RATE BASE

1.0 INTRODUCTION

This Exhibit provides the forecast of Hydro One Transmission’s rate base for the 2011 and 2012 test years and provides a detailed description of each of the rate base components. The composition of Hydro One Transmission’s assets is described in Exhibit A, Tab 4, Schedule 1.

The rate base underlying the test year revenue requirement includes a forecast of net utility plant, calculated on a mid-year average basis, plus a working capital allowance. Net utility plant is gross plant in-service minus accumulated depreciation plus the accelerated cost recovery of the Bruce to Milton project. Working capital includes an allowance for cash working capital and materials and supplies inventory.

2.0 UTILITY RATE BASE

Hydro One Transmission’s utility rate base for the transmission system for the test years is filed at Exhibit D2, Tab 1, Schedule 1. The calculation of average balances to derive net utility plant for the historical, bridge and test years is filed at Exhibit D2, Tab 3, Schedule 1 and Exhibit D2, Tab 3, Schedule 2.

Hydro One Transmission’s forecast rate base for the 2011 test year is $8,378.5 million and for the 2012 test year is $9,134.6 million. Table 1 provides a summary of the calculation of the Transmission rate base for the 2011 and 2012 test years.

Table 1.
Transmission Rate Base ($ Millions)[1]

Description	Test 2011	Test 2012
Gross Plant	12,297.3	13,509.5
Accumulated Depreciation	(4,429.1)	(4,690.6)
Net Plant in Service	7,868.2	8,818.9
Construction work in progress	485.8	289.0
Net Utility Plant	**8,354.0**	**9,107.9**
Cash Working Capital	7.1	5.0
Materials and Supplies Inventory	17.4	21.7
Total Working Capital	**24.5**	**26.7**
Transmission Rate Base	**8,378.5**	**9,134.6**

2.1 Derivation of Net Utility Plant

The mid-year gross plant balance reflects the in-service additions resulting from the capital expenditure program forecast for the test years. These programs are described in detail in the Company's written evidence at Exhibits D1, Tab 3 and in the supporting schedules filed at Exhibit D2, Tab 2, Schedules 1 and 2. The justifications for individual capital projects in excess of $3 million are filed at Exhibit D2, Tab 2, Schedule 3.

The 2011 net plant in-service of $7,868.2 million is $279.6 million or 3.7% higher than 2010 Board-approved. The 2012 net plant in-service of $8,818.9 million is $950.7 million or 12% higher than 2011 Test Year. These increases reflect the Company's infrastructure investments to address asset replacement and refurbishment needs of our aging system,

[1] 2011 and 2012 gross plant and accumulated depreciation values are calculated using a mid-year approach. Capital contributions have been netted out. Contributed capital refers to amounts contributed by third parties to specific capital projects, such as, for example, Joint Use Assets.

and to expand the system for the purposes of load growth, accommodating a modified generation mix, and expanding access to interconnected electricity markets as described in Exhibit D1, Tab 1, Schedule 2.

Hydro One is proposing that project D1 "New 500 kV Bruce to Milton Double Circuit Line" ("BxM project") be subject to accelerated cost recovery. Specifically, as outlined in Exhibit A, Tab 11, Schedule 5, 100% of annual Construction Work In Progress (CWIP) expenditures for this project are to be treated as if they were added to rate base until the project is placed into service. The financial carrying costs (i.e. cost of capital) for annual CWIP expenditures are to be treated for cost recovery purposes as if the project was declared partially in-service annually ["Accelerated Cost Recovery of CWIP"]. However, consistent with OEB direction, depreciation expenses would not be recovered as part of this treatment. The above approach has been assumed for the BxM project in the determination of the revenue requirement for the 2011 and 2012 test years.

The accumulated depreciation balance for the test years incorporates the accepted Foster Associates' Inc. methodology. The depreciation expense is further discussed at Exhibit C1, Tab 6, Schedule 1. A continuity schedule for accumulated depreciation for the test, bridge and historical years is shown in Exhibit D2, Tab 3, Schedule 3.

2.1.1 Continuity Schedule for Fixed Assets

Table 2
Continuity of Fixed Assets Summary ($ Million)

Description	Historic			Bridge	Test	
	2007	2008	2009	2010	2011	2012
Opening Gross Asset Balance	9,793	10,104	10,481	11,081	11,874	12,721
In-Service Additions	490	409	661	798	871	1,619
Retirements	(167)	(29)	(34)	(30)	(39)	(42)
Sales	(7)	(4)	0	0	0	0
Transfers	(5)	3	(27)	24	16	(0)
Closing Gross Asset Balance	10,104	10,481	11,081	11,874	12,721	14,298
Mid-Year Gross Asset Balance	9,949	10,293	10,781	11,478	12,297	13,510

A continuity schedule for fixed assets for the test, bridge and historical years is shown at Exhibit D2, Tab 3, Schedule 1. In-service additions in that exhibit reflect the placing in-service of some of Hydro One Transmission’s capital programs, shown in Exhibit D1, Tab 1, Schedule 2 and described in detail at Exhibit D1, Tabs 3.

2.2 Cash Working Capital

In 2009 Hydro One Transmission retained Navigant Consulting Inc. to undertake a lead-lag study. The provision for working capital in 2011 and 2012 incorporates the results of this new study.

The cash working capital requirement for the transmission system is based on the following factors:

- the forecast of revenues,
- the forecast of OM&A, taxes and other cash expenditures and

- the net lead lag days determined.

Applying the lead lag study methodology results in a net cash working capital requirement of $7.1 million for the 2011 test year and $5.0 million for the 2012 test year.

2.3 Materials and Supplies Inventory

The other component of working capital is materials and supplies inventory. The average annual materials and supplies inventory balances are $17.4 million for 2011 and $21.7 million for 2012. Materials and supplies inventory is discussed in further detail in Exhibit D1, Tab 1, Schedule 4.

3.0 COMPARISON OF RATE BASE TO BOARD APPROVED

Table 3 compares 2009 costs to the 2009 Rate Base approved by the Board in their Decision on Hydro One Transmission's previous application in EB-2008-0272.

Table 3
2009 Board Approved versus 2009 Rate Base
($M)

Rate Base Component	2009	2009 Board Approved	Variance
Gross Plant	10,781.3	10,940.0	(158.7)
Accumulated Depreciation	(3,966.6)	(3,954.4)	12.2
Net Utility Plant	**6,814.7**	**6,985.6**	**(170.9)**
Cash Working Capital[1]	9.4	9.4	0.0
Materials & Supplies Inventory	36.7	36.7	0.0
Total Rate Base	**6,860.8**	**7,031.7**	**(170.9)**

[1] Hydro One Transmission does not calculate actual cash working capital, thus the 2009 approved amount was used for illustrative purposes.

Total rate base was $170.9 million below the Board approved amount, a variance of 2.4%.

Table 4 compares 2010 forecast costs to the 2010 Rate Base approved by the Board in their Decision on Hydro One Transmission's previous application EB-2008-0272.

Table 4
2010 Board Approved versus 2010 Bridge Year Rate Base
($M)

Rate Base Component	2010 Bridge Year (Forecast)	2010 Board Approved	Variance
Gross Plant	11,477.5	11,768.2	(290.7)
Accumulated Depreciation	(4,188.8)	(4,179.6)	8.4
Net Utility Plant	**7,288.7**	**7,588.6**	**(299.9)**
Cash Working Capital[1]	8.6	8.6	0.0
Materials & Supplies Inventory	38.7	38.7	0.0
Total Rate Base	**7,336.0**	**7,635.9**	**(299.9)**

[1] Hydro One Transmission does not calculate actual cash working capital, thus the 2010 approved amount was used for illustrative purposes.

Total rate base was $299.9 million below the Board approved amount, a variance of 3.9%.

IN-SERVICE CAPITAL ADDITIONS

In-service additions represent increases to rate base as a result of capital work being declared in-service and ready for use by Hydro One Transmission's customers. However, the absolute amount of in-service additions and capital expenditures in any given year will typically be different. This difference arises from the multi-year nature of many capital projects and from the fact that some projects can come into service in stages.

Table 1
In-Service Capital Additions 2010 – 2012 ($ M)

	2010 - Bridge Projected	Test Years	
		2011	2012
Sustaining	315.4	366.8	399.4
Development	374.2	397.8	1,083.4
Operations	35.7	42.3	54.7
Other	73.0	63.7	81.3
Total	**798.2**	**870.6**	**1,618.8**

Hydro One Transmission is expecting to achieve this level of in-service capital additions by utilizing a mix of internal and external resources, including outsourcing. Please refer to our Work Execution Strategy in Exhibit A, Tab 12, Schedule 7 for how Hydro One Transmission intends to accomplished the increased work program.

The in-service capital additions for test years 2011 and 2012 are forecasted at $870.6 million, and $1,618.8 million respectively. One of the significant shifts affecting our planned in-service capital additions is related to the Bruce to Milton project. In the previous EB-2008-0272 transmission application, this project was scheduled to be in-service in 2011 at a cost of $619.8

million. Due to delays resulting from property rights issues, among others, the new in-service date is planned for 2012 at a cost of $672.2 million.

Hydro One Transmission is forecasting a 9% increase in in-service capital additions in 2011 compared to 2010, and an 86% increase in 2012 compared to 2011. Theses levels of in-service additions are a substantial growth over historic years. This is primarily a result of the overall increases in our work program over the past few years to address asset replacement and refurbishment needs of our aging system, to expand the system for the purposes of load growth, to accommodate a modified generation mix, and to expand access to interconnected electricity markets.

Examples of such in service additions in the 2011 and 2012 test years include:

- Market Efficiency- Network Transfer Capability, a development activity, contributing in-service capital additions of $229.1 million in 2011, and $702.8 million in 2012. The main projects contributing to the in-service amounts are as follows:
    - 2011 - $84.6 million for the 350 MVAR SVC at Nanticoke TS, $80.3 million for the installation of 230kV, 350 MVAR SVC at Detweiler TS, and $11.7 million for the installation of two 100 MVAR Shunt Cap Bank at Porcupine TS.
    - 2012 - $672.2 million for the 500 kV Bruce to Milton double-circuit line.

- Station Facility Reinvestments – a sustaining activity, contributing in-service capital additions of approximately $61.5 million in 2011, and $76.5 million in 2012. These investments are aimed at replacing multiple end-of-life assets at transformer stations such as airblast circuit breakers and metalclad switchgear.

- Overhead Lines Component Refurbishment and Replacement – a sustaining activity, contributing in-service capital additions of $61.3 million in 2011, and $58.9 million in 2012. These investments are aimed at replacing end-of-life components such as towers and tower foundations, shieldwire, switches and insulators.

- Power Transformers – a sustaining activity, contributing in-service capital additions of $35.0 million in 2011, and $44.2 million in 2012. These investments are aimed at replacing and refurbishing various types of end-of-life transformers.

- Protection, Control and Metering – a sustaining activity, contributing in-service capital additions of $59.8 million in 2011, and $64.5 million in 2012. These investments are aimed at replacing of end-of-life protection, control and metering equipment (i.e. protective relays and their auxiliaries, Remote Terminal Units, Sequence of Event Recorders, DFRs, Special Protection Schemes, local control systems and Revenue Metering systems) in a proactive manner in order to avoid major disruption to the transmission system.

- Area Supply Adequacy - a development activity, contributing $71.7 million of in-service capital additions in 2011, and $196.6 million in 2012. The items in this category include new lines or transformer stations that are required to increase supply and reliability. The main projects contributing to the in-service amounts are as follows:
    - 2011 – $70.9 million for the Woodstock Area Transmission Reinforcement.
    - 2012 - $56.4 million for the 115 kV Switchyard Burlington TS, $84.9 million for the new Hearn TS, and $37.4 million for the 115kV Leaside TS.

- TS Upgrade to Facilitate Renewables - a development activity, contributing in-service capital additions of $39.0 million in 2012. The main projects contributing to the in-service amount are the installation of In-line Circuit Breakers #1, and the installation of In-line Circuit Breakers #2.

- Load Customer Connection - a development activity, contributing in-service capital additions of $19.8 million in 2011, and $100 million in 2012. The main projects contributing to the in-service amounts are as follows:
    - 2011 - $19.8 million to replace end-of-life 115-44 kV Transformers at Long Lac T1.

- 2012 - $26.8 million to upgrade the 115-44 kV at North Bay TS, $26.7 million to build the new Duart TS, $21.6 million to build the new Commerce Way TS, and $15.5 million for Barwick TS, and $9.4 million for Tremaine TS

WORKING CAPITAL

1.0 INTRODUCTION

Working capital is the amount of funds required to finance the day-to-day operations of Hydro One Transmission and is included as part of rate base for ratemaking purposes. The determination of working capital relies on a lead-lag study.

In 2006, Hydro One Transmission commissioned Navigant Consulting Inc. (Navigant) to carry out a lead-lag study, the results of which were accepted by the Board in its EB-2006-0501 Decision with Reasons, dated August 16, 2007. In 2009, Hydro One commissioned Navigant to conduct an updated lead-lag study which is included in Exhibit D1, Tab 1, Schedule 3, Attachment 1 (entitled “A Determination of the Working Capital Requirements of Hydro One Networks’ Transmission Business – dated March 18, 2010).

2.0 SUMMARY

Hydro One Transmission’s net cash working capital requirement for the 2011 test year is $7.1 million or 1.6% of OM&A ($436.3M) expenses or 0.008% of Rate Base ($8,378.5M). Net cash working capital for 2012 is $5.0 million which is 1.1% of OM&A ($450.0M) expenses or 0.005% of Rate Base ($9,134.6M). Table 1 summarizes the net cash working capital requirements determined by using the lead-lag days from the Navigant study (see Exhibit D1, Tab 1, Schedule 3, Attachment 1) to reflect the 2011 and 2012 test years’ revenue, expense and GST amounts (Table 2).

The methodology used to determine the net working cash required is based on the Navigant study that was accepted by the OEB and updated as part of this filing, and it takes the following into consideration:

- has considered the most important elements of revenue lags, including the IESO billing lag,
- includes the most important elements of expense lead such as payroll and benefits, operations, maintenance, administration expenses, and taxes, including property taxes
- takes the major cost elements into consideration in calculating the net cash working capital.

Table 1
Transmission Net Cash Working Capital Requirement
($M Except Lead-Lag Days)

	Revenue Lag (Days)	**Expense Lag (Days)**	**Net Lag (Lead) (Days)**	**2011 Test Year Amount**	**2012 Test Year Amount**
	(A)	(B)	(C)	(D)	(E)
Expenses					
OM&A Expenses	36.40	21.73	14.67	436.3	450.0
Removal costs	36.40	30.02	6.38	18.4	18.1
Environmental Remediation	36.40	34.84	1.56	7.3	7.8
Interest on Long term debt	36.40	52.87	(16.47)	260.6	291.7
Income tax	36.40	16.51	19.89	80.9	70.0
Total				**803.5**	**837.5**
GST (see Table 2)				23.2	27.9
TOTAL AMOUNTS PAID/ACCRUED				**826.8**	**865.4**
Working Capital Required (Calculations based on above values, for each expense category, calculated using the following formula: For 2011 Col (D)*Col (C)/365 For 2012 Col (E)*Col (C)/366)					
OM&A Expenses				17.5	18.0
Removal costs				0.3	0.3
Environmental Remediation				0.0	0.0
Interest on Long term debt				(11.8)	(13.1)
Income tax				4.4	3.8
Total				**10.5**	**9.1**
GST (see Table 2)				(3.5)	(4.1)
NET WORKING CASH REQUIRED				**7.1**	**5.0**

Table 2
Transmission Summary of GST Cash Working Capital Requirement
(All Data in $M Except Lead-Lag Days)

GST Category	**2011 Test Year**		**2012 Test Year**	
		5% GST Projection		**5% GST Projection**
	(A)	(B)	(A)	(B)
Revenue	1,445.5	72.3	1,547.4	77.4
OM&A Expenses	145.3	(7.3)	149.8	(7.5)
Removal costs	18.4	(0.9)	18.1	(0.9)
Environmental Remediation	7.3	(0.4)	7.8	(0.4)
Capital	809.6	(40.5)	814.5	(40.7)
TOTAL		**23.2**		**27.9**
GST (Benefit) Cost	**2011 Test Year**		**2012 Test Year**	
	Expense Leads (Days)	**GST Amounts**	**Expense Leads (Days)**	**GST Amounts**
	(C)	(D)	(C)	(D)
The values shown in the Col (D) labeled “GST Amounts” are calculated using the expense leads shown in Col (C) divided by 365 for 2011 and 366 for 2012 and multiplied by the 5% GST projected amount in Col (B)				
Revenue	(46.58)	(9.2)	(46.58)	(9.8)
OM&A Expenses	36.59	0.7	36.59	0.7
Removal costs	43.95	0.1	43.95	0.1
Environmental Remediation	43.95	0.0	43.95	0.0
Capital	43.95	4.9	43.95	4.9
TOTAL		**(3.5)**		**(4.1)**

A Determination of the Working Capital Requirements of Hydro One Networks' Transmission Business

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Navigant Consulting has prepared this report at the request of Hydro One Networks Inc. (the "Company"). In preparing this report Navigant Consulting has relied upon the Company's budgets for 2011 and 2012. Navigant Consulting has not independently confirmed the accuracy of the budget information supplied by the Company.

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NAVIGANT CONSULTING

Section I: Introduction and Overview

Summary

In the EB-2005-0378 and EB-2006-0501 Decisions With Reasons, the Ontario Energy Board (the "Board") accepted Hydro One's (the "Company") 2006 distribution and 2007-08 transmission related requests for working cash allowances consistent with the amount recommended in lead-lag study reports prepared by Navigant Consulting, Inc. ("NCI"). In preparation for a 2011-12 transmission rate filing before the Board, the Company retained NCI to prepare an update to its prior studies. This report provides the results of the update and the working capital requirements of the Company's transmission business.

Listed below are key findings and conclusions from this study:

1. In terms of lead lag days, the results from this study are generally consistent with results from the Company's 2007-08 transmission study. Where there are differences, they have been identified, explained, and their impact on working capital requirements quantified.
2. The approach and method is the same as in the Company's prior transmission lead lag study and is generally consistent, in terms of lead and lag items, with other studies relating to the determination of working capital both in Ontario and other Canadian jurisdictions.
3. Results from the lead-lag study applied to the Company's test year transmission expenses identify that working capital amounts of $7.1 million in 2011 and $5.2 million in 2012 respectively will be required by the Company. These amounts represent approximately 1.6 percent and 1.1 percent of the Company's Operations, Maintenance, and Administration ("OM&A") expenses.
4. If the OEB's guideline of 15% of OM&A were to have been used verbatim by the Company, the result would have been a working capital requirement of approximately $68.3 million for 2011 and $70.5 million for 2012 compared with amounts identified in this study that are in the order of $61-65 million per year less.

Working Capital

Working capital is the amount of funds required to finance the day-to-day operations of a regulated utility and are included as part of a rate base for ratemaking purposes. A lead-lag study is the most accurate basis for determination of working capital and was used by NCI for this purpose.

A lead-lag study analyzes the time between the date customers (in this instance, the Ontario Independent System Operator or "IESO") receive service and the date that customers' payments are available to the Company (or "lag") and the time between the Company receipt of goods and services from its vendors and payment for them at a later date (or "lead")[1]. "Leads" and "Lags" are both measured in days and are generally dollar-weighted. The dollar-weighted net lag (i.e., lag minus lead) days is then divided by 365 (or 366 if a leap year is selected) and then multiplied by the annual test year cash expenses to determine the amount of working capital required for operations. The resulting

[1] A positive lag (or lead) indicates that payments are received (or paid for) after the provision of a good or service.

amount of working capital is then included as part of the Company's rate base for the purpose of deriving revenue requirements.

Key Concepts

Consistent with the Company's lead lag study filed in Case EB-2009-0096, two key concepts need to be defined up-front as they surface throughout the lead-lag study described in this report:

Mid-Point Method: When a service is provided to (or by) the Company over a period of time, the service is deemed to have been provided (or received) evenly over the midpoint of period, unless specific information regarding the provision (or receipt) of that service is available indicating otherwise. If both the service end date ("Y") and the service start date ("X") are known, the mid-point of a service period can be calculated using the formula:

$$\text{Mid-Point} = \frac{([Y-X]+1)}{2}$$

When specific start and end dates are unknown but it is known that a service is evenly distributed over the mid-point of a period, an alternative formula that is typically used is shown below. The formula uses the number of days in a year (A) and the number of periods in a year (B):

$$\text{Mid-Point} = \frac{A/B}{2}$$

Statutory Approach: In conjunction with the use of the mid-point method, it is important to note that not all areas of this study may utilize dates on which actual payments were made by the Company. In some instances, particularly the Goods and Services Tax ("or GST"), the due date for payments are established by statute or by regulation with significant penalties in place for missing the due date. In these instances, the due date established by statute has been used in lieu of when payments were actually made.

Method

As described in the Company's Distribution Study filed in Case EB-2009-0096, performing a lead-lag study requires two key undertakings:

1. Developing an understanding of how the regulated business works, i.e., in terms of products and services sold to customers or purchased from vendors and the collections and payment policies and procedures that govern such transactions; and
2. Modeling such operations using data from a relevant period of time and a representative data set. It is important to ascertain and factor into the study whether (or not) there are known changes to existing business policies and procedures going forward. Where such changes are known and material, they should be factored into the study.

To develop an understanding of Hydro One's Transmission operations, interviews with personnel within the regulated utility's Accounts Payable, Wholesale Market Operations, Human Resources, Payroll, Treasury, and Tax Departments were conducted. Some key questions that were addressed during the course of the interviews included:

a. What is being sold (or bought)? If a service is being provided (purchased), over what time period was the service provided (or purchased)?
b. Who are the buyers (sellers)?
c. What are the terms for payment? Are the terms for payment driven by industry norms or by company policy? Is there flexibility in the terms for payment?
d. Are any changes expected to the terms for payment either driven by industry or internally by the Company? What is the basis for such changes (if any)?
e. How is payment made (e.g., cash, check, electronic funds transfer)?

Except where otherwise noted, a calendar year 2008 data set was used in the analysis. Development of the data set entailed gathering raw data from the utility's General Accounting, Accounts Payable, Payroll, and Tax Systems. Once the raw data had been gathered from the multiple in-house systems, sampling and data validation was performed to the extent necessary and appropriate. Standard statistical sampling techniques were used, and validation generally took the form of comparing actual invoices with data from the utility's systems to ensure accuracy.

Organization of the Report

Section II of this report discusses the lags associated with the Company's collections of revenues. Included in Section II is a description of the sources of such revenues and how they were treated for the purposes of deriving an overall revenue lag as it affects the Company's transmission operations.

Section III presents a description of the various expenses and their attendant lead times. Included in the discussion on expense leads are the lead times on OM&A costs, removal costs, environmental remediation costs, interest on long-term debt, Capital and Income Taxes, and the GST. The methods used to calculate the expense lead times associated with each of the items as well as the results from the application of the methods are described.

Section IV presents the cash working capital requirements of Hydro One's transmission business including the working capital requirement associated with the GST.

Finally, Section V presents a summary comparison of the results from the 2009 study with results from prior Hydro One studies. Differences between the two have been noted, explained, and their impacts on working capital quantified. Also included within Section V is an update to the high-level benchmarking of Hydro One's lead-lag studies with other studies that have been conducted in Canada. The question addressed in the benchmarking effort is have other studies within Canada considered the various elements of revenues and expenses considered by the Company The intent of presenting the discussion in Section V is:

- To demonstrate that the approach used in this study is reasonable when compared with the Company's 2007-08 transmission study and captures the current operations of the Company;
- To show that the approach used in this study is consistent with similar studies in Canada; and,

- To emphasize that the overall result is a balance between the expectations of investors and rate-payers in terms of working capital.

Section II: Revenue Lags

An investor owned utility providing service to its customers generally derives its revenue from bills paid for service by customers. A ***revenue lag*** represents the number of days from the date service is rendered by the Company until the date payments are received from the customers and such funds are available to the Company.

Hydro One's Transmission Business receives funds from two type of Customers:

a. The Independent Electric System Operator (or "IESO"), and
b. Other miscellaneous sources such as jobbing and contracting work performed by the Company.

Based on the Company's records for calendar year 2008, approximately 95.7 percent of the Company's revenues are realized from the IESO, with about 4.3 percent being provided from other sources including customer related jobbing and contracting work. This is shown in Table 1.

Table 1. Calculation of Total Revenue Lag

Description	Un-weighted Lag Days	Weighting Factor % of Revenues	Weighted Lag Days
(A)	(B)	(C)	(D)
IESO Revenue	35.36	95.74%	33.85
Other Revenue	59.88	4.26%	2.55
TOTAL - Revenue Lag		100.00%	36.40

IESO Revenue Lag

The Company's transmission business receives the vast majority of its revenues from Ontario's IESO. Based on the Company's billings to the IESO and its receipts during 2008, a weighted expense lead time of 35.36 days was derived for the lag time associated with receipts of revenues from the IESO. This estimate of expense lead time includes both a service lead time component, generally a half month using the mid-point approach described at the outset, as well as an IESO reimbursement lag time. The payment lead time was calculated using the IESO invoicing and payment schedules for 2008. The calculation is shown in Table 2 below.

Table 2. Revenue Lag Time Associated With IESO Remittances

Delivery Month	Amounts Remitted by the IESO	Date of Receipt	Service Lead Time	Payment Lead Time	Total Lead Time	Weighting Factor	Weighted Expense Lead Time (Days)
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
January	93,249,760	02/21/2008	15.50	21.00	36.50	8.71%	3.18
February	92,814,494	03/20/2008	14.50	20.00	34.50	8.67%	2.99
March	86,017,256	04/18/2008	15.50	18.00	33.50	8.03%	2.69
April	81,336,495	05/21/2008	15.00	21.00	36.00	7.60%	2.73
May	77,784,109	06/19/2008	15.50	19.00	34.50	7.26%	2.51
June	98,591,804	07/21/2008	15.00	21.00	36.00	9.21%	3.31
July	97,940,935	08/21/2008	15.50	21.00	36.50	9.15%	3.34
August	92,358,260	09/19/2008	15.50	19.00	34.50	8.63%	2.98
September	92,661,378	10/21/2008	15.00	21.00	36.00	8.65%	3.12
October	79,671,859	11/21/2008	15.50	21.00	36.50	7.44%	2.72
November	85,983,473	12/18/2008	15.00	18.00	33.00	8.03%	2.65
December	92,301,361	01/21/2009	15.50	21.00	36.50	8.62%	3.15
TOTAL	1,070,711,185					100.0%	35.36

Other Revenue Lag

The lag time associated with other revenues was estimated using the non-energy related accounts receivables of the Company together with a service lag of a half month. Considered together, the result is 59.88 days.[2]

[2] The weighted average lag time associated with collections of non-energy related accounts receivable was determined to be 44.63 days. When a half month (i.e., 15.25 days) for service provision is added to the lag time the result is 59.88 days.

Section III: Expense Leads

As mentioned at the outset, a determination of working capital requires both a measurement of the lag in the collection of revenues for services provided by Hydro One's transmission business, and the lead times associated with payments for services provided to the Company. Therefore, in conjunction with the calculation of the revenue lag, expense lead times were calculated for the following items:

- OM&A Expenses;
- Removal Costs;
- Environmental Remediation;
- Interest on Long Term Debt;
- Income Taxes; and
- GST.

OM&A Expenses

For the purpose of the transmission lead-lag study, OM&A expenses were considered to consist of payments made by Hydro One to its vendors in the following categories:

a. Payroll and Benefits expenses;
b. Payments made to Consulting and Contract Staff;
c. Payments made to Inergi;
d. Lease Payments made on the Trinity Office Building;
e. Property Taxes;
f. Corporate Procurement Card payments; and
g. Other (Miscellaneous) Operations and Maintenance related payments.

Expense lead times were calculated individually for each of the items (a) – (g) listed above and then dollar-weighted to derive a composite expense lead time of 21.73 days for OM&A expenses.

Payroll and Benefits Expenses

The following items were considered under the umbrella of Payroll and Benefits.

a. Four types of payroll including basic, trades, management, and board of directors payroll;
b. Three types of payroll withholdings including the Canada Pension Plan, Employment Insurance, and Income Tax withholdings;
c. Contributions made by the Company to the Hydro One Pension Plan;
d. Group Health, Dental, and Life Insurance related administrative fees and claims;
e. Payments made by the Company on account of the Employer Health Tax (or "EHT"); and
f. Payments made by the Company to the Worker Safety Improvement Board (WSIB).

When all payroll, withholdings, and benefits were dollar-weighted using actual payment data for calendar year 2008, the weighted average expense lead time associated with payroll and benefits was determined to be 22.79 days (see Table 3 below).

Table 3. Expense Lead Time Associated With Payroll and Benefits

Line	Category	Total Company Payment Amounts (000s)	Expense Lead Time	Weighting Factor	Weighted Expense Lead Time (Days)
	(A)	(B)	(C)	(D)	(E)
1	Pensions	98,820	45.28	12.82%	5.80
2	Group Health and Dental - ASO	5,857	43.38	0.76%	0.33
3	Group Life Insurance Premiums	4,499	55.50	0.58%	0.32
4	Group Health and Dental - Claims	44,945	6.84	5.83%	0.40
5	Employer Health Tax:	12,240	30.87	1.59%	0.49
6	WSIB Payments:	4,217	44.42	0.55%	0.24
7	Basic Payroll	251,285	18.73	32.60%	6.10
8	Management Payroll	46,282	(0.68)	6.00%	(0.04)
9	Trades Payroll	102,347	11.78	13.28%	1.56
10	Board of Directors (BOD) Payroll	359	60.76	0.05%	0.03
11	Withholding – All Except BOD	199,849	29.05	25.93%	7.53
12	Withholding - BOD Payroll	135	64.19	0.02%	0.01
13	Total	$770,833			22.79

Payments Made to Consulting and Contract Staff

Hydro One Networks engages consulting and contract staff to provide assistance in the areas of engineering, environmental services, receivables management, accounting, and general consulting. A dollar-weighted expense lead time of 60.36 days was determined based on a review of a sample of invoices rendered and payments made by the Company for the twelve months ending March 31, 2008. As with other categories of expense, this dollar-weighted expense lead time took into account the relevant service period over which services were provided to the Company.

Payments to Inergi

Inergi (a division of CapGemini) provides a spectrum of services to Hydro One including (and not limited to) customer service operations, finance, human resources, accounts payable, information technology, IESO settlements, and supply management services. Per its contract, Hydro One is generally required to make payments in the current month for the current month. Based on a review of a sample of payments made by the Company for the twelve months ending March 31, 2008, and using a ½ month of service lead time (since payments are made monthly), a dollar-weighted expense lead time of 2.59 days was determined.

Trinity Lease Payments

The Company leases its office space in the Bell Trinity Square Building from an outside party. The Company generally makes its lease payments at the end of the month prior for the current month. Taking this information into account and using a sample of actual invoices and payments for the period ended May 31, 2008, a dollar-weighted expense **lag** time of 18.71 days was determined. Note that since lease payments are generally required to be made before the fact, the result is an expense lag rather than an expense lead. Again, since lease payments are made monthly, the calculated dollar-weighted expense lag time includes ½ month of service lead time.

Property Taxes

The Company makes property tax payments to a number of municipalities and taxing authorities in the Province of Ontario. These payments are made in the current year for the current year and are typically made in two installments; an estimate and a final. Using actual payment dates and amounts associated with the Company's transmission business for calendar year 2008, a dollar-weighted expense **lag** time of 5.10 days was determined. Since property tax payments are for the current year, a ½ year was used as indicative of the service lead time associated with property taxes.

Procurement Card Payments

Procurement (or charge) cards are used by the Company's employees for a variety of Company-related reasons including, and not limited to, purchases of materials in the field, incidental expenses, and to settle charges for travel and accommodation. Based on a sample of actual invoices for the twelve months ending March 31, 2008 from the Company's charge card provider and payments made by the Company, a dollar-weighted expense lead time of 33.52 days was determined. Since the Company receives a monthly bill for service, the dollar-weighted expense lead time includes an additional ½ month of service lead time.

Other (Miscellaneous) Operations and Maintenance Expenses

This category of expense includes a sample of items from the Company's accounts payable system that were invoiced and paid in 2008.[3] The sample was selected in a manner that reflected a reasonable mix of vendors – both small and large – and products and services. Based on a sample of approximately 568 invoices which included product purchases, equipment rentals, and provision of general services to the Company, a dollar-weighted expense lead time of 34.84 days was derived. A mid-point approach using data for the twelve months ending March 31, 2008 was used in the determination of the expense lead time associated with the delivery of both products and services to the Company.

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[3] Note that this category of expense **excludes** payments to the IESO, payroll and benefits, payments to Inergi, payments to consulting and contract staff, payments relating to the Company's lease of the Trinity Office Building, all categories of taxes, payments relating to the Company's procurement card, and payments related to interest on long term debt.

Removal Costs

The Company incurs costs when removing or replacing equipment from existing sites or rights of way. While these costs are required to be reported as a depreciation and amortization expense for accounting purposes, there is a cash flow impact associated with the Company's expenditures on such removals. The Company estimates that 40% of total removal costs relate to the Company's labor; the balance relates to materials and services required to implement removals, i.e., other (miscellaneous) operations and maintenance expenses. Taking this information into account, a weighted expense lead time of 30.02 days was determined.[4]

Environmental Remediation

The Company incurs an expense when it is required to perform environmental remediation of its existing sites. As with removals, such remediation costs are recorded on the Company's books as a depreciation and amortization expense. However, since the process of remediation involves the procurement of general materials and services, there is a cash flow impact associated with it. Thus, an expense lead time identical to that used for other (miscellaneous) operations and maintenance expenses was assigned to environmental remediation, i.e., 34.84 days.

Interest on Long Term Debt

The Company makes interest payments on its long term debt outstanding out of current year revenues. Such payments are generally made twice a year. Taking into account the various bonds and other long term debt instruments outstanding as of December 31, 2008, the dollar-weighted expense lead time associated with the Company's interest payments on its long term debt was calculated to be 52.87 days. The analysis used a calendar year approach to calculate the weighted-expense lead time associated with interest payments relative to the mid-point of the year.

Income Tax

The Company makes income tax payments in monthly installments to the Federal Government. Using actual payment data for all tax payments in calendar year 2008, a dollar-weighted expense lead time of 16.51 days was determined.

Goods and Services Tax (GST)

The expense lead times associated with the following items that attract GST were considered in the NCI update to the transmission lead-lag study:

a. IESO Revenues;
b. Payments for the Corporate Credit Card;
c. Payments for the lease of the Trinity Office Building;
d. Payments to Inergi;
e. Payments for Other (Miscellaneous) Operations and Maintenance Expenses;

[4] The derivation of the expense lead time associated with removals used the following approach:
*(40% * Payroll and Expense Benefit Lead Time) + (60% * Other (Miscellaneous) Operations and Maintenance Expense Lead Time)*

f. Payments made to Consulting and Contract Staff; and
g. Payments for Environmental Remediation, Removals, and Capital.

A summary of the expense lead times associated with each of the above items is provided in Table 4. Note that the statutory approach described at the outset was used to determine the expense lead times associated with the Company's remittances and disbursements of GST, i.e., both remittances and collections are generally on the last day of the month following the date of the applicable invoice.

Table 4. Expense Lead Times Associated With GST

Line	GST Category	Expense Lead (Lag) Time Days
	(A)	(B)
1	GST – IESO Revenues	(46.58)
2	GST - Corporate Credit Card	15.75
3	GST - Payments for Lease of the Trinity Building	39.19
4	GST - Inergi Contract	46.00
5	GST - Other Operations and Maintenance	43.95
6	GST - Consulting and Contract Staff	42.09
7	GST - Environmental Remediation	43.95
8	GST – Removals	43.95
9	GST – Capital	43.95

The expense lead times associated with the GST payments on the Corporate Procurement Card, the Trinity Building Lease, Inergi, Consulting and Contract Staff, and Other (Miscellaneous) Operations and Maintenance Expenses were then aggregated on a weighted basis into a single expense lead time using estimated GST payments made in 2008. The aggregation resulted in a weighted lead time of 36.59 days and is used in the calculation of GST costs or benefits as discussed in the next section.

As mentioned in the context of the Company's Distribution Rate Application (EB-2009-0096), the Ontario government has announced its intention to harmonize the Ontario Retail Sales Tax with the federal GST into a harmonized single sales tax effective July 1, 2010. No detailed information on the implementation (in terms of remittance dates) of the proposed harmonized single sales tax has yet been released by either taxing authority. Accordingly, no changes to the current schedule of both remittances and receipts of the GST have been considered in this study.

Section IV: Hydro One Transmission – Working Capital Requirements

Having calculated the revenue lag, expense lead, and the net lag times, the next step in the process was to calculate the Company's working capital requirement. Using the results described under the discussion of revenue lags and expense leads, and applying them to the Company's proposed transmission expenses for the test years 2011 and 2012, the Company's working capital requirements are $7.1 million in 2011 and $5.2 million in 2012. These amounts represent 1.6 percent, and 1.1 percent of the transmission business' OM&A expenses respectively.

A summary of the Company's transmission business working capital requirements is provided in Table 5. Included within the working capital amounts shown in Table 5 are GST benefits of $3.4 million, and $4.1 million for the period 2011-2012. The derivation of these amounts is shown in Table 6.

Table 5. Working Capital Requirements Associated With Transmission Operations

Line No.	Description	Revenue Lag Days	Expense Lead Days	Net Lag (Lead) Days	2011 Budget $000s	2012 Budget $000s
	(A)	(B)	(C)	(D)	(E)	(F)
1	EXPENSES					
2	OM&A Expenses	36.40	21.73	14.68	455,623	469,796
3	Removal costs	36.40	30.02	6.38	18,402	18,070
4	Environmental Remediation	36.40	34.84	1.56	7,265	7,809
5	Interest on Long term debt	36.40	52.87	(16.47)	276,491	302,298
6	Income Taxes	36.40	16.51	19.90	79,806	68,479
7	Total				837,597	866,452
8	GST (see Table 6)				22,536	27,773
9	Total amounts paid/accrued				860,124	894,225
10	WORKING CAPITAL REQUIRED					
11	OM&A Expenses				18,320	18,838
12	Removal costs				322	315
13	Environmental Remediation				31	33
14	Interest on Long term debt				(12,477)	(13,604)
15	Income Taxes				4,351	3,723
16	Total				10,547	9,306
17	GST (see Table 6)				(3,409)	(4,073)
18	Net working cash required				7,138	5,233
19	Working Capital as a % of OM&A				**1.57%**	**1.11%**

Table 6. GST Related Working Capital Requirements – Transmission Operations

All Data in $000s unless otherwise noted

Line	Description	TEST YEAR 2011		TEST YEAR 2012	
		BUDGET	GST PROJECTION Assuming 5% GST Rate	BUDGET	GST PROJECTION Assuming 5% GST Rate
		(A)	(B)	(C)	(D)
1	GST CATEGORY				
2	Revenues	**1,502,087**	75,104	**1,612,420**	80,621
3	OM&A Expenses	**151,726**	(7,586)	**156,442**	(7,822)
4	Removal costs	**18,402**	(920)	**18,070**	(904)
5	Environmental Remediation	**7,265**	(363)	**7,809**	(390)
6	Capital	**873,965**	(43,698)	**874,629**	(43,731)
			22,536		27,773
		GST (Lead) Lag Days	GST (Benefit) Cost	GST (Lead) Lag Days	GST (Benefit) Cost
		(E)	(F) = Col (E)/365 X Col (B)	(G)	(H)= Col (G)/366 X Col (D)
7	GST (BENEFIT) COST				
8	Revenue	(46.58)	(9,585)	(46.58)	(10,261)
9	OM&A Expenses	36.59	761	36.59	782
10	Removal costs	43.95	111	43.95	108
11	Environmental Remediation	43.95	44	43.95	47
12	Capital	43.95	5,261	43.95	5,251
13	GST (BENEFIT) COST		(3,409)		(4,073)

Section V: Findings and Conclusions

The purpose of this section is to demonstrate that:

- The results from this study are generally more conservative compared to the Company's 2007-08 transmission study and that the current operations of the Company are fully captured;
- The approach used in this study is consistent with similar studies in Canada; and
- The overall result is a balance between the expectations of investors and rate-payers, i.e., compensation for investors with the attendant benefits to ratepayers of a working capital requirement lower than the OEB's guideline (15% of OM&A including cost of power).

Comparison with Hydro One's Prior Transmission Study

In terms of the overall working capital requirements of the Company, results from this study (1.6% and 1.1% of OM&A expenses) are generally more conservative than that identified in the 2007-08 transmission study (3.1% and 3.0% of OM&A expenses).

In terms of specific lead-lag days, results from the current lead-lag study are generally consistent with the 2007-08 transmission study with a few exceptions. Table 7 below compares the results of the current study (in terms of days and impact on working capital) with Hydro One's transmission study accepted in 2007 in key areas.

