintenance. Capital replacement is the most technically and economically viable option to address transformers in poor or very poor condition. If 2013 requested funding levels are not approved, the overall condition of the in-service distribution transformer fleet will deteriorate further.

Transformer oil testing provides an assessment of the internal condition and visual inspection is used to identify issues such as oil leaks, corrosion, defective gauges, damaged bushings, etc. Figures 14 and 15 show two transformers with typical symptoms of aged transformers.

Figure 14: Oil leakage on a Distribution Transformer

Figure 15 – Oil Leakage on a Distribution Transformer

3.5 Performance and Impacts of Maintaining the Status Quo

Distribution station transformer failures directly affect reliability to customers who include schools, emergency services, industrial customers, shipping lanes, residential customers, native reserves, and LDCs. There is also potential impact to the environment in the event of oil spills. Figure 16 shows that the number of major transformer failures varies year over year, with a gradual increasing trend over the past 10 years. On average, there have been 9 major transformer failures per year, and 22 transformer component (ULTC, lightning arrester, selector switch, bushing, etc.) failures per year.

In 2011, the 8 major transformer failures resulted in approximately 12,800 downstream customers being impacted. Because of the lack of redundancy and transfer capability in 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.

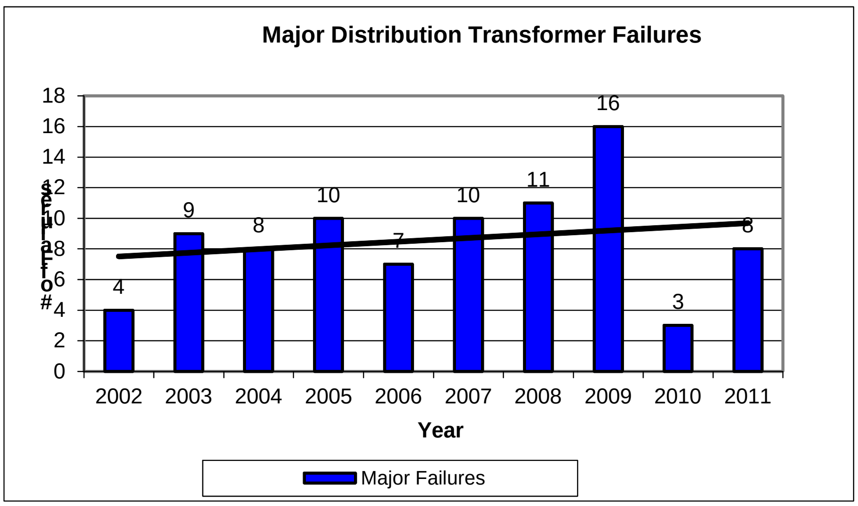


Figure 16 - Major Distribution Station Transformer Failures

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.

- Noise Pollution– Transformers emit noise from the operation of cooling fans or the mechanical vibration of internal components (transformer core steel), and the noise levels typical increase as the transformers age. Measurements in excess of provincially regulated (Ministry of Environment) noise levels require mitigation through either sound barriers or replacement of the transformer. Replacement is often the best technical and economical solution for aged transformers.
- PCBs – Approximately 10% of bushings used in transformers older than 1985 are forecast to contain oil with a PCB concentration of greater than 50ppm. Environment Canada has a regulated end-of-use date of 2025 for oil volumes greater than 50ppm. To achieve compliance by the 2025 deadline, increased replacements are required.

3.7 Program Strategy to Address the Situation

In response to the degrading condition and the aging demographics of the distribution transformer fleet, an increase to the number of replacements is required to manage risk on an ongoing basis.

Given that transformer condition and age are major inputs into the prioritization of the Station Refurbishment Program described in Section 2, the majority of transformer replacements will occur within that program. The Transformer Spares and Replacement program focuses primarily on the purchase of transformers for the renewal of the operating spare pool and for the other replacements of transformers installed in existing distribution stations.

The distribution operating spare complement is currently not at the appropriate level, and the requested funding for 2013 will begin to address this issue and allow for the purchase of the required number of spares.

With ongoing increased capital funding starting in 2013, OM&A expenditures will be reduced in transformer maintenance as Hydro One continues to shift towards condition-based maintenance and sees a reduction in expenditures for transformer refurbishments as a result of the proposed approach to purchase and install new transformers.

Summary of Required Capital Expenditures

The required expenditures for this program in 2013 are $20.3 million, which is a significant increase over historic years. The primary reason for this increase is attributed to the need to renew the operating spare transformer pool to ensure a reliable backup to the 1,212 transformers which are in-service in the distribution stations. Purchase of operating spare transformers accounts for $13.3 million.

The expenditure associated with the planned and demand driven transformer replacements is $7.0 million. This is less than the amount from the 2011 base year but the additional transformers that will be replaced as part of the Station Refurbishment program must be considered as well. Overall the increased Sustaining capital expenditure for distribution stations in 2013 will mitigate the risks associated with transformer failures.

Funding levels below the requested $20.3 million would result in Hydro One replacing failed and end life transformers with used, refurbished units as opposed to new units. This will amplify the compounding demographic pressures and result in a further degradation of fleet condition. Furthermore, OM&A expenditures for corrective maintenance and refurbishment will increase as used, refurbished transformers will be re-entering the fleet.

ESCALATED ISSUE CAPITAL - WOOD POLE REPLACEMENT PROGRAM

1.0 OVERVIEW

Hydro One must immediately begin to implement a more aggressive pole replacement strategy in order to remove a significantly increasing number of substandard poles from its system. There are 1.7 million wood poles in Hydro One's distribution system. Over the next ten years, about 340,000 poles are expected to require replacement. If the current replacement rate of 7200 poles per year is not increased to 11,000 poles in 2013 as proposed in this application and higher rates in the years after that, the backlog of end of life ("EOL") poles in the system will become unmanageable. Customers will be disrupted as increasing numbers of wood pole related outages affect the reliability of supply. Work resources will not be able to complete the backlog in addition to managing the significantly increased number of EOL poles. Risks of in service poles failing will increase significantly as old, EOL poles fall down in strong winds and severe storms where newer poles would remain standing. Cost efficiencies would also be lost as resources scramble to replace poles on a reactive basis.

Hydro One has been mitigating the risk of failure by selectively targeting replacement of EOL poles based on improved asset condition information. However, the demographics of the pole population require a change in approach. Delaying the required increase in replacement volumes would push the population of wood poles into an unmanageable state of deterioration. By investing in the aging and deteriorating wood pole population today, risks associated with system reliability, safety, future costs and future work resourcing can be mitigated to ensure the integrity of the distribution system and the reliability of supply.

Currently, about 10% of Hydro One's wood pole population is over 62 years of age (the expected useful life of wood poles). Over the next decade, another 20% of poles will exceed this level, totaling 30% by 2022. In addition, Hydro One has identified a system wide issue with a subset of poles that have not been treated to CSA standards and are experiencing premature rot and failure. This was confirmed in a 2010 third party study conducted for Hydro One. The study is filed in confidence following the Board's rules of practice for such filings. These poles represent approximately 3% of the wood pole population and must be removed from the system over the next decade to ensure that public and worker safety and system reliability is preserved. These sub-standard poles are placing upward pressure on the number of poles requiring replacement. Immediate action is required to ensure that the situation is managed in an efficient manner.

1.1 Discussion

Distribution lines total 120,200 circuit kilometers province-wide and are used to deliver power to Hydro One Distribution customers. Lines are constructed on road allowances where possible, or on rights-of-way that Hydro One can legally occupy and access for maintenance and repair. The structural integrity of distribution lines is largely dependent on the wood pole supports.

There are approximately 1.7 million wood poles in Hydro One's distribution system that vary in age up to 82 years old (refer to Figure 1). The expected useful life of distribution wood poles is 62 years of age. The condition of wood poles deteriorates over time due to factors such as decay and rot, insect and rodent damage, or mechanical impact. Once a pole's condition has deteriorated to the extent that it has a significant risk of failure under adverse weather conditions, it is deemed to be at end-of-life (EOL). All EOL poles must be replaced to ensure the system maintains an acceptable level of reliability and safety. While the pole replacement program funds the proactive replacement of poles, about 13,000 poles are replaced or newly installed each year from other demand driven programs such as storm repairs, new connections, joint use and relocations, and generator connections.