Table 7. Current Study vs. Hydro One's Accepted 2007-08 Transmission Study

Note that the Impacts shown in the Table below exclude GST and are derived using 2011 and 2012 Budgets and <u>not</u> the amounts used in the 2007-08 Transmission Rate Application

	Number of Days		Impact ($M)	
	From 2007-08 Transmission Study	**From Current Transmission Study**	**2011**	**2012**
(A)	(B)	(C)	(D)	(E)
Revenue Lag	36.96	36.40	-$1.28M	-$1.32M
OM&A	19.21	21.73	-$3.14M	-$3.23M
Interest on Long Term Debt	53.30	52.87	+$0.32M	+$0.35M
Income Taxes	15.68	16.51	-$0.18M	-$0.15M

Revenue Lag: As mentioned earlier, the revenue lag associated with the Company's transmission business consists of the lag in receipts of revenues from the IESO and the lag in receipts of other miscellaneous revenues. While the IESO revenue lag from the 2007-08 study compared with the current one is generally similar (35.15 days vs. 35.36 days), the Company's reports indicate that other revenue related weighted receivables have reduced significantly – from 108 days in the 2007-08 study to about 60 days in the current one. This reduction is driving a decrease in the overall revenue lag (36.96 days to 36.40 days) and results in an annual <u>reduction</u> in working capital requirement of about $1.3 million per year for 2011 and 2012.

OM&A: Table 7 indicates that the weighted average expense lead time associated with OM&A has increased from 19.21 days in the 2007-08 study to about 21.73 days in the current one. Major drivers of this increase include payments to consulting and contract staff, payments made on account of payroll and benefits, and payments made on account of the Corporate Procurement Card. The net effect of this increase is that it <u>decreases</u> the Company's otherwise working capital requirement by $3.14 million in 2011 and $3.23 million in 2012 respectively.

Interest on Long Term Debt: The expense lead associated with interest on long term debt has decreased by 0.43 days compared with the Company's 2007-08 transmission study. As explained in the Company's Distribution Rate Application (Case EB-2009-0096), the driver of this slight decrease is a change in the mix of bonds outstanding and their attendant interest payment dates. The net effect of this change is that it <u>increases</u> the Company's otherwise applicable working capital requirements by about $320,000 and $350,000 for 2011 and 2012 respectively.

Income Taxes: The expense lead time associated with this category of tax has increased by about 0.83 days compared with the Company's last transmission rate application. As explained in the study filed with Company's Distribution Rate Application (EB-2009-0096), the driver of this increase is true-up payments made by the Company in the year following the current year. The net effect of this increase is that it <u>reduces</u> the Company's otherwise applicable working capital requirement by about $180,000 and $150,000 for 2011 and 2012 respectively.

Comparison with Other Canadian Studies – Update from Prior Study

As identified in the Company's 2007-08 working capital study accepted by the Board, Hydro One's current transmission lead-lag study is generally consistent with studies that have been performed for other utilities both in the Province of Ontario and within other Canadian jurisdictions. Table 8 presents a high-level summary of the various elements of a lead-lag study and whether or not they have been considered in other Canadian jurisdictions involving Great Lakes Power (or "GLP"), Enbridge, Union Gas, FortisBC, ATCO, Direct Energy, Altalink, FortisAlberta, Terrasen Gas, Newfoundland Power, Ontario Power Generation, Pacific Northern, and EPCOR.. To the extent that certain elements of Hydro One's Transmission Study do not apply to others (e.g., in the instance of natural gas companies), they have been so noted within Table 8.

From a review of the information in Table 8, it is clear that the items considered in the current Hydro One transmission lead-lag study are consistent with items that have been considered in other lead-lag studies within Canada. To the extent that there are differences, they can be explained as not being relevant to an electric transmission company's operations or to the operations of an electric company for that matter.

In concluding therefore:

1. The results from this study are generally consistent, albeit more conservative, with results from the Company's 2007-08 transmission study respectively and that the current operations of the Company are fully captured;

2. When compared with other studies relating to the determination of working capital in Ontario and other Canadian jurisdictions, there is similarity; and
3. Finally, and most important, the overall result points to compensation for investors combined with an overall savings to the rate-payer. If the OEB's guideline of 15% of OM&A were to have been applied verbatim, the result would have been a working capital requirement of approximately $68.3 million for 2011 and $70.5 million for 2012 compared with the $7.1 million and $5.2 million in working capital requirements identified in this study.

Table 8. Comparison of Hydro One 2009 Transmission Study With Other Canadian Studies

Name of Utility	Jurisdiction	Type of Service	Customer /Retail Revenues	IESO/ISO Revenues	Other Revenues	Payroll and Withholdings	Employee Benefits	Cost of Power	Cost of Other Fuels	Other OM&A	Income and Related Taxes	GST	Interest Expense
(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
GLP	Ontario	Electric Transmission	N/A	Yes	Yes	Yes	Yes	N/A	N/A	Yes		Yes	
Hydro One Transmission - 2010	***Ontario***	***Electric Transmission***	***N/A***	***Yes***	***Yes***	***Yes***	***Yes***	***Yes***	***N/A***	***Yes***	***Yes***	***Yes***	***Yes***
Enbridge	Ontario	Gas	Yes	N/A		Yes	Yes	N/A	Yes	Yes		Yes	
Union	Ontario	Gas	Yes	N/A		Yes	Yes	N/A	Yes	Yes		Yes	
Manitoba Hydro	Manitoba	Electric (Integrated)				Yes	Yes		Yes	Yes		Yes	
BCTC	BC	Electric TX				Yes	Yes		Yes	Yes		Yes	
FortisBC	BC	Electric	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
ATCO	Alberta	Gas	Yes	N/A	Yes	Yes	Yes	N/A	Yes	Yes	Yes	Yes	Yes
Direct Energy	Alberta	Electric	N/A	N/A		Yes	Yes	Yes	N/A	Yes		Yes	
AltaLink	Alberta	Electric TX	Yes	Yes	Yes	Yes	Yes	Yes	N/A	Yes	Yes	Yes	Yes
Fortis Alberta	Alberta	Electric TX	Direct Connect Customers and Marketers	Yes	Yes	Yes	Yes	N/A	N/A	Yes	Yes	Yes	Yes
Pacific Northern	BC	Gas	Yes	N/A	Yes	Yes	Yes	N/A	Yes	Yes	Yes	Yes	
EPCOR	Alberta	Electric TX	N/A	Yes		Yes	Yes	N/A	N/A	Yes		Yes	Yes
Terrasen Gas	BC	Gas	Yes	N/A	Yes	Yes	Yes	N/A	Yes	Yes	Yes	Yes	
Newfoundland Power	Newfoundland	Electric	Yes	N/A	Yes	Yes	Yes	Yes	N/A	Yes	Yes	Yes	
Ontario Power Generation	Ontario	Electric	N/A	Yes	Yes	Yes	Yes	N/A	Yes	Yes	Yes	Yes	

MATERIALS AND SUPPLIES INVENTORY

1.0 STRATEGY

Hydro One Transmission maintains and optimizes materials and supplies inventory in support of our reliability, system growth and customer satisfaction objectives. Having the right material at the right work location at the right time is important in meeting these objectives.

The 2007 to 2012 inventory levels reflect impacts of increasing work programs, the increasing transmission asset base, and external cost pressures, offset by initiatives to manage inventory growth. Various initiatives undertaken by Hydro One Transmission to reduce its dependence on inventories include the following:

- Integration of planning and procurement processes to secure materials for transmission capital projects directly from vendors;
- Reduction of material costs due to the implementation of strategic sourcing practices.

A description of Hydro One Transmission's Supply Chain and initiatives undertaken are described in Exhibit C1, Tab 4, Schedule 1, Section 4.0.

2.0 INVENTORY

Hydro One Transmission carries two types of inventory; strategic spare parts inventory and routine materials and supplies inventory. Strategic spare parts are stocked to enable timely restoration of equipment having long procurement lead times. These consist primarily of breakers, transformers, and steel towers. Strategic spare parts are carried at cost and are located in warehouses in Pickering and Orangeville.

The routine materials and supplies construction materials, with low materiality typically have a high turnover rate and are required on a regular basis. Typical parts are O-rings, gaskets, and contacts. Routine materials and supplies are carried at cost and are primarily located at the Barrie warehouse.

Hydro One Transmission's inventory management strategy continues to apply to inventory reported as future use components and spare parts, under fixed assets. Effective January 1, 2008, the Company retrospectively adopted Canadian Institute of Chartered Accountants' (CICA) Handbook Section 3031, *Inventories*, with reclassification of comparative prior period amounts. This new section required certain major spare parts and standby equipment be reclassified from inventory to fixed assets. Future use land, components and spares are not depreciated until they are transferred to active capital projects and those projects are placed in-service.

While strategic spare parts inventory still forms part of Hydro One Transmission's inventory management strategy, for the purpose of Hydro One Transmission's rate application the strategic spare parts inventory is included in net utility plant as part of the calculation of rate base at Exhibit D1, Tab 1, Schedule 1.

Table 1 provides the inventory levels for 2007 to 2012. Included are both the year-end levels and annual average levels for each year.

Table 1
Inventory Levels (Transmission) 2007 – 2012 ($ Million)

	Historic			**Bridge**	**Test**	
	2007	**2008**	**2009**	**2010**	**2011**	**2012**
Year End - Materials and Supplies	10.0	11.0	12.3	13.1	21.7	26.0
Annual Average[1]	**9.1**	**10.5**	**11.7**	**12.7**	**17.4**	**21.7**

1 The average annual inventory level is calculated as the previous year-end level plus the current year-end level divided by two.

Over the 2007 to 2012 period, the average annual inventory levels rise by 138%. This increase is due to:

- the growth in the transmission work program, an increased transmission asset base and a large percentage of the asset base entering its mid-life to end-of-life age demographic, resulting in an increase in installed assets, which requires additional materials and supplies inventory, and
- a need to replenish materials and supplies inventory where numbers are low.

2.1 Planned Levels of Strategic Spare Parts

The planned levels of strategic spare parts are determined through the use of a probabilistic model which accounts for the size of the asset population requiring spare part coverage, failure rate, the lead time to replace or repair, the cost to purchase, store, and maintain the spares and the cost reliability consequences of not having the spare part available.

2.2 Monthly Inventory Levels 2007 to 2009

In response to the Board's directive to the Company to provide monthly materials and supplies balances as part of rate applications, actual monthly net inventory numbers for the years 2007 through 2009 are shown in Table 2.

Table 2
Historical Monthly Inventory Levels 2007 – 2009[1]

$M	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2007	$25.9	$26.0	$26.4	$26.4	$26.5	$26.7	$26.8	$27.0	$27.4	$27.4	$27.2	$29.7
2008	$29.4	$29.6	$28.0	$28.0	$27.9	$12.0	$30.8	$31.7	$31.6	$30.6	$30.8	$35.1
2009	$36.0	$33.7	$32.5	$32.0	$32.0	$32.6	$33.7	$33.5	$33.2	$34.2	$34.9	$34.9

[1]Includes strategic spare parts inventory.

The monthly variation in inventory levels is relatively flat, as expected.

SUSTAINMENT PLANNING AND ASSET INVESTMENT CRITERIA

1.0 INTRODUCTION

Sustaining programming for Operating, Maintenance and Administration (OM&A) and Capital is developed to meet Hydro One's strategic objectives and performance targets that are described in Exhibit A, Tab 4, Schedule 1 - Summary of Transmission Business.

This exhibit expands on the information provided in Exhibit C1, Tab 2, Schedule 2, entitled, "Transmission Assets and Investment Structure", and provides supporting information for OM&A and Capital spending presented in Exhibit C1, Tab 2, Schedule 3, and Exhibit D1, Tab 3, Schedule 2 respectively.

The exhibit provides the following information as it relates to sustainment planning:

- Asset demographic challenges.
- Asset performance highlights compared with CEA member utilities.
- Decision making framework for sustainment investment planning.
- Asset end of life (EOL) determinations.
- Decision making process for key assets for sustainment investment planning.

2.0 ASSET DEMOGRAPHICS

Hydro One's transmission system has evolved over the years in response to Ontario's growing electrical supply and demand. Hydro One manages a large fixed asset base that is mostly in middle to late stages of normal asset life with many fixed assets nearing expected end of life (EOL) over the next few years. Detailed asset demographic information can be found in Exhibit C1, Tab 2, Schedule 2, Appendix A, under the asset category in question.

As the age profile of the system increases, more assets will be in the mid-life and end-of-life regions where both Capital and/or OM&A expenditures can increase significantly. In general, in the mid-life region OM&A costs increase due to the need for more extensive maintenance as certain component parts begin to wear out. Investments are required in order to prevent premature equipment EOL and to maintain performance. Mid-life regions for major station asset categories are typically in the 20 to 30 year range. The system includes substantial populations of assets with service lives in excess of 40 or 50 years, which is the typical EOL region for many assets. When assets reach EOL they require replacement, assuming continued requirements, and this impacts capital costs.

Hydro One studies demographic trends to identify long term Capital and OM&A funding requirements that are likely to persist given the ages of transmission system assets. These trends are evident in all Stations and Lines assets.

The volume of assets that will need replacing due to asset failures or unacceptable asset performance is expected to increase gradually over the long-term. The impacts on overall performance of the transmission system and impact on workforce requirements will need to be monitored closely through Hydro One's ongoing maintenance and performance analysis programs.

It should be noted that the investments that Hydro One is making in the test years will not arrest these long term demographic trends. The following figures show examples of the kinds of demographic trends that Hydro One will experience. Figures 1 and 2 respectively show the projected number of Oil Circuit Breakers and Power Transformers that will be over 50 years of age, which is the typical EOL region, if replacements are kept near 2011 and 2012 levels.

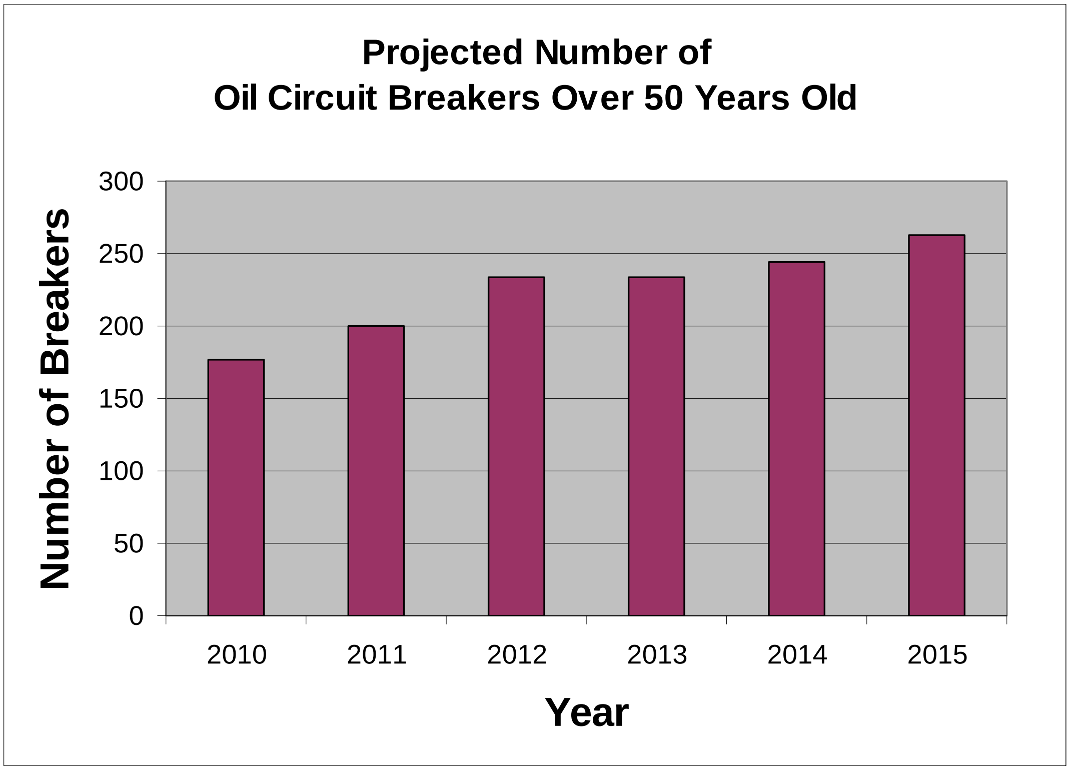

Figure 1: Number of Oil Circuit Breakers Projected to be Over 50 Years Old

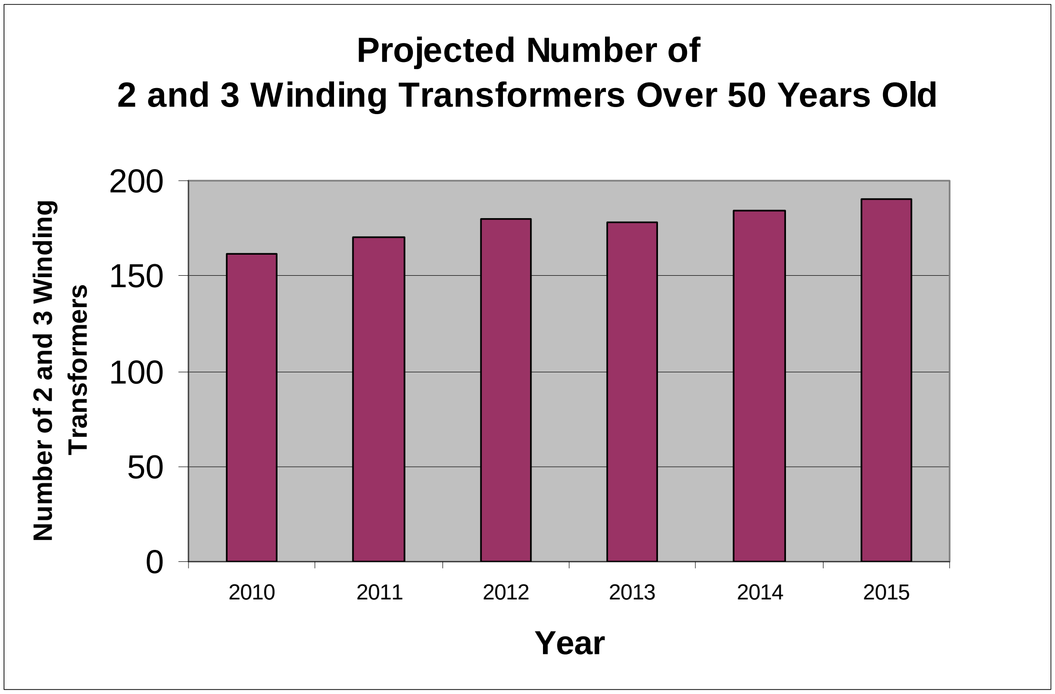

Figure 2: Number of Power Transformers Projected to be Over 50 Years Old

The following is a summary of other relevant key demographic findings:

- The system includes substantial populations of assets with service lives in excess of 40 or 50 years, which is the typical EOL region for many assets.
- For some older equipment, there is unavailability of technical support from the manufacturer and spare parts may be prohibitively expensive or unavailable.
- More than 50% of Hydro One's circuit breaker population is comprised of bulk oil circuit breakers with an age in the range of 30 to 65 years.
- More than 20% of Hydro One's power transformer population is comprised of units over the age of 50 years.
- About 50% of Hydro One's overhead lines assets are over the age of 50 years.

In summary, one can see that Hydro One Transmission is approaching a prolonged era of increasing cost pressures to maintain performance, system reliability and safety.

3.0 ASSET PERFORMANCE

Hydro One monitors the performance of key power system equipment to identify unfavourable long term trends and to develop plans to mitigate these developing risks. Asset performance remains a concern because of the demographic trends identified above. As assets age, a general decrease in performance can be expected. As part of this activity, Hydro One tracks the historical system performance as presented Exhibit A, Tab 13, Schedule 1, as well as specific equipment trends that are compared to the national All-Canada performance levels from CEA.

The analysis computes the following performance metrics to establish trends and identify areas for consideration:

- Number of outage occurrences
- Frequency
- Unavailability

The overall results of the analysis indicate that Hydro One's breaker and power transformer equipment performance is in most cases worse than the national composite averages (from CEA).

The following is a summary of the relevant Key Performance Findings:

- Transformer performance for frequency has been about 1.6 times worse than the CEA national average that includes other Canadian transmission utilities in the CEA survey.
- Transformer performance for unavailability has been about equal to CEA average for 230 kV transformers, but over 7 times worse than the average for 500 kV transformers.

- Breaker performance for frequency has been 1.4 times worse than the CEA national average that includes other Canadian transmission utilities in the CEA survey.
- The frequency of sustained outages for lines is slightly above the CEA average for 115 kV circuits and about 1.5 times for the CEA average for 230 kV lines.

CEA does not compile performance data for protections, but it must be realized that these are critical components to safeguard the electrical system in the event of failure of the assets identified above, and therefore must have a greater degree of reliability.

Detailed equipment performance charts for stations and lines are presented in Exhibit C1, Tab 2, Schedule 2, Appendix A, under the corresponding equipment/asset section.

4.0 SUSTAINMENT PLANNING OVERVIEW

The following is a general overview of the decision-making framework that is used by Hydro One to make Sustaining investment decisions. This decision-making process is used to prioritize investments within specific programs for individual asset groups. Asset specific details and examples are provided in later sections of this exhibit.

Hydro One's Sustainment programs are developed by identifying risks to the business values and determining the appropriate level of investment that mitigates these risks. Risks are continually developing as assets are essentially consumed over the course of their active duty. The assets are prioritized through a process that considers the likelihood of asset failure or loss of design functionality and the consequences of this occurrence. The applicable mitigation options are compared, and the preferred option selected based on technical and economic considerations.

The following steps are involved in making decisions to mitigate risk and are explained in further detail below:

- Assess the likelihood of asset failure or loss of design functionality
- Assess the consequences of asset failure or loss of design functionality
- Establish risks and determine the options for mitigation.
- Select the preferred option.

4.1 Assessing Likelihood of Asset Failure/Loss of Functionality

Hydro One considers many factors to determine the likelihood of an asset failure or loss of design functionality. The evaluation varies by asset type, but the following factors are generally considered:

1) Health Indexes
2) Asset Condition Assessment (ACA)
3) Asset Age & Demographics
4) Asset Performance and Reliability
5) Utilization
6) Other assessments and studies

Please refer to Exhibit A, Tab 12, Schedule 4 for a description of these considerations.

4.2 Assessing Consequences of Asset Failure/Loss of Functionality

Hydro One evaluates the consequences of asset failure/loss of functionality by assessing the impacts against Hydro One's business values. Most investment decisions are intended to reduce risk across multiple business values. The business values are provided below:

1) Safety and Environment
2) System Reliability

3) Customer Impact and Satisfaction
4) Financial / Competitiveness
5) Regulatory/Legal
6) Reputation

Refer to Exhibit A, Tab 12, Schedule 4, for added details concerning these business values.

4.3 Evaluating Options to Mitigate Risk

Risk based prioritization seeks to address the risk associated with the most consequential assets first. Consequential assets with higher likelihood of failure would be mitigated before those with a lower likelihood, considering similar consequences. Hydro One determines the appropriate investment level to mitigate the risk and to minimize the total asset life cycle costs. In some cases there are limited options for risk mitigation because of the design parameters of the asset, or it is clear that they are at EOL and need to be replaced. The decision to replace, refurbish, or maintain would involve an analysis of the risks and feasibility of the available options.

The following general options are available to mitigate the risk of asset failure:

- Increase preventive maintenance – increase scope of maintenance and/or frequency
- Increase corrective/demand budget; run some to failure
- Change operating and/or maintenance policies (deratings, implement additional barriers or controls to reduce risk exposure, etc.)
- Mid-life overhaul / major maintenance
- Eliminate the need for the assets through system reconfiguration/modifications
- Replacement

For some assets, reinforced maintenance will adequately mitigate the risk of failure. While for others, Hydro One will adjust the maintenance cycles on an asset through Hydro One's Reliability Centered Maintenance process. Mid-life refurbishment is only chosen when technically and economically feasible. The condition of the asset may increase the risks or decrease the effectiveness of mid-life refurbishment. Replacement of an asset is considered prudent when it is clear that asset functionality will be an on-going requirement, and when other alternatives are not technically or economically justifiable and/or feasible.

Later sections in this exhibit provide asset specific examples outlining the decision process to arrive at the preferred investment solution for particular asset classes, and demonstrate how Hydro One applies different risk mitigation solutions to manage a variety of issues on the transmission system.

5.0 ASSET END OF LIFE INDICATION

Assets are declared EOL in the context of Hydro One's Capital Sustainment programs when the risk of allowing an asset to remain in service in its present condition/situation exceeds acceptable risks associated with Hydro One's business values. EOL is defined as the likelihood of failure, or loss of an asset's ability to provide the intended functionality, wherein the failure or loss of functionality would cause unacceptable consequences. Identifying the appropriate indicators to project an asset's EOL is an important factor in Sustainment planning. Some assets have very specific and agreed to EOL markers, perhaps based on regulations or industry-accepted standards. Others require a number of inputs to identify the risks that prompt an EOL determination.

Hydro One generally considers the following factors when assessing an asset's remaining life:

Condition takes into consideration an asset's ability to perform as per design specifications. Asset condition can be affected by several factors including historical loading/duty, operating and environmental conditions, mechanical/electrical wear, loss in strength due to deterioration, etc.

Reliability and Performance of individual assets or groups of assets is important. If reliability or performance has deteriorated beyond acceptable levels and is irreversible, an asset can be determined to be at end of life. As well, performance can be a leading indicator of degradation against required functionality.

Utilization takes into consideration the measurable specifications against an expected application or duty (i.e. number of capacitive switching operations a circuit breaker is capable of)

Technical Obsolescence is an attribute assigned to assets that cannot be adequately operated and maintained due to unavailability of required replacement parts or specialized skill sets.

Safety & Environment is an important consideration as electrical equipment can present significant safety hazards that at times cannot be easily overcome without a change in design and replacement of equipment. Similarly, environmental considerations may require refurbishment or replacement of equipment to prevent serious damage to the environment.

Cost is a consideration from the perspective of comparing alternatives. If an asset cannot be maintained in a cost effective or safe manner, it may be declared at EOL.

Age can be used as a probabilistic EOL indicator for assets with large installed bases where statistically significant conclusions can be drawn for expected age prior to failure. For assets with smaller installed bases, typically station power equipment, asset age provides a relative indication of expected remaining life that can be used to complement other factors in determining EOL. While Hydro One does not program replacements based on age, there are generally accepted expectations for the useful service life of many components of the power system. The following tables present the expected life for some Stations, Protection and Control and Lines assets.

Station Asset / Component	Average Estimated Expected Service Life (years)
Power Transformers	40 – 65
Circuit Breakers	30 – 55
Capacitors & Synchronous Condensers	35 – 45
Surge Arresters	30 – 40
Instrument Transformers	40 – 50
Switchgear Equipment	30 – 40
Station Service Switchgear	20 – 40

Protection and Control Component	Average Estimated Expected Service Life (years)
Control Systems (SCADA and RTU)	10 – 25
Communications Systems (PLC, Microwave)	15 – 25
Protective relaying (electromechanical)	40 – 70
Protective relaying (solid state)	25 – 35
Protective relaying (electronic)	15 – 25

Line Asset / Component	Average Estimated Expected Service Life (years)
Aluminum Structures	60 – 100
Steel Structures	60 – 100
Wood Poles	30 – 50
Overhead Conductors	60 – 120
Underground Cables	40 – 65
Insulators	40 – 100

Health Indices are normally derived considering a number of factors that would be used to determine end of life. These can include condition measures, specific reliability or performance, safety risks, cost, etc. The inputs are scored and weighted to produce a numerical score. In many cases a single score does not adequately reflect the need for replacement or refurbishment of an asset. This being the case, in most cases Hydro One relies on the underlying details of the index to establish the need. Health indices provide a measure of where further assessment is required

6.0 STATIONS – OM&A DETAILED DECISION MAKING

Sustaining OM&A funding for Stations covers expenditures required to maintain the performance of the assets located within transmission stations. This section provides more detailed information regarding how Sustaining OM&A investment decisions are made for stations programs. Hydro One manages its Stations OM&A program by dividing the program into six categories:

1) Land Assessment and Remediation
2) Environmental Management
3) Power Equipment Maintenance
4) Ancillary Systems Maintenance
5) Protection, Control, Monitoring, Metering and Telecommunications

6) Site Infrastructure Maintenance

Further description of these categories can be found in Exhibit C1, Tab 2, Schedule 3, page 4.

6.1 Land Assessment and Remediation (LAR) Program

The LAR program is primarily focused on the mitigation and remediation of historical discharge of contaminates from station yards that may pose a risk to the public or Hydro One staff.

Information Required to Assess Risk:

- Historical contamination levels are based on site specific environmental assessment studies (type of soil, water table, grade, adjoining land use to the station, etc.);
- Lab analysis of soil and water samples to determine the type and degree of contamination;
- Ministry of Environment (MOE) regulations and guidelines.

Consequences from Adverse Impacts:

- Regulatory/Legal: subjecting Hydro One to punitive MOE action and/or civil litigation;
- Health Safety & Environment: adverse impact on human health;
- Reputation: degradation in municipal and provincial reputation resulting from above events.

Options and Actions:

- Analysis is completed using information acquired through the above activities and if a site has been determined to contain contaminants, an assessment is made on the likelihood of off site migration. Additional follow-up or off site sampling may be required.
- An overall risk based ranking of stations is created taking into account public and employee safety, as well as MOE regulations. The ranking determines the schedule for remediation or follow up action.

6.2 Environmental Management Program

6.2.1 PCB Retirement and Disposal of Regulated Waste Program

Hydro One initiated the PCB Retirement Program to identify and phase-out its PCB inventory to meet Environment Canada's new PCB Regulations, and End-of-Use (EoU) deadlines. In accordance with the Regulations, oil-filled power equipment (transformers, breakers, instrument transformers, and associated capacitors, bushings, reclosers) located at Hydro One's transmission stations are affected.

Information Required to Assess Risk:

- Requirements stipulated by Environment Canada;
- Equipment data and known PCB data where available;
- Potential system impacts on execution of testing/sampling program.

Consequences from Adverse Impacts:

- Regulatory/Legal: may subject Hydro One to punitive Environment Canada (EC) action and/or civil litigation;
- Safety & Environment: contaminates addressed under this program have the potential to have adverse effects on humans, and must be dealt with in a responsible manner;
- Reputation: degradation in provincial and federal reputation if regulations are not adhered to.

Options and Actions

- Equipment stipulated by EC scheduled for testing to meet sunset dates. Equipment with PCB content ≥ 500 ppm is scheduled for replacement or retro-filling before December 2014 and ≥ 50 ppm before December 2025. Coordinate work with other planned maintenance activities.

- Establish equipment that cannot be tested and plan for removal. This is the case with oil filled Low Voltage Instrument Transformers.
- Equipment with unknown concentrations (typically bushings and instrument transformers), are scheduled for sampling coincident with other planned maintenance activities to determine appropriate mitigation.
- Develop alternatives where activities to meet regulatory compliance are not practical or extremely costly, i.e., difficulty in obtaining outages for bushings as well as technical issues that cannot be overcome within the timelines required. Work with EC to land on more achievable regulations. This is in progress.

6.2.2 Oil Leak Reduction Program

The Oil leak reduction program targets leak repair and associated mid-life overhaul of power transformers. Specific investments under this program are assets with severe leaks where no capital replacement is planned. To be considered for this program, the assets must have significant remaining life and where a mid-life overhaul is technically and economically justifiable.

Information Required to Assess Risk:

- Review of oil top-up records to determine magnitude and rate of leaks;
- Analysis of preventive and corrective maintenance data;
- Supplementary field surveys and assessments.

Consequences from Adverse Impacts:

- Regulatory/Legal: may subject Hydro One to punitive MOE action and/or civil litigation;
- Safety and Environment: risk of oil migrating off-site; consideration given to condition of spill containment systems and proximity to environmentally sensitive locations;
- Reputation: degradation in provincial reputations.

Options and Actions

- Candidates are considered against the technical and economic feasibility of completing the mid-life refurbishment work;
- Candidates which cannot be effectively refurbished are further considered for capital replacement;
- Temporary controls such as drip trays and collection vessels are implemented to mitigate environmental risks until refurbishment or replacement is completed.

6.2.3 Preventive and Corrective Maintenance - Environmental Programs

The preventive maintenance program is in place to ensure that Hydro One's spill containment systems operate as designed, and to remove oil piping that is no longer in use and may contaminate the surrounding environment. The corrective maintenance program provides funding to allow Hydro One to correct minor defects where required.

Information Required to Assess Risk:

- ACA information resulting from spill risk assessment and engineering reports;
- Analytical test data on drainage effluent quality;
- Analysis of information gathered during preventive and corrective maintenance;
- Potential system and customer impacts;
- Provincial and Federal legislation;
- Historic costs on which to base demand work.

Consequences from Adverse Impacts:

- Health Safety and Environment: risk of oil migrating off-site; consideration given to condition of spill containment systems and proximity to environmentally sensitive locations.

- Regulatory/Legal: may subject Hydro One to punitive action from MOE and/or civil litigation;
- Reputation: degradation in provincial reputation.

Options and Actions

- Preventive maintenance program is developed to meet all regulated inspection and testing requirements;
- Corrective maintenance program targets the highest risk defects, with consideration given to the coordination of synergistic opportunities with other programs;
- Project demand is based on historic costs and adjust for new information.

6.3 Power Equipment - Stations

6.3.1 500 kV Autotransformer Remediation Program

This program is in place to manage the 500kV autotransformer fleet which historically has experienced an unacceptable failure rate. Since 2000, there have been four failures in this population. The program defines mid-life overhaul investments to reduce the risk of failure and defer the alternative capital investment.

Information Required for Risk Assessment

- Review of available information from preventive maintenance program (oil analysis, power factor test results, etc.);
- Detailed engineering design reviews conducted by third party transformer experts using modern day design and analysis tools;
- Post mortems on failed autotransformers.

Consequences from Adverse Impacts:

- System Reliability: failures in this population may have broad impacts to the transmission system;
- Health, Safety, and Environmental: hazards to staff in the vicinity of the transformer when failure occurs, as well as risks associated with spilling large volumes of oil;
- Financial / Competitiveness: increased costs associated with reactively responding to a 500kV transformer failure;
- Customer Impact: failures and forced outages for many of the 500kV autotransformers have a direct impact on major generation and load customers by affecting generation limits and transmission interface limits until the transformer is returned to service.

Options and Actions:

- Hydro One's decision to continue with mid-life overhauls on this transformer population has been determined to be the best available solution to complement the future capital replacements. Typical remediation activities include:
  - Hot oil vacuum processing to dryout major insulation systems;
  - Replacement of aged oil;
  - Updating accessories to reduce risk of failure (bushings, surge arrestors, Under Load Tap Changer (ULTC) filtration systems, breathers, online monitoring);
  - Leak Repair.

6.3.2 Power Equipment Preventive Maintenance

Preventive maintenance is conducted in part to meet Hydro One's obligations defined by the Transmission System Code to "inspect, test and monitor its transmission facilities to ensure continued compliance with all applicable standards and instruments".

Hydro One's power equipment preventive maintenance programs have been developed using industry-accepted Reliability Centered Maintenance (RCM) methodologies to establish safe levels of maintenance within acceptable risk tolerance.

Information Required for Risk Assessment:

- Understanding of regulated maintenance requirements such as those defined by the TSC, Boiler & Pressure Vessel Act, NPCC, etc.;
- Consideration is given to the impact of both asset and sub-component failures by using failure modes and effects analysis (FMEA) methodology to develop each planned maintenance program;
- Consideration to past performance trends of assets;
- Manufacturer's recommendations;
- Feedback from preventive and corrective maintenance programs;
- Comparison against other transmission companies to assess Good Utility Practice;
- Maintenance costs.

Consequences from Adverse Impacts:

- System Reliability: localized issues resulting from defects with individual assets as well as broader issues associated with groups of assets faced with the same failure modes;
- Safety and Environment: potential impacts to staff safety if equipment is not maintained and operated in acceptable state;
- Financial/Competitiveness: preventive maintenance allows ability to identify and correct critical defects prior to irreversible asset degradation and defects escalating to more costly and inefficient repairs;
- Regulatory/Legal: may subject Hydro One to punitive action from several regulatory bodies (NPCC, MOE, Ministry of Labour, etc.);
- Customer Impact: failures and forced outages for power equipment can have a direct impact on generation and load customers by causing momentary or sustained outages.

<u>Options and Actions:</u>

- Preventive maintenance program developed to meet all regulated inspection and testing requirements;
- Inspection and testing program that identifies defects for corrective maintenance, while also performing routine maintenance tasks to ensure continued safe and reliable operation of the equipment (i.e. lubrication of moving parts, verification/calibration of instrumentation, etc.);
- The preventive maintenance program also provides much of the data used to make long-term condition-based assessments of the assets and is used in overhaul versus replace decisions;
- Optimizing the costs associated with execution of the required maintenance through consideration of a number of factors that include expansion or contraction of maintenance cycles, equipment needs, and performance.
- Maintenance activities are triggered by combination of time-based, condition-based, and usage-based triggers:
  - Time-triggered maintenance activities: routine visual inspections, infrared thermography scans, inspection/testing of critical control and monitoring devices on transformers and breakers, lubrication of moving parts, regular oil/gas sampling of transformers/breakers/ GIS, etc.;
  - Condition-triggered maintenance activities: intrusive inspections of ULTCs and medium voltage oil circuit breakers (i.e. oil sample indicating abnormal mechanical or electrical wear);
  - Usage-triggered maintenance: number of ULTC operations since last intrusive inspection, or consideration to the number of switching and fault-interrupting operations a circuit breaker has performed to trigger invasive inspections and replacement of wear parts.

6.3.3 Power Equipment Corrective Maintenance Programs

Information Required for Risk Assessment:

- Defects identified through preventive and corrective maintenance, ACA and studies;
- Historic expenditures;
- Maintenance costs;
- Reliability and performance data.

Consequences from Adverse Impacts:

- System Reliability: potential local and system impacts if equipment defects are not corrected;
- Safety and Environment: for some equipment defects, potential impact to the safety of Hydro One staff if defects are not corrected in a timely manner, in addition to environmental consequences associated with leaks and spills;
- Financial/Competitiveness: increased costs associated with future repairs or replacement if reversible defects are not corrected in a timely manner;
- Regulatory/Legal: may subject Hydro One to punitive action from several regulatory bodies (NPCC, MOE, Ministry of Labour, etc.);
- Customer Impact: failures and forced outages for power equipment can have a direct impact on generation and load customers by causing momentary or sustained outages; failure to correct in a timely manner extends sustained outages.

Options and Actions:

- Correct reversible defects under OM&A or replace under capital if more cost effective;
- Schedule work considering reliability implications, customer implications;
- Information from corrective maintenance programs used as feedback into the preventive maintenance program to adjust maintenance tasks and frequencies.

6.3.4 115kV and 230kV Transformer Refurbishment Programs

Investments included under this program are transformer mid-life overhauls, transformer radiator refurbishment, and the ULTC modifications and upgrades program. These refurbishment expenditures are cost effective, will allow the asset to reach its expected life, maintain system and customer reliability and defer capital expenditures.

Information Required for Risk Assessment:

- Review of available information from preventive maintenance program (oil analysis, power factor test results, ULTC counter readings, visual inspection results, etc.);
- Review of oil top-up records;
- Analysis of corrective maintenance data and historical failures;
- Supplementary field surveys and assessments;
- Service advisories and recommended modifications from manufacturers.

Consequences from Adverse Impacts:

- System Reliability: can be affected as transformers are removed from service unplanned;
- Customer Impact: failures and forced outages for transformers can have a direct impact on major generation and load customers by affecting generation limits and local thermal limits until the transformer is returned to service.
- Safety and Environment: hazards may arise from leaking or failed transformers;
- Financial/Competitiveness; increased costs associated with reactively responding to transformer defects and failures. Reversible defects can be dealt with proactively prior to escalating to irreversible damage or failure.
- Regulatory/Legal: may subject Hydro One to punitive action from MOE and/or civil litigation.

Options and Actions:

- Perform mid-life refurbishment of at risk transformers where technically and economically justified, considering the assessed remaining life of the transformer;
- At risk transformers that cannot justifiably benefit from mid-life overhaul are further considered for replacement.

6.3.5 Circuit Breaker Refurbishment Programs

Investments included under this program are the ABCB component and auxiliary component refurbishment program, circuit breaker operating mechanism refurbishment program, OCB bushing /component refurbishment program and SF6 mid-life refurbishment program.

Information Required for Risk Assessment:

- Review of available information from preventive maintenance program (gas analysis, breaker timing and other diagnostic test results, operation counter readings, visual inspection results, etc.);
- Analysis of corrective maintenance data and historical defects/failures;
- Analysis of performance information;
- Supplementary field surveys and assessments;
- Service advisories and recommended modifications from manufacturers;
- Review of SF6 top-up records;
- Review of PCB content for in-service OCB bushings (in case of OCB component refurbishment program).

Consequences from Adverse Impacts:

- System Reliability: is affected as breakers are removed from service unplanned; HV breaker failure requires larger zones to be forced out of service, affecting local and system conditions;

- Customer Impact: failures and forced outages for HV breakers can have a direct impact on major generation and load customers by causing momentary and/or sustained outages;
- Safety and Environmental: hazards may arise from oil spills or SF6 emissions during failure;
- Financial / Competitiveness: increased costs associated with reactively responding to breaker defects and failures. Reversible defects can be dealt with proactively prior to escalating to irreversible damage or failure.

Options and Actions:

- Program candidates are targeted based on historical reliability and performance concerns;
- Perform mid-life refurbishment of select circuit breakers in need of refurbishment where technically and economically justified given the assessed remaining life of the asset.

6.3.6 Other Maintenance and Inspection Programs

Maintenance activities under this category include nuisance wildlife control, maintenance required for strategic inventory, and miscellaneous maintenance associated with station power cables, capacitor banks, and insulators.

These programs have generally been developed to improve or restore specific assets that have degraded condition and/or performance. Investments are targeted at specific stations or groups of assets and are not applied across the entire asset base. Examples include:

- Nuisance wildlife control program targeted at urban stations with past outages resulting from animal contacts;
- Application of protective coating to insulators, terminators, structures that are exposed to abnormal environmental contaminates, typically salt spray;
- Replacement of weathered fiberglass fuses on capacitors banks.

Investments in these programs are made to reduce the risk associated with events that would typically have an impact on local load customer's reliability.

These investment programs have been developed to perform supplementary maintenance activities on select station assets to mitigate reliability and customer impact risks where technically and economically practical.

6.4 Ancillary Equipment - Stations

6.4.1 Ancillary Equipment Preventive Maintenance

The ancillary equipment preventive maintenance program is similar to the power equipment preventative program. Refer to section 6.3.2

6.4.2 Ancillary Equipment Corrective Maintenance

The ancillary equipment corrective maintenance program is similar the power equipment corrective program. Refer to section 6.3.3.

6.5 P&C, Monitoring, Metering and Telecom Programs

6.5.1 P&C, Monitoring and Metering – Planned and Corrective Maintenance

Maintenance programs for these assets are developed to meet the requirements defined by the Transmission System Code to conduct "routine verification [that] shall ensure with reasonable certainty that the protection systems respond correctly to fault conditions", as well as NERC and NPCC reliability requirements. Planned Maintenance ensures that Hydro One's assets are functioning properly by completing systematic inspection, detection, and correction of incipient failures either before they occur or before they develop into major defects

Re-verification

P&C and revenue metering assets are subject to periodic visual inspections and periodic tests to verify correct functionality when called upon.

Information Required for Risk Assessment:

- Regulatory guidance/standards;
  - Protection systems that are considered part of the Bulk Power System (BPS) have re-verifications cycles set by NPCC. For other portions of the grid which are not classified as BPS, reverification cycles are defined by Hydro One.
  - Revenue metering systems require periodic verification of accuracy at intervals dictated by the federal Electricity Gas and Inspection Act.
- Historical asset performance is used to help determine reverification cycles;
- Asset make/model/type information used to help set reverification cycles (i.e. IED vs. electromechanical relays).

Consequences from Adverse Impacts:

- Regulatory/Legal: failure to complete reverifications may subject Hydro One to punitive fines from NPCC or NERC;
- System Reliability: Incorrect PC&T operation can have both local and system reliability impacts that result in either momentary or sustained issues. Localized consequences can be such things as damaged power equipment requiring repair or replacement, unnecessary faults contributing to a transformer's cumulative degredation, or momentary interruption to transmission-connected customers. System-wide disturbances can also occur from incorrect PC&T operation, resulting in system instability.
- Safety and Environment: Incorrect operation of PC&T systems can affect safety of employees and members of the public. Incorrect operation of a PC&T system could result in electrical safety hazards.

Options and Actions:

- Hydro One's reverification cycles are in accordance with NPCC standards for impactive assets.
- For portions of the grid where the a protection failure can have a broad impact, Hydro One performs reverifications by completing time-based electrical testing as well as detailed event analysis for automatic protection operations to ensure protections are operating as required.
- For portions of the grid where a protection failure can have only a localized impact, verifications are a combination of visual inspections and detailed analysis of protection operation events as they occur. This is typically practiced for feeder protections that emanate from the transmission station to supply the distribution systems.

Corrective Maintenance

Information Required for Risk Assessment:

- Defects identified through past preventative and corrective maintenance, ACA and studies;
- Historic expenditure levels;
- Reliability and performance data.

Consequences from Adverse Impacts:

- System Reliability: potential local and system impacts if equipment defects are not corrected;
- Safety and Environment: potential impact to Hydro One staff and public if defects are not resolved in a timely manner;
- Financial/Competitiveness: increased costs associated with future repairs or replacement if reversible defects are not corrected in a timely manner.

Options and Actions:

- Correct reversible defects under OM&A or replace under Capital if more cost effective;

- Information from corrective maintenance programs used as feedback into the to preventive maintenance program;
- Forecast demand and respond as required.

Support Processes and Preventive Maintenance

Hydro One Transmission maintains systems to keep records and manage change control of the settings and configuration of protection, control and telecommunication systems. Processes are in place for carrying out event analyses and follow-up actions, managing spare parts and tracking vendor advisories. These support processes are essential to the effective operation of the power system, and are generally mandated by regulatory bodies.

Preventive maintenance activities required for Protection, Control and Monitoring systems includes replacement of internal batteries that are used to power clocks and configuration memory on various pieces of monitoring and control equipment and replacement of isolation devices on RTUs.

6.5.2 Cyber Security

Cyber security OM&A investment programs are established to fund the planned and demand/corrective maintenance work to sustain the systems and facilities required to achieve and sustain compliance with the NERC Critical Infrastructure Protection (CIP) Standards.

6.5.3 Telecom

Maintenance

For telecom assets which are NPCC impactive, maintenance is performed in accordance with scope and cycles defined by NPCC. For telecom assets which are not NPCC impactive, maintenance is performed to Hydro One's maintenance practices, which in some cases are less stringent than NPCC's. Some variation in maintenance programs does exist between telecom technologies (PLC vs. fibre), consistent with industry practices. Hydro One's PLC-based communication does not offer continuous monitoring and may not indicate for all failure modes. As such, maintenance cycles are shorter than the counterpart digital-based fibre optic systems. Digital-based systems are verified on a cycle consistent with the protection schemes and the work is executed at the same time. The decision criteria and process is similar to P&C.

Leased Telecom Circuits and the Hydro One Telecom Contract

Hydro One leases telecommunication circuits from various carriers for protection, control and operational voice communications. Hydro One Telecom administers the contracts with these telecom carriers on behalf of Hydro One under the terms and conditions of the affiliate services agreement. For complex assets, Hydro One also contracts with the supplier for the supply of periodic updates and expert support services. Telecommunications services include monitoring of telecom systems and circuits, coordination of service restoration activities, technical support and performance reporting. Funding is based on historical levels and contractual agreements, and forecasts of identified telecom requirements for new assets going into service.

6.6 Site Infrastructure Maintenance

<u>Information Required for Risk Assessment</u>

- Preventive maintenance programs are extensively driven by regulatory requirements including building and fire codes, OH&SA, NPCC and NERC reliability standards and Ministry of Environment;
- Corrective maintenance programs are driven by defects discovered during preventive maintenance inspections and emergent risks that are required to be mitigated (i.e. repair to grounding systems as a result of copper theft, defective Heating Ventilation and Air Conditioning (HVAC) in relay rooms, etc.);

- Maintenance programs are also influenced by Hydro One's own corporate policies such as the Health & Safety Policy and the Environmental Policy;
- Transmission station site security requirements;
- Theft and unauthorized security breaches.

Consequences from Adverse Impacts:

- Regulatory/Legal: failure to adequately maintain transmission sites and infrastructure may result in Hydro One being non-compliant with regulated standards (OHSA, NERC, etc.);
- System Reliability: Possible incorrect operation of PCT systems if buildings are not adequately maintained, which can have both local and system reliability impacts;
- Safety and Environment: increased risk of safety incidents within the stations environment due to inadequate site maintenance (snow clearing, weed control, grounding systems, etc.), as well as facility maintenance. In addition, safety risks increase to workers and the public as a result of unauthorized station access and theft.

Options and Actions:

- Preventive maintenance program developed to meet all regulated inspection and testing requirements;
- Maintenance program that identifies and corrects defects, while also performing routine maintenance tasks to ensure continued safe and reliable operation of the stations (i.e. snowplowing, janitorial services, inspection/repair of security fences, etc.);
- Standard station security measures implemented throughout the system and more stringent measures implemented at stations where problems exist.

7.0 STATIONS – CAPITAL DETAILED DECISION MAKING

Sustaining Capital funding for Stations covers expenditures required to replace end of life assets located within transmission stations. This section provides more detailed information regarding how Sustaining Capital investment decisions are made for stations programs. Hydro One manages its stations capital program by dividing the program into eight categories. These categories are further explored in this section to provide additional details on how the investment decisions are made.

1) Circuit Breakers
2) Station Re-investment
3) Power Transformers
4) Other Power Equipment
5) Ancillary Systems
6) Station Environmental
7) Protection, Control, Monitoring, and Telecommunications
8) Transmission Site Facilities and Infrastructure

7.1 Circuit Breakers

Hydro One replaces circuit breakers under planned conditions using a combination of several factors to give an indication of the asset's EOL. Risk assessment is based on the following general factors for circuit breakers.

1) **Condition** assessment is generally based on data gathered through preventive maintenance or targeted special studies;

2) **Reliability and Performance**: historic performance and comparison of individual breakers against both Hydro One and industry measures in terms of the frequency and duration of

forced outages. Consideration given to performance of like groups of breakers within the Hydro One fleet;

3) **Technical Obsolescence**: unavailability of replacement parts and/or the unavailability of internal and/or external expertise to support the on-going maintenance;

4) **Utilization and Loading:** assessment of breaker nameplate interrupting capabilities against available short circuit current;

5) **Safety and Environment**: replacement of assets with increased risk of staff injury during failure, as well as consideration to frequency and magnitude of SF6 and/or oil leaks.

Capital replacement candidates are further prioritized by giving consideration to criticality of the asset by considering the consequences of failure at both the system level and the customer levels.

7.1.1 Oil Circuit Breakers

The primary factors involved in identifying OCB EOL are as follows:

Condition

- ACA information is obtained through a series of time-based and condition-based preventive maintenance activities including visual inspections, oil sampling, diagnostic testing (breaker timing, coil signature testing, etc.), intrusive maintenance and inspection of wear parts;

Reliability and Performance

- For High Voltage (HV) assets, outage frequency and unavailability are individually measured against fleet performance and industry measures;

- For Low Voltage (LV) assets, individual and fleet reliability assessment is primarily based on historical failures and feedback from preventive and corrective maintenance programs.

Technical Obsolescence

- Significant factor for OCB replacement as many breakers are no longer supported by vendors and aftermarket parts are often not available and/or cost effective.

Utilization and Loading

- Breakers that are utilized in excess or projected to be approaching their interrupting capabilities are replaced with higher-rated equipment.

Impacts of Age and Demographic Pressures

- Large installed base which needs to be managed due to above factors.

Safety and Environmental Risks

- Consideration to known oil leaks as well as PCB end of use deadlines.

These factors are assessed at both the individual asset and population levels to arrive at a list of assets that require risk mitigation. Consideration is given to options of replacement as well as major refurbishment.

Consequences associated with failure of OCBs can be local or system reliability impacts and can include environmental impacts with fire or loss of oil.

7.1.2 SF6 Circuit Breakers

The primary factors involved in assessing SF6 breaker EOL are:

Condition

- ACA information is obtained through a series of time-based and condition-based preventive maintenance activities including visual inspections, breaker diagnostics (breaker timing, coil signature testing, etc.);
- Defect information gathered from corrective maintenance programs.

Reliability and Performance

- For HV assets, distinctly measured individual asset performance as well as fleet performance in terms of frequency and duration of outages;
- For LV assets, individual and fleet reliability assessment is primarily based on historical failures and feedback from preventive and corrective maintenance programs.

Technical Obsolescence

- Significant factor for some first generation SF6 breaker replacements as many breakers are no longer supported by vendors and aftermarket parts are not available and/or cost effective.

Utilization and Loading

- Breakers that have exceeded their expected service life in terms of number of operations are considered for replacement (typical of capacitor and reactor positions).

Safety and Environmental Risks

- Frequency and magnitude of SF6 leaks.

Hydro One is replacing six different types of first generation SF6 breakers in the test years. The specific dominant reasons for replacing the six types of SF6 breakers are as follows:

Type HPL - These breakers are prone to hot spots and overheating on bushings and interrupters. The breakers are prone to SF6 leaks and exhibit excessive wear because they are used as reactor breakers on the Hydro One system. The breaker rating is no longer considered adequate for this application by today's standards.

Type PA - Hydro One has three PA breakers with a unique mechanism that is becoming inoperable, and replacement of the mechanism is not a technically or economically viable option. The replacement of these breakers with the standard types will eliminate concerns from operating small populations of a specific breaker.

Type FC4 and FG4 – The population of these breakers are in poor condition and are performing poorly. The manufacturer no longer supports these types of breaker. Hydro One spare parts inventory is no longer adequate to sustain these breakers.

Type GA - These breakers suffer from major SF6 leaks in both the high and low pressure systems within the breaker, which causes reliability and environmental concerns. These breakers are typically applied as capacitor switching positions and are no longer considered adequate for this application. The GA interrupters are technically obsolete.

Type SP – These breakers have several major design flaws as there are SF6 and pneumatic piping leaks and SF6 interrupter leaks. The air reservoir tank is also prone to rusting and subsequent leaking. The SP interrupters are technically obsolete.

The consequences associated with the failure of SF6 breakers can be local or system reliability impacts both momentary and sustained and can include environmental impacts with loss of SF6.

7.1.3 Metalclad Circuit Breakers

The primary factors involved in assessing EOL of metalclad breakers are as follows:

Health, Safety, and Environmental Risks

- Replacement of poor performing equipment with unacceptable safety consequences if they fail catastrophically;
- First generation metalclad not built to withstand arc-flash hazards.

Technical Obsolescence

- Significant factor for some first generation metalclad breaker replacements as many breakers are no longer supported by Original Equipment Manufacturers (OEMs) and aftermarket parts are not available and/or cost effective.

Reliability and Performance

- Individual and fleet reliability assessment is primarily based on historical failures and feedback from preventive and corrective maintenance programs;
- Typically supply critical load customers in major urban centres.

Condition

- ACA information is obtained through a series of time-based and condition-based preventive maintenance activities including visual inspections, breaker diagnostics (breaker timing, coil signature testing, etc.);
- Defect information gathered from corrective maintenance programs.

The consequences associated with the failure of metalclad breakers are typically local reliability impacts that can be both momentary and sustained and can include health and safety risks associated with arc-flash hazards

Vacuum Circuit Breakers

The primary factors involved in assessing vacuum breaker EOL are:

Technical Obsolescence

- Significant factor for some first generation vacuum breaker replacements as many breakers are no longer supported by Original Equipment Manufactures (OEMs) and aftermarket parts are not available and/or cost effective.

Reliability and Performance

- Individual and fleet reliability assessment is primarily based on historical failures and feedback from preventive and corrective maintenance programs.

Condition

- ACA information is obtained through a series of time-based and condition-based preventive maintenance activities including visual inspections, breaker diagnostics (breaker timing, coil signature testing, etc.);
- Defect information gathered from corrective maintenance programs.

The consequences associated with the failure of vacuum breakers are typically local reliability impacts that can be both momentary and sustained.

7.2 Station Reinvestments

It is common for a number of assets at a station to approach EOL around the same period, and these station-level investments are intended to combine these replacements where synergies exist.

High voltage air blast circuit breakers (ABCBs) and GIS breakers and switchgear are typically replaced within these projects. Guidelines on the EOL identifiers for these two key asset groups are outlined below.

7.2.1 Air Blast Circuit Breakers (ABCBs)

The primary factors in assessing ABCB EOL are the following:

Reliability and Performance

- Historic performance and comparison of industry reliability measures in terms of the frequency and duration of forced outages;
- Consideration given to performance of like groups of breakers within the Hydro One fleet.

Technical Obsolescence

- Unavailability of replacement parts and/or the unavailability of internal and/or external expertise to support the on-going maintenance; applies to breakers themselves and their auxiliary components and HP air accessories.

Safety and Environmental Risks

- Replacement of known at risk assets with unacceptable safety consequences if they fail catastrophically;

- Replacement of live-tank ABCBs with dead-tank SF6 breakers eliminates the free-standing CTs, which are a considerable safety concern considering potential catastrophic failure modes.

The consequences associated with defects and/or failures of ABCBs are significant given they are typically installed at High Voltage (HV) terminal stations with direct impact on major generation customers and general HV network stability.

These factors are assessed at both the individual asset and population levels to arrive at a list of assets that require risk mitigation. Consideration is given to options of replacement as well as major refurbishment. Although capital replacement is Hydro One's preferred option for the ABCB population, demographic pressures require some sustaining OM&A investments to be made as an interim solution until the breakers are replaced.

7.2.2 Gas Insulated Switchgear (GIS)

The primary factors in assessing EOL with the GIS equipment are the following:

Reliability and Performance

- Historic performance and comparison against industry reliability measures in terms of the frequency and duration of forced outages;
- Early GIS designs have very poor performance (breakers, switches and epoxy cone insulators) and represent a significant portion of the GIS population.

Technical Obsolescence

- Unavailability of replacement parts and/or expertise to support the on-going maintenance.

Safety and Environmental Risks

- Replacement of early generation GIS installations with poor SF6 leak performance.

Condition

- ACA information is obtained through a series of time-based and condition-based preventive; maintenance activities including SF6 sampling and breaker diagnostics;
- Defect information gathered from corrective maintenance programs.

The consequences associated with defects and/or failures of GIS are significant given they are typically installed at HV terminal stations with direct impact on major generation customers and general HV network capacity and stability.

7.3 Power Transformers

Hydro One replaces transformers under planned conditions using a combination of several factors to give an indication of the asset's EOL. Risk assessment is based on the following factors for power transformers.

Condition

Assessment is generally based on data gathered through preventive maintenance:

- Oil analysis of main tank, including DGA (dissolved gas analysis), Furanic compounds, and the Standard Oil Test including dielectric strength, acidity, moisture content, interfacial tension, power factor of oil;
- Power Factor (Doble) Testing is an electrical measurement of the insulation system's integrity as well as bushing condition;
- Oil analysis of ULTC to provide indication of dielectric strength and abnormal wear of contacts, etc.;

- Assessment of transformer general condition such as auxiliary components (gauges, fans, pumps, controls), gaskets and seals, radiators, etc.;
- Assessment of ULTC general condition such as motors, driveshafts, auxiliary components (controls, etc.) gaskets and seals, etc.;
- Design limitations of transformers can be further understood through engineering design review studies completed by transformer experts using modern tools not available when the transformers were built;

Reliability and Performance

- Comparison of individual transformers against both Hydro One and industry reliability measures in terms of the forced outage frequency and unavailability;
- Consideration given to performance of design groups of transformers within the Hydro One fleet (i.e. group identical transformers of the same design where problems are likely to repeat).

Technical Obsolescence

- Unavailability of replacement ULTC parts and/or expertise to support the on-going maintenance.

Utilization and Loading

- asset loading against nameplate ratings and overload capabilities; continuous and post-contingency scenarios;
- number of ULTC operations against expected service life.

Environmental Risks

- Frequency and magnitude of transformer oil leaks;
- Consideration to the presence/condition of spill containment and proximity to waterways;
- Consideration to noise emission relative to legislated limits;

- Consideration to PCB end of use deadlines.

These factors are assessed at both the individual asset and population levels to arrive at a list of assets that require risk mitigation. Consideration is given to options of replacement as well as major refurbishment or repair of an asset where the condition of the asset is poor due to reversible damages; assets with irreversible damage are not considered for refurbishment. Power transformer Capital investments are significantly complemented by OM&A programs. Examples include reducing environmental impacts through leak reduction, improve fleet performance of transformers through refurbishment of ULTCs, and 500kV autotransformer risk mitigation.

Capital replacement candidates are further prioritized by giving consideration to criticality of the asset by considering the consequences of failure at both the system level and the customer level.

7.4 Other Power Equipment

Hydro One replaces Other Power Equipment under planned conditions using a combination of several factors to give an indication of the asset's EOL. Risk assessment is based on the following general factors for these assets.

7.4.1 Disconnect Switches and Circuit Switchers

Condition

- ACA is based on information gathered through preventive maintenance and corrective maintenance programs, and targeted special studies with internal technical support groups.

Reliability and Performance

- Individual and fleet reliability assessment is primarily based on historical failures and feedback from preventive and corrective maintenance programs.

Technical Obsolescence

- Unavailability of replacement parts to support the on-going maintenance.

Consideration is given to options of replacement as well as refurbishment of an asset where the condition of the asset is poor due to reversible damages; assets with irreversible damage are not considered for refurbishment. Sustaining OM&A programs exist to mitigate risks that are technically or economically justified when compared to Capital replacement.

The consequences associated with the failure of disconnect switches are typically local reliability impacts that can be either momentary or sustained and can include health and safety risks associated with operating EOL switches. Also, inoperable switches increase maintenance costs and can extend planned outages.

7.4.2 Insulators

Condition

- ACA is based on information gathered through preventive maintenance and corrective maintenance programs, and targeted special studies with internal technical support groups.
- Design/manufacture deficiencies with insulators also drive end of life replacements. These include expansion of the cement that connects metal fittings and the porcelain, and this can cause the porcelain to crack reducing the effective of the insulation.

Reliability and Performance

- Historic performance and comparison against both Hydro One and industry reliability measures.

Safety and Environmental Risks

- Replacement of assets with unacceptable safety risks of catastrophic failure.

Insulator refurbishment is not an option. To maximize efficiency, insulator replacements are typically bundled with other planned work.

The consequences associated with the failure of insulators are local or system reliability impacts that can be either momentary or sustained, and health and safety risks associated with falling insulators/bus.

7.4.3 Instrument Transformers

Condition

- ACA is based on information gathered through preventive maintenance and corrective maintenance programs, and targeted special studies with internal technical support groups (Oil sampling, power factor testing, real time monitoring of secondary voltages, etc.);
- Some targeted ACA are also drawn upon for specific asset groups (i.e. 500kV CT population).

Reliability and Performance

- Individual and fleet reliability assessment is primarily based on historical failures and feedback from preventive and corrective maintenance programs.

Safety and Environmental Risks

- Replacement of assets with unacceptable safety risks of catastrophic failure;
- Compliance with PCB testing requirements and end of use deadlines will significantly drive the program moving forward;
- Consideration given to oil or SF6 leak rates.

The consequences associated with the failure of instrument transformers can be local or system reliability impacts that can be either momentary or sustained, health and safety risks associated with failing equipment, and environmental impacts associated with releasing oil or SF6. There is also the likelihood of collateral damage to other nearby assets (typically circuit breakers or transformer bushings).

7.4.4 Capacitor Banks

Condition

- ACA is based on information gathered through preventive maintenance and corrective maintenance programs, and targeted special studies with internal technical support groups (bulged capacitor cans, damaged fuses, frame corrosion, etc.).

Reliability and Performance

- Historic performance and comparison of performance against both Hydro One and industry measures;
- Individual and fleet reliability assessment is also based on historical failures and feedback from preventive and corrective maintenance programs.

Technical Obsolescence

- Unavailability of replacement capacitors to support the on-going maintenance.

Consideration is given to options of replacement as well as refurbishment of capacitor banks where the condition of the asset is poor due to reversible damages; assets with irreversible damage are not considered for refurbishment. Sustaining OM&A programs exist to mitigate risks that are technically or economically justified when comparing to capital replacement.

The consequences associated with the failure of capacitor banks can be local or system reliability impacts that can be either momentary or sustained, health and safety risks associated with failing capacitors, and environmental impacts associated with releasing oil.

7.4.5 Low Voltage Cable and Potheads

Condition

- ACA is based on information gathered through preventive maintenance and corrective maintenance programs and targeted special studies (infrared scans, visual inspections).

Health and Safety Risks

- Replacement of assets with unacceptable safety risks of catastrophic failure (i.e. Joslyn porcelain terminations installed on capacitor bank cables).

Refurbishment is not a technically viable option for this asset.

The consequences associated with the failure of cable terminations can be local or system reliability impacts that can be either momentary or sustained, and health and safety risks associated with exploding terminations. There is a likelihood of collateral damage to other nearby station assets (typically breaker bushings and capacitor banks).

7.4.6 Surge Arresters

Condition

- ACA is based on information gathered through preventive maintenance and corrective maintenance programs, and targeted special studies with internal technical support groups (infrared scans, visual inspections, etc.).

Reliability and Performance

- Individual and fleet reliability assessment is primarily based on historical failures and feedback from preventive and corrective maintenance programs.

Refurbishment is not a technically viable option for this asset.

The consequence associated with the failure of surge arresters is typically local reliability impact that can be either momentary or sustained, and health and safety risks associated with failing arresters. There is a likelihood of collateral damage to other nearby assets (typically transformer bushings).

7.5 Ancillary Systems

Hydro One replaces Ancillary assets under planned conditions using a combination of several factors to give an indication of the asset's EOL. Risk assessment is based on the following general factors for these assets.

7.5.1 High Pressure Air (HPA) System Components

Condition

- ACA is based on information gathered through preventive maintenance and corrective maintenance programs (i.e. coolant and oil leaks, compressor run time, audible air leaks, etc.).

Reliability and Performance

- Individual and fleet reliability assessment is based on historical failures and feedback from preventive and corrective maintenance programs;
- Performance of the HPA systems are directly tied to the performance of the air blast circuit breakers.

Safety and Environmental Risks

- Replacement of assets with unacceptable safety risks of catastrophic failure.

HPA system components which are identified at EOL are considered against the complementary investments associated with replacement of the ABCBs and investments made at the component level where technically and economically justified.

The consequences associated with the failure of HPA components can be local and system reliability impacts that can be either momentary or sustained, as well as the health and safety risks associated with failing high pressure pneumatics.

7.5.2 Station Service Transfer Schemes

Condition

- ACA is based on information gathered through preventive and corrective maintenance programs.

Reliability and Performance

- Individual and fleet reliability assessment is based on historical failures and feedback from preventive and corrective maintenance programs;
- Some specific manufacturer types such as Merlin Gerin have serious reliability issues and are being replaced due to their poor performance.

Technical Obsolescence

- Unavailability of replacement parts to support the on-going maintenance.

Safety and Environmental Risks

- Replacement of assets with unacceptable safety risks of catastrophic failure; considerations to arc-flash hazards.

The consequences associated with the failure of station service transfer schemes can be both local and system reliability impacts that can be either momentary or sustained, as well as potential safety risks associated with operating EOL transfer schemes (arc flash). There is also a possibility for NERC regulatory fines for not having adequate supply to back-up power supplies.

7.5.3 Batteries and Rectifiers

Condition

- ACA is based on information gathered through preventive maintenance and corrective maintenance programs:
  - battery condition: voltage and impedance measurements, capacity load testing, water consumption, specific gravity, jar and seal leaks, etc.
  - rectifier condition based on output ripple voltage, ability to provide float and equalize currents, component failures, etc.
- Regulatory demands to replace poor-condition assets on the bulk power system.

Reliability and Performance

- Individual and fleet reliability assessment is primarily based on historical failures and feedback from preventive and corrective maintenance programs.

Technical Obsolescence

- Unavailability of replacement parts to support the on-going maintenance in the case of rectifiers.

Impacts of Age and Demographic Pressures

- Review of asset type and age against life expectancy to help manage large installed base.

The consequences associated with the failure of batteries and chargers can be both local and system reliability impacts that can be either momentary or sustained, as well as the possibility for NERC regulatory fines for not having adequate back-up power supplies.

7.5.4 Station Grounding Systems

Condition

- ACA is primarily based on information gathered through station grounding evaluation studies, looking at present and projected fault levels, history of faults, phase arrangement (4-wire or 3-wire), and soil resistivity, station size, urban vs. rural site and adjacent property modifications against industry standards and good utility practice;
- ACA is also based on information gathered through preventive maintenance and corrective maintenance programs.

Safety and Environmental Risks

- Replacement of assets with unacceptable safety risks to Hydro One staff and the public

The primary consequence associated with the failure of the grounding system is health and safety of Hydro One staff and the public during fault conditions. An inadequate grounding system may also result in damage to switchyard equipment, resulting in local and/or system reliability impacts.

7.6 Environmental Systems

Hydro One installs, refurbishes, and replaces transformer oil spill containment systems under planned conditions as deemed necessary. Risk assessment is based on the following factors.

Regulatory Compliance Requirements

- Numerous spill containment systems are regulated by a Certificate of Approval (CofA), issued by the Ministry of the Environment under the Ontario Water Resources Act. The CofA imposes legally binding Terms and Conditions on Hydro One, to operate and maintain these systems, as approved, in order to remain compliant. Additionally, new CofA issued for station drainage works, typically required the installation of new or the upgrading of existing spill containment systems within a 3-5 year period, as a condition of the CofA.

Condition

- Targeted ACA studies on spill containment systems to assess site environmental and geotechnical data, drainage effluent quality, transformer leak records, proximity to receptors, etc.;
- ACA is also based on information gathered through preventive maintenance and corrective maintenance programs (visual inspections, soil/water quality tests, etc.).

Safety and Environmental Risks

- Replacement of spill containment systems which have unacceptable risks and cannot contain oil in the event of a transformer failure.

Hydro One also utilizes a spill risk analysis model to evaluate station-specific spill risks, based on transformer characteristics (i.e. number of transformers, oil volume, likelihood of failure) and potential to cause adverse human health and environmental impacts in the event of a spill. The spill risk analysis is used to identify individual station spill risk levels and provides an initial screening-level prioritization of stations.

The consequences associated with the failure of spill containment systems are health, safety, and environmental impacts associated with the failure to contain oil migration, and increased costs to deal with clean-up and remediation as opposed to repairing early. There is also a potential for punitive fines from regulators.

7.7 Protection, Control, Monitoring, Metering and Telecom

Capital funding for sustaining P&C (including Cyber Security) and telecommunications covers three types of need:

1) **Contain and correct defects that appear in new or mid-life assets:** Occasionally, defects in design, supplied product or installation can be revealed by an anomalous behaviours or events. Some defects can be managed by a revised operating or maintenance procedure. In other cases the asset may need to be replaced or refurbished.

2) **Externally Driven; new compliance requirements or coordination with others:** Under the Market Rules, Hydro One Transmission is required to comply with the NERC Reliability Standards. Since the 2003 blackout, many new standards have been and are being developed. A number of these are applicable to Protection, Control and Telecommunication. For revenue metering Hydro One Transmission is required to meet the requirements of the Electricity Gas Inspection Act enforced by Measurement Canada.

   For facilities that are connecting with other entities such as generators, load customers, or interconnected transmitters, Hydro One may need to replace protection and control facilities at its end of the connection in coordination with replacement plans of the other entity.

3) **Replacement of existing protection, control and telecommunication (PCT) facilities that have reached their EOL.** As this need drives the majority of the expenditures a more complete description of the decision making framework for EOL replacement is provided below.

Hydro One replaces these assets under planned conditions using a combination of several factors to give indication as to the appropriate time to replace the asset. Risk assessment is described within.

Consequences of Protection, Control or Telecommunication Failure

Protection, Control and Telecommunications are essential for the detection and automatic or controlled elimination of abnormal conditions such as short circuits, overloads or overvoltage conditions. The failure or incorrect operation of these systems can result in consequences that range from significant to catastrophic and have direct linkages to Hydro One's business values. A summary of key impacts is provided below.

Safety and Environment: Failure or incorrect operation of a PC&T system could result in electrical safety hazards as well as environmental hazards associated with equipment failure from release of oil or SF6, and hence has clear ties to the safety of Hydro One's employees and members of the public.

Safety hazards associated with power faults resulting from natural events, equipment failure and human error, are all controlled and eliminated through correct operation of the protection, control, and telecom systems. Increasing rates of PCT failure or incorrect operations increase both the frequency and duration of fault exposure to the public and Hydro One staff and the likelihood of environmental release due to catastrophic equipment failure.

System Reliability: Failure or incorrect PCT operation can have both localized and widespread reliability impacts that result in either momentary or sustained issues. Localized consequences can be such things as damaged power equipment requiring repair or replacement, unnecessary fault contributions to a transformer's cumulative EOL, or momentary interruption to transmission-connected customers. Widespread disturbances can also occur from incorrect PCT operation, which causes voltage collapse or system instability.

Loss of PCT systems can result in power system elements being forced and sustained out of service, eliminating redundancy in the supply network paths to customers and in some cases resulting in customer outages. The likelihood of compounding performance issues increases proportional to time and would include constrained thermal and stability limits of the power system and associated interfaces.

Customer Impact: In addition to deterioration in reliability, PCT failure or incorrect operation can expose customers to poor power quality including damaging voltage excursions. Any interruption or damage to a customer's equipment has an impact which is a function of the type of load being supplied. Tolerance for interruptions is understandably different for generation, residential, industrial, and LDC customers. Hydro One's investments are made in part to reduce the likelihood of negative customer impacts.

Financial / Competitiveness: There are both direct and indirect costs to Hydro One associated with the deterioration of PCT systems. Direct costs are more apparent and cover costs associated with things like the repair/replace of PCT components on a demand basis, or the repair/replace of a damaged station asset. An example of an indirect cost would be outage cancellation costs and the need to re-mobilize a crew due to loss of redundancy on a circuit or bus they were working on. Modern digital protections also offer advantages which reduce costs. These include self-diagnosing features which allow for lengthened re-verification cycles and the ability to provide more information on the condition of the assets they are protecting.

Regulatory/Legal: Incorrect PCT operation may subject Hydro One to punitive fines from regulators.

7.7.1 Protection Systems

Protection systems must operate as designed when called upon. If a protection scheme fails to operate correctly when required, the immediate consequences can be severe including both local and potentially widespread system disturbance, collateral equipment damage, and possible injury to workers and the public. Due to the severe consequences of protections schemes becoming unreliable, Hydro One uses a preventive replacement strategy in which protections are planned for replacement in a proactive manner. The planning must ensure a program that is feasible in terms of the available expert resources required to execute it. Consequently, Hydro One includes a 5-year margin in its replacement planning to allow for optimum scheduling and development of required staff expertise and mobilization.

Because of the large number of in-service assets and the unacceptable consequences associated with applying a run-to-failure approach, Hydro One's replacement strategy requires the prediction of EOL for protection systems. For protection systems Hydro One uses a two-pronged approach to do this:

- A macro analysis which statistically simulates population cohort failure rates resulting from varying replacement program rates;
- A Health Index assessment of individual protections schemes to determine priority replacement candidates.

The first is based on expected hard physical failures as predicted by hazard functions. It is used to determine broadly the accomplishment trends required in the protection replacement program taking into consideration realistic constraints on the availability of expert resources to carry out the work. Hydro One has more than 12,000 protection schemes and well over 2500 will be entering the EOL region over the next decade.

The health index methodology is used to determine the specific schemes to be prioritized for replacement. Escalation in maintenance also draws upon the same limited expert resources required to perform the replacement program. The following are key elements of the health index.

Reliability and Performance

- Relay performance relies on quantifiable data based on known failures
- Failures are converted into in-service performance ratings for individual relay types; which is a function of the degree to which observed population failure rates are elevated relative to the expected rates for healthy (i.e. mid-life) relays.

Impacts of Age and Demographic Pressures

Age in itself is not an effective EOL indicator, but age relative to design life can be a leading indicator for predicting future problems. Design life definition is based where possible on information provided by manufacturers or available literature and on Hydro One's failure experiences and engineering assessments.

Solid-state equipment deteriorates with years of service as internal electrical components begin to fail due to thermal effects and chemical changes. Digital equipment is also subject to failure modes of electronic components and also to obsolescence as these technologies are advancing rapidly. Electromechanical relays are more robust, however mechanical parts eventually show wear and tear and deformation due to heat.

Technical Obsolescence

- Availability of spare parts increasingly becomes an issue as equipment ages;
- Spare parts availability becomes a problem after 15 – 30 years of service;
- The process of cannibalizing equipment already removed from service for parts is only a temporary reprieve as these parts are themselves aged;

- Many protection systems were designed in a fashion which no longer meets present standards;
- Earlier versions of electromechanical relays lack many basic protection features that offer better protection to power equipment. IEEE Guides and IEEE Standards for protective relaying systems are used as a guide for comparison. Where the design falls short of these North American recognized standards the protection system may be deemed to be obsolete.

Condition-Based Visual Inspections

- Visual inspection of primary relays can help in identifying deteriorating electromechanical relays;
- The primary deterioration modes identifiable will be silver migration, condition of insulation on wires, calibration drift and general deterioration;
- Visual Inspection provides little information on digital or microprocessor based relays.

7.7.2 Remote Terminal Units (RTUs)

RTUs are considered the most critical element of Hydro One's control systems. Hydro One's decision criteria for RTU replacements are outlined below.

Regulatory Compliance Requirements

- Review of any emerging Market Rule requirements for telemetry and NERC or NPCC requirements for Cyber Security and Monitoring System functionality.

Reliability and Performance

- Calculated performance measure of Mean Time Between Failures (MTBF) for individual RTU types based on known EOL-indicative failures;

- As RTUs approaches EOL they begin showing deficiencies and decreased functionality, leading to component failure and operating out of specification, and ultimate loss of functionality.

Technical Obsolescence

- Some equipment manufacturers have gone out of business or changed their focus such that they can no longer support the RTU equipment in terms of spare parts, software, and field service.
- Hydro One does have limited strategic inventory to support breakdown maintenances as required, but long-term sustainability is dependant on planned replacements. When an RTU is of a make and model for which spare parts are in limited supply, higher priority is given to its replacement.

Impacts of Age and Demographic Pressures

- Age in itself is not an effective EOL indicator, but control systems or sub-components do have design lives that must be considered.
- Age is a factor in predicting future problems. Electronic equipment in particular deteriorates with years of service as internal components begin to fail. As the components age, their original dielectric properties change and they are no longer able to operate within their original design specification.

Consequences of RTU failures are significant, in that the effort required to design and install a replacement is complex and can take up to one year. During the period of replacement (several months), remote operation of the station is impaired or lost and a number of serious consequences need to be managed including difficulty operating the grid and monitoring real time operation relative to NERC operating criteria. RTU failures result in the need to physically staff the station, either continuously or by daily inspections depending on the importance of the station and the functions performed by the failed RTU. Outages to carry out sustainment and development work requires prior assessment for feasibility. This requires knowledge of equipment loading and condition and is impaired if the telemetry from a station is not available. If a second or third RTU were to fail on the network during the same period of time, the consequences would be compounded, as more staff would need to be reallocated to local operating stations and a greater number of planned outages would be affected if not cancelled.

7.7.3 Monitoring Systems

Protection system monitoring devices, including annunciators, digital fault recorders (DFRs) and sequence of events recorders (SERs) are widely deployed in transmission stations to provide detailed information on protection operation. End of life assessments for this equipment is similar to that of protections and controls.

7.7.4 Telecommunication Systems

Telecommunication Systems support protections on transmission lines and connected load or generation stations. They also support critical monitoring and control functions required by the OGCC.

The decision process for telecommunication assets is similar to that of protection assets.

7.8 Transmission Site Facilities and Infrastructure

7.8.1 Major Drainage Systems

The following factors are used to assess the likelihood of defects or asset failure.

Regulatory Compliance

- Numerous drainage systems are regulated by a CofA, issued by the MOE under the Ontario Water Resources Act. The CofA imposes legally binding Terms and Conditions on Hydro One, to operate and maintain these systems, as approved, in order to remain compliant;
- Building codes and safety regulations also drive replacements.

Condition

- Station specific ACA studies on civil assets and geotechnical assessments;
- ACA is also based on information gathered through preventive maintenance and corrective maintenance programs.

The prioritization and ultimate selection of candidate stations for drainage, building upgrades and system refurbishment is based on a review of the consequences of the defect/failure of the asset and the resultant impact on system reliability and health and safety (i.e. back-up flooding, pooling water, unstable ground, etc.).

7.8.2 Fire Protection Systems

The following factors are used to assess the likelihood of defects or asset failure.

Condition

- ACA is primarily based on information gathered through preventive maintenance and corrective maintenance programs (annual tests of the fire detection and deluge systems, defects recommended for repair or replacement to meet Fire Code requirements)

Regulatory Compliance

- Review of preventive and corrective maintenance programs to determine what is needed to meet Fire Code requirement.

The consequences associated with the failure of fire protection systems is typically sustained local reliability impacts, as well as the possibility of health, safety, and environmental impacts if the systems fail to protect. There is a possibility of collateral asset damage in the event of in-operation or mis-operation, as well as possible of regulatory fines for not having adequate fire protection systems.

7.8.3 HVAC Systems

Condition

- ACA is primarily based on information gathered through preventive maintenance and corrective maintenance programs (visual inspections and function tests).

Technical Obsolescence

- Unavailability of replacement parts to support the on-going maintenance.

The consequences associated with the failure of HVAC systems can be local or system wide from loss of protections that can be either momentary or sustained. There is a possibility of collateral asset damage in the event of protection in-operation and a possibility of regulatory fines for not having adequate protection systems.

7.8.4 Civil Works Projects

The following factors are used to assess the likelihood of defects or asset failure.

Condition

- ACA is primarily based on information gathered through preventive maintenance and corrective maintenance programs (visual inspections);
- Main areas of concern are cracked or broken concrete footings, poor access due to roadway issues and minor station flooding which effects both access and proper station grounding.

The consequences associated with the failure of civil systems can include increasing costs to deal with degrading infrastructure as opposed to repairing early, health and safety risks associated with slips trips and falls, standing water, etc.

7.8.5 Security Infrastructure

Hydro One tracks theft of copper and other components/equipment at its transformer stations and assess if the existing deterrents are adequate. The primary factors involved in assessing site security involve:

Health, Safety and Environment

- Unauthorized access results in safety risks to those entering an electrical station environment;

- Theft of copper or other electrical components results in severe safety risks to workers, thieves and increases safety risks to the public near any of the affected stations and transmission line facilities.