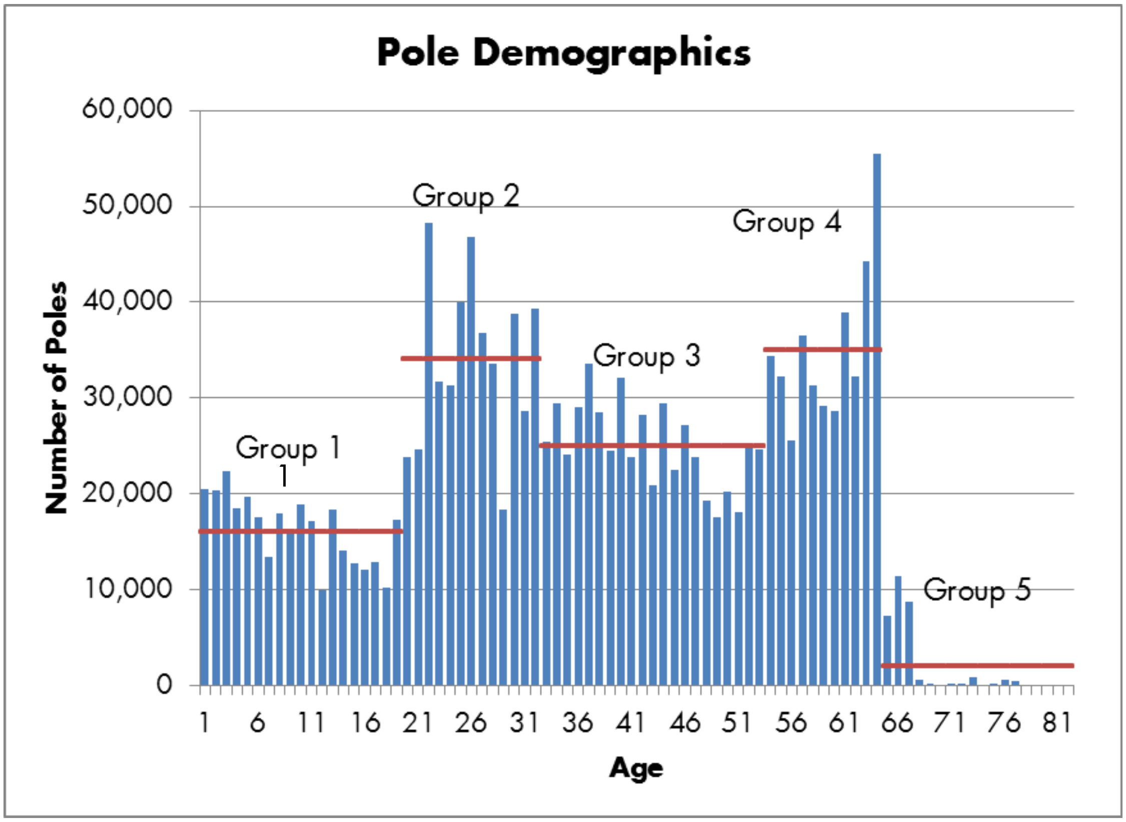


Figure 1: Current demographics of Hydro One Distribution wood poles

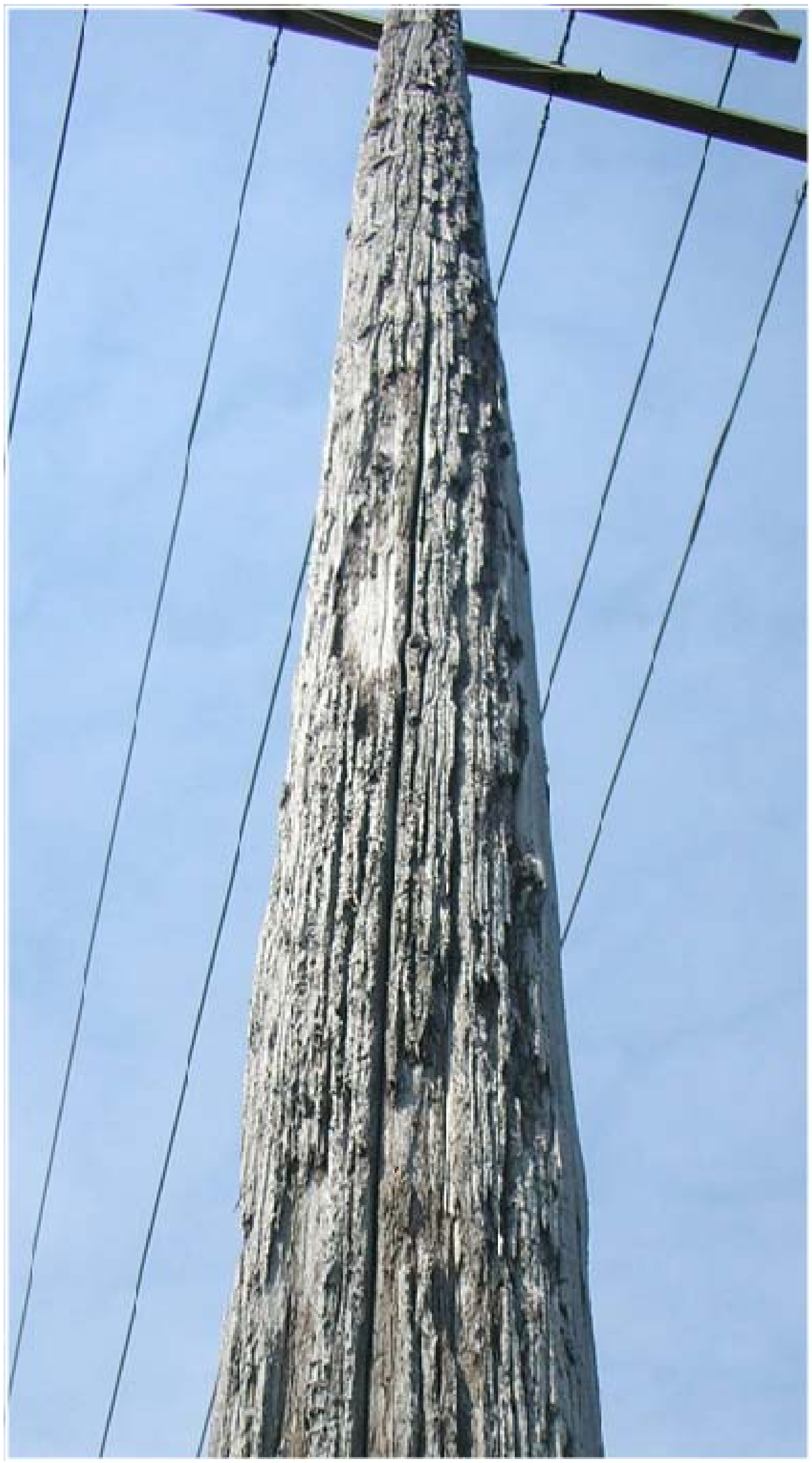
The horizontal lines in Figure 1 represent average replacement volumes required over time for five specific groups of poles. The following table summarizes these groups.

Group	Age Range	Total Poles in Group
1	0-19	310,000
2	20-32	440,000
3	33-53	530,000
4	54-64	390,000
5	65-82	30,000

Group four represents poles that will require replacement over the next 10 years at an average replacement rate of 35,000 per year. Group one represents the average volumes of poles replaced and new poles added in the past twenty years. The average replacement rate of EOL wood poles since 2007 is approximately 7,200/year.

Replacing poles on a planned basis is recognized as a good utility practice and is less costly than "emergency" or reactive type replacements. In addition to the increased labour costs (i.e. overtime premiums), reactive replacements result in longer outage durations to customers and increased safety risks.

On average, a planned outage that replaces a pole is only 2 hours while an unplanned outage that involves replacing poles lasts 9 hours.



Picture 1: Picture of Old EOL Pole

Picture 2: Hammer test of rot below ground level.

Picture 3: Pole failure due to rot at ground level.

1.1.1 Pole Inspection Program

Specific candidates for pole replacement are identified through Hydro One's pole testing and assessment program, which identifies poles that exhibit wood decay, cracks and other defects that may jeopardize the structural integrity of a pole. The EOL determination for wood poles complies with the Canadian Standards Association ("CSA 22.3 No. 1 – Overhead Systems") criteria for pole strength. This inspection and replacement program maximizes reliability to customers, reduces public safety risks, complies with regulations and ensures optimal utilization of the wood pole population.

From 2005 to 2010, the entire Distribution System's 1.7 million poles were assessed and approximately 3% of the poles were found to be EOL. The percentage of EOL poles on the system has remained relatively steady in recent years due to the efforts of the Wood Pole Replacement Program but it is expected to rise significantly given the demographics of the distribution system's pole population.

1.1.2 Poles with Substandard Treatment

In addition to concerns with demographics, Hydro One must manage a system-wide issue with a subset of poles that are deteriorating prematurely because they were not treated according to CSA standards. There are approximately 55,000 poles in this subset that are located across the province.

One of the largest incidents reported involved the failure of ten of these poles during a winter storm in December 2006. During restoration, it was discovered that these ten poles showed varying degrees of internal rot. This incident prompted an investigation into the entire subset of poles. Several preliminary studies were conducted both internally and externally to determine the magnitude of the issue and the cause. It was found that the presence of premature rot existed in some of these poles, suggesting a potential treatment issue resulting in premature failure. This was raised as an issue in EB-2009-0096.

To assess the seriousness of the problem, in 2010 Hydro One retained a consultant to conduct a third party investigation which identified that these poles do not meet the CSA standard for penetration and retention of treatment. This confirmed Hydro One's initial findings. This study recommended pro-active removal of these poles from our system over an aggressive timeline of 10 years. As noted earler this study is filed in confidence following the Board's rules of practice for such filings.

The study found that Hydro One must replace all poles within this category. By leaving sub-standard poles in-service, the risk of in-service failures is greatly increased as poles within this subset are frequently located adjacent to each other. A failure of one sub-standard pole can lead to a cascading failure effect on nearby poles, as was seen during the multi-pole failure during December 2006. From both a safety and economic perspective these types of failures are especially devastating. The damage caused is far more dramatic than a single pole failure and more costly to restore. The outages associated with these failures are also lengthier in time. Cascading failures pose a higher risk to employee and public safety due to their increase in magnitude.

The need to replace this subset has placed an upward pressure on the growing number of sub-standard poles on the distribution system. It is important that the rate of pole replacements be increased as rapidly as possible to ensure that the added burden from this subset and the aging pole population are dealt with proactively.

The 2013 spending requirement for the Wood Pole Replacement program is $81.8 million. This represents a replacement of approximately 11,000 wood poles.

Table 1: Net costs for the Wood Pole Replacement Program

Year		**$M**
2009	*Actual*	50.9
2010	*Actual*	53.6
2011	*OEB Approved*	58.9
2013	*Proposed*	81.8

Funding levels below the requested $81.8 million for the Pole Replacement Program will increase reliability and safety risks. It will prevent Hydro One from fully meeting due diligence obligations to remove known defective assets that present a potential hazard to workers and the public.

A scenario analysis is provided in Section 1.2 that demonstrates the impact of various replacement rates on the wood pole population.

1.2 Scenario Analysis

Distribution wood poles have an expected useful life of 62 years. While the actual age of failure may be younger or older for individual poles, for analysis purposes, any poles in the distribution system that have reached this age are considered to require replacement.

Below are three scenarios that illustrate the impacts of three different planned replacement rates through the Wood Pole Replacement program. The three scenarios are run over a 30-year time period and are used for illustrative purposes. They are defined as:

1) 7,500 poles replaced annually
2) 11,000 poles replaced in 2013 + an incremental increase of 2,000 poles per year, until a total volume of 20,000 poles replaced annually is reached
3) 30,000 poles replaced annually until 2023 then reduce the annual volume gradually until 2026 to 22,000 poles a year

For each scenario, it is assumed that the current volume (about 13,000) of wood poles replaced from other programs than the wood pole replacement program are maintained. Other programs include upgrades, new connections, joint use and relocations, generation connections and storm damage. These programs are demand driven so the average pole age was assumed for the replacements. Also each scenario prioritizes the replacement of the subset of poles that were not treated to CSA standard and are deteriorating prematurely.

1.2.1 Summary

To compare the long-term impacts of the scenarios, the numbers of EOL poles remaining in-service each year are considered. These are shown in Figure 2.