Reliability & Performance

- Station equipment reliability is in jeopardy with missing copper grounds and may cause damage to equipment under fault conditions;
- Equipment may have to be removed from service to prevent risk of damage and ensure a safe working environment. This has negative implications on the security of electrical supply.

Financial/Competiveness

- Repair costs are significant to replace copper that has been removed from equipment and station grounding systems. The material removed represents a fraction of the damage that is caused by these actions.

8.0 LINES OM&A – DETAILED DECISION MAKING

8.1 Vegetation Management

The vegetation management program is required to manage natural vegetation found on transmission rights of way, as well as the landscaped plantings common in urban areas.

Information Required to Assess Risk:

- Vegetation growth and proximity to energized lines;
- Brush conditions and height;
- Regulatory requirements, i.e., NERC, Municipal and Provincial Regulations, OHSA;
- Industry practice;
- Restrictions due to environmental considerations;

- Work practices and cost for various right of way conditions.

Consequences from Adverse Impacts:

- Financial / Competitiveness: objective is to optimize long term costs. Costs can increase significantly if clearing and brush control is deferred;
- Regulatory/Legal: NERC non-compliance should vegetation conditions be allowed to deteriorate causing a significant outage;
- Safety & Environment: if trees are left to grow within the proximity of conductors public and worker safety are at risk;
- System Reliability: if trees are left to grow in proximity of conductors lines will be taken out of service due to contact;
- Reputation: if significant tree growth is allowed on rights of way, approval for removals can become challenging resulting in municipal and adjacent landowner resistance, negatively impacting reputation.

Options and Actions

- Optimizing program activities and timing for line clearing and brush control;
- Build program to address local municipal requirements and regulations.

8.2 Overhead Lines

8.2.1 Overhead Lines Preventive Maintenance and ACA

The overhead lines preventive maintenance program provides funding to inspect and maintain the transmission lines system.

Information Required to Assess Risk:

- The likelihood and mode of failures and/or major defects on overhead lines and associated components;

- Historic inspection data and failure rates;
- Condition information from a suite of available inspection and ACA techniques, e.g., foot patrol, helicopter inspections;
- Number of at risk assets requiring monitoring or added maintenance, e.g., salt contamination on insulators;
- Industry practices;
- Data collections requirements to support capital programs;
- Customer considerations.

Consequences from Adverse Impacts:

- Regulatory/Legal: lines are located in the public domain and failures can result in legal or regulatory action;
- Safety & Environment: if lines are not adequately maintained the public is at risk, as are workers;
- System Reliability: defects have to be identified and repaired or they will eventually result in outages and disruption of power to customers.

Options and Actions

- Program inspections, patrols, ACA and maintenance in a cost effective manner to meet objectives;
- Targeted inspections and maintenance based on weak elements of the system, or areas where problems have been identified;

8.2.2 Overhead Lines Corrective Maintenance

Information Required to Assess Risk:

- Defects identified through preventive activities, ACA and studies;
- Feedback from historical preventive and corrective maintenance programs;
- Reliability and performance.

Consequences from Adverse Impacts:

- Regulatory/Legal: lines are located in the public domain and failures can result in legal and regulatory action;
- Safety & Environment: if lines are not maintained the public is at risk, as are workers;
- Reliability: defects have to be repaired or they will eventually result in outages and disruption of power to customers.

Options and Actions

- Correct under OM&A or replace under capital if cost effective;
- Schedule work considering reliability implications, customer implications, property owners and seasonal restrictions;
- Forecast demand and respond as required.

8.3 Underground cables

8.3.1 Underground Cables Preventive Maintenance

The underground cables preventive program provides funding to inspect, test and maintain the underground cable system.

<u>Information Required to Assess Risk:</u>

- The likelihood and mode of failures and/or major defects on the underground lines system;
- Historic inspection data, diagnostics, failures and issues;
- Condition data from a suite of available inspection and ACA techniques, e.g., polarization tests for cathodic protection, jacket test, oil lead detection methodologies;
- Number of at risk assets requiring monitoring or added maintenance, e.g., potheads that may be near highways, cables leaking small quantities of oil;
- Industry practices;
- Data collections requirements to support capital programs.

<u>Consequences from Adverse Impacts:</u>

- Safety & Environment: oil leaks are to be avoided as they will cause damage to the surrounding environment. There is a need to protect the public from safety hazards when digging near cables and prevent damage to cables;
- Reliability: defects have to be identified for repaired or they will eventually result in outages and disruption of power to customers and to downtown areas of major centres in Ontario;
- Financial / Competitiveness: insufficient asset condition and maintenance will result in costly replacements of cables;
- Reputation: inadequate maintenance can result in high impact power outages in the Toronto, Hamilton and Ottawa downtown areas negatively impacting reputation.

<u>Options and Actions</u>

- Program inspections, patrols, ACA, cable diagnostics maintenance in a coordinated and cost effective manner to meet objectives;
- Targeted inspections and maintenance based on weak elements of the system or areas where problems have been identified;
- Information and data management plan.

8.3.2 Underground Cables Corrective Maintenance

Information Required to Assess Risk:

- Defects identified through preventive activities, ACA, diagnostics and studies;
- Feedback from historical preventive and corrective maintenance programs;
- Reliability and performance.

Consequences from Adverse Impacts:

- Regulatory/Legal: cables are located in the public domain and failures can result in legal or regulatory action;
- Safety & Environment: if cables are not adequately maintained the public is at risk, as are workers and there is a risk of an oil spill;
- System Reliability: defects have to be identified and repaired or they will eventually result in outages and disruption of power to customers;

Options and Actions

- Correct under OM&A or replace under capital if cost effective;
- Schedule work considering reliability implications, customer implications, property owners and restrictions;
- Forecast demand and respond as required.

9.0 LINES CAPITAL – DETAILED DECISION MAKING

9.1 Overhead Lines and Components

The following provides details on the end of life determination for the primary components that make up a transmission line.

9.1.1 Wood Poles

The following factors are used to assess the likelihood of defects or asset failure.

Condition

- Determined and rated based on data gathered from the preventive and corrective maintenance programs.

System Reliability

- Number of historical forced outages are a consideration;
- Customer impacts and duration are a consideration in programming.

Health, Safety & Environment

- Wood structure failures result in risks to the public and to workers.

Wood pole or wood arm failures create a significant hazard for the public as energized conductor generally come close to the ground upon failure. As well, reliability suffers when poles or arms fail. Outages can be of an extended duration due to difficult access.

End of life is primarily determined based on the condition of the wood arm and poles. Scheduling and urgency for replacements considers public exposure, history of failures and system configuration, i.e., radial lines receive higher priority for replacement than redundant supply.

9.1.2 Steel Towers

The following factors are used to assess the likelihood of defects and manage the life cycle of this asset class.

Condition

- Condition of towers is determined through patrols and detailed corrosion assessment. Towers are rated based on the degree of corrosion.

Financial /Competiveness

- The condition of the protective coating drives tower refurbishment and coating;
- Optimum time from a life cycle cost is to coat when there remains a small amount of coating without metal loss;
- Reinstating the protective coating presents the lowest life cycle cost. If not done, towers would have to be replaced at some time in the future at a high cost and in most cases with a significant customer and system impacts as a result of outage requirements.

Utilization

- Corrosive environments are assessed first and monitored more closely.

The consequences of not reinstating the protective coating would result in continued deterioration of the condition of Hydro One towers requiring higher costs in the future to replace or repair towers. Reliability is not a major consideration in determining the end of life of the coating, but if not reinstated, uncontrollable tower failures would result thereby jeopardizing reliability.

9.1.3 Phase Conductor

The following factors are used to assess the likelihood of defects or asset failure.

Condition (Aluminum Conductor Steel Reinforced)

- Conductor samples are removed from a line to determine degree of deterioration of the steel core and the condition of the aluminum wires. Wires are rated for ductility and tensile strength is determined;
- Conductor defects, e.g., overheating of splices are also taken into consideration;
- Existing line clearances as they relate to the conductor rating are a consideration in the final solution.

Health, Safety & Environment

- Should transmission conductors start to deteriorate to unacceptable levels, failures can occur at multiple locations thereby creating unacceptable safety risks to the public and workers.

Reliability/Customer

- Number of forced outages are a consideration.

Utilization

- Corrosive environments are given priority for testing and monitoring;
- Design ice loading and thermal loading also impacts the decision to replace.

Consequences include reduced reliability of line if conductor is allowed to deteriorate to such a condition that failures can occur at multiple locations. Similarly this will result in safety hazards to the public and workers.

EOL is determined to ensure the condition does not reach extreme situations noted above. If the remaining tensile strength is below the CSA threshold for operating conditions experienced by the conductor, or the ductility of the steel wires is reduced below a certain threshold, the conductor is deemed to be at end of life.

Phase conductor investment decisions are based primarily on conductor condition and line section performance.

9.1.4 Shieldwire (Galvanized Wire)

The process to establish the end of life of shieldwire is similar to conductor.

9.2 Underground Cables

Hydro One's capital investment decision on underground cables are based on several factors taking into account condition, reliability, equipment design deficiencies, operating history and HS&E considerations. Hydro One's EOL assessment criterion is summarized below:

Condition

- Determined based on data gathered from the preventive and corrective maintenance programs:
    - Condition of protective covering
    - DGA analysis on oil-filled cables
    - History of oil leaks
    - Defects found on cable accessories (potheads, joints, bonding, etc.)
    - Insulation testing as opportunity allows in conjunction with other work
    - Condition of backfill

Reliability/Customer

- Considers the number of forced outages and the cumulative number of electrical faults.

Utilization

- Consideration is given to historical continuous and peak loading as it affects condition and reliability.

Health, Safety and Environment

- Stray current;
- History of oil leaks;
- Reduction of slip, trip, fall hazards in Hydro One's facilities.

Hydro One uses a health index approach to assess the overall operating condition of a cable. Information collected through preventive maintenance programs, diagnostic investigations, reliability and performance, and site conditions are inputs for the health index.

EOL is usually determined by irreversible damage to one of the key components of the cable, i.e., the insulation, the sheath which is the outer metallic cover for low pressure oil pipe type cable, or corroded pipe beyond repair on high pressure systems. Performance is another consideration. If a cable fails twice in a relatively short time frame, the insulation is suspect and the cable is scheduled for replacement as these facilities must deliver a high degree of reliability

SUMMARY OF CAPITAL EXPENDITURES

1.0 SUMMARY OF CAPITAL BUDGET

The proposed capital expenditures result from a rigorous business planning and work prioritization process that reflects risk-based decision-making to ensure that the appropriate, cost-effective solutions are put into place to meet Hydro One Transmission objectives. These processes are described in detail at Exhibit A, Tab 12, Schedules 1 to Schedule 6.

The capital expenditures proposed in this filing represent investments that will ultimately become in-service capital assets supporting the Hydro One Transmission business. Specifically, these expenditures include:

a) design and development of specific assets providing future economic benefits;
b) purchase, construction and commissioning of specific assets providing future economic benefits;
c) additions to specific assets; and
d) betterments that result in improvement of capacity, efficiency, useful life span, or economy of specific assets.

As described in the following schedules of this Exhibit, the proposed capital programs address Hydro One Transmission's integrated set of asset replacement and expansion needs to meet its objectives of: public and employee safety; maintenance of transmission reliability at targeted performance levels; meeting system growth requirements; compliance with regulatory requirements (such as specified within the Transmission System Code); environmental requirements; and Government direction. The development of these capital programs is based on comprehensive asset condition information, system loading versus capacity information and various studies.

Hydro One Transmission's capital budget is grouped into four different investment categories: Sustaining, Development, Operations, and Shared Services Capital. Table 1 provides a summary of Hydro One Transmission's capital expenditures for the historical, bridge and test years.

Table 1
Summary of Transmission Capital Budget ($ Million)
Including Capitalized Overheads and AFUDC

Description	**Historic**			**Bridge**	**Test**	
	2007	**2008**	**2009**	**2010**	**2011**	**2012**
Sustaining	210.0	280.4	300.0	308.3	424.0	443.4
Development	272.6	310.9	516.2	537.9	617.2	456.8
Operations	4.7	23.1	20.0	10.1	44.3	57.4
Shared Services Capital	72.2	89.8	81.5	73.6	66.3	50.6
TOTAL	**559.5**	**704.2**	**917.8**	**930.0**	**1,151.8**	**1,008.3**

The Transmission Capital requirements have grown over the 2010 to 2012 period to address asset replacement and refurbishment needs of our aging system, and to expand the system for the purposes of load growth, accommodating a modified generation mix, and expanding access to interconnected electricity markets.

Investment Summary Documents in support of capital projects with cash flows in excess of $3.0 million in either 2011 or 2012 are filed at Exhibit D2, Tab 2, Schedule 3.

2.0 SUSTAINING

The Sustaining capital program includes the costs for investments required to replace or refurbish components to ensure that existing transmission system facilities function as originally designed. Hydro One Transmission manages its sustaining program within two program categories, namely stations and lines. Details of the expenditures under this program are provided at Exhibit D1, Tab 3, Schedule 2.

3.0 DEVELOPMENT

The Development capital program consists of the investments required to upgrade or enhance transmission system capabilities to address load growth, generation connection requirements and transmission congestion, and to ensure that the system is designed and operated in a safe, secure and reliable manner. Details of the expenditures under this program are provided at Exhibit D1, Tab 3, Schedule 3.

4.0 OPERATIONS

The Operations capital program represents investments in infrastructure required to sustain the Central Transmission Operations function, which is operated from Hydro One's Ontario Grid Control Centre. Details of the expenditures under this program are filed at Exhibit D1, Tab 3, Schedule 4.

5.0 SHARED SERVICES AND OTHER CAPITAL

Shared Services capital consists of the sustainment and enhancement of existing equipment and infrastructure, including computer-related hardware and software, facilities and transport and work equipment, as well as projects initiated to improve business support functions. Shared Services investments are described in detail at Exhibit D1, Tab 3, Schedules 5 through 9.

6.0 COMPARISON OF CAPITAL COSTS TO BOARD APPROVED

Table 2 provides a comparison between the 2009 actual capital expenditures and the 2009 expenditures approved by the Board in their Decision on Hydro One Transmission's previous application in Proceeding EB-2008-0272.

Table 2
2009 Board Approved versus 2009 Actual Capital Expenditures

Capital Category	2009 Board Approved ($ million)	2009 Actuals ($ million)	Variance ($ million)
Sustaining	279.9	300.1	20.3
Development	545.9	516.2	(29.7)
Operations	18.2	20.0	1.8
Shared Services	92.4	81.5	(10.9)
Total	**936.5**	**917.8**	**(18.7)**

Hydro One Transmission's capital expenditures in 2009 were approximately $19 million lower than the level approved by the Board due to the following offsetting work program factors:

- Additional Sustaining program effort in order to meet NERC cyber-security requirements, as well as Protection and Control system reliability improvement priorities, partially offset by reallocation of Station Reinvestment program funding. In addition, during 2009 there was a major 230 kV line failure north of Lake Superior that required above normal restoration expenditures.

- The Development program is under spent primarily due to delays in the new 500kV Bruce to Milton Double Circuit Line project approval and the Woodstock Area Transmission reinforcement due to land acquisition issues.
- Shared Services actual capital expenditures were lower than approved primarily due to lower Facilities and Real Estate spending related to a delay in the timing of the head office leasehold improvements compared with EB-2008-0272.

Table 3 provides a comparison between the 2010 projected capital expenditures and the 2010 expenditures approved by the Board in their Decision in Proceeding EB-2008-0272.

Table 3
2010 Board Approved versus 2010 Projected Capital Expenditures

Capital Category	**2010 Board Approved** ($ million)	**2010 Bridge Year** ($ million)	**Variance** ($ million)
Sustaining	321.6	308.3	(13.3)
Development	642.3	537.9	(104.4)
Operations	28.9	10.1	(18.8)
Shared Services	64.9	73.6	8.7
Total	**1,057.6**	**930.0**	**(127.6)**

Hydro One Transmission’s projected capital expenditures in 2010 are $128 million below the expenditure levels approved by the Board in EB-2008-0272 due to the following work program factors.

- The Sustaining program is under spent due to delays in line refurbishment and station reinvestment projects;
- The Development program is under spent primarily due to delays in the new 500kV Bruce to Milton Double Circuit Line project approval as well as the reassessment of the timing of required projects in light of system conditions and/or customer requirements e.g. Static Var Compensator at Mississagi TS.

- The Operations program is under spent due to an intentional slowing down of some programs and delays to projects in order to re-assess their scope and priorities in the face of major emerging new requirements associated with the green energy initiatives such as distributed generation and Smart Grid and the future evolution of NERC Cyber Security requirements.
- An increased Shared Services capital program due to the increase in Facilities and Real Estate spending for head office improvements including replacement of end of life furniture systems and additional investments required to secure leased administrative office space; greater Information Technology costs primarily related to a new Enterprise GIS Strategy and an increased Minor Fixed Asset Program; and, increased Transport and Work Equipment spending driven by the planned work program levels. Increases are partially offset by lower Cornerstone capital spending.

7.0 STATUS OF NIAGARA REINFORCEMENT PROJECT (NRP)

As of the summer of 2006, completion of the project has been indefinitely delayed due to unforeseen circumstances which are out of the control of Hydro One Transmission. Expenditures to date are $99 million.

In its Decision with Reasons in EB-2006-0501, the Board "decided to allow Hydro One Transmission to expense – rather than capitalize – the AFUDC associated with the project based on the actual expenditures made to date, effective January 1, 2007 with no explicit time limit as it remains uncertain when the Caledonia dispute will be resolved". As a result, through the current Ontario Uniform Transmission Rates, Hydro One is recovering the AFUDC associated with NRP. Hydro One Transmission is continuing to apply this OEB directive and as such the AFUDC associated with NRP has been included in the 2011 and 2012 Revenue Requirement (as referenced in Exhibit E1, Tab 1, Schedule 1).

In its EB-2006-0501 Decision, the Board also stated that "if Hydro One requires additional relief prior to the project being completed and in-service, it is free to bring an application seeking such further relief". Hydro One Transmission remains hopeful that at some point it will be able to complete the NRP and is not seeking further relief at this time.

SUSTAINING CAPITAL

1.0 INTRODUCTION

Sustaining capital investments are required to refurbish or replace transmission system components which are at end of life ("EOL") for technical or economic reasons. These investments sustain existing transmission system facilities so that they function at required levels of performance. All of the required investments covered under sustaining capital will contribute to ensuring that the overall reliability of the system is maintained at the existing level and that all reliability, legislative, regulatory, environmental and safety requirements are met.

Sustaining capital expenditures manage risks associated with the fleet of aging transmission assets. Spending requirements are driven by the asset needs at the time, taking into account the number of assets determined to be in need of refurbishment or at EOL based on age demographics, condition data, reliability and performance information and cost.

Hydro One Transmission manages its sustaining Capital program by dividing the investments into two categories:

- Stations, which funds the capital investments required to refurbish/replace existing power equipment and other assets located within transmission stations and existing protection and control, and telecommunication assets that have reached end of life, and
- Lines, which funds the capital investments required to refurbish/replace existing assets associated with overhead and underground transmission lines that have reached end of life.

2.0 SUSTAINING CAPITAL SUMMARY

The rigorous investment planning, prioritization and approval process described in Exhibit A, Tab 12, Schedules 4 to 6, respectively, has been completed for all Sustaining Capital programs to ensure that assets are managed prudently while meeting customer, operational and regulatory needs.

Exhibit C1, Tab 2, Schedule 2 contains a detailed description of the transmission assets and an outline of the sustainment investment structure. Furthermore, Exhibit D1, Tab 2, Schedule 2, provides asset demographics, asset performance data and outlines the decision process that underlies the sustaining investments.

Over the long term, an adequately maintained transmission system that performs to a level of its original design is in the best interest of Hydro One and its customers. As outlined in Exhibit D1, Tab 2, Schedule 1, Section 2, a greater portion of Hydro One's transmission system is reaching an age where the deterioration of condition is taking place at an increasing rate. This will place added cost pressures to respond to an increasing number of end of life assets in the future. Capital expenditures proposed in this exhibit address the needs identified in the test years and do not address expected increases in future volumes of work which will continue as a result of the aging asset base. It must also be recognized that any reductions applied to the test years spending will have a compounding effect on cost pressures in the future, both in capital replacements and corrective maintenance.

The required funding for stations and lines for the test years, along with the spending levels for the bridge and historical years is provided in Table 1 below.

Table 1

Sustaining Capital ($ Millions)

Description	Historic Years			Bridge Year	Test Years	
	2007	**2008**	**2009**	**2010**	**2011**	**2012**
Stations	142.7	223.9	224.1	241.8	337.3	357.0
Lines	67.2	56.5	76.0	66.6	86.7	86.5
Total	**210.0**	**280.4**	**300.1**	**308.3**	**424.0**	**443.4**

The overall Sustaining Capital investment for the test year 2011 is about 38% greater than the 2010 bridge year. This is primarily due to increases in Station Re-investment projects necessary to maintain reliability and performance. Many of these facilities have been identified as either in poor condition and at end of life, or obsolete with no spare parts available as explained further on in the exhibit. Other power equipment spending has increased due to regulatory PCB compliance requirements and increased replacement of EOL high voltage disconnect switches. Protection and Control Programs replacement spending has also increased due to the components identified to be at end of life or obsolete with no spare parts available. Increases in the lines programs are attributed to a requirement to replace two significant lengths of 115 kV underground oil filled cables in downtown Toronto that serve critical load; and, these added expenditures are somewhat offset with a lower investment in overhead lines replacement.

The test year spending increases over historic years are attributed to a need to address an aging fleet of assets that are now deemed to be at end life and a greater emphasis on station security to prevent unauthorized access and theft, primarily copper. In addition to work identified above, the 2011 and 2012 programs include the replacement of a greater number of power transformers that are at a high risk of failure and breakers to maintain reliability. As well, replacements in ancillary equipment have increased that are needed to maintain a secure AC/DC power supply at specific transformer stations to ensure operation of protections and breakers and other equipment as required.

Reduction in the Sustaining capital funding would have impacts in a number of areas:

- There would be a marked reduction in reliability and equipment performance at specific transformer stations as a result of the likelihood of transformer failure, inoperable breakers and switches, and reduced reliability of station power.
- Risk of non-compliance with Ministry of Environment regulations concerning adequate drainage and oil spills, and citations for inaction in response to Environment Canada PCB regulations. These would be in addition to the environment risks that the company faces.
- Late response to aging infrastructure would significantly elevate risks in protection and control that could result in wide spread power disruptions should these critical elements of the power system start to fail. A similar situation applies to several classes of breakers that are aging and do not have support for spare parts.
- There is a risk of non-compliance with NPCC and NERC regulations that require secure facilities for connection to the north east power grid. Protections are critical in this regard and if reliability cannot be maintained, Hydro One Transmission risks citations and fines.
- There will be an increase in power outages to lines facilities due to failure of wood poles, insulators and other components that make up the lines system. These facilities are located in the public domain and as such need to be kept in a state of good repair to adequately manage public safety and to maintain customer and system reliability.

3.0 STATIONS

Transmission Station facilities are used for the delivery of power, voltage transformation and switching, and serve as connection points for both customers and generators. Station facilities contain many of the following components: power transformers, measuring devices, circuit breakers, disconnect switches, bus work, insulators, power cables, surge arrestors, capacitor banks, reactors, station service, grounding systems, site infrastructure and buildings.

Stations Sustaining Capital funding covers capital investments required to sustain existing assets located within transmission stations including protection and telecommunications facilities. Hydro One Transmission manages its Stations Sustaining Capital program by dividing the program into eight categories.

- Circuit Breakers, which funds the capital investments to refurbish or replace circuit breakers that have reached end of life;
- Station Reinvestment, which funds the capital investments to refurbish or replace several station components or systems that have reached end of life at a station at about the same time;
- Power Transformers, which funds the capital investments to refurbish or replace power transformers that have reached end of life;
- Other Power Equipment, which funds the capital investments to refurbish or replace power equipment, other than power transformers and circuit breakers, that have reached end of life;
- Ancillary Systems, which funds the capital investments to refurbish or replace ancillary systems (such as station service systems, grounding systems, air systems etc.) that have reached end of life;

- Station Environment, which funds the capital investments for the installation, replacement and refurbishment of transformer spill containment systems that have reached end of life;
- Protection, Control, Monitoring and Telecommunications, which funds the capital investments to refurbish or replace protection, control, monitoring and telecommunications equipment that have reached end of life;
- Transmission Site Facilities and Infrastructure, which funds capital investments to refurbish and replace station infrastructure (such as station buildings, heating, ventilation, water supplies, sewage, fences, security, fire protection, etc.) that have reached end of life.

Further details concerning changes in spending over historic and bridge year are provided in the remainder of this exhibit.

Required funding for the test years, along with the spending levels for the bridge and historical years are provided in Table 2 for each of these categories.

Table 2

Stations ($ Millions)

Description	Historic Years			Bridge Year	Test Years	
	2007	2008	2009	2010	2011	2012
Circuit Breakers	0.6	11.6	16.6	30.8	23.6	24.9
Station Re-investment	48.9	71.1	34.6	16.8	84.0	84.7
Power Transformers	18.7	40.7	48.7	71.3	63.5	65.7
Other Power Equipment	11.5	9.0	13.1	15.4	19.6	21.2
Ancillary Systems	8.9	9.9	6.0	9.1	18.0	18.1
Station Environment	5.9	6.2	3.0	2.8	8.4	8.5
Protection, Control, Monitoring, and Telecommunications	44.1	55.2	82.0	72.5	93.8	107.5
Transmission Site Facilities and Infrastructure	4.0	20.3	20.1	23.1	26.5	26.4
Total	**142.7**	**223.9**	**224.1**	**241.8**	**337.3**	**357.0**

The overall Stations Capital investment for the test year 2011 is about 40% greater than the 2010 bridge year. This is due to increases in Station Re-investment projects necessary to maintain reliability and performance. Other power equipment costs have increased due to PCB compliance requirements and increased replacement of end of life high voltage disconnect switches. Additional end of life assets have been identified on ancillary systems that need to be addressed to maintain reliability and grounding systems, need upgrading to respond to safety issues and protect equipment from damage. Station environmental costs are increasing as a result of a need to install added oil spill containment facilities to meet Ministry of Environment requirements. Protections and control work is increasing to respond to specific end of life challenges;

telecommunications work is also increasing in order to restore reliable communications between a number of transformer stations which will maintain system operability.

3.1 Circuit Breakers

3.1.1 Introduction

Circuit breakers provide protection to the system under fault conditions, and provide a switching function under normal operating conditions. Hydro One has approximately 4,450 circuit breakers on the transmission system. Programs are developed to manage populations considered at risk due to premature physical deterioration, a decrease in reliability performance and an aging asset base. Hydro One Transmission has circuit breakers from approximately 30 unique manufacturers currently in service. There are over 120 unique breaker types operating on the system. The four main classification/interrupting type of circuit breakers within this program are Oil, Sulfur Hexafluoride (SF6), Metalclad and Vacuum circuit breakers. Generally this program does not include the replacement of Air Blast Circuit Breakers (ABCB) or GIS, as replacements of this type involve a broader scope than just a “one for one” replacement. This being the case, ABCB are replaced on a project basis under Stations Re-investment. Please refer to Section 3.2 of this exhibit.

3.1.2 Investment Plan

In order to effectively manage the circuit breaker replacement programs, data is obtained from numerous sources. Specific maintenance tests have been developed to obtain the data required to determine the condition and the likelihood of failure of circuit breakers. These tests, along with the operating history and application, individual breaker and breaker family performance, asset criticality and demographic data provide the basic information requirements to conduct equipment assessments and determine solutions.

Please refer to Exhibit D1, Tab 2, Schedule 1, Section 7, for details concerning the process to determine replacements for this class of equipment.

Hydro One is planning to replace four categories of breakers as outlined below.

S1: Oil Circuit Breakers (OCB)

Hydro One is managing a population of over 2,000 oil circuit breakers that are no longer manufactured and therefore no spare parts are available, other than those salvaged from other units removed from service. The reasons for replacing oil circuit breakers are to manage a large population of obsolete breakers that in some cases cannot be repaired and therefore impact on Hydro One Transmission's ability to supply reliable power. Many of these circuit breakers are well beyond mid-life (refer to Exhibit D1, Tab 2, Schedule 1, Section 2) and as they age, they will further deteriorate, creating untenable conditions in keeping this class of equipment in service in a reliable condition. The program focuses on the older breakers at short circuit levels beyond their design capabilities and poor performing breakers that are in poor condition. Capital spending for the test years 2011 and 2012 equals \$6.9 million and \$7.9 million respectively and will result in 34 OCB's being replaced.

S2: SF6 Circuit Breakers

Hydro One is replacing six designs of SF6 Circuit breakers during 2011 and 2012. These breakers need to be replaced, as there is a shortage of spare parts to maintain them, there is an inability to control SF6 leaks and the breakers do not adequately handle the required duty cycle imposed by capacitor switching, resulting in greater repair costs and frequency of maintenance. Capital spending for test years 2011 and 2012 equals \$13.2 million and \$13.4 million respectively which will result in the replacement of 68 SF6 circuit breakers.

Other Projects and Programs

Hydro One Transmission is removing one design of Metalclad breaker and one design of Vacuum breaker from its system in 2011 and 2012. These designs are no longer supported by the manufacturer and spare parts are not available. This being the case, and should one of these breakers fail, customer reliability is at risk with extended outage durations. In total 28, breakers are planned for replacement during the test years. As well, the circuit breaker program funds demand costs to replace failed units.

Total capital spending for these other projects and programs for the test years 2011 and 2012 equals $3.5 million and $3.6 million respectively.

3.1.3 Summary of Expenditures

The spending level for test year 2011 is $23.6 million, which is a 23% decrease over bridge year 2010. The spending level for 2012 is $24.9 million which is an increase of 5% over test year. The increase in spending between 2011 and 2012 is attributed to an increase in the number of breakers being scheduled for replacement during 2012.

A reduction in this program will see an increase in corrective maintenance in order to keep these obsolete breakers in service. In addition, breaker performance will suffer, jeopardizing customer reliability. Currently Hydro One Transmission’s breaker performance is below the average CEA performance measures, and reductions in this program will further remove Hydro One Transmission’s performance from that of other Canadian Transmitters. Refer to Exhibit D1, Tab 2, Schedule 1, Section 3, for a comparison with CEA utilities.

Table 3 below provides a list of those circuit breaker programs that exceed $3.0 million in either of the test years and additional details for these programs are provided in the Investment Summary Documents in Exhibit D2, Tab 2, Schedule 3.

Table 3

Circuit Breakers
Capital Projects > $3 Million in Test Year 2011 or 2012 ($ Millions)

Ref #	Description	Cash Flow Test Years 2011	Cash Flow Test Years 2012	Total Cost	Removal Cost	Capital Cost
S1	2011/2012 Oil Circuit Breaker Replacement Program	7.7	8.8	16.5	1.7	14.8
S2	2011/2012 SF6 Breakers	14.6	14.8	29.4	2.9	26.5
	Other Projects/ Programs < $3M	3.9	4.0	7.9	0.8	7.1
	Total Cost	**26.2**	**27.6**	**53.9**	**5.4**	**48.5**
	Removal Cost	**2.6**	**2.8**	**5.4**		
	Capital Cost	**23.6**	**24.9**	**48.5**		

3.2 Stations Re-investment

3.2.1 Introduction

Older stations typically contain a number of components that reach EOL at about the same time. Efficiency gains are achieved in many cases by replacing all such components within the station as part of the same project. This practice 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 are removed from service. This approach is found to be economical due to the more efficient utilization of staff and equipment, and the ability to better co-ordinate planned outages. Stations re-investment work complements individual component replacement programs, such as circuit breakers, power transformers, and other power equipment as described in Sections 3.1, 3.3, and 3.4 respectively.

Station Re-Investment projects and the individual power equipment replacements noted above are coordinated with Development projects, and all work is planned and carried out in an efficient and integrated manner.

3.2.2 Investment Plan

Investment decisions are based on historical information, maintenance reports, and detailed asset condition information. In addition, the implementation of newly-developed asset strategies, data from asset surveys, diagnostic tests, station criticality and recent findings from new technologies are also factored into investment decisions. All critical components within a station are assessed against required functionality, condition, performance, safety and environmental impacts. The required work is then combined in the most economical manner.

The following projects make up the 2011 and 2012 Station Re- Investment program.

S3: Greater Toronto Area (GTA) Metalclad Circuit Breaker Replacement

The Toronto Hydro Electric System Limited (THESL) and Hydro One Transmission share a number of indoor stations in the GTA and each own metalclad breaker arrangements at these stations. The THESL and Hydro One Transmission breakers are electrically connected and function in series. These metalclad breakers are aging, with thirty one (31) of the 100 Hydro One Transmission metalclad breaker arrangements in the GTA currently exceeding the manufacturer's recommended life expectancy of 40 years. THESL and Hydro One Transmission have commenced a program to replace the EOL metalclad breaker lineups over the next 10 years. EOL is based on age, parts availability, reliability and safety considerations. Expenditures for test years 2011 and 2012 are $10.5 million and $10.7 million respectively, which will result in the replacement of 4 metalclad line ups.

S4: Beck #1 Switching Station (SS): Air Blast Circuit Breaker (ABCB) Re-Investment

Beck #1 SS facilitates bulk power transfers on the 115 kV network and connects about 560 MW of hydroelectric generation at Beck #1 Generation Station. The work includes replacing six English Electric (EE) type ABCB's that are 56 and 52 years old. The original breaker manufacturer is no longer in business. Technical support and spare parts are no longer available. Also included is the replacement of four end of life 115 kV SF6 breakers, as well as replacement of 32 high voltage switches, two high voltage ground switches, and 12 high voltage instrument transformers. This investment will enable a staged demerger of all Hydro One assets from the Beck 1 station powerhouse. Expenditures for test years 2011 and 2012 are $25.5 million and $20.6 million respectively.

S5: Abitibi Canyon Switching Station (SS) and Pinard TS - Replace EOL Components

Abitibi Canyon SS facilitates 350 MW of hydraulic generation and bulk power flows on the 230 kV and 115 kV networks. The 115 kV breakers at Abitibi Canyon SS are 62 years old and have proven to be poor performers. Furthermore, the sole provider of spare parts for these breakers has indicated that they no longer support the breaker type. In addition to the breakers, the insulation systems, switches, protection and control facilities, foundations and ancillary systems have all reached end of life. An asset condition and risk assessment has determined that the five 115 kV OCB's at Abitibi Canyon SS have reached end of life and have been prioritized for replacement with new SF6 breakers. In addition, investments are required to fully de-merge the integrated control, metering, relaying, annunciation and ancillary systems for both the 230 kV and 115 kV systems as well as build a new breaker diameter at Pinard TS. Expenditures for test years 2011 and 2012 are $10.3 million in each of the test years.

S6, S7, S8, S9, S10 : Air Blast Circuit Breaker (ABCB) Re-Investments

The type of ABCB's planned for replacement is the worst performing breakers in the system.. This family of breakers is not produced anymore and there is no support for spare parts. The breakers planned for replacement have been problematic and are at end of life based on performance and obsolescence. Replacements in the test years are planned at Nanticoke TS, Orangeville TS, Richview TS, Pickering A switchyard and Hanmer TS. In total, these projects will address 58 ABCB's. The replacements will include the removal of the air systems, as the breakers will be replaced with an SF6 type and will also include the replacement of adjoining equipment determined to be at end of life. Expenditures at all five stations total $31.4 million for test years 2011 and $32.7 million for test year 2012.

S11: Merivale GIS

Merivale TS facilitates bulk power transfers on the 230 kV network between Cherrywood TS and Hawthorne TS. Merivale TS contains some early vintage (31 years old) Gas Insulated Switch bus duct runs that are known poor performers and are at end of life. This investment is required to address the EOL condition of the GIS bus ducts and the associated assets. Work will include the replacement of all bus components including switches and insulators. Expenditures for test years 2011 and 2012 are $6.3 million and $6.4 million respectively.

S12: NRC TS EOL Replacements

This investment is required to replace the non-standard 115 kV and 14 kV switchyard portions of National Research (N.R.C) TS and other station components to address several issues associated with older equipment that affect the operability and reliability of this station. Both transformers are supplied off the same bus with only one disconnect switch for isolation, therefore when a transformer protection operates, both transformers are taken out of service. Service cannot be resumed until the faulted equipment is physically isolated. This investment will mitigate the condition and reliability risks around the two transformers built in 1957 with EOL spill containment systems, five LV breakers in excess of their interrupting capabilities, and associated LV switchgear, instrument transformers, surge arresters, and structures. Spending for the test year 2012 is $ 4.0 million.

3.2.3 Summary of Expenditures

The spending level for test year 2011 and 2012 is $84.0 million and $84.7 million respectively. This represents a substantial increase from 2010 as well as an increase over the historic years. The increases are the result of the need to replace a greater number of end of life equipment with projects that have a larger scope, predominantly air blast circuit breakers (ABCB) and gas insulated switch (GIS) bus. Expenditures in Stations Re-investment are highly dependent on the type and magnitude of specific projects carried out each year, as such there can be significant variations from one year to the next.

Specific projects that include ABCB replacements include Beck #1 SS, Nanticoke TS, Orangeville TS, Richview TS, the Pickering A switchyard and Hanmer TS. All of these are important stations and are showing reduced breaker reliability with limited or no spare parts, and should one of the breakers fail without ability to repair, the system would be in a precarious state with risk of bottling large amounts of generation and/or loss of customer supply. As well, Hydro One Transmission’s breaker performance is substantially worse when compared to other Canadian transmitters as identified in Exhibit D1, Tab 2, Schedule 1, Section 3. This further demonstrates that this type of equipment is problematic and action needs to be taken so that Hydro One Transmission can provide a level of reliability that is similar to its peer group.

Furthermore, the Merivale TS GIS bus project is required to replace end of life GIS bus that has had a number of failures and jeopardizes local supply in the Ottawa area and transfer capability from generation to load customers.

Station Re-Investment capital investment programs requiring in excess of $3 million in either test year 2011 or 2012 are provided in Table 4 below. Additional details for these programs are provided in the Investment Summary Documents in Exhibit D2, Tab 2, Schedule 3.

Table 4

Station Reinvestment
Capital Projects > $ 3 Million in Test Year 2011 or 2012 ($ Millions)

Ref #	Description	Cash Flow Test Years 2011	Cash Flow Test Years 2012	Total Cost	Removal Cost	Capital Cost
S3	2011/2012 Metalclad Circuit Breakers Replacement – GTA	11.6	11.9	23.5	2.4	21.1
S4	Beck #1 SS: Air Blast Circuit Breaker (ABCB) Re-Investment	26.2	21.2	47.4	1.4	46.0
S5	Abitibi Canyon Switching Station (SS) and Pinard Transformer Station (TS) - Replace EOL Components	10.9	10.8	21.7	1.1	20.6
S6	Nanticoke TS: Air Blast Circuit Breaker (ABCB) Re-Investment	4.9	0.0	4.9	0.6	4.3
S7	Orangeville TS: Air Blast Circuit Breaker (ABCB) Re-Investment	11.3	11.6	22.9	2.0	20.9
S8	Richview TS 230 kV Switchyard: Air Blast Circuit Breaker (ABCB) Re-Investment	5.7	11.4	17.1	1.7	15.4
S9	Hanmer TS 500 kV ABCB Replacement	9.3	9.5	18.8	1.9	16.9
S10	Pickering A switchyard : Air Blast Circuit Breaker (ABCB) Re-Investment	3.6	3.7	7.3	0.8	6.5
S11	Merival GIS Bus Replacement	7.0	7.1	14.1	1.4	12.7
S12	N.R.C Transmission Station	0.0	4.4	4.4	0.4	4.0
	Total Cost	**90.6**	**91.7**	**182.3**	**13.6**	**168.6**
	Removal Cost	**6.6**	**7.0**	**13.6**		
	Capital Cost	**84.0**	**84.7**	**168.6**		

3.3 Power Transformers

3.3.1 Introduction

In total, Hydro One has 1467 transmission transformers in service. The most common power transformer is the step-down transformer, which converts a transmission level voltage (230 kV or 115 kV) to a lower distribution voltage of less than 50 kV for customer supply. Another type is the autotransformer which connect to high voltage transmission systems such as 500/230 kV and 230/115 kV. Other transformers included in this group are phase shifting transformers, shunt reactors, regulating transformers, grounding transformers and station service transformers.

A complete description of the transformer types can be found in Exhibit C1, Tab 2, Schedule 2, Appendix A.

3.3.2 Investment Plan

Power Transformers are critical for the operation of the electric system. In order to effectively manage the power transformer population, data is obtained from numerous sources which include inspections, diagnostic testing, planned maintenance activities and equipment performance reports, vendor lead time for delivery, industry performance reports and operating and system reports that provide equipment loading.

Transformer replacements and purchases under this program are provided below.

S13, S14, S15: End of Life Transformer Replacements

This program is in place to replace transformers that have reached end of life. Specific maintenance tests have been developed to obtain the data required to determine condition and the likelihood of failure. The results from these tests, in combination with data on the operating history, individual transformer and transformer family performance, equipment criticality and demographic data provide the information required to determine if a unit is deemed to be at end of life and in need of replacement. Further details on the decision process to determine a need for transformer replacement are provided in Exhibit D1, Tab 2, Schedule 1, Section 7.

Hydro One Transmission has identified, that 19 Canadian General Electric (CGE) transformers have a design flaw that cannot be repaired. There have been three transformer failures of this type and Hydro One Transmission has had to place those transformers that are in-service under operating load restrictions to prevent further failures. In addition, a total of 5 transformers have been identified to be at end of life at Richview TS and Leaside TS.

Expenditures for test years 2011 and 2012 are $43.1 million and $43.6 million respectively, which will result in the replacement of 17 power transformers.

S16: Spare Station Service and Power Transformers Purchases

Hydro One Transmission uses a probabilistic approach to determine the number of spare transformer requirements. The analysis considers performance trends of Hydro One Transmission's various power transformer types, as well as the national performance levels supplied by CEA. The analysis also includes lead time for delivery and the number of transformers that are estimated to be damaged beyond repair. The results of the analysis has identified that Hydro One Transmission will require 21 additional spare transformers for the 2011 and 2012 period (9 power transformers and 12 station service) with expenditures for test years 2011 and 2012 of $13.2 million and $13.3 million respectively.

Other Programs and Projects

- The stations service transformer program has been designed to replace transformers that have reached end of life. Station Service transformers step down high primary voltages, i.e., 230 kV, 115 kV, 44 kV, 28 kV and 14 kV to lower secondary voltages of 600/120 volt AC to supply station auxiliary equipment such as battery chargers, transformer tap changers, and heaters. Hydro One Transmission determines which of its 544 station service transformers require replacement based on the results from visual inspections, Dissolved Gas Analysis (DGA) tests and performance history.
- Capital refurbishment of transformers includes replacing or upgrading auxiliaries such as replacing transformer fan sets or coolers. During 2011 and 2012 a number of transformers will be refurbished that are in poor condition with a risk of failure.
- Demand funding required to respond to failed transformers is determined from historic failure rates and expenditures, and is included in this program.

Total capital spending for other projects and programs for the test years 2011 and 2012, equals $7.2 million and $8.8 million respectively.

3.3.3 Summary of Expenditures

The spending level for test year 2011 is $63.5 million, which is a decrease of about 11% over the 2010 bridge year spending. The higher level of spending in 2010 is as a result of a need to replace end of life transformers that have a design flaw as described below. The spending level for 2012 is $65.7 million which is an increase of 3% over test year 2011. The increase in spending between 2011 and 2012 is primarily attributed to variations in specific project costs and escalation.

The primary reason for the increase in test year spending over the historic years is attributed to a greater number of transformers determined to be at end of life through analysis and the decision process, as outlined in Exhibit D1, Tab 2, Schedule 1, Section 7. More specifically, the recent problems with CGE transformers has placed focus on these replacements in order to restore full rating capabilities, which is very important to a number of our LDC customers.

The consequences of reductions in this program will have pronounced effects on customer reliability and will result in failures, as has occurred with the CGE transformers and others in the past. As well, insufficient numbers of spares will put the system and customers at risk as a result of loss of redundancy should a transformer fail without the availability of a spare. In addition, under these conditions maintenance will suffer as planned outage restrictions will have to be placed on equipment remaining in-service. This will result in possible equipment damage, a reduction in service life and possible system outages that will create difficult situations for LDC customers, as they may be required to shift load with possible temporary provisions to maintain customer supply.

Power Transformer capital investment programs requiring in excess of $3.0 million in either test year 2011 or 2012 are provided in Table 5 below. Additional details for these programs are provided in the Investment Summary Documents in Exhibit D2, Tab 2, Schedule 3.

Table 5

Power Transformers
Capital Projects > $ 3 Million in Test Year 2011 or 2012 ($ Millions)

Ref #	Description	Cash Flow Test Years 2011	Cash Flow Test Years 2012	Total Cost	Removal Cost	Capital Cost
S13	Richview TS - Replace EOL Transformers T7/T8	7.0	3.1	10.1	0.9	9.2
S14	Replace EOL CGE Transformers	35.3	38.2	73.5	7.3	66.1
S15	Leaside TS - Replace EOL Transformers T19, T20 and T21	5.2	6.8	12.0	0.6	11.4
S16	Purchase Spare Transformers	13.2	13.3	26.4	0.0	26.4
	Other Projects/ Programs < $3M	7.6	9.2	16.8	0.8	16.0
	Total Cost	**68.3**	**70.6**	**138.8**	**9.7**	**129.2**
	Removal Cost	**4.8**	**4.9**	**9.7**		
	Capital Cost	**63.5**	**65.7**	**129.2**		

3.4 Other Power Equipment

3.4.1 Introduction

In addition to circuit breakers and power transformers, there are other components and system elements that are integral parts of transmission stations. These include disconnect switches, circuit switchers, capacitor banks, surge arrestors, low voltage cables and potheads, instrument transformers and insulators. These components provide over-voltage protection, electrical insulation, metering and protection capability, electrical isolation, and voltage control.

3.4.2 Investment Plan

The data sources detailed below, along with operating history, historic load profile, individual equipment (and family of equipment) performance, asset criticality and demographic data provide the information required to conduct focused condition assessments and determine end of life.

Investments that are included in Other Power Equipment are noted below.

S17: Switch Replacement Program

Switches (high voltage, low voltage and circuit switchers) are used to provide an open connection in an electrical circuit. They can be manually or electrically driven and can be three phase or single phase. There are over 14,000 of these switches of various types and sizes and voltage levels within the transmission system. Replacement information is obtained primarily from visual inspections (current carrying parts, insulators, and mechanism and linkages), and operational tests. In the case of circuit switchers, information is obtained from visual inspections, functional operating tests, control voltage tests, contact wear measurements, micro-ohm tests and the measurements of the motor current during open and close operations.

There has been a marked reduction in performance of this asset category requiring increased replacements to address this aging asset class. Capital expenditures for test years 2011 and 2012 are $5.1 million and $5.2 million respectively, which will replace 83 switches found to be at end of life over the two test years.

S:18 Capacitor Bank Replacement Program

There are over 350 capacitor banks positioned throughout the Hydro One transmission system. They play a vital role in voltage regulation and power factor correction. Replacement information is mainly obtained through visual inspections for bulged, corroded, leaking capacitor cans, frame damage, insulator damage and reactor corrosion. Expenditures for test years 2011 and 2012 are $3.1 million and $3.3 million respectively, which will replace 8 capacitor banks found to be at end of life.

Instrument Transformer Replacement Program

Instrument transformers play a vital role in the operation of the power system. Current and potential transformers are instrument transformers whose role is to provide the intelligence necessary for protective relays to operate properly. They also provide the necessary metering information for system operators at the Ontario Grid Control Centre to dispatch the system in a safe and economic way. Replacement information is obtained from visual inspections (bushing and porcelain, corrosion, external contamination, oil levels), resistance tests, measurements of power factor and capacitance, Dissolved Gas in Oil (DGA) and oil moisture tests. Through the analysis of data collected it has been established that 168 Instrument Transformers are in need of replacement. Expenditures for test years 2011 and 2012 are $2.6 million and $2.7 million respectively

PCB Equipment Replacements

This program addresses the new PCB regulations as they apply to instrument transformer replacements. The smaller class of instrument transformers contain insulating oil without means of testing, and in order to comply with Environment Canada PCB regulations, these must be removed from the system prior to 2015. Replacements in this program have been designed to achieve this. Spending for test years 2011 and 2012 is $1.3 million and $2.3 million respectively and will remove and replace instrument transformers in order to comply with PCB regulations.

Insulator Replacement

Insulators are used in transmission stations for termination of conductors at structures and to support buses or equipment e.g. disconnect switches, circuit breakers, instrument transformers, etc. Station insulators are subject to both electrical and mechanical stresses at the installation point. Insulators are inspected or tested to determine their condition and those that meet end of life criteria are replaced. There are over 220,000 insulators throughout Hydro One's transmission stations. Insulator replacement includes many small projects that address numerous equipment and station insulator types. During 2011 and 2012, plans are in place to replace 2,160 unreliable insulator posts and strings, and cap and pin insulators that are prone to failure, causing outages and possibly equipment damage. Accumulated spending for these smaller projects and programs for the tests years 2011 and 2012 is $4.5 million and $4.8 million.

Low Voltage Cable and Pothead Replacement Program

Many customers are supplied from transmission stations via underground cable. These cables are terminated inside a station via a cable pothead where they then connect to the station bus structure. Cable potheads can leak over time, reducing their dielectric strength resulting in failures. There are over 1,500 cable potheads within the system. Replacement information is obtained via visual inspections and infrared scans. Capital spending for test years 2011 and 2012 are $1.4 million in each of the test years, which will replace 58 cable potheads found to be at end of life.

Surge Arrestor Replacement Program

Surge Arrestors are used to protect transformers from the effects of lightning strikes. They act as an insulator during normal power flow but will discharge high energy power surges as a result of a lightning strike to ground. Hydro One Transmission has over 1,800 surge arrestors within the system. Replacement information is obtained through visual inspections. Planned expenditures for test years 2011 and 2012 are $ 1.4 million and $1.5

million respectively and will replace 29 surge arrestors to protect transformers from damage and reduce equipment outages.

3.4.3 Summary of Expenditures

The spending requirement for test year 2011 is $19.6 million, which is an increase of 27% over the bridge year 2010. The increase in spending is mainly attributed to increases in instrument transformer replacements to comply with PCB regulations and an increased focus on replacing poor performing high voltage disconnect switches. The spending requirement for test year 2012 is $21.2 million, which is an increase of 8% over the test year 2011. The increase is primarily driven by instrument transformer replacements to comply with PCB regulations.

The components under this program are an integral element of the electrical system and must be kept in good repair or other prime elements such as transformers within the electrical system will suffer. The consequences of a reduction in spending on Other Power Equipment would include a continued increase in switch failures, making switches inoperable and resulting in an inability to maintain key elements of the power system, (e.g., transformers and breakers). Reduced maintenance will result in an accelerated rate of deterioration of Hydro One Transmission's aging assets. As well, the insulators planned for replacement are prone to failure and if not addressed will result in power outages and reduced equipment performance. If components such as defective surge arrestors and cable potheads are not replaced, they will negatively affect the performance of the larger equipment, (e.g., transformers and cables) and may also lead to loss of customer supply and equipment damage. Additionally, Hydro One Transmission may face Environment Canada PCB citation of noncompliance should instrument transformer replacements not proceed.

Other Power Equipment capital investment programs requiring in excess of $3.0 million in either test year 2011 or 2012 are provided in Table 6 below. Additional details for these programs are provided in the Investment Summary Documents in Exhibit D2, Tab 2, Schedule 3.

Table 6

Other Power Equipment
Capital Projects > $ 3 Million in Test Year 2011 or 2012 ($ Millions)

Ref #	Description	Cash Flow Test Years 2011	Cash Flow Test Years 2012	Total Cost	Removal Cost	Capital Cost
S17	2011/2012 Station HV Disconnect replacement Program	5.6	5.8	11.4	1.1	10.3
S18	Capacitor Bank Replacement	3.5	3.6	7.1	0.7	6.4
	Other Projects/ Programs < $3M	12.7	14.1	26.8	2.7	24.1
	Total Cost	**21.8**	**23.5**	**45.3**	**4.5**	**40.8**
	Removal Cost	**2.2**	**2.4**	**4.5**		
	Capital Cost	**19.6**	**21.2**	**40.8**		

3.5 Ancillary Systems

3.5.1 Introduction

Ancillary Systems are comprised of high pressure compressed air (“HPA”) systems, station service, oil processing facility, inverters, grounding systems, batteries and battery chargers. These systems provide key services to various station components (breakers, power transformers, protections, controls, and monitoring and infrastructure systems).

3.5.2 Investment Plan

Asset condition information is obtained for the various ancillary systems in order to effectively manage the replacement program. This information, plus asset demographic data and an understanding of the consequence to the system due to the failure, provides the basic information requirements to conduct equipment assessments and determine those assets in need of replacement.

S19: Station Service

Station service systems comprise all equipment necessary to provide AC or DC power to station facilities. The AC station service supplies power for transformer cooling, tap changer control, switchgear heating, battery chargers, HVAC, etc., all of which are essential to the provision of reliable power by the transmission stations and to connected loads. The DC station service supplies power for protection, control and communication systems, which protect and provide remote control of station equipment. In the event of a power supply failure, the station service transfer system is designed to enable the transfer of loads over to the second station service supply. Replacement information is obtained primarily through visual inspections, operating history, and spare part availability. Capital spending for test years 2011 and 2012 are $11.6 million and $11.8 million respectively to replace end of life station service at 18 systems.

Station Battery/rectifier Replacement Program

Circuit breakers, motorized disconnect switches, transformer tap changers, and in particular communication, protection, and control systems in transmission stations must have a guaranteed source of power to ensure they can operate under all system conditions, particularly during fault conditions. All Hydro One’s transmission stations are provided with at least one DC system, comprising a battery, battery charger, and a DC distribution system made up of DC breakers, fuses and associated cable distribution system. Battery systems designated as Station batteries supply all protection and control and other station ancillary DC services while Telecom designated batteries supply communication system DC requirements at selected stations.

Replacement information is obtained through visual inspections (battery cells, trays, racks, plate condition, connections, and jar seals), electrolyte level and specific gravity, impedance tests, voltage tests, equalize charge tests, battery load test, and battery discharge duration, functional tests (calibration check and alarm), charger volt and amp readings, DC float and DC output test. Capital spending for test years 2011 and 2012 are \$2.7 million for each of the test years to replace 49 end of life battery/rectifier systems.

Station Grounding System Program

Grounding systems are designed to ensure safety of personnel and equipment in and around transmission stations. Grounding systems provide a means of ensuring a common potential between metal structures and equipment accessible to personnel so that hazardous step, touch, mesh and transferred voltages do not occur. In addition, effective grounding systems limit the damage to equipment during faults or surges and they ensure proper operation of protective devices such as relays and surge arresters. Replacement information for grounding systems is obtained from visual inspection, present and projected fault levels, history of faults, system configuration and soil resistivity. Capital spending for test years 2011 and 2012 are \$2.7 million for each of the test years to replace deficient grounding systems at 3 transmission stations.

High Pressure Air (HPA) system, Air Receivers and Relief Valves

Centralized HPA systems are installed at all locations that have a population of ABCBs. These breakers employ compressed air as an interrupting and insulating medium. This requires a high-pressure compressed air supply consisting of a centralized HPA compressor/dryer plant as well as an air storage facility. Replacement information is obtained through visual inspection, audible leaks, and operating concerns discovered through functional tests. Spending for test years 2011 and 2012 is $1.1 million and $0.9 million respectively. This will replace deficient HPA system components at two transmission stations.

Demand

The requirement for demand capital is needed to replace equipment as a result of failures and is based on historic spending. Spending for the test years 2011 and 2012 is projected to be $0.2 million for each of the test years.

3.5.3 Summary of Expenditures

The spending requirement for test year 2011 is $18 million. This is attributed to the need to increase end of life station service replacements and to address grounding at stations to respond to safety issues and prevent damage to equipment. The spending requirement for test year 2012 is $18.1 million, which is a 1% increase from the 2011 test year.

The consequences of reduced spending in Ancillary Systems would be an inability to operate and maintain key station equipment (e.g., transformer tap changers, air blast circuit breakers, etc.), resulting in equipment damage and possible power outages.

Ancillary capital investment programs requiring in excess of $3.0 million in either test year 2011 or 2012 are provided in Table 7 below. Additional details for these programs are provided in the Investment Summary Documents in Exhibit D2, Tab 2, Schedule 3.

Table 7
Ancillary Systems
Capital Projects > $ 3 Million in Test Year 2011 or 2012 ($ Millions)

Ref #	Description	Cash Flow Test Years 2011	Cash Flow Test Years 2012	Total Cost	Removal Cost	Capital Cost
S19	2011/2012 Station Service Upgrades	12.8	13.1	25.9	2.6	23.3
	Other Projects/ Programs < $3M	7.1	7.1	14.2	1.4	12.8
	Total Cost	**20.0**	**20.2**	**40.1**	**4.0**	**36.1**
	Removal Cost	**2.0**	**2.1**	**4.0**		
	Capital Cost	**18.0**	**18.1**	**36.1**		

3.6 Stations Environment

3.6.1 Introduction

This program is driven by environmental requirements. It covers the installation, replacement and refurbishment of transformer spill containment systems which are barriers designed to capture and control transformer oil spills to minimize risk to the environment.

3.6.2 Investment Plan

Hydro One Transmission demonstrates effective environmental stewardship and corporate risk mitigation by proactively managing its transformer spill containment system infrastructure through End of Life (EOL) refurbishment/replacements. Approximately 60% of Hydro One's transmission power and auto transformers are equipped with spill containment systems; 160 of these spill containment systems are regulated by Ministry of the Environment (MOE) issued Certificate of Approval (C of A), which mandates operational and maintenance requirements. Based on condition assessments and the vintage of the various systems, Hydro One Transmission estimates that 50% to 80% of the older systems (i.e. pit liner systems installed in the 1970s) have either significantly reduced functionality or are nearing end of life, and do not meet Hydro One Transmission's current standards. Additionally, the MOE is increasing requirements for C of A applications at stations where this type of containment pit liner is used.

The prioritization and selection of new or retrofit sites and existing spill containment refurbishment is based on asset condition information, site environmental and geotechnical data, drainage effluent quality, transformer leak records, and station-specific spill risk analysis. During the 2011 and 2012 test years Hydro One Transmission will be replacing or retrofitting 39 spill containment systems at 19 stations.

3.6.3 Summary of Expenditures

The spending requirement for test years 2011 and 2012 is $8.4 million and $8.5 million respectively. The spending increase over historic years is primarily attributable to increased C of A requirements expanding the scope of the work to replace total site spill containment as opposed to one or two containment systems.

The consequences of a reduction in spending on Stations Environment include a potential release of oil off site, due to failed containment systems, which would result in a potential for punitive action by the MOE and an increase in corrective maintenance expenditures.

Stations Environment capital investment programs requiring in excess of $3.0 million in either test year 2011 or 2012 are provided in Table 8 below. Additional details for these programs are provided in the Investment Summary Documents in Exhibit D2, Tab 2, Schedule 3.

Table 8
Station Environment
Capital Projects > $ 3 Million in Test Year 2011 or 2012 ($ Millions)

Ref #	Description	Cash Flow Test Years		Total Cost	Removal Cost	Capital Cost
		2010	**2011**			
S20	2011/2012 Spill Containment Refurbishment - Major	8.8	8.9	17.8	0.9	16.9
	Other Projects/Programs < $3M	0.0	0.0	0.0	0.0	0.0
	Total Cost	**8.8**	**8.9**	**17.8**	**0.9**	**16.9**
	Removal Cost	**0.4**	**0.4**	**0.9**		
	Capital Cost	**8.4**	**8.5**	**16.9**		

3.7 Protection, Control, Monitoring and Telecommunications

This program funds the capital investments to replace protection, control, monitoring and telecommunications equipment that have reached end of life.

Protective relays and their associated systems (e.g. telecommunications) are devices connected throughout the Transmission Network for the purpose of sensing abnormal conditions (e.g. as a result of natural events, physical accidents, equipment failure). Upon sensing an abnormal condition, protection systems immediately operate the appropriate circuit breakers to isolate the affected equipment (e.g. transmission line, transformer, generator, buswork) from sources of energy and the rest of the transmission system.

Control systems are used to perform control, monitoring, and alarming functions for each station remotely from the Ontario Grid Control Centre (OGCC), the back-up control centre, or locally at the station. Control systems also provide real time data to the IESO's energy management system in accordance with the Market Rules. Monitoring systems provide detailed, high speed records of normal and abnormal events that occur in stations or on transmission lines. These systems are required to meet NPCC and IESO requirements, and are used to analyze the performance of protective relays and schemes and to ensure due diligence. The information obtained from monitoring systems is also used for maintenance scheduling, diagnostic analysis and post-mortem event analysis, consistent with good utility practice.

Telecommunication systems provide high reliability and high-speed communication required for the protection of Hydro One's transmission system and for the monitoring and control of the power system. Hydro One Transmission's telecommunication system consists of digital fiber-optic networks, Power Line Carrier (PLC) systems (which use transmission line conductors to transmit low voltage high frequency communication signals), owned or leased metallic cables, digital microwave, and auxiliary telecommunication equipment associated with the primary systems.

Capital investments to meet the needs identified above are grouped into three categories according to the function of the asset or the compliance requirement:

- Protection, Control and Metering cover protective relays and their auxiliaries, RTUs, SERs, DFRs, Special Protection Schemes (SPSs), local control systems and Revenue Metering systems;
- Auxiliary telecommunication equipment, which funds replacement of DC Remote Trip systems, Tone Channels, failed fibre optic cable and telecom batteries; and
- Cyber Security, which funds the implementation of systems and facilities required to achieve and sustain compliance with the NERC Critical Infrastructure Protection (CIP) Standards and address other cyber security vulnerabilities of equal or greater risk.

The required funding for Protection, Control and Telecommunications for the test years, along with the spending levels for the bridge and historical years is provided in Table 9 below.

Table 9
Station - Protection, Control, Monitoring and Telecommunications ($ Millions)

Description	**Historic**			**Bridge**	**Test**	
	2007	**2008**	**2009**	**2010**	**2011**	**2012**
Protection, Control and Metering	23.1	26.1	40.7	55.3	60.5	67.0
Auxiliary Telecommunication Equipment	17.7	13.2	19.3	12.7	25.3	34.0
Cyber Security	3.3	15.9	22.1	4.5	8.0	6.5
Total	**44.1**	**55.2**	**82.0**	**72.5**	**93.8**	**107.5**

3.7.1 Protection, Control and Monitoring Equipment

3.7.1.1 Introduction

Protection, Control and Monitoring assets exist in very large numbers. There are over 14,000 protection and control systems, each system consisting of up to 100 components. These systems cannot be out of service for longer than several days without incurring significant cost due to market inefficiency, or disrupting planned outages, or impacting reliability. The time required to engineer and install replacements is in the order of months to over one year depending on the nature of the system. Furthermore, work capacity limits restrict the number that can be done in any year. Consequently, a replacement-on-failure sustainment strategy is not feasible for these assets. In order to avoid major disruption to the transmission system, it is essential to plan and execute the replacement programs for these assets in a proactive manner so that they are replaced before end of life.

3.7.1.2 Investment Plan

The key information needed for planning the capital investments in this area includes:

- actual failure rates
- information from inspections
- calibration drift
- obsolescence, including lack of manufacturer support
- demographic data on the age distribution of a particular asset cohort
- NERC and NPCC standards
- nature and scope of defects

End of Life (EOL) replacement requirements are determined using a two-faceted approach:

- analyses of the demographics of population cohorts relative to the expected physical failure and end of life distributions for each.
- a Health Index to prioritize the replacement of individual assets relative to each other based a weighted set of factors which represent cost and reliability risks.

It is critical to ensure that assets installed over a short period of years, with a well defined EOL, are all replaced before onset of failure or rapidly increasing maintenance costs. The risk of replacing assets early is far outweighed by the potentially disastrous consequences of allowing a large population of assets essential to the operation of the grid to begin failing simultaneously in large numbers. For further information concerning the decision process to determine EOL, please refer to Exhibit D1, Tab 2, Schedule1, Section 7.

Specific planned replacement projects and programs are described below:

<u>S21: Bruce Special Protection System (BSPS) Replacement</u>

The Bruce Special Protection System (BSPS) has been designed to minimize restrictions on generation in the Bruce Area during times of inadequate transmission by performing pre-defined control actions in response to specific contingencies. This investment is required to address the end of life and obsolescence issues with the existing system. Spending for test years 2011 and 2012 is $7.6 million and $11.1 million respectively.

<u>S22: Interprovincial Transmission Company (ITC) - Line Protection Replacements</u>

The interconnection facility to Michigan in the Sarnia/Windsor area consists of four transmission circuits crossing the St Clair River: B3N, J5D, L4D, and L51D. The line protection and associated communication systems on these circuits have been assessed to be at EOL. Replacement is necessary to avoid deterioration in the reliability of the

Ontario Michigan interconnection facilities and to maintain the interconnection, as both ITC and Hydro One Transmission are replacing protections to ensure compatibility between the two systems. Spending for test years 2011 and 2012 is $ 4.8 million and $ 4.9 million respectively.

S23: NYPA Tie-Lines - Beck Line Protection Replacement

The interconnection facility to the New York Power Authority (NYPA) consists of two transmission circuits crossing the St Lawrence River near Cornwall and three circuits crossing the Niagara Gorge near Niagara Falls. The line protection and associated communication systems on these circuits have been assessed to be at end of life. Replacement is necessary to avoid deterioration in the reliability of the Ontario New York interconnection facilities. This project replaces the protections on the Tie Lines crossing the Niagara Gorge. Both NYPA and Hydro One Transmission need to replace the protections at their respective line terminals to ensure compatibility between the two systems. Spending for test years 2011 and 2012 is $ 3.2 million and $ 3.4 million respectively.

S24: Station P&C Replacement

All protection and control systems for load supply stations are generally housed in a single building. Hydro One has developed a standardized design whereby the entire building is replaced with all protection and control racks pre-built, installed and wired at the factory. For stations where most of the protection systems are at end of life, it is more cost effective and simpler from the perspectives of design, outage management and staging into service, to replace the entire relay building using this standard design rather than replace individual systems. Hydro One has identified 34 load supply stations at which most of the P&C systems have reached or are approaching end of life. Ten of these will be replaced in 2011 and 2012. Spending for test years 2011 and 2012 is $ 22.0 million and $22.2 million respectively.

S25: Protection Replacements

Protection systems are essential to the operation of every element (circuit, transformer, bus, breaker, etc.) of the grid. The failure of a protection system to operate immediately when required will have serious consequences including one or more of: equipment damage, injury to people, and a possible wide spread outage. An element for which the protection systems are known to be non-functional or unreliable, must be removed from service.

Hydro One Transmission's protections are aging similar to other equipment on the transmission system as demonstrated in Exhibit D1, Tab 2, Schedule 1, Section 2. Considering the importance of these systems, protection schemes are identified for replacement based on mean time to failure and health indices. Currently Hydro One Transmission has identified 1,800 protections that need to be replaced over the next five years. Spending for test years 2011 and 2012 is $ 8.1 million and $ 11.8 million respectively

S26: RTU replacement

Remote Terminal Units (RTU's) are essential components for the central operation of the transmission network. The RTU provides remote monitoring and operational control of all transmission stations to the Ontario Grid Control Center (OGCC) and telemetry to the Independent Electricity System Operator (the IESO). 152 RTU's have reached a Poor or Very Poor Health rating and are in need of replacement over the next 5 years. This is validated by condition assessments and failure data. Fourteen RTU's will be replaced in each of the years 2011 and 2012 under this program, plus an additional 5 per year under the Station P&C replacement program for a total of 38. Spending for this program in the test years 2011 and 2012 is $5.1 million and $ 5.6 million respectively.

Other Projects and Programs

Included in this category are all projects and programs where spending during any year is less than $3.0 million. These include:

- Benchboard Replacement will replace end of life legacy local station control facilities that consist of hardwired physical control panels. These facilities are more than 50 years old without spare parts and difficult to maintain. These controls are not addressed as part of the system control replacements, as such a separate program is required.
- Demand corrective program deals with end of life protection and control issues that are causing significant customer or system impacts and require priority attention.
- The New York Power Authority (NYPA) Tie Line Protection Replacement at St. Lawrence is a joint project with NYPA to replace the end of life protections on the tie lines near Cornwall.
- Programmable Synchrocheck Relays are special control devices that allow isolated parts of the grid to be connected together (re-synchronised) remotely. They are mainly used following system disturbances to restore the system to normal condition as quickly as possible with minimum load or generation interruption. Hydro One has a population of 60 Synchrocheck Relays and 15 are not reliable and will be replaced by this program in 2011 and 2012.
- Connection of Monitoring Systems to Satellite Clocks. Monitoring systems capture records of events which are essential for root cause analysis and the determination of appropriate corrective measures. They are mandated by NERC and NPCC. Most events on the grid affect more than one station and it is necessary to match up the records captured at one station with those captured at others. Electrical events take place in very short periods of time and an error in the matching of events between stations can lead to incorrect sequencing and erroneous or indeterminate conclusions. This problem is corrected by synchronizing the clocks in all the monitoring systems at various stations to the common time reference provided by satellite.

- Sequence of Event Recorders (SER) are one type of monitoring system. Hydro One Transmission has a population of 200 SERs, of which 90 are at end of life and 40 will be replaced by this program in 2011 and 2012.
- Station Networks are special high reliability redundant networking systems that are required to interconnect modern digital station Protection, Control and Monitoring Systems within the station. Hydro One Transmission normally installs station networks as part of an RTU Replacement. There are stations that require a network to be installed to interconnect new protections or monitoring systems but where the RTU does not require replacement. This program addresses those stations.

In total, spending for the work listed above for test years 2011 and 2012 is $10.0 million and $8.5 million respectively.

3.7.1.3 Summary of Expenditures

The spending level for test year 2011 and 2012 is $60.5 million and $67.0 million respectively. The spending in the test year 2011 is 9% greater than the 2010 bridge year. This additional spending is required to increase end of life replacement for protections to ensure that these critical system elements do not deteriorate further. As well, 2011 will see a need to commence work on a number of key facilities, e.g., the Bruce Special Protection System (BSPS) and the ITC project as highlighted previously. The spending for the test year 2012 is 11% greater than the 2011 test year. The reason for the increase is again the need to increase end of life protection replacements and the BPSP project.

Reductions in this program will see a significant increase in risks to the power system. Failure of an RTU results in complete loss of monitoring and control of a station. Failure of protections to immediately isolate abnormal conditions can cause a widespread power outage and destruction of equipment, as well as injury to workers and the public.

Protective relays and their associated systems are therefore essential for the safe and healthy operation of the Transmission Network.

Protection, Control and Monitoring Equipment capital investment programs requiring in excess of $3.0 million in either test year 2011 or 2012 are provided in Table 10 below. Additional details for these programs are provided in the Investment Summary Documents in Exhibit D2, Tab 2, Schedule 3.

Table 10
Protection, Control and Monitoring Equipment
Capital Projects > $ 3 Million in Test Year 2011 or 2012 ($ Millions)

Ref #	Description	Cash Flow Test Years 2011	Cash Flow Test Years 2012	Total Cost	Removal Cost	Capital Cost
S21	BSPS Replacement of End-of-Life Equipment	7.8	11.3	19.1	0.4	18.7
S22	ITC – Line Protections Replacements	4.9	5.0	9.9	0.2	9.7
S23	NYPA Tie Lines – Beck Line Protections Replacements	3.3	3.5	6.8	0.2	6.6
S24	2011 – 2012 Station P&C Replacement	23.2	23.4	46.6	2.4	44.2
S25	2011-2012 Protection Replacements	8.2	12.0	20.3	0.4	19.9
S26	2011-2012 RTU Replacement	5.1	5.6	10.7	0.3	10.4
	Other Projects/ Programs < $3M	10.0	8.5	18.5	0.4	18.1
	Total Cost	**62.5**	**69.3**	**131.8**	**4.3**	**127.5**
	Removal Cost	**2.0**	**2.3**	**4.3**		
	Capital Cost	**60.5**	**67.0**	**127.5**		

3.7.2 Auxiliary Telecommunication Equipment

3.7.2.1 Introduction

Telecommunication systems provide high reliability and high-speed communication required for the protection of Hydro One's transmission system and for the monitoring and control of the power system. Hydro One Transmission's telecommunication system consists of digital fiber-optic networks, Power Line Carrier (PLC) systems (which use transmission line conductors to transmit low voltage high frequency communication signals), owned or leased metallic cables, digital microwave, and the associated auxiliary telecommunication equipment for each.

3.7.2.2 Investment Plan

S27, S28: DC Signaling (Communication Cables plus Terminal Equipment)

Hydro One owns and leases metallic cables for Direct Current (DC) signaling in urban Toronto, Hamilton, Windsor and Ottawa areas. These DC signaling facilities typically are well over 40 years old, are obsolete and have deteriorating sheaths that require ongoing repairs and result in constant operation and frequent failure of air compressor equipment. These DC facilities are frequently out of service, reducing the reliability of major load supply stations. Telcos have informed their customers, including Hydro One Transmission that they are getting out of the DC circuit business and their tariffs state that services can be terminated with 12 months notice. Trouble response is on a best effort basis and during normal working hours only. Average restoration time has risen from 12 hours 10 years ago to over 140 hours in 2009. When a DC circuit is out of service, the design supply redundancy of a load supply station is lost and any single contingency will cause load outage. On average, the total amount of load supplied through stations using DC signaling is over 11,000 MW.

Hydro One Transmission embarked on a DC signaling replacement program, to replace over 529 DC telecom signaling channels and relaying which are at end of life. Of these, 122 will be replaced by the end of 2010. An additional 116 will be replaced during the 2011 and 2012 period. This will leave 291 to be replaced in subsequent years. Expenditures for test years 2011 and 2012 are $10.3 million and $14.5 million respectively.

S29: Protection Tone Channel Replacement (Terminal Equipment)

Line protection systems use telecommunications to transfer the protection signals between terminals of high voltage transmission lines. One of the early technologies developed for this purpose was through a change in tone pitch. These types of telecommunications are referred to as tone channels. The end devices used in tone channels which were deployed from the late 1960's and through the 1970's have been reaching end of life since 2001. Hydro One has had a program to replace them since 2002 and of the original population of 370, 200 have been replaced. In the 2011 and 2012 period another 51 will be replaced. The remaining 119 will be replaced before 2016. Tone channel replacements are scheduled to coordinate with the replacement of the protections they serve for work efficiency reasons.

Hydro One has assigned highest priority to sustaining the reliability of those protections as they are subject to NPCC and NERC Reliability Standards and consequences of failures can be most severe. Expenditures for test years 2011 and 2012 are $5.6 million and $ 8.2 million respectively

S30: Power Line Carrier (PLC) Replacement (Terminal Equipment)

Hydro One's Power Line Carrier (PLC) systems provide highly reliable high-speed communication for the protection of the transmission lines (primarily in Eastern and Northern Ontario). PLC systems may also carry critical data traffic for the monitoring and control of the power system. The majority of the PLC replacement program is now complete. However, a small number of PLC systems remain which are more than 30 years old, have increasing failure rates, and are considered at, or approaching, the end of life. The systems are obsolete and are no longer supported by the manufacturer. Expenditures for test years 2011 and 2012 are $ 3.2 million and $ 2.2 million respectively.

Other Projects and Programs

Included in this category are all projects and programs where spending during any year is less than $3.0 million. These include:

- All power system telecommunications must operate reliably independent of the grid and consequently must be powered from batteries during a local or widespread outages. Hydro One Transmission has a program to replace end of life batteries and charges that supply telecommunication systems.
- The microwave replacement project began in 2001 with near completion in 2008. Funding in 2011 and 2012 is required to replace the last of the local microwave link in the north east.
- Neutralizing Transformers are required to protect the metallic communication circuits and equipment of telephone companies from high voltages that can occur in transmission stations. They are required for the safety of Telco workers and the protection of Telco equipment. This program funds the replacement of end of life Neutralizing Transformers.
- Operations Support Systems are used in the Telecommunication Management Centre that monitors and responds to problems with the Power System Telecommunication System. This program funds capital sustainment for refreshing computer hardware and minor functionality enhancements which are required to achieve efficiency and effectiveness improvements.

- The protection, control and monitoring systems in the stations capture large amounts of information that is valuable for locating faults, analysis of events and analysis of the utilization and condition of the assets in the station. Due to cyber security requirements and good practice, all dial-up interfaces to these systems were disconnected. This project is replacing those dial up connections with a secure internal network connection. This will allow the data to be extracted quickly without the time and cost of having a P&C staff person drive to the station. For many Hydro One stations the driving time can be several hours.
- Special Protection Schemes (SPS) are systems that ensure the grid will remain stable and without overloads following contingencies in which some transmission elements are automatically removed (tripped) from operation. They do this by shutting off an amount of load and/or generation simultaneously with the tripping of the transmission element. Hydro One has 35 SPS's in service and each will have many telecom circuits. Some SPS systems are over 40 years old. This program will replace 6 end of life telecom channels on systems in the northwest.

In total, spending for the work listed above for the test years 2011 and 2012 is $6.2 million and $9.2 million respectively.

3.7.2.3 Summary of Expenditures

The spending level for test year 2011 and 2012 is $25.3 million and $34.0 million respectively. The spending in the test year, 2011 is about 100% greater than the bridge year 2010. The increase in spending is attributed to end of life replacements of tone equipment copper cable and powerline carrier systems. The spending for the test year 2012 is 34% greater than the test year 2011 due to further increases in the number of end of life replacements as required to keep pace with asset aging.

Delaying these programs and projects will result in decreasing load supply reliability and decreasing transmission reliability. Continuing use of DC cable facilities will result in increasing numbers of outage events as the frequency and duration of DC circuit outages continues to increase. It will also consume increasing amounts of field staff time, reducing their availability for planned development and sustainment work. Delaying the replacement of end of life tone channels and powerline carrier systems will result in protection telecom failing and requiring transmission circuits to be forced out of service with increasing frequency and duration. This will result in one or more of market inefficiency, reduced load supply reliability and disruption to the planned outage program.

Auxiliary Telecommunication Equipment capital investment programs requiring in excess of $3.0 million in either test year 2011 or 2012 are provided in Table 11 below. Additional details for these programs are provided in the Investment Summary Documents in Exhibit D2, Tab 2, Schedule 3.

Table 11
Auxiliary Telecommunications Equipment
Capital Projects > $3 Million in Test Year 2011 or 2012 ($ Millions)

Ref #	Description	Cash Flow Test Years 2011	Cash Flow Test Years 2012	Total Cost	Removal Cost	Capital Cost
S27	DC Signaling (Remote Trip) Replacements	7.2	6.6	13.7	0.3	13.7
S28	DC Signaling Replacements (Toronto North & East)	3.4	8.2	11.6	0.2	11.4
S29	NPCC Regulated Lines – Tone Equipment Replacements	5.7	8.3	14.0	0.2	13.8
S30	PLC Replacement Program	3.3	2.2	5.5	0.1	5.4
	Other	6.3	9.4	15.7	0.3	15.4
	Total Cost	**25.8**	**34.7**	**60.6**	**1.2**	**59.3**
	Removal Cost	**0.5**	**0.7**	**1.2**		
	Capital Cost	**25.3**	**34.0**	**59.3**		

3.7.3 Cyber Security

3.7.3.1 Introduction

The Canadian and US Federal governments categorize the energy sector as a critical infrastructure. To protect the reliability of the interconnected grid, NERC developed a set of eight Critical Infrastructure Protection standards (CIP002-CIP009), also referred to as the "Cyber Security" standards. In addition, NPCC Directory 4 which came into force Dec 2009 provides specific requirements for ensuring cyber security of grid protection systems. Hydro One Transmission must maintain compliance with the requirements of these standards. In addition, Hydro One follows good utility and IT Security practice to ensure that all cyber vulnerabilities are identified and secured.

3.7.3.2 Investment Plan

S31: Telecom Device Control Network Cyber Security

This project is to address vulnerabilities associated with the telecom network used for the protection of the Grid. This work is mandated by NPCC.

Other Projects

Other Cyber Security investment in 2011 and 2012 include new Cyber Vulnerabilities as required by NERC in response to regulatory notification and added Cyber Asset Protection Facilities. In total, spending for the work listed for test years 2011 and 2012 is $2.7 million and $1.4 million respectively.

3.7.3.3 Summary of Expenditures

The 2011 test year spending of $8.0 million is above the 2010 bridge year expenditures. This is attributed to the Telecom Device Control Network Cyber Security project and other smaller projects to address new Cyber vulnerabilities. The 2012 test year level declines by $1.5 million as compared to 2011 due to the projected cash flow patterns of these projects.

Cyber Security capital investment programs requiring in excess of $3.0 million in either test year 2011 or 2012 are provided in Table 12 below. Additional details for these programs are provided in the Investment Summary Documents in Exhibit D2, Tab 2, Schedule 3.

Table 12
Cyber Security Compliance Readiness
Capital Projects > $3 Million in Test Year 2011 or 2012 ($ Millions)

Ref #	Description	Cash Flow Test Years		Total Cost	Removal Cost	Capital Cost
		2011	2012			
S31	TDCN Cyber Security	5.3	5.1	10.4	0	10.4
	Other Projects/ Programs < $3M	2.7	1.4	4.1	0	4.1
	Total Cost	**8.0**	**6.5**	**14.5**	**0**	**14.5**
	Removal Cost	**0**	**0**	**0**		
	Capital Cost	**8.0**	**6.5**	**14.5**		

3.8 Transmission Site Facilities and Infrastructure

3.8.1 Introduction

The Transmission Site Infrastructure Systems are comprised of yard surface, drainage, fire protection, security, structural footings, station buildings, heating, ventilation and air-conditioning, access roads, water supplies, sewage, and fences. These systems provide infrastructure and support services to all other station components.

3.8.2 Investment Plan

S32: Site Drainage

Transformer and switching stations require functional drainage systems for worker safety and to prevent damage to property and electrical equipment. Condition assessment, investigations and studies have identified that three sites require major modifications in order to bring the site drainage to acceptable standards. Spending to restore adequate drainage at the three sites for test years 2011 and 2012 are $ 4.3 million and $ 4.4 million respectively.