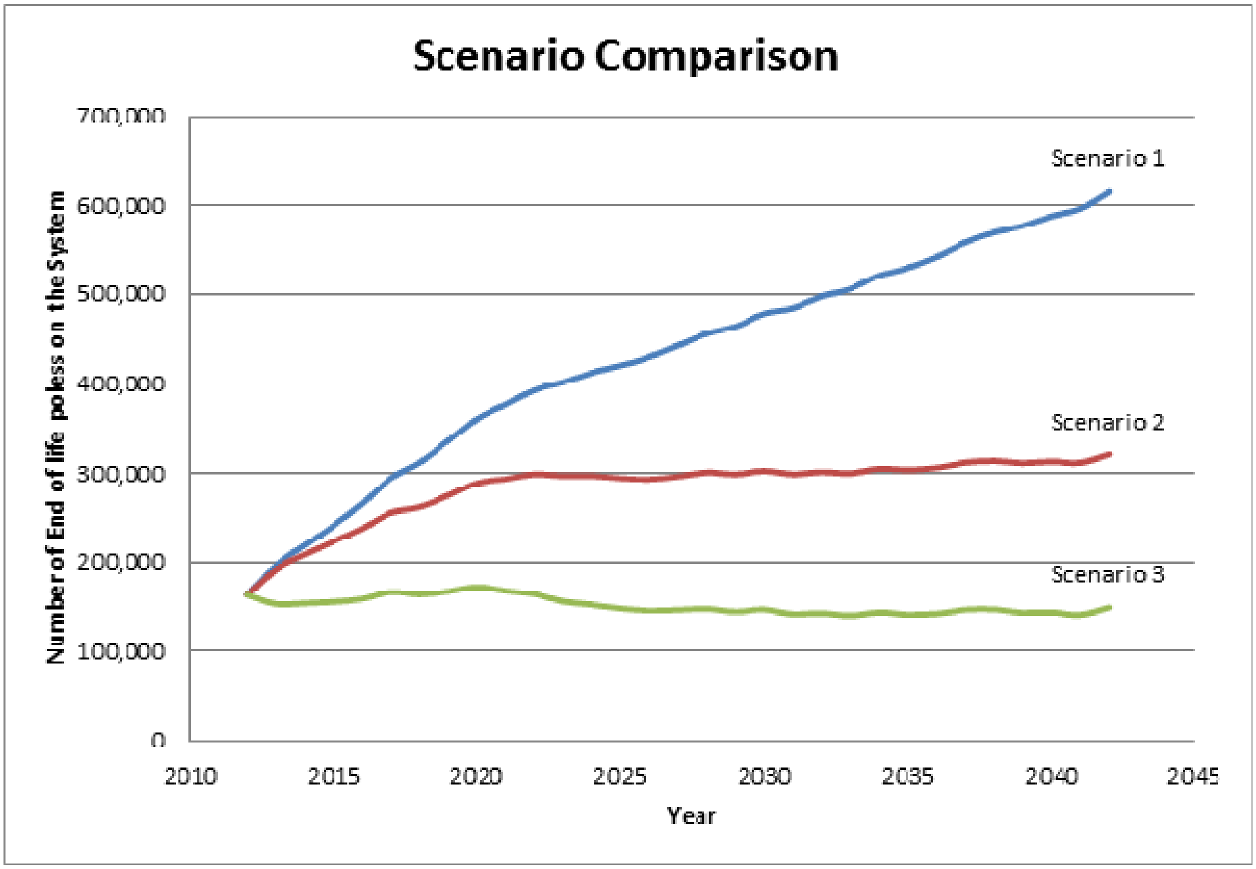


Figure 2: End-of-life wood poles existing in the distribution system over the next 30 years

Scenario 1 demonstrates what will happen if Hydro One continues to replace only 7,500 poles per year. After 10 years the number of EOL poles will be 390,000, after 20 years that number will increase to 500,000. By 2042, 30% (~620,000) of all poles remaining in the system will have exceeded their expected useful life. In Scenario 1, the number of EOL poles increases annually. This is because the replacement rate is not aggressive enough to replace the number of EOL poles added to the system each year. Instead, a growing backlog of poles develops and grows with time.

Scenario 2 shows what will happen assuming a volume of 11,000 poles in 2013 plus an incremental increase of 2,000 poles replaced annually through the Wood Pole Replacement program up to 20,000 poles annually by 2018. At the end of 10 years the volume of EOL poles will increase to 300,000. After 20 years that volume will remain the same. By 2042, about 20% (~320,000) of all poles remaining in the system will have exceeded their expected useful life. Scenario 2 is similar to Scenario 1 during the first eight years. However, due to its ramp-up in replacement values it is able to maintain a relatively stable level of EOL poles existing on the system beginning in 2021. However, throughout this period the number of EOL poles on the system would be over 300,000 poles, more than double the current amount.

Scenario 3 attempts to maintain the current volume of EOL poles. It assumes that 30,000 poles are replaced annually until 2023, after which the volume is reduced to 22,500 poles a year until 2026 and maintained at that rate thereafter. In this scenario, after 10 years the number of EOL poles will reach approximately 160,000 and after 20 years that number will be reduced to 140,000 poles and after 30 years the number of end of life poles will be at 150,000. Scenario 3 generally maintains the current level of EOL poles. Due to its aggressive replacement rate, the number of EOL poles in the system does not exceed the amount that is removed each year. While this scenario is only used for illustrative purposes, it is important to note how high the replacement volume needs to be in order to keep the Hydro One system at its current risk level. The other two scenarios result in a state that is worse than the present.

From the scenarios illustrated above, it is evident that if replacement rates are not increased in the near future, annual volumes of EOL poles will accumulate to an unmanageable amount. However, if an appropriate replacement plan is implemented the volume of these poles existing in the system can at least be maintained at a generally constant level.

For 2013, Hydro One is proposing a transitional increase in its spending to $81.8M to increase the replacement rate from 7,200 per year to about 11,000 as per the first year of Scenario 2. Hydro One is not pursuing a larger increase in 2013 as the current resources could not manage a larger change in one year. Instead, transitional steps will be taken to begin to address the increasing accumulation of poles reaching their EOL. Hydro One will seek approval for increased pole replacement levels in future applications.

1.3 Conclusion

As demonstrated by the above Scenarios, Hydro One must immediately implement a more aggressive pole replacement strategy in order to maintain a manageable population of EOL poles. In the next ten years, 340,000 poles are expected to require replacement. If the replacement volume is not increased, the backlog of end of life poles in the system will become unmanageable. Customers will see an increase in outages and customer satisfaction and the reliability of the system will deteriorate. Work resources will not be able to complete the backlog in addition to their regular workload and risks of in-situ poles failing will increase significantly. Cost efficiencies would also be lost as resources scramble to replace poles on a reactive basis.

Hydro One has been prudently mitigating risk on its system while keeping the replacement levels reasonable and appropriate. However, significant increase to the wood pole replacement volumes is now required to address substandard and EOL poles. By investing in the aging wood pole population today, risks associated with system reliability, safety, future costs and future work resourcing can be reduced to a manageable state.

NON-TYPICAL CAPITAL - CUSTOMER INFORMATION SYSTEM

1.0 NEED

Hydro One's Customer Information System ("CIS") has reached its end of life and must be replaced immediately. This critical replacement falls under the capital spend category of non-typical spending as described in Exhibit B, Tab 1, Schedule 1.

The project, which allows Hydro One to improve service to customers, provides a more efficient customer system which is less costly to maintain than the obsolete customer information system installed in 1998 for the old Ontario Hydro.

Hydro One had planned the CIS program in-service date for 2016, however several factors prompted the necessity to bring forward the in-service date to 2013. The drivers for this change were as follows:

- Frequent changes to the system prompted by government initiatives amongst others, were putting customers and the Company at too great a risk for total system failure.
- An updated system to handle the IESO upgrades to Smart Metering/MDM/R processes and systems was required as the current systems are cumbersome, require significant manual effort, and are subject to frequent costly enhancements.
- The processes and systems built to handle new Distributed Generation ("DG") connections, process generation data and statements, and pay the generators, were built using the existing open market systems which are not scalable to handle the volumes of DG connections anticipated over the next three to five years. The new CIS will alleviate this problem in an integrated fashion.
- More formal demand management conservation obligations require the ability to implement, manage and track the resulting conservation programs in a more rigorous fashion in order to quantify the results and consequently refine and enhance the

scope, scale and efficacy of the programs. The new CIS will have the ability to implement and monitor CDM activities as part of mainstream customer service processes.

- The timeline leaves sufficient time for system stabilization before the possible transition of outsourced IT and Customer Care services provider functions. It was not feasible to conduct a CIS Replacement in parallel with the Outsourcing Contract RFP. Hydro One could not risk a change in a critical supplier mid-stream during the CIS Replacement project.
- The next feasible window, a 2016 start for 2019 cut-over, would result in the existing CIS being **20 years old** at the time of replacement. This would introduce a high amount of risk associated with a legacy system that is 20 years old with no vendor support as well as require increased expenditure for any system changes between now and 2019.

This project was presented to and discussed with stakeholders as part of an initial information session on June 29, 2011, and followed with an update at the stakeholder session on October 19, 2011. Please see Exhibit A, Tab 4, Schedule 1 for further details on the Stakeholder Consultation.

2.0 CURRENT CUSTOMER INFORMATION SYSTEM

The CIS project will replace Hydro One’s end of life Customer Information System including customer/account services, billing, settlements, and open market systems. The CSS (Customer Service System) or Customer/1 application was purchased from Andersen Consulting (now Accenture). The application has undergone significant modifications in order to address the changes in the Ontario regulatory environment and to meet Ontario Energy Board requirements. This is an extensively customized product which is very costly to maintain and very costly to modify to meet new regulatory and business needs. Accenture no longer develops or supports the application.

Customer/1, installed in 1998, is the primary billing system for retail and general accounts. Changes to the system, no matter how small, generally represent core modifications which are expensive and time consuming. CSS runs on its own dedicated mainframe hardware which is expensive to maintain. The Open Market Systems suite ("OMS") is the set of applications that are integrated to perform the company's market transactions, settlements and complex billing functions. This suite was installed in 2002 to accommodate market opening. The OMS systems have since been modified to support market rule updates and the calculation of payments to generators.

CSS and OMS together effectively represent the "Cash register" of the company. Virtually all Distribution revenue flows through these two systems and thus their stability and operation are vital to the financial health of the company. Beyond that, CSS is also the platform with which we communicate with customers and initiate service orders to the field. The current CIS solution includes multiple custom applications integrated to meet various requirements. Many manual steps are necessary to meet customer, government and industry demands thus reducing productivity along the entire process life cycle.

3.0 PROJECT OVERVIEW

The CIS project is replacing the legacy CIS systems with a unified platform based primarily on SAP's industry leading billing application – Customer Relationship and Billing ("CRB"). For Meter Data management, Itron's Enterprise Edition application will use out-of-the-box integration with the SAP core to facilitate integration to and from the IESO for billing of Time Of Use residential customers as well as perform meter data management for interval billed commercial and industrial customers.

The project is expected to be in service in 2013. Approximately 30 disparate systems will be retired and replaced with the SAP and Itron applications. The Market rules and Settlements will be handled by a vendor supported SAP module. Meter Device information will also be migrated into SAP.

This implementation will upgrade numerous capabilities across the organization including customer interaction, customer demand management, service order processing, and meter management. By implementing SAP for CIS functionality, Hydro One will have an integrated enterprise platform based on SAP which will provide benefits in the CIS area due to its integration with the Work and Asset Management and Finance modules.

Total project costs by Phase, including OM&A are included in Table 1.

Table 1

CIS Project Costs by Phase and Item

($ Millions)

Item	Discovery	Blueprint Phase	Realization	Final Prep	Verification & Stabilization	TOTAL ($ million)
Implementation Effort (discovery, labour/services, commissioning and other support)	$9.1	$21.0	$34.5	$27.5	$21.3	$113.4
Hardware						$10.0
Software						$13.4
Interest and Overhead						$17.5
Contingency						$25.5
Total						$179.8

Table 2 identifies the CIS capital expenditures for the period 2011 to 2012.