S33: Station Security Infrastructure

Transmission System Security Infrastructure is designed to effectively deter, delay, detect and respond to security threats that target transmission facilities. Security infrastructure provides improved physical security to protect key components of the high voltage system and promotes greater safety within the station environment. The focus of Security Infrastructure is to enhance perimeter security first before considering other areas within a station. The program follows a risk based approach using Threat & Risk Assessments (TRA) to determine the appropriate level of Security Infrastructure. TRAs assess station criticality, exposure to criminal, domestic extremist and terrorist threats and the resulting impacts to reliability, safety and regulatory requirements. Security infrastructure follows a layered approach in selecting security equipment such as reinforced perimeter. Since 2006, there has been a significant increase in criminal activity aimed at transmission stations. These incidents include copper theft, trespassing and major breaches of the perimeter fence. In 98% of all criminal incidents recorded from 2006 to present, the perimeter chain-link fence has been breached.

Spending levels for the test years 2011 and 2012 of $8.3 million and $8.5 million respectively are required to add and modify station security to reduce theft and unauthorized entry onto transmission station premises.

Other Projects

Additionally there are many other smaller programs and individual projects that are undertaken within this larger program that are necessary to support station infrastructure and facility requirements. They include:

- Civil and Support Structures - This is work associated with refurbishing damaged footings and structures within transmission stations.
- Heating Ventilation and Air Conditioning (HVAC) - This work involves the replacement of EOL HVAC units in Hydro One buildings.
- Fire protection system/deluge replacements - This work involves the replacement of EOL fire protection systems in transmission stations.
- Cable Trench cover replacement - This work involves the replacement of deteriorated concrete or wood covered cable trench covers. The trenches are used to house numerous control and power cables.
- Building/roof replacement - This work involves the replacement/refurbishment of EOL transmission station roofs.
- Station site surface treatment - This work involves paving and gravel requirements within a transmission station.

- Water supply upgrades - This work involves the refurbishment/replacement of water supply facilities to transmission stations.
- Station Perimeter fences - This work involves the replacement/refurbishment of end of life station perimeter fences as well as the addition of animal abatement measures to reduce outages attributed to nuisance wildlife.

Reliability requirements, security, regulatory, safety and environmental criteria are all factors which need to be taken into consideration when performing the assessments necessary to develop investment plans for Transmission Facilities and Infrastructure. Programs are generally identified based on EOL determination which includes, asset condition assessments, known deficiencies, system needs, consequences of failure and regulatory requirements.

Planned expenditures for test years 2011 and 2012 are $ 13.9 million and $ 13.6 million respectively to ensure that site facilities, structures and infrastructure continue to provide the functionality necessary for a transmission station.

3.8.4 Summary of Expenditures

The spending level for test years 2011 and 2012 is $26.5 million and $26.4 million respectively and is about 15% above the 2010 test year spending. Spending for the test year 2012 is about the same as the test year 2011.

The test years spending has increased over prior years due to regulatory requirements, in particular the Ministry of Environment Certificate of Approval requirements for drainage. In addition, increased funding requirements stem from fire protection systems and cable trench cover facilities coming to end of life as well as a greater focus on keeping nuisance wildlife out of stations and away from energized equipment. Wildlife is a significant contributor to unreliability at transmission stations.

The consequences of a reduction in spending on Transmission Infrastructure and site facilities would result in an increased risk to employee safety, reduced vehicular access to station equipment and possibly equipment damage due to flooding and potential regulatory noncompliance.

Transmission site facilities and infrastructure capital investment programs requiring in excess of $3.0 million in either test year 2011 or 2012 are provided in Table 13 below. Additional details for these programs are provided in the Investment Summary Documents in Exhibit D2, Tab 2, Schedule 3.

Table 13
Transmission Site Facilities and Infrastructure
Capital Projects > $ 3 Million in Test Year 2011 or 2012 ($ Millions)

Ref #	**Description**	**Cash Flow Test Years**		**Total Cost**	**Removal Cost**	**Capital Cost**
		2011	**2012**			
S32	2011/2012 Spill - Major Drainage	4.5	4.6	9.1	0.5	8.6
S33	Station Security Infrastructure	8.6	8.8	17.3	0.5	16.8
	Other Projects/ Programs < $3M	13.9	13.6	27.5	0.0	27.5
	Total Cost	**27.0**	**26.9**	**53.9**	**1.0**	**52.9**
	Removal Cost	**0.5**	**0.5**	**1.0**		
	Capital Cost	**26.5**	**26.4**	**52.9**		

4.0 LINES

Hydro One Transmission's system consists of approximately 29,000 circuit km of overhead transmission lines and 280 circuit km of underground transmission cables. Transmission lines are used to transmit electric power to connected industrial and commercial customers and local distribution companies, who in turn distribute the power to end-use customers. Transmission lines operate at voltages of 500 kV, 345 kV, 230 kV, 115 kV and 69 kV.

Sustaining Capital for Lines includes investments required to replace or refurbish overhead and underground transmission lines or specific components that have reached EOL. Hydro One Transmission manages its Lines Sustaining Capital programs by dividing them into three categories.

- Overhead Lines Refurbishment and Component Replacement, which funds the capital investments to refurbish or replace line components that have reached EOL. It also funds capital corrective work associated with clearance corrections and right of way facilities, as well as tower refurbishment and coating;
- Transmission Line Reinvestment, which funds the capital investments to refurbish complete line sections on a project basis and is usually undertaken on line sections where conductors have reached EOL;
- Underground Transmission Line Refurbishment and Replacement, which funds the capital investments to refurbish or replace cable sections and components that have reached EOL. Components include cables, terminations, oil pressure systems and grounding systems.

Required funding for the test years, along with the spending levels for the bridge and historical years are provided in Table 14 for each of these categories.

Table 14
Lines Sustaining Capital ($ Millions)

Description	Historic			Bridge	Test	
	2007	2008	2009	2010	2011	2012
Overhead Lines Refurbishment and Component Replacement	46.4	44.0	56.8	54.9	55.6	57.6
Transmission Lines Re-investment	6.2	7.3	15.2	9.8	8.9	7.3
Underground Lines Cables Refurbishment and Replacement	14.6	5.3	4.1	1.9	22.2	21.6
Total	**67.2**	**56.5**	**76.0**	**66.6**	**86.7**	**86.5**

The spending requirement for the test year is $86.7 million which is 30 % greater than the bridge year 2010. The spending level for 2012 is slightly less than the 2011 test year spending.

The increase in the test years spending is due to an increase in the requirement to replace underground oil filled 115 kV cables that are leaking oil due to corroded lead sheaths. Underground cables are very costly to replace and these particular circuits are over 5 km in length and located in downtown Toronto. Other increases under the Lines programs are due to an increase in tower coating and shield wire replacement to address these aging assets that are corroding.

4.1 Overhead Lines Refurbishment and Component Replacement

4.1.1 Introduction

In many cases, it is more cost-effective to replace one or more of the transmission line components that have reached their end of life rather than to rebuild the entire line.

Activities within this program include replacement of individual components such as wood poles, insulators, shieldwire and switches, and refurbishment of corroded towers, as well as providing funding for other projects e.g. electrical clearance corrections, right-of-way upgrades and emergency replacements.

It should be noted that in terms of component replacement, the focus of this program is the replacement of line components other than conductors. When a conductor reaches EOL, the project takes on a much larger scope than individual component replacement with an emphasis to replace all components nearing EOL, thereby re-instating the condition of a line to as close to new as feasible. Conductor EOL is addressed under the Transmission Line Re-Investment Program, which is discussed in Section 4.2.

4.1.2 Investment Plan Process

Hydro One considers asset condition assessment results, regulatory compliance, asset performance, and safety requirements when carrying out assessments on line components such as wood pole structures, steel towers, and shieldwire. Components that are deemed to be at end-of-life are prioritized based on risk (e.g. safety, reliability) and scheduled for refurbishment or replacement.

S34: Transmission Wood Pole Replacement Program

Hydro One Transmission’s system contains about 42,000 wood pole structures. Wood pole structure replacement is the primary cost contributor to this program and averages about 55% of total expenditures. The end-of-life determination is based on the results of wood pole inspections and tests. Once deemed to be at EOL, structures are scheduled for replacement.

Historic replacements have averaged about 780 structures per year and projections based on condition data and reliability performance data indicate that replacements during the test years should average about 850 structures to address the problem identified on the 230 kV Gulfport type structures. The Gulfport structures utilize a wood pole rather than a rectangular timber to support the conductor and studies show that these poles are deteriorating on the inside. The 230 kV system is critical to the electrical supply of the province and failures of this type must be minimized. There are about 5,800 structures of this type in the system and 2700 remain that still have the defective arm that requires upgrading. These structures are of the larger type and more costly to replace than the smaller 115 kV type structures. Spending for the wood pole replacement program in test years 2011 and 2012 is $30.8 million and $31.3 million respectively.

S35: Steel Structure Coating Program

Hydro One Transmission's system includes about 47,000 steel towers and about 35% are older than 55 years, with many showing noticeable degrees of corrosion. Steel towers are manufactured with a zinc-based galvanized coating that protects the underlying steel against corrosion. The coating will generally last from 30 to 60 years, with the more corrosive environments depleting the galvanizing at a quicker rate. Asset condition assessment is carried out on an annual basis with a focus on line sections with in-service dates greater than 30 years that are located in highly corrosive areas and in locations where known problems exist. The assessments determine the amount of galvanizing that remains on the structure, or in the case where the coating is depleted, the amount of metal loss that has occurred. Recent condition assessments have shown that more than 320 structures on several line sections have, to a large part, lost their galvanized coating and need to have the corrosion protection re-instated during 2011 and 2012. Spending for the tower coating program in test years 2011 and 2012 is $5.5 million and $6.5 million respectively.

S36: Shieldwire Replacement Program

The shieldwire in Hydro One's system is primarily made up of galvanized steel wire that is positioned above the conductors to protect a circuit against lightning related outages and to provide continuity of the grounding system. When the zinc galvanizing has depleted, the underlying steel begins to corrode, resulting in pitting and loss of metal and eventual failure if not replaced in time. Hydro One Transmission has implemented a shieldwire testing program where a sample of wire is removed from a line section and tested in a laboratory to determine the condition of the wire and the need for replacement. Based on test results, about 200 km of shieldwire will be replaced during 2011 and 2012, at the cost of $4.2 million and $4.3 million respectively.

S37: Transmission Lines Emergency Restoration

A number of transmission line components fail each year due to adverse weather, component deterioration, vandalism, or through accidents caused by public activity. This is a demand program needed to restore power following transmission line failures and to replace or repair those line components where there is an imminent danger of failure as identified through line patrols or asset condition assessment.

Emergency work under this program includes the replacement of failed or defective transmission line components such as wood structures, wood crossarms, towers, insulators, conductor, shieldwire and hardware. Funding is based on recent historic costs and it is estimated that $6.6 million will be required in each test year to address emergency work.

Other Projects/ Programs

Other component replacements include replacement of insulators, switches, right of way access bridge components and aviation lights that have reached end of life. Replacements of these components are based on end of life assessment and are essential to maintain system reliability and to address public and employee safety risks. In addition, this program funds the restoration of steel tower foundations. About 70% of the towers in Hydro One Transmission's system utilize buried steel grillages to support towers and these foundations are susceptible to corrosion. Some foundations need the corrosion protection re-instated and damaged steel members replaced to extend the life of the towers. Transmission line clearance corrections are also part of this program and are required to reinstate electrical ratings for the circuits in question. This may involve raising a structure or installing an inter-space structure to improve clearances to that required. In total, spending for these component replacements, refurbishment of foundations and electrical clearance corrections for test years 2011 and 2012 is $8.4 million and $8.9 million respectively.

4.1.3 Summary of Expenditures

The spending requirement for the test year is $55.6 million which is 1 % greater than the bridge year 2010 and the $57.6 million spending level for 2012 is 4% greater than the 2011 test year. To some degree the increase is attributed to an increased need for tower coating.

Reductions in this program will result in an increase in line component failures, (e.g. wood arms, insulators and shieldwires) which in many cases will create safety hazards for the public. In addition, failures of this type will leave customers without power for lengthy periods of time until repairs are made. Reductions in tower coating and foundation repairs will result in increased costs in the future for costly tower repairs and in some cases complete tower replacement where towers are beyond repair. As well, reduced capital investments in this category will increase corrective maintenance costs for repairs and to address more safety issues as they arise.

Overhead lines refurbishment and component replacement programs requiring in excess of $3.0 million in either test year 2011 or 2012 are provided in Table 15 below. Additional details for these programs are provided in the Investment Summary Documents in Exhibit D2, Tab 2, Schedule 3.

Table 15
Overhead Lines Refurbishment and Component Replacement
Capital Projects > $ 3 Million in Test Year 2011 or 2012 ($ Millions)

Ref #	Description	Cash Flow Test Years		Total Cost	Removal Cost	Capital Cost
		2011	2012			
S34	2011/2012 Transmission Wood Pole Replacement Program	34.2	34.8	69.0	6.9	62.1
S35	2011/2012 Steel Structure Coating Program	5.5	6.5	12.0	0.0	12.0
S36	2011/2012 Shieldwire Replacement Program	4.7	4.8	9.5	1.0	8.6
S37	2011/2012 Transmission Lines Emergency Restoration	7.2	7.3	14.5	1.2	13.3
	Other Projects/ Programs < $3M	9.2	9.6	18.8	1.5	17.3
	Total Cost	**60.8**	**62.9**	**123.7**	**10.5**	**113.2**
	Removal Cost	**5.2**	**5.3**	**10.5**		
	Capital Cost	**55.6**	**57.6**	**113.2**		

4.2 Transmission Lines Re-Investment

4.2.1 Introduction

Transmission line conductors are one of the most critical elements of a transmission line, both from an operational and safety perspective. When the conductor condition deteriorates to a critical level, failures are likely to occur in multiple locations anywhere on a line section. The overhead lines reinvestment program addresses the need to re-build sections of transmission line based primarily on conductor EOL. As well, the work includes replacement of other components at or nearing EOL.

4.2.2 Investment Plan

Hydro One considers asset condition assessment results, performance data and asset demographics when making investment decisions related to conductors. To gather condition data, conductors are assessed by removing samples from a line or section. The samples are then tested in a laboratory to assess conductor strength, corrosion and serviceability characteristics (e.g. ductility and damage due to metal fatigue).

Specific transmission line sections are selected for replacement from the assessment of conductor condition based on the conductor testing results and the criticality of the line. In addition, line sections are prioritized to minimize overall safety and reliability risks. Once selected, the entire transmission line section is then refurbished to meet present and future system requirements.

S38: Circuit A6P – Reserve Jct. to Port Arthur TS Transmission Line Refurbishment

Expenditures are included in 2011 and 2012 for the rehabilitation of a transmission line between Reserve Jct. and Port Arthur TS (Circuit A6P) in the Thunder Bay area. This circuit was built in 1920 and consists of 560 wood pole structures and associated conductor and is 73.7 km in length

Other Projects and Programs

This program includes secondary land use projects where Hydro One Transmission is required to relocate its facilities to accommodate new roads or other infrastructure changes where cost sharing agreements are in place with road authorities. Projected expenditures are required to accommodate upcoming highway expansion plans. Test year expenditures are $1.8 million in 2011 and $1.1 million during 2012.

4.2.3. Summary of Expenditures

The year over year costs can vary significantly under this program depending on the number and size of the line projects that require re-conductoring and refurbishment. Conductor and structure failures present unacceptable risk to public safety and to the reliability of the electrical system, and as such need to be avoided.

Transmission Lines Re-investment projects requiring in excess of $3.0 million in either test year 2011 or 2012 are provided in Table 17 below. Additional details for these programs are provided in the Investment Summary Documents in Exhibit D2, Tab 2, Schedule 3.

Table 17
Transmission Line Re-Investment
Capital Projects > $ 3 Million in Test Year 2011 or 2012 ($ Millions)

Ref #	Description	Cash Flow Test Years 2011	Cash Flow Test Years 2012	Total Cost	Removal Cost	Capital Cost
S38	Circuit A6P – Reserve Jct. to Port Arthur TS Transmission Line Refurbishment	7.5	6.5	14.0	0.7	13.3
	Other Projects/ Programs < $3M	1.9	1.2	3.1	0.2	2.9
	Total Cost	**9.4**	**7.7**	**17.0**	**0.9**	**16.2**
	Removal Cost	**0.5**	**0.4**	**0.9**		
	Capital Cost	**8.9**	**7.3**	**16.2**		

4.3 Underground Lines Cables Refurbishment and Replacement

4.3.1 Introduction

This program funds the replacement or refurbishment of components of the high voltage underground ("HVUG") cable system and the replacement of underground line sections that have been determined to have reached end of life. HVUG cable systems are comprised of a number of sub-systems and components that need to function properly in an integrated manner to be able to deliver a reliable supply of electricity. The primary components and sub-systems are:

- The cable itself, which is made up of an inner core conductor of either copper or aluminum, insulation that is made of liquid impregnated paper or cross-linked polyethylene, and a protective sheath or steel pipe with a protective cover or coating.
- Cathodic protection systems to protect the steel pipe against corrosion.

- Liquid pressurization systems that include pumping plants to ensure oil or gas pressure is maintained at acceptable levels.
- Bonding and grounding systems to address safety risks and control induction on the cable sheath.
- Insulated cable terminations that connect a cable to an overhead line or connect a cable to a transformer station.

Planned capital investments in primary cable components and sub-systems vary from year to year depending on system needs as identified through asset condition assessment results, reliability risks, and end of life determinations. Unplanned investments (i.e. Emergency Repairs) on HVUG cables are also funded through this program and may target any of the aforementioned components and sub-systems.

4.3.2 Investment Plan

Planned capital investments in primary cable components and sub-systems vary from year to year depending on system needs as identified through asset condition assessment results, reliability risks, and end-of-life determinations. Unplanned investments (i.e. Emergency Repairs) in cables, are also funded through this program and may target any of the aforementioned components and sub-systems.

The decision to deem underground cable and or cable components at end-of-life is made considering a number of factors. Although age is considered, it is not a significant determinant in EOL, which is driven predominantly by cable performance, condition, and component obsolescence. Of particular importance is condition data that is gathered from cable diagnostics and maintenance activities such as condition patrols, cable pipe corrosion surveys, oil tests, jacket tests, infrared scans and intrusive examination of insulation systems when afforded the opportunity. Details of these cable diagnostics and maintenance activities are contained in Exhibit C1, Tab 2. Exhibit 2.

As Hydro One's underground cables supply city centres in Toronto, Ottawa and Hamilton, they are essential for electrical supply and as such require a very high degree of reliability. Experience has shown that underground cables are costly to replace when they reach end of life, thereby making it prudent to avoid failures that will jeopardize the long term viability of these costly assets. To establish needed component and system replacements, Hydro One analyzes data from a number of diagnostic tools and activities to determine the condition of the cable system and the existing risks based on operating conditions, system redundancy and cable system condition.

For Emergency Repairs, a forecast of expenditure levels is set after analyzing historical expenditure levels and assessing any factors that could drive a change from historical levels.

Based on assessment findings, entire cables or their subsystems are scheduled for replacement or refurbishment. Priority is given to assemblies and or cables that have been found to be in poor condition and that are critical to the operation of the transmission system. In the case of Emergency Repairs, funding is forecasted using historic experience and knowledge of overall cable conditions.

<u>S39: H2JK/K6J Cable Replacement (Riverside Jct. x Strachan TS)</u>

The plan under this program is to replace two paper insulated oil filled 115 kV cables that are each 5.6 km in length and have reached EOL due to chronic leaks caused by a corroded lead sheath. They are located in downtown Toronto along the western waterfront area.

4.3.3 Summary of Expenditures

Underground Cables capital for test year 2011 is substantially more than the investment for bridge year 2010. This is due to the requirement to replace two long circuit lengths of 115 kV oil filled cable that have reached end of life in Toronto. The 2012 spending is 3% lower than 2011 as the work level on this three year replacement project is expected to decline.

The year over year costs can vary significantly depending on the number of cable replacement projects completed during any given year or the need to complete large scale replacements such as a pumping plant. Specifically, 2007 expenditures were high as it became necessary to relocate a cable on CN property to accommodate a rail expansion. In contrast, 2008 and 2009 expenditures were low as only a short section of cable was replaced from Gerrard TS to Bloor St Jct in mid town Toronto.

Reductions in this program will jeopardize the electrical supply reliability to the downtown areas of the major centres in Ontario, as well as increase environmental risks associated with an increase in oil leaks from the underground cable system. Additional details for these programs are provided in the Investment Summary Documents in Exhibit D2, Tab 2, Schedule 3.

Table 18
Underground Cables Refurbishment and Replacement
Capital Projects > $ 3 Million in Test Year 2011 or 2012 ($ Millions)

Ref #	Description	Cash Flow Test Years 2011	Cash Flow Test Years 2012	Total Cost	Removal Cost	Capital Cost
S39	H2JK / K6J Cable Replacement (Riverside Jct. x Strachan TS)	22.9	22.2	45.1	4.5	40.6
	Other Programs/Projects < $3M	1.8	1.8	3.5	0.4	3.2
	Total Cost	**24.7**	**24.0**	**48.7**	**4.9**	**43.8**
	Removal Cost	**2.5**	**2.4**	**4.9**		
	Total Cost	**22.2**	**21.6**	**43.8**		

DEVELOPMENT CAPITAL

1.0 INTRODUCTION

Transmission Development Capital covers funding for projects related to new or upgraded transmission facilities to:

- Provide inter-area network transfer capability to enable electricity to be delivered from areas with sources of supply to load centers.
- Provide adequate capacity to reliably deliver electricity to the local areas connected to the Hydro One Transmission's system.
- Connect load customers (load connections) and generating stations (generation connections) to Hydro One Transmission's system.
- Maintain the performance of Hydro One Transmission's system in accordance with Customer Delivery Point Performance ("CDPP") Standards.
- Develop and implement cost effective solutions to enable better use of existing infrastructure or for upgrading the infrastructure to address the impacts of the connection of renewable generation.

The projects take into consideration the need to plan and operate the interconnected Bulk Electric System in a safe, secure and reliable manner that meets Hydro One Transmission's license requirements and complies with criteria and standards based on good utility practice.

This exhibit does not include funding for development work to support the development of major, long-term plans required to implement the *Green Energy and Green Economy Act, 2009* (GEGEA) as outlined by the Minister of Energy and Infrastructure in a letter to

Hydro One dated September 21, 2009. The costs associated with this development work are discussed in Exhibit C1, Tab 2, Schedule 4.

2.0 DEVELOPMENT CAPITAL PLANNING PROCESS

2.1 Summary of Guidelines and Criteria

Reliability is a key business value for Hydro One Transmission and thus, the Company focuses heavily on achieving its reliability objectives and on contributing to adequacy of electricity supply in the province. The importance of reliability is reinforced by obligations placed by various regulatory and reliability authorities on Hydro One Transmission to maintain acceptable voltages, keep equipment operating within established ratings, and maintain system stability during both normal operation and under recognized contingency conditions on the transmission system. These requirements of the Ontario Government and industry regulatory authorities include those of the North American Electric Reliability Council ("NERC"), the Northeast Power Coordinating Council ("NPCC"), the Ontario Energy Board ("OEB"), the Ontario Power Authority ("OPA"), and the Independent Electricity System Operator ("IESO") which utilizes its "Ontario Resource and Transmission Assessment Criteria" when conducting System Impact Assessments ("SIA") for new transmission facilities. In particular, Hydro One is also required to comply with the Transmission System Code ("TSC") and its Transmission License requirements.

2.2 Development Capital Planning Process

An overview of the Development Capital Planning process is provided in Exhibit A, Tab 12, Schedule 4. A more detailed explanation of the planning for each different type of investment (i.e. Load Connection, Local Area Supply, Generation Connection, Network

Upgrades, Enabling Facilities, Station Equipment Upgrades & Additions to Facilitate Renewables, Protection and Control for Enablement of Distribution Connected Generation, Performance Enhancement, Risk Mitigation and Smart Grid) is provided in Sections 2.2.1 to 2.2.9 respectively. The details on specific projects that are presently in various stages of conceptual or detailed planning, approval work, and engineering and construction are outlined in Sections 3.1 to 3.10.

2.2.1 Planning for Load Connections

The planning for new load connections is driven primarily by customer requests. The connection needs may be satisfied through new and/or modified transmission connection facilities, including: new line connections, new feeder positions at existing Transformer Stations ("TSs"), increase of capacity at existing TSs, or construction of new TSs.

In accordance with the TSC, new load connections may be self-provided by the transmission customer or, at the discretion of the transmission customer, they may be provided by Hydro One Transmission. If requested, Hydro One Transmission is required by the TSC and its Transmission Licence to provide a pool funded option for new line connections and transformation connection. The costs of these investments are the responsibility of the benefiting customer(s) and the costs are fully recovered from these customers via incremental connection revenues and/or capital contribution as per a Connection Cost Recovery Agreement ("CCRA"), the calculation of which is based on Hydro One Transmission's Connection Procedures approved by the OEB.

2.2.2 Planning for Local Area Supply

The planning for local area supply is driven by load growth and local area reliability. New or upgraded facilities may be required in order to maintain acceptable voltages, equipment operating within the ratings, system stability, and/or operating flexibility. The term ‘Local Area’, for the purpose of this exhibit, refers to a confined, small or radial portion of the system supplying multiple transmission delivery points serving one or more customers. The geographic and electrical size of a local area varies based on the area system characteristics and connectivity to the bulk transmission system.

There are several ways in which planning for local area supply is triggered:

- The OPA recommends local area supply initiatives aimed at ensuring regional and local area reliability.
- Hydro One Transmission, on its own or in consultation with Local Distribution Companies (“LDCs”) and other customers, carries out system studies to identify needs and potential solutions to resolve constraints related to local area supply adequacy. In these cases, Hydro One Transmission always consults with the OPA to confirm that the need and potential solutions are consistent with the OPA’s plans.
- Hydro One Transmission monitors the IESO’s SIA reports for Load Connections and other projects. If any SIA suggests that transmission reinforcements may be required in the local areas where the load connections or other projects are being contemplated, Hydro One Transmission undertakes additional studies to assess alternatives for Local Area Supply and to identify recommended transmission solutions.
- Hydro One Transmission monitors the transmission system and identifies concerns about equipment overloading, system performance constraints, or restricted operating and maintenance flexibility.

Solutions for local area supply range from the utilization of special protection systems or installation of capacitor banks to maximize the use of existing facilities (in order to defer the need for a major investment) to major transmission expansion projects to meet long-term needs. Major transmission expansion projects may include construction of new transmission lines into the area, and/or new or additional 230/115kV autotransformer capacity. These major projects typically require long lead-times, particularly if there are approval requirements under the Environmental Assessment ("EA") Act or Section 92/95 of the OEB Act as described below.

2.2.3 Planning for Transmission Connected Generation

The planning for transmission connected generation is based solely on customer requests and it is significantly impacted by external factors such as: the Ontario Government's initiatives, the OPA initiatives for procurement of clean and renewable energy, and private sector investments.

In accordance with Hydro One's Transmission License, Hydro One Transmission is required to connect new generators that meet the requirements of the Market Rules and all other applicable codes, standards and rules while maintaining system security and reliability for existing connected customers. In addition to the specific radial connection itself, modifications may be required to Hydro One Transmission's network and up-stream connection facilities in order to incorporate the generation into the system. Examples of modifications that may be required include enhancements to protection systems, voltage or reactive power support, and/or breaker and station upgrades due to increased short circuit levels contributed by the generator. The customer capital contributions, as per a CCRA, are determined in accordance with the TSC, with clarification provided by the Compliance Bulletin #200606, dated September 11, 2006.

2.2.4 Planning for Network Upgrades

The planning for network upgrades is based on either increasing the inter-area transfer capability between generation and load centers within Ontario or increasing the interconnection capability with neighbouring utilities. Constraints in the provincial transmission system can inhibit the efficient use of Ontario's own generation resources and the import and export of power through interconnection facilities. In order to maintain or enhance the transfer capability; new or upgraded facilities are required to ensure adequacy of electricity supply for the province.

There are several ways in which planning for network upgrades is triggered:

- The OPA, through its initiatives related to procurement of additional supply resources for the province, recommends the need for inter-area transmission reinforcements. Typically, this recommendation is based on the Ontario Government's initiatives and energy policies regarding renewable generation and/or phasing out of coal-fired generating stations in Ontario.
- Hydro One Transmission monitors the IESO's SIA reports for generation projects.
- Hydro One Transmission monitors the transmission system and identifies projects based on concerns about equipment overloading, system performance constraints, or restricted operating and maintenance flexibility.
- Hydro One Transmission assesses significant and pervasive concerns expressed by load and/or generation customers, particularly when these concerns are in matters related to reliability or safety matters.

The solutions for improving transfer capability range from the installation of capacitor banks or static-var compensation to major transmission reinforcement or interconnection projects. The major network upgrades may involve long lead-times in the approval process (based on requirements under the EA Act and/or Section 92/95 of the OEB Act) and construction phase of the project.

2.2.5 Planning for Enabling Facilities

The planning for enabling facilities is based solely on customer requests for connection of renewable generators and is significantly impacted by external factors such as: the Ontario Government's initiatives and the OPA Feed-In-Tariff ("FIT") program. The Ontario Government as part of the GEGEA has recommended Enabling Transmission projects (Schedule B) to accommodate the anticipated increase of renewable generation, refer to Exhibit A, Tab 11, Schedule 4.

Solutions for enabling generation include: construction of new 230kV or 115kV enabler lines and/or construction of new 230kV or 115kV enabling transformer stations. These enabling facilities will not be undertaken without obtaining all necessary project specific approval requirements under the EA Act or Section 92/95 of the OEB Act and a supporting letter of project need from the OPA.

2.2.6 Planning for Station Equipment Upgrades & Additions to Facilitate Renewables

The planning for station equipment upgrades is driven by the need to facilitate renewable generation in accordance with the Ontario Government's initiatives and the OPA initiatives for procurement of clean and renewable energy.

In a letter dated September 21, 2009, the Minster of Energy and Infrastructure requested Hydro One to immediately proceed with planning, development and implementation of upgrades to enable distribution system connected generation (Schedule B Projects), refer to Exhibit A, Tab 11, Schedule 4.

Station Equipment Upgrades that are required to Hydro One Transmission's network in order to incorporate the generation into the distribution system include: reactive power support, in-line breakers and/or station upgrades.

2.2.7 Planning for Protection and Control for Enablement of Distribution Connected Generation

The connection of generation to the distribution system ("DG") requires changes and additions to the protection and control facilities in transmission stations. These changes are required to meet requirements for Bulk Power System reliability, requirements of the Distribution System Code and to increase the reverse power flow capacity of the Transmission Stations. These changes do not have a one-to-one correspondence with individual DG projects but will generally support many DG connections. They become necessary at certain thresholds of aggregate DG capacity at a transmission station. To ensure the required changes do not become an undue impediment to the progress of DG connections, Hydro One will undertake these changes proactively. The planning process to achieve this requires predicting the amount of generation connecting to each transmission station, and initiating modifications in advance of the required capacity thresholds being achieved. Hydro One uses best available information from the various OPA generation procurement initiatives to predict generation amounts.

2.2.8 Planning for Smart Grid

The planning for smart grid is based on developing long-term innovative strategies relating to Smart Zone development. These strategies offer value to Hydro One customers through improvements in protection and control systems as well as enhancing transmission infrastructure to connect additional renewable energy generation as called upon by the GEGEA. The projects will aim to improve the reliability and quality of supply to customers or improve performance monitoring for the transmission system.

The strategies for smart grid range from implementing and testing end to end the new Smart Zone architecture, managing reactive power with a DVAR controller at transformer stations with high DG penetration, enhancing monitoring and control at transformer stations, and installing new technologies and next generation intelligent electronic devices (IEDs) at transformer stations for station equipment condition diagnostics.

2.2.9 Planning for Performance Enhancement and Risk Mitigation

The planning for performance enhancements and risk mitigation projects is focused on upgrading transmission system assets to minimize high impact risk and address power quality issues to ensure safe, secure and reliable operation of Hydro One Trasmission's system in accordance with the Market Rules, TSC and other mandatory industry standards such as NERC and NPCC.

In accordance with the requirements of the TSC, Hydro One Transmission on January 17, 2008 filed its CDPP Standards proposal [EB-2004-0424] outlining the process to identify and address delivery points demonstrating poor performance and/or deteriorating trends in reliability performance. The proposal was approved by the Board in its Decision with Reasons of April 2, 2008.

3.0 DEVELOPMENT CAPITAL INVESTMENTS

Development Capital includes work on both network and connection facilities. The type of transmission development investments covered in this exhibit are: Inter-Area Network

Transfer Capability, Local Area Supply Adequacy, Load Customer Connection, Generation Customer Connection, Enabling Facilities, Station Equipment Upgrades to Facilitate Renewables, Protection and Control for Enablement of Distributed Generation, Smart Grid, and Performance Enhancement and Risk Mitigation.

Hydro One Transmission's development capital programs and proposed spending levels under these investment types are summarized below.

Table 1
Development Capital

Investment Type	**($ Millions)**					
	Historical			**Bridge**	**Test**	
	2007	**2008**	**2009**	**2010**	**2011**	**2012**
Inter Area Network Transfer Capability	80.7	152.8	344.0	424.5	303.4	116.7
Local Area Supply Adequacy	105.5	91.4	93.7	63.4	163.3	116.5
Load Customer Connection	63.7	53.6	70.8	48.1	130.6	124.2
Generation Customer Connection	55.8	29.3	9.7	10.8	44.5	23.3
Enabling Facilities *(Government Instruction)*	0.0	0.0	0.0	0	0.1	16.9
Bulk & Regional Transmission *(Government Instruction)*	0.0	0.0	0.0	0.0	4.5	22.6
Station Equipment Upgrades & Additions to Facilitate Renewables *(Government Instruction)*	0.0	0.0	0.2	0.0	33.6	64.5
Protection and Control for Enablement of Distribution Connected Generation *(Government Instruction)*	0.0	0.0	3.3	0.6	11.4	36.0
Smart Grid	0.0	0.0	0.4	1.4	7.8	6.8
Performance Enhancement	2.8	2.0	2.2	1.7	4.0	4.0
Risk Mitigation	5.2	0.9	17.0	15.8	20.0	3.2
Gross Capital Total	**313.7**	**330.0**	**541.3**	**566.3**	**723.2**	**534.7**
Capital Contributions as per TSC	(41.2)	(19.1)	(25.1)	(28.5)	(106.1)	(77.9)
Net Capital Total	**272.6**	**310.9**	**516.2**	**537.9**	**617.2**	**456.8**

The overall spending on Development Capital work in the 2011 test year has increased over historical levels. The increase is largely attributable to the Bruce to Milton project, additional load connection projects and new government instructed projects to increase renewable generation across Ontario. Further details for each Investment Type are provided in Sections 3.1 to 3.10 below which include explanations of changes in spending patterns compared to historical levels, a brief summary of major projects and, where appropriate, a summary of aspects related to prudency of cost for these projects.

As initiated in Transmission Revenue Requirement proceeding (EB-2008-0272), based on input received during the previous Transmission Revenue Requirement proceeding (EB-2006-0501), Hydro One Transmission has adopted the following Capital Project Category classification to provide an indication as to when specific projects would be considered approved for inclusion in the rate base.

- *Category 1* - Development capital projects for which the OEB has already granted project-specific approval in another proceeding (for example, a proceeding for approval of the project under Section 92 of the OEB Act). For these projects, the actual in-service costs would be included in the rate base when the project goes in-service.
- *Category 2* - Development capital projects that have an in-service date in one of the test years (2011 or 2012) and that do not require an approval under Section 92 of the OEB Act or any other such Board proceeding. Through the current proceeding, Hydro One Transmission is seeking approval for these projects to be included in the rate base when the projects are declared in-service (i.e. upon energization of the facilities).
- *Category 3* - Development capital projects that have significant spending within the test years (2011 or 2012), yet do not have an in-service date in any of the test years and do not require project-specific approvals from the OEB. For these projects, Hydro One Transmission is seeking guidance from the OEB on the appropriateness of the

need, the proposed solution, and the recoverability of the project cost. The actual in-service costs would be included in rate base when the project goes in-service subject to Board approval at a future revenue requirement proceeding.

- *Category 4* - Development capital projects that have significant cash flows within the test years but they will require future project-specific approvals from the OEB in the form of Section 92 applications. Hydro One Transmission is not seeking approvals for these projects within this application since the prudency review for these projects will be tested during the Section 92 process.

3.1 Inter-Area Network Transfer Capability

3.1.1 Description of Inter-Area Network Transfer Capability Investments

The integrated inter-area network, or bulk electric system, operates primarily at 500kV or 230kV over relatively long distances incorporating major generation resources and delivering their output to major load centers in the Province through interconnection points to major transmission stations. The network is also interconnected with the transmission systems in Manitoba, Québec, Michigan, Minnesota, and New York enabling imports and exports.

The investments in the Inter-Area Network Transfer Capability category provide new or upgraded transmission facilities to increase the transfer capability between generation areas and load centers within Ontario and/or with neighbouring utilities, on the basis of planned changes in generation sources and load patterns.

The consequences of not proceeding with these investments include increased risks to reliability and security of the interconnected system as a result of the lack of adequate transmission capacity to integrate supply sources and load demand. Constraints in the provincial transmission system can inhibit the use of Ontario's own generation resources, and imports and exports of power through interconnection facilities. These would result in negative economic or supply adequacy impacts, as well as potentially inhibiting the fulfillment of contractual provisions under agreements signed by the Ontario Government and the OPA.

Funding levels for 2011 and 2012 for Inter-Area Network Transfer Capability projects, along with the spending levels for the bridge and historic years are provided in Table 2 of Appendix A to this exhibit. Projects with gross total funding requirements in excess of $3 million in either of the test years are separately identified in Table 2.

The overall spending in Inter-Area Network Transfer Capability projects has a decreasing trend over the Test Years. The primary reason is that most major projects in this category are coming into service and new projects, per Government Instruction, will not commence construction until after approvals are obtained.

Projects scheduled to be in-service within 2010 to 2011 include:

- Cherrywood TS x Claireville TS: Unbundle 500kV circuits C550V/C551V
- Northeast Transmission Reinforcement: Install Static Var Compensators at Porcupine TS & Kirkland Lake TS
- Northeast Transmission Reinforcement: Install series capacitor banks at Nobel SS
- Install Seven 230 kV Capacitor Banks in South Western Ontario: OPA Near-Term Measures for Bruce Area Generation
- Detweiler TS: Install 230 kV, 350 MVar Static Var Compensator
- Nanticoke TS: Install 500 kV, 350 MVar Static Var Compensator

3.1.2 Summary of Inter-Area Network Transfer Capability Projects

The following summarizes the major inter-area network transfer capability projects separately identified in Table 2. Additional details for the projects identified below are provided in the Investment Summary Documents in Exhibit D2, Tab 2, Schedule 3.

All of the projects described below have either already been approved (Category 1) or are non-discretionary (as defined in the OEB Filing Requirements for Transmission and Distribution Applications).

Project D1: *New 500kV Bruce to Milton Double Circuit Transmission Line*

This project comprises building a new double circuit 500kV line from the Bruce area to load centres in central Ontario. It will provide for the incorporation of two refurbished Bruce GS units and contracted wind power from the Bruce area. The project was approved by the OEB under Section 92 of the OEB Act in its Decision and Order dated September 15, 2008 under Proceeding EB-2007-0050, and is classified as Category 1.

There has been a revision in the project cost estimate since Proceeding EB-2008-0272. There are several factors that resulted in the increase which include:

- Higher than expected bids received for the construction and materials contract.
- A sixteen month delay in forecast start date for construction due to delayed approvals. This resulted in increased carrying costs including additional cost for storage of equipment and construction material.
- An increase of material costs (steel, towers, electrical equipment) at an unprecedented rate exceeding 20% for most materials. The original estimates had assumed a 3% annual escalation.

In a letter dated January 5, 2010 to the OEB, Hydro One provided an update on the developments related to the Bruce to Milton Project; which included notifying the Board of the change in cost and in-service date.

Project D2: *Northeast Transmission Reinforcement: Installation of Static Var Compensators at Porcupine TS and Kirkland Lake TS*

This project comprises the installation of two static var compensators north of Sudbury (one at Porcupine TS and one at Kirkland Lake TS) to enhance the transfer capability to incorporate the new hydroelectric and wind generation that is planned in northern Ontario. This project (along with the project to install two 750MVar Series Capacitors on the 500kV lines between Sudbury and Toronto) is required to incorporate new renewable generation to satisfy government directives and recommendations by the OPA. On December 16, 2009 the project was approved by the OEB under EB-2008-0272 Supplementary Filing, and is classified as Category 1.

Projects D3, D4: *Installation of Static Var Compensators at Detweiler TS and Nanticoke TS*

These projects comprise the installation of two static var compensators (one at Nanticoke TS and one at Detweiler TS) to provide voltage support and to provide for near-term measures to reinforce transmission capability from the Bruce Area in advance of the expected in-service date of the proposed 500kV transmission facility.

These two static var compensator projects were referenced during Proceeding EB-2007-0050 on the Bruce x Milton Reinforcement Project. While these near-term measures themselves were not the subject of the approval request from Hydro One in that case, the need for increased transfer capability in the Bruce area was ultimately determined and evidence was produced supporting the notion that a residual value of the "near-term measures" existed beyond the installation of the Bruce to Milton Transmission line.

In proceeding EB-2008-0272, the Board ruled in the Decision Order that similar interim measures (i.e. the installation of capacitor banks and protection system modifications) were justified on the basis of their relationship to the approved Bruce to Milton Transmission facility; as such these projects are classified as Category 1.

The primary reason for the increase in cost estimate over the cost submitted in proceeding EB-2008-0272 is attributable to the identification of additional requirements during the detailed design and engineering phase. The previous estimate prepared did not have the benefit of site-specific engineering and detailed estimates from vendors.

Project D5, D6, D7: *Installation of Shunt Capacitor Banks at Essa TS, Porcupine TS, and Hanmer TS*

These projects comprise the installation of one shunt capacitor bank at Essa TS, two shunt capacitor banks at Porcupine TS, and one shunt capacitor bank at Hanmer TS to provide voltage support in northern Ontario. The project is required to incorporate new renewable generation to satisfy government directive(s) and recommendations by the OPA.

During the Supplementary Filing for EB-2008-0272, the OPA submitted the rationale for these four shunt capacitor banks along with the Northeast Transmission Reinforcement projects (series capacitors at Nobel SS and Static Var Compensators at Porcupine TS and Kirkland Lake TS). The projects are classified as Category 2 as the in-service date is within the test years.

The OPA has provided support for these projects in its document, "OPA Information Regarding Proposed Facilities in Hydro One's 2011 – 2012 Transmission Rate Application, March 2010." This document is attached in Appendix B to this exhibit.

Project D8: *Installation of Shunt Capacitor Banks at Dryden TS*

This project comprises the installation of two shunt capacitor banks at Dryden TS as a near term measure to improve the transmission capability that currently restricts the grid connection of new renewable energy resources in the west of Atikokan area. This project will be committed only if the OPA recommends it, in order to accommodate new renewable generation to satisfy government directive(s). The project is classified as Category 3 as the in-service date is beyond the test years.

3.2 Local Area Supply Adequacy

3.2.1 Description of Local Area Supply Investments

The local area supply systems operate primarily at 230kV, 115kV, with a few pockets at 69kV, and they link the inter-area network to load centers, such as LDCs and large industrial customers, and, in some cases, to local generators.

Local Area Supply investments provide for new or upgraded facilities in order to provide for area supply adequacy, and to meet load forecast requirements in an area where the loading on existing transmission facilities reach capacity.

The consequences of not proceeding with these investments are dependent on the specific situation, for example:

- Curtailment of load in order to ensure that the power system operates in a reliable mode and within the equipment rating.
- Insufficient reactive support causing system and voltage instability that would lead to widespread adverse impact on the interconnected power system.

Funding levels for 2011 and 2012 for Local Area Supply Adequacy projects, along with the spending levels for the bridge and historic years are provided in Table 3 in Appendix A to this exhibit. Projects with gross total funding requirements in excess of $3 million in either of the test years are separately identified in Table 3. Customer capital contributions, where applicable, were determined in accordance with the TSC and Hydro One Transmission's Connection Procedures approved by the Board.

The primary driver for the increase in 2011 spending on Local area Supply projects, compared to historical levels, is a result of the addition of three new projects: Rebuild Hearn SS, Leaside TS Equipment Uprate, and Manby TS Equipment Uprate to address aging facilities and to increase short-circuit capability to enable more distributed generation in Toronto, as identified in the Minister's letter to Hydro One dated September 21, 2009, Schedule B. Hydro One has received support for this project from the OPA in its document, "OPA Information Regarding Proposed Facilities in Hydro One's 2011 – 2012 Transmission Rate Application, March 2010." This document is attached in Appendix B to this exhibit. Hydro One has also received letters of support from a number of other organizations. These letters of support are attached in Appendix C to this exhibit.

3.2.2 Summary of Local Area Supply Projects

The following summarizes the major local area supply adequacy projects identified in Table 3. Additional details for the projects identified below are provided in the Investment Summary Documents in Exhibit D2, Tab 2, Schedule 3.

Project D9: ***Woodstock Area Transmission Reinforcement***

This project is planned to provide reliable supply capacity to accommodate for load growth in the Woodstock area. There is a need to improve reliability since the existing 115kV transmission supply to Woodstock is expected to be overloaded by spring 2010 should there be a contingency involving the outage of one circuit supplying the Woodstock area. The project was approved by the Board under its Proceeding EB-2007-0027 and is classified as Category 1.

Project D10: ***Rebuild Burlington TS 115kV Switchyard***

This project merges several planned investments for Burlington TS into a single integrated project to rebuild the 115kV switchyard. The project is required to address under-rated equipment with respect to ampacity and short circuit withstand that is limiting the operation and reliable supply of customers from Burlington TS. The project is classified as a Category 2 project as the in-service date is within the test years. This project is for safety and reliability of the transmission system and hence no capital contributions are required.

The primary reason for the increase in cost estimate over the cost submitted in the EB-2008-0272 proceeding is attributable to scope changes to the project.

Project D11: ***Toronto Area Station Upgrades for Short Circuit Capability: Rebuild Hearn SS***

This project is planned to address both aging infrastructure affecting the reliability of supply and under-rated equipment that limits new distributed generation to be connected in the City of Toronto. The project is classified as a Category 2 project as the in-service date is within the test years.

Project D12, D13: ***Toronto Area Station Upgrades for Short Circuit Capability: Leaside TS and Manby TS Equipment Uprate***

These projects are planned to address both aging infrastructure and under-rated equipment that limits the connection of renewable generation in the City of Toronto. The Leaside TS project is classified as a Category 2 project as the in-service date is within the test years; and the Manby TS project is classified as a Category 3 project as the in-service date is beyond the test years.

Project D14: ***Midtown Transmission Reinforcement Plan***

This project is planned to provide reliable supply capacity to the City of Toronto. This project is required to reliably accommodate existing load since the existing 115kV transmission supply is inadequate to meet the coincident summer peak loading under the contingency condition where there is a loss of one circuit. The project is classified as a Category 4 project since further approvals from the Board in the form of a Section 92 application will be required. The Section 92 application for this project was filed on December 23, 2009.

There has been a revision in the project cost estimate since the EB-2008-0272 proceeding. There are several factors that resulted in the increase which include:

- Real Estate costs for the preferred route are higher based on existing land values in the area.
- The tunnel option, being the only way to cross Yonge Street, is significantly more expensive than the solution in the previous estimate which did not contemplate the need for tunneling.
- Construction costs have escalated over the intervening period.

Project D15: *Guelph Area Transmission Reinforcement*

This project is planned to provide reliable transmission supply capacity for load growth in Guelph Area. This project is required as the transmission system is inadequate to meet the local area's existing demand and forecast load requirements. The project is classified as a Category 4 project as further approvals from the Board in the form of Section 92 application will be required.

3.3 Load Customer Connection

3.3.1 Description of Load Customer Connection Investments

Load customer connections can be addressed by new or modified transformation connection facilities including new feeder positions at existing transformer stations, increase of capacity at existing stations, or construction of new lines and stations. The projects are initiated based on the customers' requirements for capacity, reliability, and/or power quality. Because these types of projects are customer driven, the magnitude and volume of work can vary significantly year over year.

The consequences of not proceeding with these projects include: impairment of customers' ability to supply their current and expected loads, increased risk of rotating blackouts where existing facilities are overloaded, and/or violation of Hydro One Transmission's license, specifically, Section 8, "Obligation to Connect", and clause 5 which ensures that the company shall not refuse to make an offer to connect.

Funding levels for 2011 and 2012 for Load Customer Connection projects, along with the spending levels for the bridge and historic years are provided in Table 4 in Appendix A to this exhibit. Projects with gross total funding requirements in excess of $3 million are separately identified in Table 4.

The increase in overall spending on Load Connection projects, compared to historical levels, is a result of several factors which include:

- Deferral of in-service dates on some of the projects compared to the in-service dates identified in previous rate filing Proceeding EB-2008-0272.
- Several projects nearing end-of-life are being refurbished and upgraded at the same time to take advantage of synergies available.
-

3.3.2 Summary of Load Customer Connection Projects

The following is a summary listing of the load customer transformation connection projects by Category Type for which cash flow details are provided in Table 4. All of these projects are non-discretionary and customer driven.

Category 1 Projects	Category 2 Projects	Category 3 Projects	Category 4 Projects
D16: Commerce Way TS	D17: Kirkland Lake TS D18: South Halton Tremaine TS D24: Long Lac TS D25: North Bay TS D26: Barwick TS D27: Duart TS	D19: Ancaster TS D20: East Ottawa TS D22: New Northern Mississauga TS[1] D23: Enfield TS	D21: Leamington TS

[1]New Northern Mississauga TS may require a line connection longer than 2 km, in which case it would become a Category 4 project.

These projects are funded by customers through a combination of future rate revenues and a capital contribution, where required, as determined in accordance with the TSC and Hydro One Transmission's Connection Procedures approved by the OEB. Additional details about these projects are provided in the Investment Summary Documents in Exhibit D2, Tab 2, Schedule 3.

3.4 Generation Customer Connection

3.4.1 Description of Generator Customer Connection Investments

Generation customer connections are addressed by a radial connection; however in some cases other modifications may be required to Hydro One's local area connection facilities in order to incorporate the generation into the system.

Since the middle of 2004, there has been growing generation connection activity in direct response to the initiatives taken by the Ontario Government and the OPA. These initiatives include renewable Request for Proposals ("RFPs"), clean generation RFPs, combined heat and power RFPs, the FIT program, and other project procurements.

The consequences of not proceeding with these investments include:

- Failure to connect generators which have been contracted by the OPA or which have otherwise developed appropriately under the applicable codes and rules, many of which contribute to meeting the Ontario Government's targets for renewable electricity capacity
- Contravention of Hydro One Transmission's obligation to connect new generators under its Transmission License and the TSC.

Funding levels for 2011 and 2012 for Generation Customer Connection projects, along with the spending levels for the bridge and historic years, are provided in the attached Table 5 in Appendix A to this exhibit. Projects with gross capital spending in excess of $3 million in either of the test years are separately identified in Table 5.

The increase in spending level in 2011, compared to historical levels, is primarily due to the January 2009 awarding of long-term contracts for six green energy projects under the Renewables III RFP for in-service by 2012.

3.4.2 Summary of Generator Customer Connection Projects

The following is a summary listing of the pertinent new generators that have been either contracted by the Ontario Government or the OPA, or that are considered substantially advanced (in terms of negotiations and/or implementation), so that they require allocation of funding for transmission upgrades within the test year periods.

- Lower Mattagami Generation Connections (450MW)
- Peaking Generation in Northern York Region (350MW)

- 500MW Renewables III RFP (Talbot, Greenwich, Gosfield, Chatham, Raleigh, and Byran Wind Farms)
- Chatham Wind Generation Connection (260MW)

A provision for future generation connections has also been included to account for unforeseen connections that may be required within the test years to accommodate new generation; these are assumed to be fully funded by the generator proponent.

These projects are categorized as "Customer Driven" because they are requested by the customer to accommodate new generation and connection facilities are fully funded by the customer.

In some cases, network facilities may be triggered which would be the responsibility of Hydro One in accordance with the TSC, and in other cases, Hydro One Transmission takes the opportunity to upgrade or refurbish its equipment while providing a new or modified generation connection. In such cases, the project may include some net cash flow (to be funded by Hydro One Transmission) associated with the refurbishment work. Additional details about these projects are provided in the Investment Summary Documents in Exhibit D2, Tab 2, Schedule 3.

3.5 Enabling Facilities

3.5.1 Description of Enabling Facilities Investments

Enabling Facilities projects are investments in infrastructure, such as: 230kV or 115kV enabler lines and/or 230kV or 115kV enabling transformer stations, in order to facilitate connection of renewable generation to the transmission system. The proposed enabler facilities will be constructed where there is high interest in renewable generation development as identified by the OPA's FIT program.

The projects are initiated based on customer requests for connection of renewable generators. However, the need for the enabler facilities has been recommended by the Ontario Government under the Green Energy and Green Economy Act (refer to Exhibit A, Tab 11, Schedule 4). The need for the investments will be reconfirmed by the OPA on a project by project basis before detailed design and construction is initiated.

The consequences of not proceeding with these investments include:

- Failure to connect generators which have been contracted by the OPA or which have otherwise developed appropriately under the applicable codes and rules, many of which contribute to meeting the Ontario Government's targets for renewable electricity capacity

Funding levels for 2011 and 2012 for Enabling Facilities projects, along with the spending levels for the bridge and historic years are provided in the attached Table 6 in Appendix A to this exhibit. Projects with gross capital spending in excess of $3 million in either of the test years are separately identified in Table 6.

3.5.2 Summary of Enabling Facilities Projects

There are two primary types of enabling facility projects, enabling lines or enabling transmission stations, for which cash flow details are provided at the end of this exhibit. As outlined in Table 6, the government instructed enabling facilities site-specific details are still under development as the FIT program was only launched in October 2009 and the OPA is still in the process of conducting the Economic Connection Test (ECT) for applicants in the FIT Reserve. This process is not expected to be completed by the OPA until late 2010 or early 2011.

None of the enabling facilities projects will be undertaken without obtaining all necessary project specific approval requirements under the EA Act or Section 92/95 of the OEB Act and Hydro One will continue to work closely with the OPA in the planning of these projects. Additional details for these projects are provided in the Investment Summary Documents in Exhibit D2, Tab 2, Schedule 3.

3.6 Bulk & Regional Transmission *(Government Instruction)*

3.6.1 Description of Bulk & Regional Transmission Investments

The investments in the Bulk & Regional Transmission category provide new or upgraded transmission facilities to increase the transfer capability between generation areas and load centers within Ontario, as requested by the Minister in his letter to Hydro One of September 21, 2009, Schedule A, refer to Exhibit A, Tab 11, Schedule 4. Hydro One will work closely with the OPA on the planning of these projects before detailed design and construction is initiated.

The consequences of not proceeding with these investments include:

- Increasing risks to reliability and security as a result of the lack of adequate transmission capacity to integrate supply sources and load demand, and
- Inhibiting the fulfillment of contractual provisions under agreements signed by the Ontario Government and the OPA.

Funding levels for 2011 and 2012 for Bulk & Regional Transmission projects, along with the spending levels for the bridge and historic years, are provided in Table 7 in Appendix

A to this exhibit. Projects with gross total funding requirements in excess of $3 million in either of the test years are separately identified in Table 7.

3.6.2 Summary of Bulk & Regional Transmission Projects

The following summarizes the bulk & regional transmission projects separately identified in Table 7. Additional details for the projects identified below are provided in the Investment Summary Documents in Exhibit D2, Tab 2, Schedule 3.

Project D34: ***Algoma x Sudbury Transmission Expansion***

This project comprises building a 500 kV transmission line (approximately 210 km) along an existing corridor from Sudbury to the Algoma Area. This project is required, in conjunction with other transmission projects, to transmit renewable generation developed in the Northwest to the load centres in Southern Ontario. The project will require approval by the OEB under Section 92 of the OEB Act, and is classified as Category 4.

Project D35: ***Northwest Transmission Reinforcement (Pickle Lake x Nipigon)***

This project comprises building a new single-circuit 230 kV transmission line approximately 430 km from the Nipigon area along the east side of Lake Nipigon and Wabakimi Park to a new TS near Pickle Lake. This new transmission facility is required to reinforce the northwestern Ontario transmission system to allow for the future connection to the grid of the area’s renewable hydro and wind potential, to provide capacity to supply the area’s long-term load growth, particularly in the mining sector, to provide opportunities for near and long term connection to the grid by remote communities and to enable economic development. The project will require an

Environmental Assessment approval and must be approved by the OEB under Section 92 of the OEB Act, and is classified as Category 4.

3.7 Station Equipment Upgrades and Additions to Facilitate Renewables *(Government Instruction)*

3.7.1 <u>Description of Station Equipment Upgrade Investments</u>

Station equipment upgrades are driven by transmission station capacity constraints that are limiting the amount of embedded generation that can be connected to the distribution system.

The projects are initiated based the Ontario Government's request as outlined in a letter to Hydro One dated September 21, 2009 requesting Hydro One to immediately proceed with planning, development and implementation of upgrades to enable distribution system connected generation (Schedule B Projects), refer to Exhibit A, Tab 11, Schedule 4. Hydro One will work closely with the OPA on the planning of these projects before detailed design and construction is initiated.

The consequences of not proceeding with these investments include:

- Failure to connect generators which have been contracted by the OPA or which have otherwise developed appropriately under the applicable codes and rules, many of which contribute to meeting the Ontario Government's targets for renewable electricity capacity

Funding levels for 2011 and 2012 for Station Equipment Upgrades projects, along with the spending levels for the bridge and historic years, are provided in the attached Table 8 in Appendix A to this exhibit. Projects with gross capital spending in excess of $3 million in either of the test years are separately identified in Table 8. It has been assumed that these projects will be pool funded, based on the interpretation of Compliance Bulletin #200606 issued by the Ontario Energy Board on September 11, 2006.

3.7.2 Summary of Station Equipment Upgrade Projects

There are two primary types of station upgrade projects, installation of static var compensators and installation of in-line circuit breakers, for which cash flow details are provided in Table 8. All of these projects are non-discretionary and are classified as FIT Driven. As such, until the OPA finalizes the FIT contracts and site-specific project details are developed, work will not be undertaken on these projects. Additional details for these projects are provided in the Investment Summary Documents in Exhibit D2, Tab 2, Schedule 3.

3.8 Protection and Control for Enablement of Distribution Connected Generation *(Government Instruction)*

3.8.1 Description of Protection and Control Modifications for Distribution Connected Generation Investments

The connection of generation to the Distribution Systems supplied from the Hydro One Transmission System requires a number of modifications and additions to the Protection and Control systems in the Transmission Stations. These modifications are required to preserve the loading capability of the feeders, to preserve the proper function of station protections, to preserve the effectiveness of Bulk Power System protection systems that require prompt shedding of load and to provide correct transfer trip signaling to the distribution connected generators.

The consequences of not proceeding with these programs include:

- Risk to reliability as a result of all generation connected to the transmission station having to be forced out of service during various transmission outages,
- Contravention of Hydro One's reliability compliance obligations, as they pertain to the NPCC's requirements for under frequency load shedding, and the reliability of Special Protections Schemes.
- Premature aging of transformer station equipment due to over-utilization, and
- Further inhibiting the amount of distributed generation that can be connected to the system.

Funding levels for 2011 and 2012 for Protection and Control Modification projects, along with the spending levels for the bridge and historic years, are provided in the attached Table 9 in Appendix A to this exhibit. Projects with gross capital spending in excess of $3 million in either of the test years are separately identified in Table 9.

3.8.2 Summary of Protection and Control Modifications for Distribution Connected Generation Projects

The following is a summary listing of the investments identified under the Protection and Control for Enablement of Distribution Connected Generation program. All of these programs are non-discretionary.

Transmission Station Protection Modifications:

- Feeder Protection Replacement for DG
- Bus Protection Modification for DG
- TS Transformer Protection Modification for DG
- Line Protections

Transfer Trip Facilities

- Station Telecom Facilities for Transfer Trip
- Transmission Island Detection Facilities

Others

- Station telemetry expansion
- Under Frequency Load Shedding and Load Rejection Modifications for DG

Additional details on those Programs with annual gross capital spending in excess of $3 million in either of the test years as identified in Table 9 are provided in the Investment Summary Documents in Exhibit D2, Tab 2, Schedule 3.

3.9 Smart Grid

3.9.1 Description of Smart Grid Investments

The main objective of investments under this driver is to test the implementation and integration of technology in an innovative manner that will permit Hydro One to implement Smart Grid/Zone solutions as other asset solutions and replacement strategies are decided. Development Capital will provide the funding for work in the following key areas:

- Interoperable bus architecture (IEC 61850 Standards) at a transformer station
- Field pilot(s) to test new protection and control techniques at transformer stations including real time dynamic control of feeders to manage DGs.
- DVAR controller at transformer stations to manage reactive power with high DG penetration

The consequences of not proceeding with this investment include:

- Inability to effectively accommodate distributed generation resulting from the feed-in tariff program and other green initiatives advocated through the Ontario Government's GEGEA;
- Insufficient testing/understanding of IEC 61850 Standards, which are very critical because integrated testing, evaluation, and validation of various smart devices including communication interfaces is needed prior to major deployment.

The field pilots will also allow Hydro One to study and evaluate cost benefits appropriate to a large rural electrical network.

3.9.2 Summary of Smart Grid Investments

Hydro One plans to build its Smart Grid on the foundations of the Smart Meter Program and the Conservation and Demand Management Program so that it will also be able to facilitate a robust integration of DGs on its transmission system. This will require a well planned and interoperable architecture at its transformer stations that will provide enhanced protection and control to manage its assets and connected load and generation customers on the distribution feeders. Investments are planned in the following thematic areas, but not limited to:

1. Implementation and end-to-end testing of the new architecture at Owen Sound TS and Meaford TS (Smart Zone)
2. Installation of DVAR controller at TS to manage reactive power with high DG penetration.
3. Enhanced monitoring and control

Development Capital expenditures will fund long-term innovative strategies relating to Smart Zone development in the Owen Sound Area. These strategies offer value to Hydro One customers through improvements in protection and control systems as well as enhancing transmission infrastructure to connect additional renewable energy generation as called upon by the GEGEA. The projects will aim to improve the reliability and quality of supply to customers or improve performance monitoring for the transmission system. This capital spending will fund pilots for field testing that will involve installation of new equipment along with hardware and software implementation at transformer stations. For example, new technologies and next generation intelligent electronic devices (IEDs) for station equipment condition diagnostics will be installed at the transformer station. These diagnostics will allow better understanding of asset condition and will become a key element to improve maintenance programs (e.g. optimized maintenance schedule and prioritized equipment refresh). These transmission investments will also complement and be coordinated with distribution projects and connection of DG for seamless integration of the two systems. In some cases projects will be undertaken in partnerships with vendors, universities and other utilities on an as needed basis.

The smart grid capital expenditures in 2011 and 2012 represent the costs associated with the Smart Zone Pilot only. Based on these findings from this pilot work, new programs may be created in the future.

Funding levels for 2011 and 2012 for Smart Grid projects, along with the spending levels for the bridge and historic years, are provided in the attached Table 10 in Appendix A to this exhibit. Additional details on these projects are provided in the Investment Summary Documents in Exhibit D2, Tab 2, Schedule 3.

3.10 Performance Enhancement and Risk Mitigation Programs

The program investments in this category are grouped into two categories; Performance Enhancement and Risk Mitigation as outlined below:

3.10.1 Performance Enhancement

There are two types of Performance Enhancement programs: Delivery Point Performance and Power Quality.

a) Delivery Point Performance

Delivery Point Performance investments are initiated to improve the performance of either group or individual customer's performance at their delivery point. As per the Customer Delivery Point Performance Standard issued by the Board under Proceeding EB-2002-0424, a delivery point for a customer is defined as an outlier delivery point ("ODP") when the reliability performance of that delivery point is worse than its historical baseline performance over a defined period of time.

There are two types of investments undertaken to address ODPs. The first are investments associated with the regular maintenance program (eg. pole replacement program) and the second are investments to address a specific problem or to implement a corrective solution (eg. installation of fault indicators to target the location of phase spacers, surge arrestors).

b) Power Quality

Power Quality issues are complex and generally mitigation measures are unique to customer operations. The installation of Power Quality monitors are needed to collect and assess Power Quality data to understand the issues and then work with individual customers to address their issue. To date, 42 power quality monitors have been installed at critical sites to capture this information.

The consequences of not proceeding with these Performance Enhancement investments include: non-compliance with the applicable regulatory requirements, increased customer complaints, and reliability issues.

Funding levels for 2011 and 2012 for Performance Enhancement projects, along with the spending levels for the bridge and historic years, are provided in the attached Table 11 in Appendix A to this exhibit. Additional details on those programs with annual gross capital spending in excess of $3 million in either of the test years are provided in the Investment Summary Documents in Exhibit D2, Tab 2, Schedule 3.

3.10.2 Compliance/Mitigate High-Risk

Work to ensure compliance with mandatory standards (such as NERC, NPCC) is met, and high risk situations are mitigated, is funded through this development program.

With the exception of Force Majeure events such as the 1998 ice storm and the 2003 blackout, events presenting unacceptable risks to supply reliability are identified. Projects are identified to address needs normally not planned on a priority basis considering legislative, regulatory, environmental and safety requirements. Accordingly, the funding levels under this program can vary based on issue(s) and required remedial actions.

The consequences of not proceeding with these investments include: non-compliance with the applicable regulatory requirements, increased customer complaints, and inability to mitigate high-risk safety, security and reliability issues. For example, in 2007 a capacitor bank remediation plan to address system security and safety for various stations was developed due to a catastrophic event at Richview TS. During 2008, detailed studies were required to identify more specialized mitigation measures to be implemented at some stations (because of their unique characteristics); as a result, there was no significant funding of capital projects in this program area during that year. The stations requiring specialized mitigation have now been identified and the required funding for the work to be carried out has been allocated in 2009, 2010 and 2011.

Funding levels for 2011 and 2012 for Risk Mitigation projects, along with the spending levels for the bridge and historic years, are provided in the attached Table 12 in Appendix A to this exhibit. Additional details on those programs with annual gross capital spending in excess of $3 million in either of the test years are provided in the Investment Summary Documents in Exhibit D2, Tab 2, Schedule 3.

Appendix A

Summary of Development Capital Projects in Excess of $3 Million

Table 2
Inter-Area Network Transfer Capability: Summary of Development Capital Projects in Excess of $3 Million

Item#	Investment Description	Classification as per OEB Filing Guideline	Capital Project Category	EA Status	Section 92 Status	Gross Cash Flow ($ Millions)									In-Service Years
						Historical			Bridge	Test	Test	Gross Total Cost[1]	Capital Contribution[2]	Net Total Cost[3]	
						2007	2008	2009	2010	2011	2012				
D1	New 500 kV Bruce to Milton Double Circuit Transmission Line[4]	Development, Non-Discretionary	Category 1	Completed	Completed	6.6	44.8	150.1	191.0	184.4	94.3	695.5	0	695.5	10/31/2012
D2	Northeast Transmission Reinforcement: Install SVC's at Porcupine TS & Kirkland Lake TS	Development, Non-Discretionary	Category 1	Not Required	Not Required	0.4	1.8	29.3	57.0	33.1	0	121.6	0	121.6	12/31/2011
D3	Nanticoke TS - Install 500 kV, 350 MVar Static Var Compensator	Development, Non-Discretionary	Category 1	Not Required	Not Required	0	0.1	2.8	59.6	22.1	0	84.6	0	84.6	5/31/2011
D4	Detweiler TS – Install 230 kV, 350 MVar Static Var Compensator	Development, Non-Discretionary	Category 1	Not Required	Not Required	0	0.2	1.2	44.0	34.9	0	80.3	0	80.3	5/1/2011
D5	Essa TS – Install 250 MVar Shunt Capacitor Bank	Development, Non-Discretionary	Category 2	Not Required	Not Required	0	0	0.1	0.3	5.9	0	6.3	0	6.3	9/1/2011
D6	Porcupine TS - Install two100 MVar Shunt Capacitor Banks	Development, Non-Discretionary	Category 2	Not Required	Not Required	0	0	0.1	1.1	10.3	0.2	11.7	0	11.7	12/31/2011
D7	Hanmer TS - Install 149 MVar Shunt Capacitor Bank	Development, Non-Discretionary	Category 2	Not Required	Not Required	0	0	0	0.5	7.9	0.1	8.5	0	8.5	12/31/2011
D8	Dryden TS – Install a Shunt Capacitor Bank	Development, Non-Discretionary	Category 3	Not Required	Not Required	0	0	0.1	0	0.1	10.3	10.7	0	10.7	12/1/2013
	Other Capital Projects (<$3M) with 2011-12 Cashflows[5]					0	0	0.2	0	2.1	11.8	407.9	0	407.9	
	Other Historical Projects (pre-2011)[6]					73.7	105.9	160.1	71.0	2.6	0.0	508.2	1.3	506.9	
	Total					**80.7**	**152.8**	**344.0**	**424.5**	**303.4**	**116.7**	**1935.3**	**1.3**	**1934.0**	

Notes

Note 1: **Gross Total Cost:** of the plan cost, including the sum of the cash flows in the years before 2011 and after 2012 and the amount of customer contribution where applicable.
Note 2: Customer Contribution: the sum of the cash flows that is paid by the customer (where applicable). The capital contribution amounts indicated herein are considered preliminary, since they are yet to be finalized, based on the signed CCRA and the actual project cost.
Note 3: Net Total Cost: Gross Total Cost minus Customer Contribution.
Note 4: The cost estimate assumes the accelerated recovery of project costs as outlined in Exhibit A-11-5.
Note 5: The cash flows shown in **"Other Capital Projects"** comprise accumulated gross cash flows for projects that require non-zero expenditures of less than $3 million in either 2011 or 2012.
Note 6: The cash flows shown in **"Other Historical Projects"** comprise accumulated gross cash flows in Historical and Bridge years for projects that do not have any expenditure in 2011 or 2012.

Table 3
Local Area Supply Adequacy: Summary of Development Capital Projects in Excess of $3 Million

Item#	Investment Description	Classification as per OEB Filing Guideline	Capital Project Category	EA Status	Section 92 Status	Gross Cash Flow ($ Millions)									In-Service Years
						Historical			Bridge	Test	Test	Gross Total Cost[1]	Capital Contribution[2]	Net Total Cost[3]	
						2007	2008	2009	2010	2011	2012				
D9	Woodstock Area Transmission Reinforcement	Development, Non-Discretionary	Category 1	Done	Done	0.7	3.8	20.8	24.7	20.7	0	70.9	0	70.9	4/30/2011
D10	Rebuild Burlington TS 115kV Switchyard	Development, Non-Discretionary	Category 2	Not Required	Not Required	0.1	2.2	2.4	19.8	30.4	1.4	56.4	0	56.4	Summer 2012
D11	Toronto Area Station Upgrades for Short Circuit Capability: Rebuild Hearn SS	Development, Non-Discretionary	Category 2	Required	Not Required	0	0	0.3	3.0	54.6	27.0	84.9	0	84.9	12/31/2012
D12	Toronto Area Station Upgrades for Short Circuit Capability: Leaside TS Equipment Uprate	Development, Non-Discretionary	Category 2	Not Required	Not Required	0	0	0	2.0	13.5	21.9	37.4	0	37.4	12/31/2012
D13	Toronto Area Station Upgrades for Short Circuit Capability: Manby TS Equipment Uprate	Development, Non-Discretionary	Category 3	Not Required	Not Required	0	0	0	0	9.0	9.2	30.4	0	30.4	12/31/2013
D14	Midtown Transmission Reinforcement Plan	Development, Non-Discretionary	Category 4	Underway	Underway	0.1	0.1	0.9	3.8	31.0	36.7	107.3	44.2	63.1	4/1/2013
D15	Guelph Area Transmission Reinforcement	Development, Non-Discretionary	Category 4	In Progress	Required	0	0.2	0.2	1.0	1.0	4.1	50.7	0	50.7	5/31/2014
	Other Capital Projects (<$3M) with 2011-12 Cashflows[5]					0.3	0.6	0.2	0.1	3.1	16.2	706.8 [7]	0	706.8	
	Other Historical Projects (pre-2011)[6]					104.3	84.5	68.9	9.0	0.0	0.0	185.7	8.1	177.6	
	Total					**105.5**	**91.4**	**93.7**	**63.4**	**163.3**	**116.5**	**1330.5**	**52.3**	**1278.2**	

Notes

Note 1: **Gross Total Cost:** of the plan cost, including the sum of the cash flows in the years before 2011 and after 2012 and the amount of customer contribution where applicable.
Note 2: Customer Contribution: the sum of the cash flows that is paid by the customer (where applicable). The capital contribution amounts indicated herein are considered preliminary, since they are yet to be finalized, based on the signed CCRA and the actual project cost.
Note 3: Net Total Cost: Gross Total Cost minus Customer Contribution.
Note 5: The cash flows shown in **"Other Capital Projects"** comprise accumulated gross cash flows for projects that require non-zero expenditures of less than $3 million in either 2011 or 2012.
Note 6: The cash flows shown in **"Other Historical Projects"** comprise accumulated gross cash flows in Historical and Bridge years for projects that do not have any expenditure in 2011 or 2012.
Note 7: The Gross Total Cost consists of several major multi-year projects under consideration for beyond 2012, which have some minimal cashflow in 2011 and/or 2012 in order to perform preliminary studies and engineering.

Table 4
Load Customer Connection: Summary of Development Capital Projects in Excess of $3 Million

Item#	Investment Description	Classification as per OEB Filing Guideline	Capital Project Category	EA Status	Section 92 Status	Gross Cash Flow ($ Millions)									In-Service Years
						Historical			Bridge	Test	Test	Gross Total Cost[1]	Capital Contribution[2]	Net Total Cost[3]	
						2007	2008	2009	2010	2011	2012				
D16	Commerce Way TS: Build new TS and Line Connection (formerly Woodstock East TS)	Connection, Customer Driven	Category 1	Completed	Completed	0.0	0.3	1.0	10.9	27.1	6.5	45.8	24.2	21.6	1/31/2012
D17	Kirkland Lake TS: Reconnect Idle K4 Line	Connection, Customer Driven	Category 2	Required	Not Required	0	0	0.1	0.1	13.3	0.2	13.7	13.7	0	4/1/2011
D18	South Halton Tremaine TS: Build New Transformer Station	Connection, Customer Driven	Category 2	In Progress	Not Required	0.0	0.1	0.3	1.6	20.9	5.5	28.5	19.1	9.4	6/1/2012
D19	Ancaster TS: Build new Transformer Station and Line Connection	Connection, Customer Driven	Category 3	Required	TBD	0	0	0	0	3.4	17.0	24.1	8.2	15.9	5/30/2013
D20	East Ottawa TS: Build new Transformer Station	Connection, Customer Driven	Category 3	Required	Not Required	0	0	0	0	3.6	21.3	33.4	30.2	3.2	5/30/2013
D21	Leamington TS: New 230/27.6 kV DESN and Line Connection	Connection, Customer Driven	Category 4	In Progress	Required	0.1	0.3	0.5	0.1	15.4	33.8	62.4	0	62.4	5/31/2013
D22	New 230/28 kV Transformer Station in Northern Mississauga & Line Connection	Connection, Customer Driven	Category 3	Required	TBD	0	0	0	0	0.1	7.4	39.3	30.2	9.1	5/1/2014
D23	Enfield TS: Build 230/44 kV DESN and Line Connection (formally Oshawa Area TS)	Connection, Customer Driven	Category 3	Required	Not Required	0.3	0.3	0.1	0	0	4.9	28.7	8.0	20.7	5/31/2014
D24	Long Lac TS: Replace End-of-Life 115-44 kV Transformers	Connection, Customer Driven	Category 2	Not Required	Not Required	0.1	0.2	5.5	8.5	5.3	0	19.8	0	19.8	5/31/2011
D25	North Bay TS: Upgrade to a 115-44 kV Transformer Station	Connection, Customer Driven	Category 2	Not Required	Not Required	0	0	0.1	0	18.3	8.4	26.8	0	26.8	5/1/2012
D26	Barwick TS: Build new Transformer Station	Connection, Customer Driven	Category 2	In Progress	Not Required	0	0.1	0.4	0	8.8	6.2	15.5	0	15.5	10/29/2012
D27	Duart TS: Build new Transformer Station and Line Connection (formerly Rodney TS)	Connection, Customer Driven	Category 2	Completed	Not Required	0.2	0.1	0.9	0.7	12.1	12.6	26.7	0	26.7	12/31/2012
	Other Capital Projects (<$3M) with 2011-12 Cashflows[5]					0.1	0.0	0.0	2.7	2.3	0.4	44.2	31.0	13.2	
	Other Historical Projects (pre-2011)[6]					62.9	52.2	61.9	23.5	0.0	0.0	115.6	23.0	92.6	
	Total					**63.7**	**53.6**	**70.8**	**48.1**	**130.6**	**124.2**	**524.5**	**187.6**	**336.9**	

Notes

Note 1: **Gross Total Cost:** of the plan cost, including the sum of the cash flows in the years before 2011 and after 2012 and the amount of customer contribution where applicable.
Note 2: Customer Contribution: the sum of the cash flows that is paid by the customer (where applicable). The capital contribution amounts indicated herein are considered preliminary, since they are yet to be finalized, based on the signed CCRA and the actual project cost.
Note 3: Net Total Cost: Gross Total Cost minus Customer Contribution.
Note 5: The cash flows shown in **"Other Capital Projects"** comprise accumulated gross cash flows for projects that require non-zero expenditures of less than $3 million in either 2011 or 2012.
Note 6: The cash flows shown in **"Other Historical Projects"** comprise accumulated gross cash flows in Historical and Bridge years for projects that do not have any expenditure in 2011 or 2012.

Table 5
Generation Customer Connection: Summary of Development Capital Projects in Excess of $3 Million

Item#	Investment Description	Classification as per OEB Filing Guideline	Capital Project Category	EA Status	Section 92 Status	Gross Cash Flow ($ Millions)									In-Service Years
						Historical			Bridge	Test	Test	Gross Total Cost[1]	Capital Contribution[2]	Net Total Cost[3]	
						2007	2008	2009	2010	2011	2012				
D28	500 MW Renewables III RFP (Talbot Wind Farm)	Connection, Customer Driven	Category 2	Not Required	Not Required	0	0	0	1.9	23.0	0	25.0	25.0	0	2011
D29	350 MW Peaking Generation in Northern York Region	Connection, Customer Driven	Category 2	Not Required	Not Required	0	0	0	0.4	4.5	0	4.9	4.9	0	2011
D30	Chatham Wind Generation Connection (260MW)	Connection, Customer Driven	Category 2	Not Required	Not Required	0	0	0	0	0.1	4.1	4.2	4.2	0	2012
D31	Lower Mattagami Generation Connections	Connection, Customer Driven	Category 4	Required	Required	0.3	0	0.1	0.5	2.0	4.0	8.3	8.3	0	2012
	Future Generation Provision	Connection, Customer Driven	Category 2	Unknown	Unknown	0	0	0	0	10.4	11.1	31.6	31.6	0	annual
	Other Capital Projects (<$3M) with 2011-12 Cashflows[5]					0.0	0.0	0.0	1.8	4.5	4.1	18.5	18.5	0	
	Other Historical Projects (pre-2011)[6]					55.5	29.3	9.6	6.2	0.0	0.0	100.6	40.4	60.2	
	Total					**55.8**	**29.3**	**9.7**	**10.8**	**44.5**	**23.3**	**193.1**	**132.9**	**60.2**	

Notes

Note 1: **Gross Total Cost:** of the plan cost, including the sum of the cash flows in the years before 2011 and after 2012 and the amount of customer contribution where applicable.
Note 2: Customer Contribution: the sum of the cash flows that is paid by the customer (where applicable). The capital contribution amounts indicated herein are considered preliminary, since they are yet to be finalized, based on the signed CCRA and the actual project cost.
Note 3: Net Total Cost: Gross Total Cost minus Customer Contribution.
Note 5: The cash flows shown in **"Other Capital Projects"** comprise accumulated gross cash flows for projects that require non-zero expenditures of less than $3 million in either 2011 or 2012.
Note 6: The cash flows shown in **"Other Historical Projects"** comprise accumulated gross cash flows in Historical and Bridge years for projects that do not have any expenditure in 2011 or 2012.

Table 6
Enabling Facilities (Government Instruction): Summary of Development Capital Projects in Excess of $3 Million

Item#	Investment Description	Classification as per OEB Filing Guideline	Capital Project Category	EA Status	Section 92 Status	Gross Cash Flow ($ Millions)									In-Service Years
						Historical			Bridge	Test	Test	Gross Total Cost[1]	Capital Contribution[2]	Net Total Cost[3]	
						2007	2008	2009	2010	2011	2012				
D32	Enabling 230/44kV TS #1 and Short (<2km) Tap *(Item #2 in Schedule B)*	Development, Non-Discretionary	Category 3	Required	Not Required	0	0	0	0	0.05	8.4	33.8	0	33.8	2013
D33	Enabling 115/44kV TS #1 and Short (<2km) Tap *(Item #2 in Schedule B)*	Development, Non-Discretionary	Category 3	Required	Not Required	0	0	0	0	0.05	8.4	33.8	0	33.8	2013
	Other Capital Projects (<$3M) with 2011-12 Cashflows[5]					0	0	0	0	0	0.1	71.0	0	71.0	
	Other Historical Projects (pre-2011) [6]					0	0	0	0	0	0	0	0	0	
	Total					**0.0**	**0.0**	**0.0**	**0**	**0.1**	**16.9**	**138.6**	**0**	**138.6**	

<u>Notes</u>

Note 1: **Gross Total Cost:** of the plan cost, including the sum of the cash flows in the years before 2011 and after 2012 and the amount of customer contribution where applicable.
Note 2: Customer Contribution: the sum of the cash flows that is paid by the customer (where applicable). The capital contribution amounts indicated herein are considered preliminary, since they are yet to be finalized, based on the signed CCRA and the actual project cost.
Note 3: Net Total Cost: Gross Total Cost minus Customer Contribution.
Note 5: The cash flows shown in **"Other Capital Projects"** comprise accumulated gross cash flows for projects that require non-zero expenditures of less than $3 million in either 2011 or 2012.
Note 6: The cash flows shown in **"Other Historical Projects"** comprise accumulated gross cash flows in Historical and Bridge years for projects that do not have any expenditure in 2011 or 2012.