Table 2

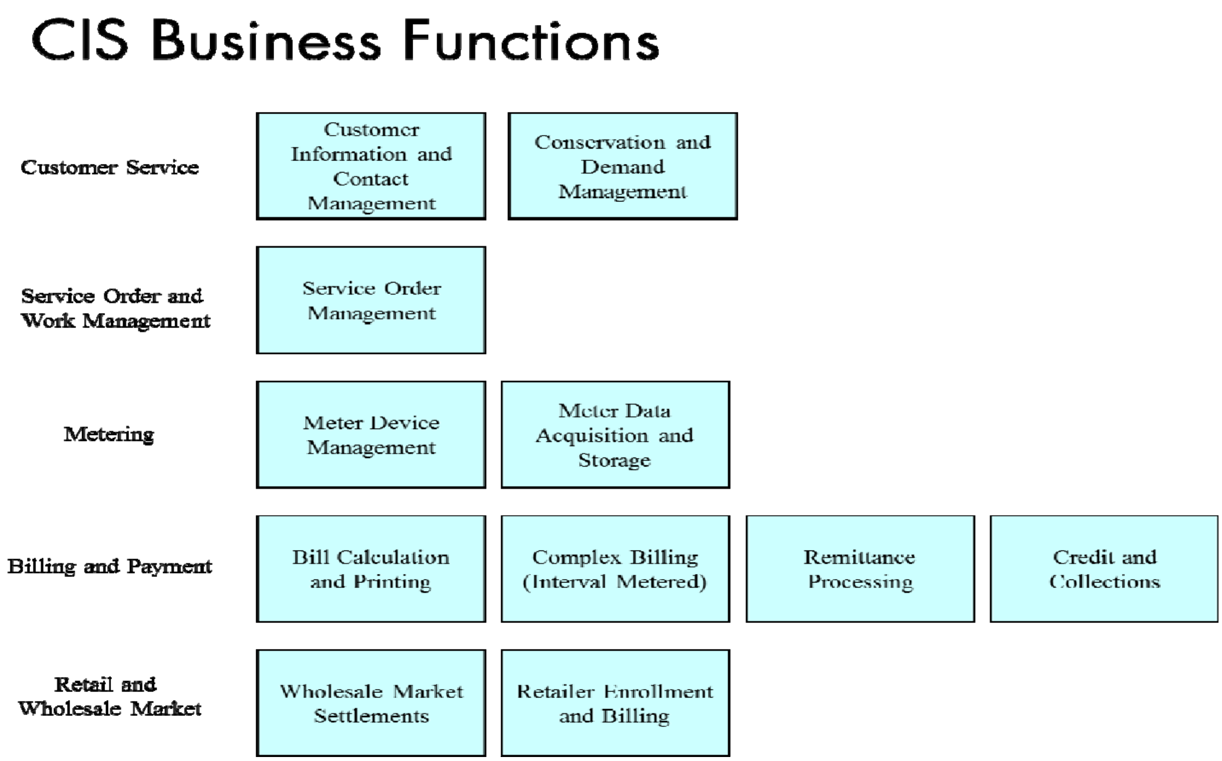
CIS Capital 2011– 2012 ($ Millions)

	2011	2012	Total In-service 2013
Minor Fixed Assets	10.1	0	10.1
Development Project	41.5	103.8	145.3
Total Capital Cost	51.6	103.8	155.4

The CIS capital expenditures consist of Minor Fixed Assets and Development Costs. The latter includes all the costs to acquire, install and place into service the new systems.

Functional Overview:

Below is a high level overview of the functions enabled by the Customer Information System. The primary CIS functions are described in the detail following the graphic.



Customer Service:

Customer Information & Contact Management

The Customer Information and Contact Management function covers the capturing, look up and updating of customer, property, account, and service data required to perform utility customer care processes and activities. This data also enables interactions with customers, generators and other partners such as retailers and social service agencies.

Conservation and Demand Management

Conservation and Demand Management ("CDM") has been and continues to be a focus of Hydro One. There are numerous objectives and targets set internally and by the provincial government to help encourage the wise use of electricity and provide for a more environmentally friendly future. CDM is a provincial government mandated program aimed at reducing demand through load control and load shifting to off-peak times, and reducing energy consumption through conservation and efficiency. CDM functionality is limited to tracking the programs in which the customer is enrolled. The embedded CDM functionality provided by the new CIS adds no additional cost to the project.

Service Order and Work Management:

Service Order Processing

Hydro One's customers request work to be performed – such as new connections to Hydro One's distribution system, underground cable locates, etc. The Service Order Processing function receives and responds to these customer/internal requests via the Customer Information System.

Metering:

Meter Device Management

This function encompasses the life cycle management of metering devices, specifically meters and instrument transformers (current and potential) – from set up to retirement. Each device must be uniquely identified and the complete definition of its attributes must be maintained in a system that Measurement Canada, as the regulatory body, accepts as the 'System of Record'. In addition, the definition of the attributes of each meter installation must also be managed. Both functions are necessary to meet technical and regulatory requirements in order to measure and bill, or pay customers for their electricity consumption and/or power production.

Meter Data Acquisition and Storage

The Meter Data Acquisition and Storage function covers the retrieval and processing of meter readings to provide data required to bill consumers and settle with electricity providers. This capability will facilitate integration to and from the IESO for billing of Time of Use residential customers as well as perform meter data management for interval-metered commercial and industrial customers.

Billing and Payment:

Bill Calculation and Printing

The Bill Calculation and Printing Function covers the billing determinant processing, bill calculation and invoice production for approximately 1.2 million customers. Customer bills are comprised mainly of delivery, commodity and regulatory charges. Also included in the calculation and display of the bill are late payment charges, and other miscellaneous debits and credits.

Bill presentation includes the formatting of the statement, and the delivery of that statement to the customer via Canada Post or web-based electronic presentment. As part of the bill presentment process, bill messages and bill inserts are prepared and delivered to specific customer segments along with the bill itself.

As the bill is calculated, various checks and controls are performed to minimize the risk of a customer receiving an incorrect bill. The CIS system supports the execution of these checks, together with workflow functions to support the manual handling of the resulting exceptions, and the efficient execution of billing adjustments, cancellation and rebilling as necessary.

Complex Billing

The Complex Billing function covers the meter data processing and bill calculation of interval metered customers connected to Hydro One's distribution system. These customers include the largest commercial and industrial accounts, retail generators and other local distribution companies ("LDCs"). It also includes the billing of embedded wholesale market participants (i.e., those connected to Hydro One's distribution systems), who are billed for commodity related charges by the province's Independent Electricity System Operator ("IESO") and by Hydro One for delivery related charges.

Remittance Processing

Hydro One partners with TD Bank and Symcor, as well as other payment processors, to handle the processing of payments received from customers. Encrypted payment files are received daily and posted to customer accounts via CIS. CIS reconciles payments via our SAP financial modules.

Credit & Collections

The Collection program is responsible for mitigating financial risk and debt exposure by applying and maintaining security deposits and by completing electricity disconnection in response to customer non-payment of arrears. Credit and Collections activities are conducted in compliance with OEB regulations which define specific business rules around, for example, the payment and refund of security deposits.

Retail and Wholesale Market:

Wholesale Settlements

The Wholesale Settlements functional area covers Hydro One's financial and related wholesale market transactions with Ontario's Independent Electricity System Operator and the procurement of power from retail generators connected to Hydro One's distribution systems. It also covers settlement with other Local Distribution Companies connected to Hydro One's distribution systems for power purchased at retail points of delivery and power supplied under short-term and long-term load transfer arrangements with those distributors.

Retailer Enrolment & Billing

In the Ontario electricity market, energy customers have a choice when it comes to the purchase of their electricity commodity. The Ontario market has almost 20 active electricity retailers. Hydro One has over 140,000 customers actively enrolled with electricity retailers.

The Ontario market rules support a bill-ready retailer billing model, in which the LDCs inform electricity retailers of the amount of electricity consumed by each of their customers, and the retailers inform the LDCs of the commodity charge to add to their customer's bills. In a bill-ready market, the retailers are required to calculate the commodity charge based on the customer's consumption. This market supports both distributor consolidated billing ("DCB") and retailer consolidated billing ("RCB"). For a DCB customer, the bill is issued by Hydro One to the customer using the commodity charge ($) provided by the retailer and all other charges as calculated by Hydro One. For a RCB customer, all of the charges normally billed to the customer (including the commodity charge) are billed by the retailer. The retailer decides which bill option they will use. CIS functionality in this area also automates the calculation and processing of settlement payments between Hydro One and the retailers who do business within Hydro One's service territory.

Data and Reporting Improvements:

As part of the CIS project, Hydro One will be extending the existing SAP Business Intelligence ("BI") solution which was implemented as part of the earlier Cornerstone phases. As a result, the BI solution will be extended to include the customer, billing, metering and payment data which is in scope for the CIS solution. This will allow the new data to be combined with the existing asset, financial and resource data which is being gathered in the current SAP solution. There are two major benefits associated with this ability:

- significant effort is required today from IT staff to extract data from legacy CIS systems, due to the age and complexity of the technology employed. In future, Hydro One staff will be able to access the BI solution themselves and 'self-serve' many of their requests; and
- the ability to combine data relating to both customers, and their usage patterns, with distribution system data (assets, outages, work programs) will enable better insight into Hydro One's business operations, and the relationship between customer behaviour/satisfaction and the performance of the distribution system.

The improved usability of the BI solution coupled with the richness of the data available, will assist Hydro One in business planning to optimize operational and capital expenditures from a safety, reliability and customer satisfaction perspective.

4.0 CUSTOMER CARE/CIS COSTS AND BENEFITS

4.1 Costs

At the June 29, 2011 Stakeholder session, stakeholders requested Hydro One provide a template similar to the one Enbridge Gas Distribution Inc. included in their application EB-2011-0226, Exhibit JCTC1.4 (See June 29 Stakeholder Notes, Appendix B, Item 6, included in Exhibit A, Tab 4, Schedule 1, Appendix C). Hydro One's template, shown as Table 3, includes the line items which represent the Hydro One CIS costs equivalent to those Enbridge included in its template as agreed with its stakeholder group.

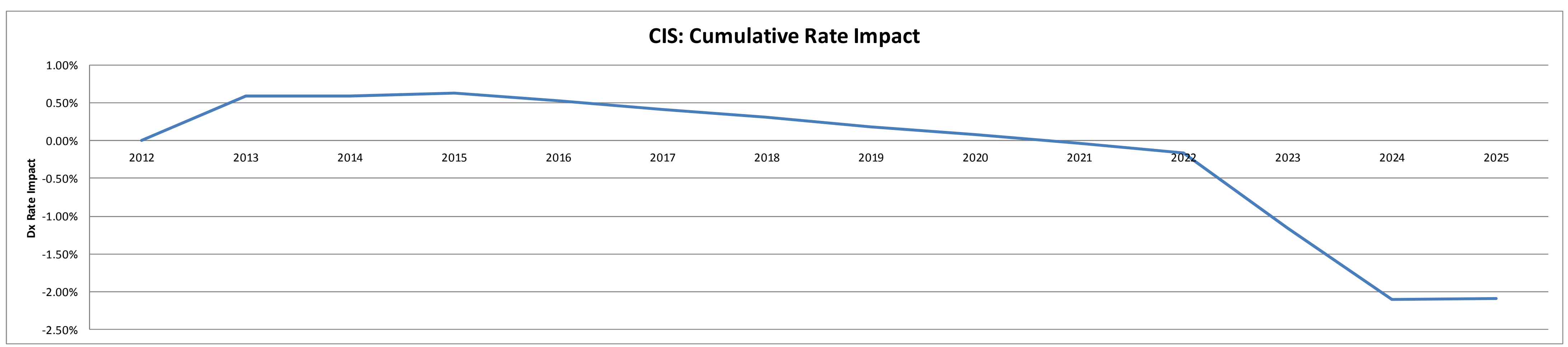
Table 3

CIS Cost Template

#	Category of Cost	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2009 - 2024 Total
	LEGACY CIS COSTS																	
1	License Fees	$1,108,600	$1,108,600	$1,108,600	$1,108,600													$4,434,400
2	CIS Hosting & Support	$15,134,259	$15,134,259	$15,134,259	$14,636,716													$60,039,492
3	CIS Backoffice	$3,907,408	$3,962,116	$3,843,227	$3,843,227													$15,555,978
	LEGACY CIS COSTS SUBTOTAL	**$20,150,267**	**$20,204,974**	**$20,086,086**	**$19,588,543**													**$80,029,870**
	NEW CIS COSTS																	
4	License Fees					$3,087,845	$2,421,685	$2,421,685	$2,421,685	$2,421,685	$2,421,685	$2,421,685	$2,421,685	$2,421,685	$2,421,685	$2,421,685	$2,421,685	$29,726,380
5	CIS Hosting & Support					$13,587,614	$9,958,897	$7,133,131	$7,133,131	$7,133,131	$7,133,131	$7,133,131	$7,133,131	$7,133,131	$7,133,131	$7,133,131	$7,133,131	$94,877,818
6	CIS Backoffice					$4,187,319	$4,110,576	$2,793,227	$2,793,227	$2,793,227	$2,793,227	$2,793,227	$2,793,227	$2,793,227	$2,793,227	$2,793,227	$2,793,227	$36,230,166
	NEW CIS COSTS SUBTOTAL					**$20,862,778**	**$16,491,158**	**$12,348,043**	**$12,348,043**	**$12,348,043**	**$12,348,043**	**$12,348,043**	**$12,348,043**	**$12,348,043**	**$12,348,043**	**$12,348,043**	**$12,348,043**	**$160,834,365**
7	**CIS Project Costs @ 40% Equity**					**$6,798,917**	**$6,798,917**	**$30,955,707**	**$29,973,306**	**$28,668,294**	**$27,398,776**	**$26,106,948**	**$24,807,886**	**$23,495,209**	**$22,185,898**	**$10,761,240**	**$0**	**$237,951,098**
	TOTAL CIS COSTS:	**$20,150,267**	**$20,204,974**	**$20,086,086**	**$19,588,543**	**$27,661,696**	**$23,290,075**	**$43,303,750**	**$42,321,348**	**$41,016,337**	**$39,746,819**	**$38,454,991**	**$37,155,929**	**$35,843,252**	**$34,533,941**	**$23,109,282**	**$12,348,043**	**$478,815,333**
	Number of Customers	1,189,183	1,201,195	1,210,889	1,220,514	1,231,476	1,243,713	1,256,331	1,268,421	1,280,511	1,292,600	1,304,689	1,316,779	1,328,869	1,340,958	1,353,048	1,366,579	20,405,755
	CIS Cost per Customer	$16.94	$16.82	$16.59	$16.05	$22.46	$18.73	$34.47	$33.37	$32.03	$30.75	$29.47	$28.22	$26.97	$25.75	$17.08	$9.04	$23.46
	CIS Cost per Customer Annual Change			-1.4%	-3.2%	40.0%	-16.6%	84.1%	-3.2%	-4.0%	-4.0%	-4.1%	-4.3%	-4.4%	-4.5%	-33.7%	-47.1%	

The overall impact of the CIS project investment on the DX rates is summarized below. This is as requested by stakeholders (see Item 7, Appendix B, Notes from Stakeholder session of June 29, 2011)

#	Category of Cost	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2009 - 2024 Total
8	**CIS Revenue Requirement**					**$6,798,917**	**$6,798,917**	**$7,248,911**	**$6,069,530**	**$4,761,761**	**$3,459,279**	**$2,046,071**	**$824,253**	**($498,967)**	**($1,852,916)**	**($13,279,389)**	**($24,142,480)**	**($1,766,111)**
9	**2011 OEB Approved Revenue Requirement**					**$1,148,885,481**	**$1,148,885,481**	**$1,148,885,481**	**$1,148,885,481**	**$1,148,885,481**	**$1,148,885,481**	**$1,148,885,481**	**$1,148,885,481**	**$1,148,885,481**	**$1,148,885,481**	**$1,148,885,481**	**$1,148,885,481**	
10	**Dx Rate Impact (Cumulative)**					**0.59%**	**0.59%**	**0.63%**	**0.53%**	**0.41%**	**0.30%**	**0.18%**	**0.07%**	**-0.04%**	**-0.16%**	**-1.16%**	**-2.10%**	



4.2 Table 3 Cost Descriptions

Rows 1 and 4 – License fees

These rows represent the fees paid to commercial software vendors for maintenance of the licensed CIS software. In the legacy CIS environment this includes fees paid to Accenture for the Customer/1 foundation software, fees paid to Itron and other software vendors for the applications included in the OMS suite, and miscellaneous other maintenance contracts including mainframe operating system support.

In the new CIS environment, these costs increase in aggregate due to the maintenance fees associated with the new CIS software components licensed primarily from SAP and Itron. These increases are partially offset by the elimination of the mainframe legacy CIS software and the elimination of some components of the OMS suite of applications.

Rows 2 and 5 - CIS Hosting and Support

This row represents the charges from Inergi for:

- Maintaining and fixing issues associated with the CIS applications. The CIS is managed in a problem management framework, to service levels that have been established with the relevant lines of business within Hydro One and which reflect the criticality of these applications.
- Operation, maintenance, and management of hardware (servers, mainframe, storage area network and data storage devices), operating systems, associated applications and infrastructure required to run the CIS applications, including the costs incurred to provide back up and disaster recovery capability for these applications.

With the implementation of the new CIS, which is based on commercial off-the-shelf software, and which is configurable instead of requiring expensive time consuming code changes, it is anticipated that the service provider costs will reduce considerably once the new CIS application has been stabilized. The new CIS application will also allow the existing mainframe computers to be retired, which will provide further savings. These savings will be fully realized via the re-tendering of IT services which will occur prior to 2015 when the current Inergi contract expires.

Rows 3 and 6 - CIS Backoffice

These rows are the costs of Hydro One staff who oversee the maintenance and operation of the CIS, and who oversee the implementation of changes to the CIS to meet regulatory and customer service requirements. It also includes costs from Hydro One's Customer Care service provider to provide CIS-related services including an end-user helpdesk, quality assurance (to ensure that the CIS application is producing accurate business outputs such as customer bills), reporting, and user acceptance testing of regular monthly releases of CIS.

As for the application maintenance activities, the implementation of the new CIS is anticipated to produce lower costs in this area once the new CIS application has been stabilized. This is due to the configurable nature of the application and the fact that it is based on off-the-shelf software which is supported by the vendor. These savings will be fully realized upon the re-tendering of the IT services contract.

The costs reflected in lines 1 to 6 show what is necessary to operate and maintain the applications (either legacy CIS or new CIS) in a fully functional state to support the customer service and billing business processes based on current business requirements. They do not include the cost of any future development activity, application enhancements, or refresh of the application software or associated hardware. Such costs will be included in future cost of service filings.

Row 7 – New CIS project capital costs

The total cost depicted in Row 7 is Hydro One's regulated return @ 40% equity.

Row 8, 9 and 10 – Revenue requirement and rate impact of CIS

Row 8 represents the annual revenue requirement for CIS after allowing for the impact of CIS benefits. Row 9 is the 2011 OEB approved revenue requirement used as the basis of determining cumulative rate impact due to CIS. Row 10 shows the projected impact of CIS on distribution rates, expressed as a percentage change relative to the base revenue requirement shown in Row 9. Any future cost of service applications and work program changes are not included in this calculation.

4.3 Savings and Benefits Summary

Hydro One expects Distribution Business savings from the CIS implementation to total $172 million over a 7 year time horizon.

Hydro One continues to explore opportunities with other Ontario LDCs to look for project cost savings synergies associated with sharing knowledge and deliverables regarding Hydro One's CIS implementation. Any such cost savings will be reflected in lower project and on-going costs. Hydro One has insufficient information at this time to quantify the amount of these potential savings.

CIS benefits have been identified through collaborative efforts by Hydro One, the CIS solution integrator, SAP and Hydro One's outsourced partners. The benefits approach has been developed based on our CIS solution integrator's best practices/framework. The benefits from CIS are enabled primarily through application and process changes, greater data transparency, integration and collaboration across Hydro One's Lines of Businesses.

The CIS investment enables a future customer service delivery model that will: meet the needs of the evolving utility customer of the future; support the achievement of key corporate objectives

(Customer Satisfaction, Innovation, Productivity); and ensure that related strategic technology investments yield maximum value.

Customer Care

An integrated CIS which provides a 360 degree view of the customer profile with enhanced customer issue resolution capability will reduce handling time on calls and correspondences, improve billing timeliness and accuracy, increase first call resolution ("FCR") and improve customer satisfaction.

Included in these benefits are avoided cost savings associated with the high cost of customizing an end of life legacy customer information system to meet ongoing and future business needs (See Attachment 1 for Ontario Green Energy Benefit Example). The new CIS based on a standard SAP platform is easier to configure and will require less agent training time. There will also be a reduction of bad debt expense through better tracking of delinquent accounts and more efficient collection processes. Integration of CIS with other enterprise SAP platforms and new technologies such as smart meters will drive work force productivity improvement

Finance

Benefits will be realized through reducing the time required to issue bills which will result in significant cash flow savings. Accounting processes will also be streamlined in the new CIS due to the integrated nature of CIS with the existing SAP ECC platform.

IT

Benefits will be realized through operational and capital savings from the decommissioning of mainframe. Rationalization of the hardware environment on which SAP runs will reduce infrastructure management and support costs as well as facility costs and hardware refresh. A common SAP platform for CIS enhances productivity in the area of application maintenance support and enhancement work program across Hydro One and Hydro One's outsourced service provider.

5.0 STAKEHOLDER INFORMATION REQUESTS

As previously mentioned, the CIS project was presented to and discussed with stakeholders as part of an initial information session on June 29, 2011, and followed up with an update at the stakeholder session on October 19, 2011. During those sessions there were several stakeholder requests for specific information to be included in Hydro One's CIS evidence. The information requested by stakeholders is included in the following sections.

5.1 Cost for Hydro One staff working on CIS Project

Hydro One was asked to provide more details about the estimated costs for the use of Hydro One personnel in the project, with specific interest in the costs of back-filling for seconded staff. (See June 29 Stakeholder Notes, Appendix B, Item 17, included in Exhibit A, Tab 4, Schedule 1, Appendix C).

The cost for Hydro One staff on the CIS project is shown in the Table 4.

Table 4
Costs for Hydro One staff on CIS Project

($M)	2011	2012	2013	TOTAL
Hydro One	4.7 *	7.6 *	0.6 *	12.9*

***costs area allocated to Capital or OMA based on accounting treatment for work activity**

In very large projects such as CIS, it is typical that significant numbers of key staff are seconded to the project for a number of months / years, leaving a resource gap in the home base organization. The intent of the cost treatment applied to this project is to provide funding for the home base organizations to bring in backfill resources through either temporary employees or external contract staff. It should be noted, however, that in some circumstances staff have been moved from another capital project in which case their costs would not impact OM&A.

5.2 Project Contingency

Hydro One was asked to provide more details about the project contingency and the governance of these funds. (See June 29 Stakeholder Notes, Appendix B, Item 8, included in Exhibit A, Tab 4, Schedule 1, Appendix C).

In very large projects such as CIS, Hydro One includes a portion of funding in contingency to cover any project issues such as clarification on requirements, system issues, technology performance and external factors unknown to the project at the time the business case is approved. If the CIS initiative does not utilize the full contingency, the project cost will be lower. This lower asset value would be reflected as the actual in-service amount in the next cost of service rate filing. Hydro One expects to utilize the contingency as the project complexity has resulted in the need to draw down these funds.

5.3 Ontario Clean Energy Benefit implementation

Hydro One was asked to provide more information about the study that was referenced in the session which illustrated the cost of making changes in the legacy CIS vs. the new CIS. (See June 29 Stakeholder Notes, Appendix B, Item 10, included in Exhibit A, Tab 4, Schedule 1, Appendix C).

Ontario Clean Energy Benefit study:
The implementation of the Ontario Clean Energy Benefit is representative of the type of change to customer charges that Hydro One has to implement from time to time. Implementing this change in the existing CIS system – CSS – was performed by Inergi late in 2010, on a very

aggressive timeline. As with all billing changes there was considerable detail to be worked through in design to determine:

- exactly which customers were eligible
- how the benefit would be calculated for each different charge and each customer type
- how the benefit would be displayed on the bill
- how the benefit would be calculated and displayed in the cutover month
- what accounting would occur for the benefit and therefore what information the CIS would need to feed to the Finance systems to support proper accounting
- what were the reporting requirements for the benefit.

A solution was proposed and validated, and then the changes were designed to all the various modules of CSS that needed to be updated in order to produce the required outcome. As the code changes were made, a comprehensive set of test scenarios was identified in order to test all the impacted account types through the cutover and ensure that the code changes were working properly. As always, the implementation of the this change had to be coordinated with other changes occurring in the CIS systems at the same time, to ensure cross impacts were identified and mitigated.

The actual effort to implement these changes in the legacy CIS was 4,480 hours broken up as follows:

Phase	**Hours**
1 – Planning	221
2 – Design	794
3 – Build	1,264
4 - Test	448
5 – Deploy	160
6 - Post Production Support	302
7 - Process & Training	186
8 - Project Management	1,105
Grand Total	**4,480**

Within the new SAP-based CIS, the design and implementation of a charge or credit like OCEB is simplified since the implementation can be handled through configuration of billing parameters in SAP – the benefit can be defined as a charge type, eligibility for the charge type can be defined in configuration tables, and the other charges to which the OCEB benefit is to be applied can also be defined in configuration tables. Significantly, the definition of the charge type includes the definition of how the charge is pro-rated at the beginning and the end of the period of time (currently defined as five years) during which the OCEB is to be applicable. Hence the effort estimate for the planning, design, build and test of OCEB in the new CIS was reduced from 2,727 hours to approximately 800 hours. Other elements of the estimate were reduced to a lesser extent, creating an overall estimate of 1,600-2,200 hours as noted below

Phase	**Hours**
1 – Planning	800
2 – Design	
3 – Build	
4 - Test	
5 – Deploy	80-120
6 - Post Production Support	140-240
7 - Process & Training	80-140
8 - Project Management	500-900
Grand Total	**1,600-2,200**

Attachment 1 to this exhibit provides the estimate from our CIS System Integrator HCL-Axon for the cost of implementing the Ontario Clean Energy Benefit in the new CIS solution.

5.4 Hydro One Board Approval document

Hydro One was asked to provide the Hydro One Board Approval document for the CIS Project (See June 29 Stakeholder Notes, Appendix B, Item 5, included in Exhibit A, Tab 4, Schedule 1, Appendix C). The Hydro One Board document is provided as Attachment 2.

Estimate for Clean Energy Benefit:

Hydro One Green Energy Benefit

Green Energy Benefit Implementation Assessment

April 2011

HCL AXON

FOREWORD

This document provides an initial assessment of what, given specific assumptions, it would take to implement the Ontario Green Energy Benefit requirements into an SAP environment. This initial assessment may change based upon further and deeper analysis of the requirements.

This document was prepared at the request of Hydro One to provide a comparative analysis for Hydro one to compare effort estimates to develop the Green Energy Benefit functionality in SAP versus Customer/1

This estimate is high level and initial and has been prepared by HCL AXON, for the sole use of Hydro One Networks Inc. The contents of this document shall remain the confidential property of HCL AXON and should not be communicated to any other party without the prior written approval of HCL AXON.

The furnishing of this document shall be subject to contract and shall not be construed as an offer or as constituting a binding agreement on the part of HCL AXON to enter into any relationship.

HCL AXON warrants that, to the best of their knowledge, those who prepared this response have taken all reasonable care in preparing it and, have made all reasonable enquiries to establish the veracity of the statements contained in it and believe its contents to be true. (HCL AXON cannot however warrant the truth of matters outside of its control and accordingly does not warrant the truth of all statements set out in this document to the extent that such statements derive from facts and matters supplied by other persons to HCL AXON. The statements in this document are qualified accordingly.)

VALIDITY

This estimate and all information contained within it are valid for a period of 30 days from April 15th, 2011.

Management Summary

The Ontario government recently passed the Ontario Clean Energy Benefit Act, 2010 (OCEB), which will provide eligible customers a 10 per cent rebate on the total cost of electricity on their bills including HST, effective with electricity consumed January 1, 2011. This rebate will be in effect for five years until December 31, 2015.

This document summarizes the understanding of the requirements of this functionality (as articulated by Hydro One to HCL Axon) and an initial assessment of what could be required to implement this functionality in a standard SAP environment to provide the OCEB credit to eligible customers in accordance with the Ontario Government order

Purpose and Scope of the OECB Implementation

HCL AXON understands that there is a need to implement the OECB rebate act and supporting requirements and functionality into SAP.

The scope of the OECB rebate elements required to be implemented are applicable to:

- All Residential customers (Residential, seasonal, farm with RRRP) as well as small business (energy-billed and less than 50 kW) customers as long as they do not use more than 250,000 kWh annually are eligible under the OCEB for the ten percent rebate.
- Customers eligible for the Regulated Price Plan (RPP) two-tiered prices and Time-of-Use (TOU) prices are also eligible for the OCEB rebate and this includes retailer enrolled customers and customers electing spot as long as they would otherwise be RPP eligible.
- Remote communities and Cat Lake customers are also eligible for the OECB Rebate.

The Ontario Clean Energy Benefit rebate must:

- Start to appear on customer bills issued after January 18, 2011.
- The first bill issued with the rebate will be prorated as the rebate only applies to your electricity use as of January 1, 2011. This pro-ration is based on the number of eligible days in the billing period.
- Appear as a separate line item on bills. The new line item will be called “Ontario Clean Energy Benefit (-10%)” and will appear below the “Total of your electricity charges” line item. In addition, there will be a “New total of your electricity charges” line item showing the net charges after applying the Ontario Clean Energy Benefit.

Other general elements around the OCEB rebate include:

- Eligible customers will receive a bill insert from the government that explains the rebate. This insert will be included with the first bill issued with the Ontario Clean Energy Benefit, starting on January 13, 2011.
- Information about Ontario Clean Energy Benefit must be posted to the Hydro One website.

- Call Center work instructions must be updated with information about Ontario Clean Energy Benefit
- Call Center agents must be trained with Ontario Clean Energy Benefit program information

Guidelines to Implement the OECB Rebate

Per guidance provided by HONI, HCL AXON understands that there is a need to implement the OECB rebate act and supporting requirements and functionality into SAP.

The scope of the OECB rebate elements required to be implemented are applicable to:

- All Residential customers (Residential, seasonal, farm with RRRP) as well as small business (energy-billed and less than 50 kW) customers as long as they do not use more than 250,000 kWh annually are eligible under the OCEB for the ten percent rebate.
- Customers eligible for the Regulated Price Plan (RPP) two-tiered prices and Time-of-Use (TOU) prices are also eligible for the OCEB rebate and this includes retailer enrolled customers and customers electing spot as long as they would otherwise be RPP eligible.
- Remote communities and Cat Lake customers are also eligible for the OECB Rebate.

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- Information about Ontario Clean Energy Benefit must be posted to the Hydro One website.

- Call Center work instructions must be updated with information about Ontario Clean Energy Benefit
- Call Center agents must be trained with Ontario Clean Energy Benefit program information

Requirements to Implement the OECB Rebate

Per guidance provided by HONI, detailed below are the requirements and potential solution options to implement the OCEB Rebate program in an SAP environment.

It is important to note that these requirements and potential solutions have been documented based on very High Level discussions and it is safe to assume that requirements could change or expand and solutions could change materially based on further investigation and discussions.

Requirements and Potential Solution Approaches

HL Rqmt #	High Level Requirement Description	Detail Rqmt #	Detailed Requirements Description	Potential Solution
1	Customer Eligibility	1.1.	The Ontario Clean Energy Benefit (OCEB) credit will apply to Residential, Small Commercial and Farms customers.	A new charge type could be defined to calculate the OCEB credit. This charge type is attached to all accounts. If an account is not eligible for OCEB credit, an exception will be setup for the account. Also, OCEB calculation and eligibility will be evaluated at primary level. In addition, proration will be done at primary level.
		1.2	All customers who are RPP Eligible with the addition of the following customers: * Retailer Enrolled Customers (Who are otherwise RPP eligible) * Electing SPOT customer (Who are otherwise RPP eligible) * Customers that are served by a Distribution System not connected to the Grid (Remotes) but otherwise meet the RPP Eligibility Criteria. Note: These accounts need to flagged separately from other RPP Eligible customers	
		1.3	Cat Lake customers are eligible	
2	Bill Calculation	2.1	The 10% OCEB credit will be applied to all charges in the electricity portion of the bill. This includes commodity, provincial benefit, OEB approved rates including CSTA, TLA, RPP Variance True Up, Estimation Adjustment, delivery charges, regulatory charges, debt retirement charges, HST on these	The OCEB credit will be based on specific charges on the bill. This will be setup through the CSS charge type charge type table where it lists all the charges that will be eligible for OCEB. Currently, the rental charge is not eligible for OCEB.

			items	
		2.2	For Remotes and Cat Lake the credit will apply to the tiered Electricity Line Items, Service Charge, Debt Retirement Charge (If Applicable) and HST.	
		2.3	The OCEB credit excludes equipment rental charges.	
3	Non Summary Bill Image Impacts	3.1	Two new line items for the OCEB credit will be displayed in the Electricity portion of the bill after the presentment of tax line items. * The first line item will appear after the Electricity Charges (After the "Total of your electricity charges") - "Ontario Clean Energy Benefit (-10%)" * Immediately below will be a new line item for "New total of your electricity charges"	A new field will be passed to RRD (bill print vendor) to carry the amount to print as the Total Electricity Charge. Also, the OCEB credit line will be passed as a print line like a normal line item. In addition, the New total will be passed on the existing field for the total electricity charge.
4	Summary Billing Image Impacts	4.1	Two new line items for the OCEB credit will be displayed in the Electricity portion of the Master Summary Bill after the presentment of tax line items. * The first line item will appear after the Electricity Charges (After the "Total of your electricity charges") - "Ontario Clean Energy Benefit (-10%)" * Immediately below will be a new line item for "New total of your electricity charges"	The print lines passed to RRD are also passed to OMS to generate the summary master bill and detail spreadsheet.

		4.2	The Summary Bill Detailed Statement will also have to have a new column for the OCEB credit and a new column for the Net New Charges.	
6	Communication	6.1	A government bill message (in English & French) must be printed on first eligible and subsequent bills through 2011 to inform eligible customers about the OCEB credit. Text for the message has been supplied by MEI as follows: "The Ontario Government has taken 10% off your electricity bill to help you with the costs of building a clean energy future. Learn about the new Ontario Clean Energy Benefit: Ontario.ca/energyplan or 1-888-668-4636." Audience: All customers eligible for OCEB credit Timing: First effective bill with OCEB credit and through 2011 Bill Message Priority: Highest	CSS bill message module is modified to print the bill message for bills with OCEB credit. There are 2 bill messages. The first bill message is only printed on the first bill with OCEB credit. This has a very high priority. The second bill message is printed on succeeding bills with OCEB credit and also has a very high priority.
		6.2	A bill insert (English & French) buck slip is being developed by the government to be inserted in the first eligible bills to inform eligible customers about the OCEB credit. To be delivered to H1 by end of December according to volume/specs of last OEB bill insert. Audience: All customers eligible for OCEB credit Timing: First effective bill with OCEB credit	Bill inserts will be added to the bill. This is applicable to customers that are eligible for OCEB credit. The list of accounts will be extracted and setup to receive the bill insert.

		6.3	Other Communications via Hydro One site Web Updates to be done by Hydro One Prepare a prominent promotional graphic on homepage displaying the new OCEB credit. Customer Information sections need to be updated with background information, key messages and Q&A's	OCEB Customer communication updates will be done through Corporate Web Pages
		6.4	Other Communications via eCustomer site Updates to eCustomer website informing customers about new OCEB credit	
7	GL Impacts	7.1	The OCEB credit needs to be applied to a new GL account. The current Revenue GL's are not impacted and it will follow the existing process. For the new GL there is a need to add the appropriate Profit Center (Responsibility Center - CSS Terms)	The new OCEB will be setup as a charge type with appropriate profit center in General Ledger. This new GL entry will flow through the current process.
8	Reports	8.1	Detailed Level Report Account Number, Profit Center, Revenue Class, Commodity Type, Bill Date, Bill Type (Cancel / Re-Bill), Dollars Billed (i.e. the gross amount the 10% is applied to), OCEB Credit Dollars.	CSS will extract the financial audit trail daily for the OCEB charge, and pass these to OMS. OMS will collect the daily extract and produce the report at the end of each month.
		8.2	Summary Level Report This report is organised by Profit Center and Revenue Class and also contains the following fields: Dollars Billed, OCEB Credit Dollars	OMS will also generate the summary level report based on the extract from CSS.
		8.3	Grand Total Report This report is organised by Profit Center and also contains the following fields: Dollars Billed, OCEB Credit Dollars	OMS will also generate the grand total report based on the extract from CSS.

		8.4	Timing - The Detailed / Summary & Grand Total Reports need to be generated by CSS on the last Wednesday of the month (e.g. CSS Fiscal Month End)	This report will be scheduled at the fiscal month end, at the same time as other fiscal month end reports.
		8.5	Ensure that "Profit or Operating Center" is added to the CS341 Report in support of Cat Lake and Remotes.	The new field will be added to the OCEB detailed level report to indicate if the account is in Cat Lake or Remote community.
		8.6	Existing Revenue Report impacts Assess the existing revenue related reports for potential impacts eg. AR, aging reports.	Existing reports have been reviewed and no changes are required.
9	Cutover Bill	9.1	The OCEB credit will only be effective from January 1, 2011. For cross over bills during this cut over period the OCEB credit will be prorated, so the eligible customers will receive the OCEB credit only for their usage after midnight December 31, 2010. Proration will be done based on number of eligible days in the billing period.	OCEB calculation and determination will be done at primary level. If only a portion of the bill period is eligible for OCEB (i.e., start date is prior to Jan 1, and end date is after Jan 1) the bill will be prorated according to the number of days. Conventional, Remote, and Cat Lake bills with reading-to date of Jan 1 and beyond will receive the OCEB credit (unless ineligible because of high volume). TOU bills with reading-to date of Jan 2 and beyond will receive the OCEB credit (unless ineligible because of high volume).
		9.2	Estimated Bill Adjustment that portion of the adjustment related to Jan 1 / 11 or later consumption will be included in the calculation of the 10% credit. Similar proration based on number of eligible days in the billing period will occur for retailer IBR's and for RPP Variance True-Ups, etc.	A new charge type to be defined that will calculate the OCEB credit. This charge type will be associated to all accounts. If an account is not eligible for OCEB credit, an exception will be setup for that particular account. OCEB calculation and eligibility will be evaluated at primary level. Also, proration will be done at primary level.

10	Agent Scripting	10.1	Prepare background, key messages and FAQ's for the CCC.	CCC work instruction will be updated with OCEB information.
		10.2	Create two sets of Agent Scripting. Scripting for Pre-Go-Live and another set for Post-Go-Live.	
11	Back Office Impacts	11.1	Make necessary updates to all impacted tools (e.g. the Bill Calculation worksheet) to reflect the new OCEB credit.	CCC tools will be updated to calculate the OCEB charge and reflect the correct total.
		11.2	Controlled materials, including but not limited to, Manual Bill Template, published customer communication correspondence, work materials, work instructions, etc. will be reviewed in order to determine if updates are needed in support of the new OCEB credit. This material will be updated as required and provided to Hydro One for review.	
		11.3	Update existing work instructions and/or create new work instructions to reflect OCEB credit as required.	CCC work instruction will be updated with OCEB information.
		11.4	Train CCC agents, Remotes and CRC staff in relation to new OCEB credit. Develop training plan, materials and execute training.	Existing remotes work instruction will be updated with OCEB information.
		11.5	Develop a new business process for Remotes to annually monitor OCEB eligibility utilizing Networks existing Price Protection monitoring process.	CCC will develop new business process to monitor OCEB eligibility for remotes annually.
		11.6	Modify existing Networks business processes for annual Price protection monitoring to include monitoring of OCEB eligibility.	CCC will update existing annual demand monitoring business process to monitor OCEB eligibility of RPP customers
12	Call Forecasting	12.1	Develop and provide strategy for Call Handling.	Training materials will be developed and training will be provided to call center staff on OCEB functionalities.

Initial High Level Estimates to Implement OCEB Rebate

Detailed below are initial high level effort estimates, quantified in hours, to implement the OCEB Rebate program in an SAP environment.

It is important to note that these estimates have been documented based on very High Level discussions and it is safe to assume that they could change.

In addition, these estimates are based on a number of assumptions as documented in the assumptions section and they specifically exclude estimates for the following:

i. Hydro One effort hours
ii. Other third party hours
iii. Hydro One effort hours
iv. Project Management
v. Basis Work
vi. Agent or other Training
vii. Work instruction or other non-technical document updates
viii. Assumes no G/L changes or re-testing
ix. Assumes no Cutover Testing as it will be part of operational transports
x. Assumes no changes to existing reports, only validation testing
xi. Assumes no backoffice changes, only validation testing

The Initial High Level Estimates are as follows:

#	Work Stream	Design	Config	Test	Total
1	CRM	22	22	11	**56**
2	Billing	22	22	11	**56**
3	StreamServe	0	22	34	**56**
4	Communications Framework	0	22	0	**22**
5	Web	0	22	22	**45**
6	G/L	0	0	0	**0**
7	Reports 1-5	34	34	45	**112**
8	Existing Report Validation	0	0	56	**56**
9	Cutover	0	0	0	**0**
10	Scripting	22	22	22	**67**
11	Back Office	0	0	56	**56**
	Total Func:	**101**	**168**	**258**	**526**
12	Developers (pool)	34	56	34	**123**
13	Test of Developments		22	56	**78**
	Total Dev:	**34**	**78**	**90**	**202**
	Total HCL Axon Hours:	**134**	**246**	**347**	**728**

Assumptions

1. The OCEB Rebate will be implemented in a standard SAP environment that is at least at an n-1 version level with no Core Code Modifications and no pre-existing FRICEW objects that will be impacted by this work.
2. This work will be performed by HCL Axon using HCL Axon standard methodology, tools, practices, etc.
3. Hydro One effort hours
4. Other third party hours
5. Hydro One effort hours
6. Project Management
7. Basis Work
8. Agent or other Training
9. Work instruction or other non-technical document updates
10. Assumes no G/L changes or re-testing
11. Assumes no Cutover Testing as it will be part of operational transports
12. Assumes no changes to existing reports, only validation testing
13. Assumes no backoffice changes, only validation testing. All business decisions are taken based on the previous OCEB Rebate implementation
14. All material is ready to workshop based on the previous OCEB Rebate implementation
15. All regulator decision are taken based on the previous OCEB Rebate implementation
16. Texts and images for Bills and Web are designed and approved based on the previous OCEB Rebate implementation
17. This change is not large enough to be its own release therefore will be deployed within the normal on existing transport flow and promotion to production
18. No PM oversight - part of ongoing maintenance
19. Updates to Corporate Website will be done by HONI Corporate website team.
20. Bill Inserts will be provided to bill print vendor RRD by HONI Communication team

Hydro One Inc.
Submission to the Board of Directors

hydroOne

Date: May 12, 2011

Subject: Cornerstone Phase 4 – Request for Funding

Submitted by:

INFORMATION COPY
Original Signed by:
Carmine Marcello

Carmine Marcello
Executive Vice President, Strategy

Approved for Submission to the Board by:

INFORMATION COPY
ORIGINAL SIGNED BY
LAURA I. FORMUSA

Laura Formusa
President and Chief Executive Officer

RECOMMENDATION

THAT the Board of Directors of Hydro One Inc. approve the implementation of Cornerstone Phase 4 at a cumulative capital and operating cost of $180 million. Phase 4 will replace the Customer Information Systems (CIS) of the company including customer/account services, billing, settlements and meter data management.

KEY HIGHLIGHTS

- Cornerstone Phase 4 eliminates the risk associated with relying on a set of aging, customized, legacy customer systems which are built on discontinued platforms.
- Phase 4 will upgrade capabilities across all customer-facing parts of Hydro One. The investment yields direct benefits in the range of $144M to $172M over a 7-year period.
- The new CIS solution will act as a key enabler to a broader Customer Service Delivery Vision that improves the quality of service for customers from a leaner and more productive service delivery model.
- Phase 4 is expected to take approximately 21 months to complete with an estimated go-live date of October 2012.
- There is adequate funding in the 2011-2015 Business Plan for this project. The timing of future OEB rate filings introduces a regulatory risk of cost recovery, which is partially offset by the substantial benefits to be realized by the CIS investment.

This Board Memorandum was reviewed and approved for submission to the Board of Directors of Hydro One Inc. by the Business Transformation Committee at its meeting on May 11, 2011.

EXECUTIVE SUMMARY

Background

A competitive CIS Cornerstone Phase 4 - Request For Proposal (RFP) was developed and issued on July 30, 2010. The RFP solicited both a software solution and system integration services to meet the stated requirements. An extensive evaluation of the responses was conducted during October and early November 2010. A selection was made and negotiations for the Discovery Phase were completed in January 2011. A three-month Discovery Phase commenced in February 2011 resulting in a finalized scope and a fixed price for System Integrator services to implement the project. Projected in-service is planned for October 2012, to maximize our leverage entering into the Outsourcing Agreement RFP process. The current Outsourcing Agreement with Inergi expires in March 2015 and must be put out to RFP.

1. Strategic Significance:

With the introduction of new programs such as smart meters and associated Time-of-Use pricing; new Conservation and Demand Management (CDM) programs; and growing Feed-In Tariff (FIT) and MicroFIT programs, the nature of customer service is rapidly evolving. Future utility customer programs will likely include personalized communication channels, specialized segment specific programs (i.e. low income), services for electric vehicles, and home energy management support. The electrical energy industry is at the beginning of broad transformational change that will require a new level of complexity in properly servicing and supporting the utility customer of the future.

With these future customer challenges in mind, as well as corporate objectives of improved Productivity and 90% Customer Satisfaction, a team of Hydro One customer managers developed a Customer Service Delivery Vision of the future. The Vision points to the delivery of a more customized service, from a streamlined, laterally integrated, empowered delivery organization. This new organization will have an emphasis on simplifying the interactions for customers (first contact resolution) and driving efficiency and effectiveness through innovation and service delivery transformation. The Vision will be enabled through the investment in a core set of foundational technologies. The CIS investment will be one of these key building blocks to developing the Service Delivery Model of the future Other dependent technologies include: GIS (Geographic Information Systems), mobile, WEP (Work Execution Projects) upgrade, and existing SAP modules.

More specifically, CIS along with the other enabling technologies will allow for a consolidation and streamlining of customer back-office functions leading to a leaner and more **productive** workforce. These functions currently involve approximately 800 staff (includes both insourced and outsourced resources). Currently, many manual steps are necessary to meet customer, government and industry demands thus reducing productivity along the entire process life cycle. The new CIS will drive **innovation** through the implementation of best practice approaches to customer services. These facets of improved customer service have direct relationship on quality metrics that are key drivers to **90% Customer Satisfaction**. In conclusion, the CIS investment enables a future customer service delivery model that will: meet the needs of the evolving utility customer of the future; support the achievement of key corporate objectives (Customer Satisfaction, Innovation, Productivity); and ensure that related strategic technology investments yield maximum value.

2. Purpose

The CIS investment serves three primary purposes. First, it is a core enabler of the Customer Service Delivery Vision of the future (as outlined above). Second, the investment will realize immediate value. And third, it addresses a current need to replace an aging CIS infrastructure.

Realize Immediate Value:

The planned CIS solution will primarily be built upon a vanilla, out-of-the-box, SAP solution representing industry best practice in core utility customer functions. The new solution integrates with existing SAP components providing all customer-facing staff with a more complete set of service capabilities and customer information. The value obtained in the new solution will be measureable in the form of several key service quality metrics such as the items listed below.

Service Quality Metric	Current Baseline	Target based on Planned Solution
First Call Resolution	87%	92%
Average Handle Time – Calls (1.5M agent handled calls per year)	305 seconds	285 seconds
Average Handle Time – Correspondence (280,000 items per year)	250 seconds	234 seconds

Average Handle Time – Billing Exceptions (400,000 items per year)	325 seconds	305 seconds
Escalated Complaints - Agent Lack of Knowledge (2959 complaints per year)	276 complaints per year	97 complaints per year

Address Current Need:

The core application components within the legacy CIS functionality is CSS (Customer Service System) and OMS (Open Market Systems). CSS is based on a Customer1 platform, originally put in-service in 1998. CSS combines many customer-related functions including billing, customer account management, and initiation of customer-demand work. OMS scope includes systems that support our interval metered customers, Distributed Generation (DG) customers, retailer enrolment and billing as well as wholesale settlements. OMS is tightly integrated with Customer1, and together support the customer-related functions of our consolidated customer base. Over the last number of years, many changes to the system have been implemented to support mandated programs such as Market Opening, Smart Metering and Time-of-Use billing. While this has been done successfully, it reinforces the concern that the legacy CIS is: expensive to maintain; expensive to modify to satisfy an accelerated pace of change; increasingly at risk for instability; and no longer vendor-supported.

Core Deliverables for Phase 4 include:

- Replacement of Customer1 and current Open Market systems with a modern system platform (SAP + ITRON) to support the meter to cash processes across all customer segments
- Improved customer relationship management capabilities (communication channels, self-serve capabilities, Conservation and Demand Management (CDM) support to enable customer choice and assist Hydro One in fulfilling constantly increasing conservation targets)
- Improved capabilities to support projected DG customer growth. The current legacy system requires manual processes to pay MicroFIT generators that will not be feasible at projected future volumes.
- Integration with Cornerstone Phases 1 and 2 installed system and processes
- Leveraging SAP equipment management capabilities to support metering devices
- Leveraging SAP Business Warehouse/Business Intelligence (BW/BI) capabilities for customer analytics, which will enable us to execute a continuous improvement cycle that drives future improvements to customer satisfaction and productivity

3. Alternatives

a) Proceed indefinitely with the current legacy system

For the reasons specified in the last section, we do not recommend this alternative.

b) Wait for OEB commitment to the project before proceeding with the investment

To mitigate regulatory risk, the project could be timed to be executed once OEB approval of the associated 2012-2013 Distribution rate requirement is approved. The assumed Distribution Filing would take place in late 2011, with a hearing in summer 2012. The project would then launch in late 2012 or early 2013 once the OEB Distribution Rate Filing outcomes were known. Leveraging current work, the CIS Implementation would still take approximately 24 months. This schedule would lead to an in-service date of early 2015. The problem that arises with this schedule is that the current outsourcing arrangements for both IT and Customer Service Operations (CSO) expire on February 28th, 2015. An open and competitive bid process for this set of services will be conducted with a possible outcome that a new vendor(s) may be chosen. This timing of the project is not recommended as the risk associated with a change in our key outsourcing partners at this late stage in CIS project implementation would not be tolerable. Inergi and Vertex will be required to play key roles in making the CIS project implementation successful.

c) Replace CIS after expiry of current outsourcing contract

The implementation of a new outsourcing contract as of March 2015 would require a transition and stabilization period. Therefore, the CIS project would commence late in 2015. The project would require an entirely new RFP and Discovery period. The earliest reasonable date to have the new CIS in-service would be late 2018. At this point, the legacy CIS will be in its 20th year of operation - well past its end-of-life. The additional 5-year delay will mean accommodating incremental regulatory changes that are likely to introduce new customer requirements which will be expensive to meet and will increase the risk of instability on the legacy environment. Finally, the benefits expected from this project would be delayed by 5 years. Therefore, this timing is not recommended.

4. Cost Estimate and Recovery

Cornerstone Phase 4 project cost is estimated at $180M. This amount includes interest, overhead, and funds allocated for risk mitigation. Although the amount is within the approved business plan budget of $197M, spread over 2011 to 2014, it is important to note that funding will need to be advanced into 2011 and 2012.

The overall Cornerstone Program costs and benefits are as follows:

		Costs	Benefits (projected over 7 years)
Phase 1	Enterprise Asset Management	$127M[1]	$200M
Phase 2	Finance/Human Resources/ Payroll, Business Reporting, IFRS in SAP	$166M[1]	$50M
Phase 3	Enhanced Enterprise Asset Management	$60M	$150M
Phase 4	**Customer Information System**	**$180M**	**$153M[2]**
Total		$533M	$553M
Phase 4	Avoided costs associated with unforeseen large enhancements, upgrades to OMS to accommodate MicroFIT volumes.		$19M[2]
Total Cornerstone Program		$533M	$572M

[1] Actual cost of phase 1 and 2 projects

[2]The Phase 4 benefits are the midpoint of the range provided on page 1 ($144M to $172M)

5. Regulatory

In several recent OEB rate hearings, the Cornerstone program was discussed at length and described as a 4-phase plan, with the fourth phase being CIS replacement. Cornerstone has been viewed within these proceedings as a successful transformational initiative and Phases 1 and 2 were approved for full cost recovery. Similar to past Cornerstone Phases, approval to proceed with Phase 4 implementation is being sought prior to discussion of the specific expenditure with the OEB. The likely timing of planned future Distribution hearings means that the OEB outcomes will not be known until late into the Implementation stage of the CIS project. For previous phases, associated OEB approvals on the investment of the Cornerstone projects were known earlier in their implementation schedules. Unlike other Cornerstone phases, the CIS project is not allocated between transmission and distribution so the full expenditure is at risk of approval in the next Distribution proceeding. Based on the above considerations, there exists a cost recovery risk. However, the significant benefits associated with the investment serve to partly mitigate the risk of OEB non-approval. The impact to rates from the CIS investment is estimated to be approximately 1% of revenue requirement on average annually over 7 years.

6. Risk Analysis

Risk	Mitigation
Quality of project outcomes and realization of targeted project benefits.	• Selected a proven systems integrator. HCL Axon is a leader in the CIS SAP utility systems integration marketplace. They have led over 36 SAP Customer Relationship & Billing (CR&B) implementations. • HCL Axon approach is benefits-driven. It has included a focus on benefits during Discovery that will continue through to final design. The plan also includes comprehensive and focused change management, communications, and training programs to accelerate staff preparedness from awareness to understanding to buy-in and adoption through a proactive, engaging, and managed process.
Project delivered on time	• Target date of October 2012 is built on Axon's 17-month work plan that has been scrutinized in the Discovery Phase • Established a governance framework similar to the model successfully employed in past Cornerstone Phases • Internal audit will review the project management methodology at key stages in the project schedule • HCL AXON's 590 SAP utility professionals is the largest pool of experienced resources in North America. Their depth of utility experience includes fully-configured SAP CR&B specific tools, templates, and pre-configured solutions that will reduce the risk of project delays
Project delivered on budget	• HCL Axon will be contracted for the project through a fixed price arrangement • The Discovery Phase included several design workshops on all aspects of the proposed solution. This effort should greatly minimize the chances of unforeseen scope changes being required during the Implementation Phase. • The project cost estimate has included a contingency budget of approximately \$25M (20% of project cost) for mitigation against unforeseen issues.