Table 7
Bulk & Regional Transmission (Government Instruction): Summary of Development Capital Projects in Excess of $3 Million

Item#	Investment Description	Classification as per OEB Filing Guideline	Capital Project Category	EA Status	Section 92 Status	Gross Cash Flow ($ Millions)									In-Service Years
						Historical			Bridge	Test	Test	Gross Total Cost[1]	Capital Contribution[2]	Net Total Cost[3]	
						2007	2008	2009	2010	2011	2012				
D34	Algoma x Sudbury Transmission Expansion[4] *(Item #4 in Schedule A)*	Development, Non-Discretionary	Category 4	Required	Required	0	0	0	0	0	5.7	431.6	0	431.6	12/31/2015
D35	Northwest Transmission Reinforcement[4] *(Item #14 in Schedule A)*	Development, Non-Discretionary	Category 4	Underway	Underway	0	0	0	0	4.5	16.9	399.5	0	399.5	12/31/2014
	Other Capital Projects (<$3M) with 2011-12 Cashflows[5]					0	0	0	0	0	0	0	0	0	
	Other Historical Projects (pre-2011)[6]					0	0	0	0	0	0	0	0	0	
	Total					**0.0**	**0.0**	**0.0**	**0.0**	**4.5**	**22.6**	**831.1**	**0.0**	**831.1**	

Notes

Note 1: **Gross Total Cost:** of the plan cost, including the sum of the cash flows in the years before 2011 and after 2012 and the amount of customer contribution where applicable.
Note 2: Customer Contribution: the sum of the cash flows that is paid by the customer (where applicable). The capital contribution amounts indicated herein are considered preliminary, since they are yet to be finalized, based on the signed CCRA and the actual project cost.
Note 3: Net Total Cost: Gross Total Cost minus Customer Contribution.
Note 4: Accelerated recovery of project costs will be sought as part of the individual Section 92 Applications as outlined in Exhibit A-11-4.
Note 5: The cash flows shown in **"Other Capital Projects"** comprise accumulated gross cash flows for projects that require non-zero expenditures of less than $3 million in either 2011 or 2012.
Note 6: The cash flows shown in **"Other Historical Projects"** comprise accumulated gross cash flows in Historical and Bridge years for projects that do not have any expenditure in 2011 or 2012.

Table 8
Station Equipment Upgrades & Additions to Facilitate Renewables (Government Instruction): Summary of Development Capital Projects in Excess of $3 Million

Item#	Investment Description	Classification as per OEB Filing Guideline	Capital Project Category	EA Status	Section 92 Status	Gross Cash Flow ($ Millions) Historical 2007	Historical 2008	Historical 2009	Bridge 2010	Test 2011	Test 2012	Gross Total Cost[1]	Capital Contribution[2]	Net Total Cost[3]	In-Service Years
D36	Static Var Compensator #1 at Existing Station in South Western Ontario *(Item #1 in Schedule B)*	Development, Non-Discretionary	Category 3	Not Required	Not Required	0	0	0	0	0.4	32.9	78.7	0	78.7	2013
D37	In-Line Circuit Breakers #1 *(Item #4 in Schedule B)*	Development, Non-Discretionary	Category 2	TBD	Not Required	0	0	0	0	13.4	6.9	20.3	0	20.3	2012
D38	In-Line Circuit Breakers #2 *(Item #4 in Schedule B)*	Development, Non-Discretionary	Category 2	TBD	Not Required	0	0	0	0	13.4	6.9	20.3	0	20.3	2012
D39	In-Line Circuit Breakers #3 *(Item #4 in Schedule B)*	Development, Non-Discretionary	Category 3	TBD	Not Required	0	0	0	0	3.2	7.2	20.8	0	20.8	2013
D40	In-Line Circuit Breakers #4 *(Item #4 in Schedule B)*	Development, Non-Discretionary	Category 3	TBD	Not Required	0	0	0	0	3.2	7.2	20.8	0	20.8	2013
D41	In-Line Circuit Breakers #5 *(Item #4 in Schedule B)*	Development, Non-Discretionary	Category 3	TBD	Not Required	0	0	0	0	0	1.2	21.6	0	21.6	2014
D42	In-Line Circuit Breakers #6 *(Item #4 in Schedule B)*	Development, Non-Discretionary	Category 3	TBD	Not Required	0	0	0	0	0	1.2	21.6	0	21.6	2014
	Other Capital Projects (<$3M) with 2011-12 Cashflows [5]					0	0	0.2	0	0	1.0	170.8	0	170.8	
	Other Historical Projects (pre-2011)[6]					0	0	0	0	0	0	0	0	0	
	Total					**0.0**	**0.0**	**0.2**	**0.0**	**33.6**	**64.5**	**374.9**	**0.0**	**374.9**	

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Notes

Note 1: **Gross Total Cost:** of the plan cost, including the sum of the cash flows in the years before 2011 and after 2012 and the amount of customer contribution where applicable.
Note 2: Customer Contribution: the sum of the cash flows that is paid by the customer (where applicable). The capital contribution amounts indicated herein are considered preliminary, since they are yet to be finalized, based on the signed CCRA and the actual project cost.
Note 3: Net Total Cost: Gross Total Cost minus Customer Contribution.
Note 5: The cash flows shown in **"Other Capital Projects"** comprise accumulated gross cash flows for projects that require non-zero expenditures of less than $3 million in either 2011 or 2012.
Note 6: The cash flows shown in **"Other Historical Projects"** comprise accumulated gross cash flows in Historical and Bridge years for projects that do not have any expenditure in 2011 or 2012.

Table 9
Protection and Control for Enablement of Distribution Connected Generation (Government Instruction):
Summary of Development Capital Projects in Excess of $3 Million

Item #	Investment Description	Classification as per OEB Filing Guideline	Gross Cash Flow ($ Millions)					
			Historical			Bridge	Test	Test
			2007	2008	2009	2010	2011	2012
D43	Station Protection Upgrades for Distributed Generation	Development Non-Discretionary	0	0	0	0	5.3	15.8
D44	Transfer Trip Facilities	Development Non-Discretionary	0	0	0	0	4.7	14.0
	Other Capital Projects (<$3M) With 2011-12 Cashflows[5]		0	0	3.3	0.6	1.4	6.2
	Total		**0.0**	**0.0**	**3.3**	**0.6**	**11.4**	**36.0**

<u>Notes</u>

Note 5: The cash flows shown in **"Other Capital Projects"** comprise accumulated gross cash flows for projects that require non-zero expenditures of less than $3 million in either 2011 or 2012.

Table 10
Smart Grid: Summary of Development Capital Programs

Item #	Investment Description	Classification as per OEB Filing Guideline	Gross Cash Flow ($ Millions)					
			Historical			Bridge	Test	Test
			2007	2008	2009	2010	2011	2012
D45	End to End Testing for Interoperable Bus Architecture at Owen Sound and Meaford Transformer Stations	Development Non-Discretionary	0	0	0	0	5.5	5.5
	Other Capital Projects (<$3M) With 2011-12 Cashflows[5]		0	0	0.4	1.4	2.3	1.3
	Total		**0.0**	**0.0**	**0.4**	**1.4**	**7.8**	**6.8**

<u>Notes</u>

Note 5: The cash flows shown in **"Other Capital Projects"** comprise accumulated gross cash flows for projects that require non-zero expenditures of less than $3 million in either 2011 or 2012.

Table 11
Performance Enhancement: Summary of Development Capital Programs

Item #	Investment Description	Classification as per OEB Filing Guideline	Gross Cash Flow ($ Millions)					
			Historical			Bridge	Test	Test
			2007	2008	2009	2010	2011	2012
D46	Various lines and TSs outliers-inliers	Development Non-Discretionary	2.8	2.0	2.2	1.7	4.0	4.0
	Total		**2.8**	**2.0**	**2.2**	**1.7**	**4.0**	**4.0**

Table 12
Risk Mitigation: Summary of Development Capital Programs

Item #	Investment Description	Classification as per OEB Filing Guideline	Gross Cash Flow ($ Millions)					
			Historical			Bridge	Test	Test
			2007	2008	2009	2010	2011	2012
D47	Mitigate Reliability Problems of HV Shunt Capacitor Installations	Development Non-Discretionary	4.0	0.3	14.8	12.2	16.8	0.0
	Other Capital Projects (<$3M) With 2011-12 Cashflows[5]	Development Non-Discretionary	1.2	0.6	2.2	3.6	3.2	3.2
	Total		**5.2**	**0.9**	**17.0**	**15.8**	**20.0**	**3.2**

Notes

Note 5: The cash flows shown in **"Other Capital Projects"** comprise accumulated gross cash flows for projects that require non-zero expenditures of less than $3 million in either 2011 or 2012.

ONTARIO POWER AUTHORITY

OPA Information Regarding Proposed Facilities in Hydro One's 2011-2012 Transmission Rate Application

March 2010

Ontario Power Authority

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1.0 INTRODUCTION

The following document provides information from the OPA with respect to system enhancements as proposed in Hydro One's 2011-2012 Transmission Rates Application.

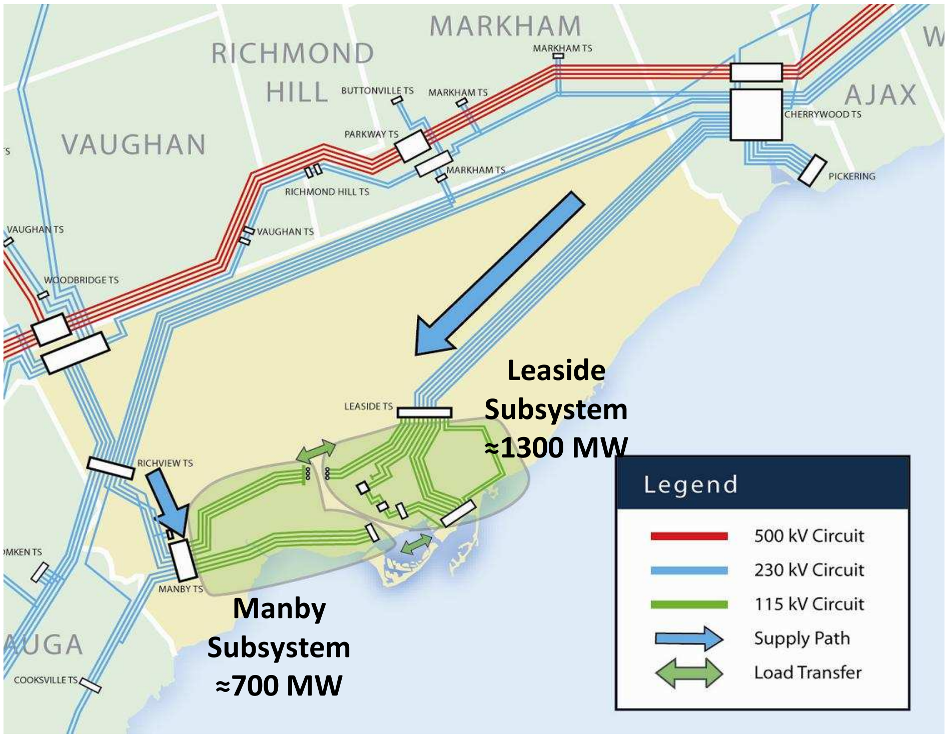
2.0 CENTRAL AND DOWNTOWN TORONTO UPGRADES: PURPOSE AND PROJECT DESCRIPTION

The Ontario Power Authority ("OPA") has been informed by Hydro One Networks Inc. that the Hearn switching station ("SS") has reached end of life and refurbishment is required by the end of 2012. In conjunction with this work, Hydro One intends to upgrade the short circuit capability at this station. Based on information from Hydro One, the OPA understands that the facilities at Leaside transformer station ("TS") and Manby TS are nearing end of life and must be replaced within the next few years as well. Hydro One intends to complete similar upgrades to these facilities. Leaside upgrades are planned to be in service in 2012 and Manby upgrades in 2013. Descriptions of these projects are provided in the evidence submitted by Hydro One. The OPA offers no opinion on the appropriateness of this investment from a sustainment perspective, however, it is understood that the short circuit limits will be increased to 50 kA at each of these stations. This will enable incorporation of at least 300 MW of distributed generation ("DG") in the central and downtown area of Toronto. The following evidence provides further information regarding the potential distributed generation ("DG") and demand response ("DR") programs in the Toronto area, which would be enabled by Hydro One's proposed facilities.

2.1 Project Benefits

Central and downtown Toronto is supplied by a 115 kV network that has two main supply points connected to the 230 KV transmission system in the Greater Toronto Area: Manby TS in southern Etobicoke and Leaside TS in East York. These transformer stations supply the Manby and Leaside 115 kV subsystems, as shown in Figure 1 below.

Figure 1 – Central and Downtown Toronto 115 kV System



The local 115 kV system is also supplied by a 550 MW combined cycle gas fired generating station within the City, known as Portlands Energy Centre. This generating station is connected to the 115 kV system serving the central and downtown area of the city via the Hearn SS.

The existing supply arrangement subjects switching facilities and other equipment within Leaside TS, Manby TS and Hearn SS to short-circuit levels that are near the capability limit of the existing facilities. An IESO study of Short Circuit Impacts shows that even 20 MW of incremental synchronous generation in the Leaside 115 kV subsystem would exceed short circuit limits at the Leaside TS and Hearn SS. This study was previously filed in the IPSP at EB-2007-0707, Exhibit E, Tab 5, Schedule 5, Attachment 4. The OPA believes that the incorporation of DG would be part of any integrated plan for meeting the long term supply requirements of the City of Toronto, for the following reasons :

- The response to the Feed-in Tariff (“FIT”) program has resulted in numerous FIT applications within the City of Toronto, some of which involve the use of generation technologies that increase short circuit levels.

- The OPA, in conjunction with Toronto Hydro, has performed a study to determine the feasible and economic DG potential in the central and downtown area of Toronto. The study has been filed in Toronto Hydro’s 2010 Rates Application at EB-2009-0139, Exhibit Q1, Tab 4, Schedules 1-1, 1-2 and 1-3. It estimates the DG potential to be 140 MW in the medium-term (within about 5 years) and 550 MW in the long-term (within about 10 years).

- The OPA has two outstanding directives for the incorporation of DG on a province-wide basis, one related to Combined Heat and Power ("CHP") and the other related to the Clean Energy Standard Offer Program ("CESOP"), which have been attached to this evidence at Attachment 1. Based on the findings of the Toronto Hydro DG study discussed above, the OPA expects that some of the most economic potential for these programs resides in central and downtown area of Toronto and these opportunities are critical to fulfilling the requirements of these directives.

- Through its discussions with CESOP and CHP proponents, the OPA is aware of developer interest in at least 7 projects within the central and downtown area of Toronto totaling between 106 and 157 MW of generation capacity within this area of the City. Some of these proposals could either be connected to the Leaside or Manby 115 kV subsystems.

- Publically available information, as shown in Attachment 2, also indicates that there are significant opportunities for incorporating DG within the City of Toronto.

It should also be noted that the OPA continues to investigate conservation-based options such as DR programs that can provide benefits for provincial ratepayers as well as individual customers. With the ability to use gas-fired generation for emergency purposes and new Ministry of Environment emissions requirements coming into effect January 1 2011, additional opportunities are expected to exist for customer participation in future DR based programs. Since the central and downtown area of Toronto has the highest concentration of emergency generators in the province, this area likely represents the best potential for capturing these future conservation-based opportunities. DR programs of this nature require the synchronous operation of these emergency generating units, which increases the short circuit current in the area. Therefore upgrading the short circuit levels at the high voltage transmission system stations serving this area would also enable the implementation of this potential option.

The existing short circuit capability of equipment at Leaside TS, Manby TS and Hearn SS represents a barrier to incorporating these potentially significant sources of DG and DR. The OPA agrees that with the proposed upgrades to Hearn, in conjunction with advancing similar work for Leaside and Manby, these barriers would be reduced. The timing of the work for upgrading the short circuit capability in the area (2012 / 2013) coordinates well with the target for the phase-out of coal generation (2014), the phase-in of projects responding to the FIT program and the timing for future conservation initiatives.

3.0 SHUNT CAPACITORS AT ESSA, PORCUPINE AND HANMER: PROJECT DESCRIPTION

Hydro One is proposing to install mechanically-switched shunt capacitor banks at three transformer stations, as described below:

- Project D5: one 250 MVar shunt capacitor bank at Essa TS,

- Project D6: two 100 MVar shunt capacitor bank at Porcupine TS, and

- Project D7: one 149 MVar shunt capacitor bank at Hanmer TS.

3.1 Project Benefits

The need for these three projects was addressed in the supplemental evidence that the OPA provided to Hydro One as part of their request for more information regarding the series capacitors and static var compensators projects that were approved as part of Hydro One's 2009/2010 rate application. This evidence is attached as Attachment 3.

In that document, the OPA detailed the need for additional transmission capability on the North-South tie to connect committed and planned generation resources in Northern Ontario. The OPA also described that these projects were crucial to allow the connection of FIT generation in northern Ontario. Since the filing of the supplemental evidence last September, the OPA has launched the FIT Program and has received over 9,000 MW of applications. The table below summarizes the capacity and locations for FIT applications received during the Launch Period.

Region	Capacity of FIT Applications (MW)
Northwest	800
Northeast	1,700
Total	2,500

Note: capacities have been rounded to the nearest 100 MW.

Based on the large number of applications received through the FIT Program, the OPA supports Hydro One's work on these projects, which will facilitate the connection of FIT projects and other generation in northern Ontario.

Attachment 1

ORIGINAL M.LYLE

Minister of Energy

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Ministre de l'Énergie

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JUN 15 2007

Ontario

JUN 14 2007

Dr. Jan Carr
Chief Executive Officer
Ontario Power Authority
1600–120 Adelaide Street West
Toronto, Ontario
M5H 1T1

Dear Dr. Carr:

Re: Clean Energy and Waterpower in Northern Ontario Standard Offer

I write in connection with my authority as Minister of Energy in order to exercise the statutory power of ministerial direction that I have in respect of the Ontario Power Authority (OPA) under section 25.32 of the *Electricity Act, 1998*.

On August 18, 2005, I wrote to you and to Mr. Howard Wetston, QC, Chair of the Ontario Energy Board (OEB), requesting that the OPA and the OEB co-operate in developing the terms and conditions for a standard offer program for small clean and renewable generators embedded in the distribution system that use clean or renewable resources.

In her letter of March 21, 2006, then Minister of Energy, the Honourable Donna Cansfield, noted that, as per her request, she had received the report of the OPA and the OEB on a proposed Standard Offer Program for Renewable Energy Projects. Under the provisions of the *Electricity Act, 1998*, she directed the OPA to assume responsibility for exercising the powers and performing the duties of the Crown under the Standard Offer Program initiative with the objective of having the program in place by the fall of 2006. Her letter noted an expectation that the OPA will enter into such contracts with small renewable generators as are necessary to implement the program. The Renewable Energy Standard Offer Program was launched by the OPA on November 22, 2006.

..../cont'd

Minister Cansfield subsequently wrote to you on March 27, 2006, requesting that the OPA investigate the economic and technical issues involved with connecting small waterpower projects to transmission systems in northern Ontario, and where economically and technically feasible, report back with recommendations regarding a procurement approach for these projects.

I have now received your report on the clean energy supply component of the Standard Offer Program, as well as your recommendations on small, transmission-connected waterpower projects in northern Ontario.

It is my view that it is appropriate to expand the Standard Offer Program initiative in the areas of clean energy supply and small, transmission-connected waterpower projects in northern Ontario. Pursuant to section 25.32 of the *Electricity Act, 1998*, and with the objective of ensuring electricity supply through the extension of the Standard Offer Program initiative, I hereby direct the OPA to assume, effective as of the date of this letter of direction, responsibility for exercising the powers and performing the duties of the Crown under the Standard Offer Program initiative in regard to:

- clean energy supply; and
- small, transmission-connected waterpower projects in northern Ontario.

The objective is to have these parts of the Standard Offer Program in place by the fall of 2007. It is expected that, as a consequence of this direction, the OPA will enter into such contracts with small generators as necessary to implement these parts of the Standard Offer Program.

This Directive shall be effective and binding as of the date hereof.

Sincerely,

Dwight Duncan
Minister

Minister of Energy

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Ontario

April 10, 2008

Dr. Jan Carr
Chief Executive Officer
Ontario Power Authority
1600–120 Adelaide Street West
Toronto ON M5H 1T1

Dear Dr. Carr:

Re: Procurement for Electricity From Combined Heat and Power (CHP) Renewable Co-generation Projects

I write in connection with my statutory power of Ministerial direction pursuant to Section 25.32 of the *Electricity Act, 1998* (the "Act") in order to address the ongoing need to procure electricity from renewable co-generation, specifically from projects which are involved with high-efficiency combined heat and power (CHP) renewable co-generation.

As you know, I had previously issued a Ministerial direction to the OPA on June 15, 2005, wherein I directed the OPA to commence several procurement processes and to execute and deliver definitive contracts for the selected projects to address the need for up to 1,000 MW of high-efficiency combined heat and power projects across Ontario. That direction also specified that "preference should be given, through a separate procurement process, for projects fuelled by renewable energy sources."

In relation to that direction, the OPA's RFP for up to 1,000 MW of Combined Heat and Power projects (CHP I) closed on August 17, 2006. The OPA signed contracts with seven projects, representing a total of 414 MW of capacity. The OPA did not receive any responses to the separate procurement process for renewable co-generation projects within that RFP.

Since it is desirable that renewable energy projects continue to be fostered, the Crown has been working directly with proponents of renewable co-generation projects, the OPA and other Crown Ministries, including the Ministry of Natural Resources and the Ministry of Finance, to understand the specific challenges facing such projects that led to no proposals being submitted to the OPA.

.../cont'd

The Crown's initiative identified the need for flexible procurement processes to address operational, technical, legal and financial challenges and for consultations with stakeholders to inform the initiative on those issues. The Crown's objective is to have the procurement process launched no later than June 30th, 2008 with contracts executed for approximately 100 MW of high efficiency renewable fuelled CHP energy no later than December 31, 2008 with individual projects to have a capacity greater than ten (10) MW. The process would be open to both new proponents as well as proponents participating in other competitive procurement processes with compatible requirements.

Therefore, I hereby exercise my statutory authority pursuant to section 25.32 of the Act in order to direct that the OPA develop a procurement process with the goal of executing and delivering definitive contracts for approximately 100 MW of power with proponents of renewable energy projects which derive their energy from combined heat and power, and which are greater than 10 MW in size.

In the development of this procurement process, the OPA shall first perform such consultations as are necessary to design a procurement that is responsive to the specific technical, financial and operational considerations of these projects. The OPA shall develop and launch this procurement no later than June 30, 2008, so that the OPA may enter into definitive contracts no later than December 31, 2008.

The OPA must also be mindful of the Crown's constitutional duty to consult First Nations and Métis peoples. In the event that the duty is triggered by any of the projects under this direction, the OPA should ensure that appropriate consultation with First Nations and Métis peoples takes place through the application of the guidelines and processes developed in accordance with my direction of August 27, 2007, amended appropriately for the circumstances.

This direction is in effect as of the date hereof.

Sincerely,

Gerry Phillips

Gerry Phillips
Minister

Attachment 2

ONTARIO
CLEAN AIR
ALLIANCE

Memo to: **Board of Directors, Ontario Power Authority**

From: **Jack Gibbons, Ontario Clean Air Alliance**

Re: Need for a CHP Standard Offer Program

Date: **November 11, 2009**

Introduction

The Ontario Clean Air Alliance (OCAA) has received funding from the Toronto Atmospheric Fund, an agency of the City of Toronto, to promote and facilitate the installation of natural gas-fired combined heat and power (CHP) systems in the healthcare sector.

In June 2005 the Minister of Energy directed the Ontario Power Authority (OPA) to procure up to 1,000 MW of combined heat and power (CHP). To-date the OPA has procured 429 MW.

In June 2007 the Minister of Energy directed the OPA to establish a CHP standard offer program. According to the directive the program should be in place by December 2007.

The OCAA urges the OPA to implement a CHP standard offer program as soon as possible to:

- Achieve compliance with the above noted directives;
- Facilitate electricity security of supply for Ontario's hospitals and extended care facilities in the event of a blackout;
- Avoid the need for the proposed Third Line to downtown and central Toronto; and
- Help meet Ontario's base-load electricity needs.

Facilitate Electricity Security of Supply for Ontario's Hospitals and Extended Care Facilities in the Event of a Blackout

The vast majority of Ontario's hospitals and extended care facilities cannot operate at full capacity during a blackout for two reasons. First, the capacity of their emergency diesel generators is significantly lower than their peak electricity demand. Second, in the event of a prolonged blackout they may not be able to obtain a continuous supply of diesel fuel.

For example, the peak day demand (22 MW) of the University Health Network (Toronto General, Toronto Western and Princess Margaret) is 8 MW greater than its on-site diesel generation capacity (14 MW). Similarly, the peak demand of Sunnybrook (12.8 MW) is 8.2 MW greater than its on-site diesel generation capacity (4.6 MW).

While these hospitals would like to install natural gas-fired CHP systems, in order to increase their electricity security, the payback period for such investments is currently considered too long as a result of Ontario's artificially low electricity commodity price.

A number of Toronto hospitals have told us that they would be willing and able to install CHP systems if they could obtain a CHP electricity supply contract from the OPA. For example:

- The MARS Discovery District has developed a 20 MW CHP and district energy system proposal to meet its needs and those of Hospital for Sick Children, Toronto General Hospital, Princess Margaret, Mt. Sinai, Toronto Rehabilitation Hospital and the University of Toronto Medical School.
- Sunnybrook would like to install a 5.7 MW CHP unit.
- The Humber River Regional Hospital would like to install a 6 MW CHP unit at their new 665 bed hospital at Keele and Wilson which is scheduled for completion in 2015.
- St. Michael's would like to install a 6 MW CHP unit in their proposed new 18 storey tower.

Hospitals are particularly well suited to using CHP due to their high heat loads (space heating, hot water and steam), growing power demands (increasing use of electronic equipment) and security of supply needs. Extended care and other in-patient facilities have much the same profile. Because the natural gas distribution system does not rely on grid-supplied electricity, CHP systems can operate continuously to provide both power and heat during an extended blackout.

Avoid the Need for the Proposed Third Line to Downtown Toronto

According to a recent report by Navigant Consulting for the OPA and Toronto Hydro, "Central and Downtown Toronto faces a number of potential electricity system reliability challenges in the 2015 – 2017 timeframe including the need for additional area supply capacity, infrastructure renewal, and supply diversity to mitigate against low probability but high impact events."[1]

One option to increase Toronto's security of supply would be to build a new third transmission line to serve downtown and central Toronto. On the other hand, as Navigant notes, installing 300 MW of well distributed generation in central and downtown Toronto "could defer the need for a major transmission upgrade and other upgrades that would otherwise be necessary to meet peak demand."[2] According to the Navigant report, the CHP potential in central and downtown Toronto is 1,060 MW.[3]

This would also serve interests beyond the health care sector. Toronto Community Housing Corporation, for example, would like to enter into electricity supply contracts with the OPA to facilitate the installation of CHP at Regents Park, Lower St. James Town, Moss Park and numerous other locations.

Help Ontario Meet its Base-Load Electricity Needs

High efficiency CHP is our lowest cost source of incremental base-load supply to replace our aging nuclear fleet.[4] As a consequence, a well designed CHP standard offer program can simultaneously increase the electricity security of supply of our healthcare facilities; help avoid the need for the proposed Third Line; and provide good value to Ontario's electricity consumers.

Finally, it is important to note that there has never been NIMBY opposition to the installation of low-profile CHP units in Ontario.

Recommendation

In September 2008, the OPA released a proposal for a CHP standard offer program.[5] It is the OCAA's recommendation that the OPA should implement this CHP standard offer program as soon as possible with the following modifications:

- Raise the base capacity value to reflect the fact that the capital cost of combined-cycle generation (the benchmark alternative to CHP) has risen from $1,174[6] to $1,333 per kW.[7]
- Raise the credit for avoided or postponed transmission investment for CHP projects in Toronto from $5.46/kW-year[8] to $83.87/kW-year to reflect the value to electricity consumers of avoiding the proposed Third Line.[9]
- Raise the maximum project size to at least 20 MW to permit the participation of the MARs Discovery District CHP proposal and other district energy projects and to facilitate the achievement of economies of scale.

Endnotes

1 Navigant Consulting, *Executive Summary: Distributed Generation in Central and Downtown Toronto*, Presented to Toronto Hydro Electric System and Ontario Power Authority, (July 28, 2009), page 2.

2 *Distributed Generation in Central and Downtown Toronto*, pages 2 & 4.

3 *Distributed Generation in Central and Downtown Toronto*, page 4, Table 1.

4 Ontario Clean Air Alliance, *Powerful Options: A review of Ontario's options for replacing aging nuclear plants*, (May 19, 2009).

5 OPA, *Updated Report on the Ontario Power Authority's Revisions to the Clean Energy Standard Offer Program for Small Electricity Generators Connected to a Distribution System*, (September 2008).

6 *Updated Report*, page 7.

7 The new 900 MW TransCanada combined-cycle power plant has a forecast capital cost of $1.2 billion. OPA, *News Release*, "Clean Air Strategy and Replacement Power for Southwest GTA", (September 30, 2009).

8 *Updated Report*, page 26.

9 According to Navigant, the cost of the third line would be approximately $1 million per MW. Assuming a 40 year amortization period and an 8% cost of capital, the annual cost is $83.87 per kW. Navigant Consulting, *Central and Downtown Toronto Distributed Generation Final Report*, Prepared for Toronto Hydro Electric System and Ontario Power Authority, page 119.

Contact

Jack Gibbons, Chair
Ontario Clean Air Alliance
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Attachment 3

Ontario Power Authority

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August 21, 2009

Mr. Carmine Marcello
Senior Vice President, Asset Management
Hydro One Networks, Inc.
483 Bay Street, 14th floor-north
Toronto, Ontario M5G 2P5

Dear Carmine,

Please find attached the Ontario Power Authority's supporting evidence for the reinforcement projects to the transmission system between Timmins and Barrie. This evidence is provided in response to your June 30, 2009, letter requesting a more fulsome justification of the facilities that the Board did not approve in your 2009-2010 Transmission Revenue Requirement application. The attached evidence provides support for the committed projects that were of particular concern to Hydro One: the series capacitor banks at Nobel SS, and the static var compensators at Porcupine TS and Kirkland TS that the OPA recommended in the May 20, 2008, letter to Hydro One. The evidence also addresses the shunt capacitor banks at Porcupine TS, Hanmer TS, and Essa TS that were also recommended in the May 20, 2008, letter.

The supporting evidence details the information and analysis that the OPA used in its May 2008 recommendation, as well as changes since then that provide continued support for the need of these facilities.

Please feel free to contact us should you require any clarification or further information.

Yours Truly,

R.F. Chow

for Amir Shalaby
Vice-President
Power System Planning

Cc: Bob Chow, OPA
Michael Lyle, OPA
Bruce Campbell, IESO
Kim Warren, IESO
Allan Cowan, Hydro One
Bing Young, Hydro One

THE ONTARIO POWER AUTHORITY'S SUPPORTING ANALYSIS FOR INCREASING THE TRANSFER CAPABILITIES OF THE NORTH-SOUTH AND SUDBURY-NORTH TRANSMISSION SYSTEMS BY 2010

1.0 PURPOSE

The purpose of this document is to provide supporting evidence for the May 20, 2008, letter that the Ontario Power Authority ("OPA") sent to Hydro One Networks Inc. ("Hydro One") recommending that Hydro One proceed with the installation of reinforcements to the transmission system between Timmins and Barrie. This letter was filed in EB-2008-0272 at Exhibit J1.3, Attachment 4. This supporting evidence is filed in response to the Ontario Energy Board's ("OEB") May 28, 2009, decision to not approve the cost recovery of the two projects listed below due to insufficient evidence at that time. The details of these projects are as follows:

- Project D7: Installation of a static-var-compensator (SVC) at Porcupine 230 kV TS with +300/-100 MVAr and another SVC at Kirkland Lake 115 kV TS with +200/-100 MVAr rating
- Project D8: Installation of series capacitors for 50% compensation of the Essa TS x Hanmer TS 500 kV lines (X503E and X504E) at Nobel SS

In the same letter, the OPA also recommended the installation of shunt capacitor banks at three transformer stations, as follows:

- Project D12: Installation of two shunt capacitor banks at Porcupine 230 kV TS (125 MVAr @ 220 kV each)
- Future Project: Installation of one shunt capacitor bank at Hanmer 230 kV TS (149 MVAr @ 220 kV)
- Future Project: Installation of one shunt capacitor bank at Essa 230 kV TS (182 MVAr @ 220 kV)

These five projects will be referred to as the "Reinforcement Projects".

2.0 THE CONTEXT OF THE OPA'S LETTER

This section describes the generation forecast, transmission system limitations, and the rationale for the OPA's recommendation to Hydro One at the time that the letter was written.

2.1 Generation Forecast

On December 20, 2007, the "Hydroelectric Energy Supply Agreements" ("HESA") directive was issued by the Ministry of Energy. This directive required the OPA to contract with Ontario Power Generation ("OPG") for the development of several hydroelectric facilities in northeastern and northwestern Ontario. These facilities have a combined capacity of approximately 500 MW. At that time, these facilities were expected to come into service in the 2008 to 2013 timeframe. Table 1 provides the capacity and expected in-service date of the HESA facilities at the time that the OPA issued its letter.

Table 1
Capacity and Expected In-Service Date of HESA Facilities as of May 2008

Site	Capacity (MW)	Expected In-Service Date
Lac Seul	12	2008
Hound Chute	10	2009
Upper Mattagami	35	2009-2010
Lower Mattagami	450	2011-2013

Source: OPA

The OPA also identified committed and other near-term generation projects that were expected to be developed in Northern Ontario by 2013 in its letter to Hydro One. These resources totaled almost 400 MW and are listed in Table 2 below. This information was included at Exhibit E, Tab 3, Schedule 1 in the Integrated Power System Plan (IPSP), which is application EB-2007-0707.

Table 2
Committed and Other Near-term Generation Projects in Northern Ontario as of May 2008

Site	Type	Capacity (MW)
Committed Resources		
RES I Umbata Falls	Hydro	23
CHP Algoma	Gas	63
Committed RESOP	Wind	140
RES II Island Falls	Hydro	20
Total Committed		**246**
Other Resources		
Alexander	Hydro	1
Espanola	Hydro	16
Cameron Falls	Hydro	4
Mattagami Lake Dam	Hydro	5
Pine Portage	Hydro	2
Ragged Chute	Hydro	4
Gravelle Chute	Hydro	3
At Highway 17	Hydro	3
Trowbridge Falls	Hydro	1
Northern Thunder Bay	Hydro	1
Newpost Creek	Hydro	25
Bentley Creek	Hydro	2
Biomass Atikokan	Biomass	35
Big Beaver Falls	Hydro	11
Biomass northwest	Biomass	10
25.6 – 19.2 km from mouth	Hydro	10
Timmins South	Hydro	1
Total Other Resources		**134**
Total Committed and Other Resources		**380**
Source: OPA		

2.2 Transmission System Limitations

The existing transmission system connection between Northern and Southern Ontario is referred to as the North-South Tie. It is comprised of two 500 kV circuits between Hanmer TS in Sudbury and Essa TS in Barrie and one 230 kV circuit between Holden GS (east of North Bay) and Des Joachims GS (near Chalk River). At the time of the letter, a number of generation resources had already come into service in Northern Ontario which had increased the level of southbound flows on the North-South Tie so that it was operating near its capability of about 1,300 MW. Occasionally, generation rejection had been armed on some generation units in Northern Ontario in order to increase the pre-contingency flows on the North-South Tie to 1,400 MW. As discussed above, the generation forecast indicated that there would be almost 900 MW of new generation resources in Northern Ontario and these additional resources would cause southbound flows on the North-South Tie to greatly exceed its capability.

On May 15, 2007, the Independent Electricity System Operator ("IESO") issued a System Impact Assessment ("SIA") report stating that the implementation of the Reinforcement Projects would allow the major HESA facilities listed in Table 1 to be connected to the system, as well as other near-term generation resources. In addition, these projects would provide the dynamic reactive support that is required to control post-contingency voltages on the power system North of Sudbury. The SIA was filed in Hydro One's rate case as Exhibit I-1-61, Attachment 1 and was also filed in the IPSP at Exhibit E-3-1, Attachment 1. An addendum to this SIA was issued by the IESO on August 15, 2007, and this was filed in the IPSP at Exhibit E-3-1, Attachment 2.

2.3 Rationale for the OPA's Recommendation

At the time that the OPA issued its recommendation to Hydro One, the HESA generation resources were intended to support meeting system adequacy after coal-fired generation was phased out. The June 13, 2006, directive to the OPA on the IPSP goals stated that the OPA should "[plan] for coal-fired generation in Ontario to be replaced by cleaner sources in the earliest practical time frame that ensures adequate generating capacity and electric system reliability in Ontario." Delays to transmission projects could delay the incorporation of the HESA facilities and other generation resources in Northern Ontario that were expected to replace coal-fired generation. The OPA aimed to mitigate the impact of delays to transmission projects by targeting for transmission projects to come into service in advance of when generation projects would require additional transmission capability to connect to the power system.

Furthermore, over 250 MW of the non-HESA generation resources were expected to come into service by 2010. These resources were expected to increase the southbound flow on the North-South Tie, which would require an increased capability by 2010.

Several directives also required the OPA to procure for, and plan for the utilization of, renewable resources. The June 13, 2006, directive on the IPSP goals required the OPA to plan to increase Ontario's use of renewable energy. The August 27, 2007, directive required the OPA to procure up to 2,000 MW of Renewable Energy Supply by 2011. It was expected that these targets for renewable development would be met in part by the development of resources in Northern Ontario. However, resources in Northern Ontario can only be developed and utilized if there is capability available on the North-South Tie.

For the above reasons, the OPA determined that the capability of the North-South Tie would need to be increased by 2010.

Next, the OPA considered two basic alternatives to increase the capability of the North-South Tie: (a) the implementation of the Reinforcement Projects, and (b) the construction of a new transmission line.

The OPA determined that the implementation of the Reinforcement Projects was preferable to a new transmission line for three major reasons. First, the Reinforcement Projects maximize the capability of the existing transmission system without the need for additional right-of-way. Second, these projects require a shorter timeline for installation than a new line, and therefore have a lower exposure to risks of delay that could prevent the incorporation of critical generation facilities. Finally, these projects provide more flexibility than a new transmission line because they provide a smaller incremental increase in transmission capability and do not prevent the installation of a new transmission line at a later time if it is needed. The Reinforcement Projects would continue to provide on-going value should the capability of the North-South Tie be scaled up to meet future development. Therefore, the OPA determined that the implementation of the Reinforcement Projects was preferable to the construction of a new transmission line.

On this basis, the OPA recommended that Hydro One proceed with the installation of the Reinforcement Projects by 2010.

3.0 CHANGES SINCE THE OPA ISSUED ITS RECOMMENDATIONS

Since the OPA issued its letter in May 2008, new government policies and changes in generation development timelines have continued to support the need to increase the capability of the North-South Tie. These changes are detailed below.

There have been revisions to the expected in-service dates of the HESA and other generation projects. These changes are summarized for the HESA resources in Table 3. The total capacity of the other generation resources expected to be in-service by 2013 has increased from about 400 MW to over 700 MW, including an increase in committed resources from about 250 MW to almost 400 MW, as shown in Table 4. In particular, OPG's intention to convert the Thunder Bay and Atikokan coal-fired generation plants to biomass facilities has resulted in a significant increase in the near-term generation capacity expected to come into service in Northern Ontario. The hydroelectric resources that could be developed in the longer-term, but are no longer expected to be in-service by 2013, are shown in Table 5 below. Note that the capacities of some of the sites listed in Tables 4 and 5 have been updated with the latest available information.

Table 3
Capacity and In-Service Date of the HESA Sites as of May 2008 and Today

Site	Capacity (MW)	Previous Expected In-Service Date	Current Expected In-Service Date
Lac Seul	12	2008	In-service
Hound Chute	10	2009	2010
Upper Mattagami	35	2009-2010	2010
Lower Mattagami	450	2011-2013	2014
Source: OPA			

Table 4
Committed and Other Near-Term Generation Projects in Northern Ontario as of Today

Site	Type	Capacity (MW)
In-Service and Committed Resources (Note 2)		
RES I Umbata Falls	Hydro	23
CHP Algoma	Gas	63
In-Service RESOP	Various	5
Committed RESOP	Various	177
RES II Island Falls	Hydro	20
Biomass northwest	Biomass	(Note 1)
RES III Greenwich Windfarm	Wind	99
Total Committed		**387**
Other Resources		
Cameron Falls	Hydro	4
Namewaminikan - 8 km & 12.8 km	Hydro	10
Alexander	Hydro	1
Mattagami Lake Dam	Hydro	6
Pine Portage	Hydro	4
Biomass Atikokan	Biomass	200
Thunder Bay Biomass	Biomass	150
Total Other Resources		**375**
Total by 2013		**762**

Source: OPA
Note 1: This site was included separate from the RESOP potential in the May 20, 2008 letter, but has since been contracted for through RESOP and is included in the committed RESOP site in this Table.
Note 2: Not all in-service resources are included in this Table. Only the resources that were included in May 20, 2008 letter that have since come into service are included in this Table.

Table 5
Hydroelectric Resources Included in the May 20, 2008, Letter that are no Longer Expected to Develop by 2013

Site	Type	Capacity (MW)
Espanola	Hydro	16
Ragged Chute	Hydro	4
Gravelle Chute	Hydro	2
At Highway 17	Hydro	2
Trowbridge Falls	Hydro	1
Northern Thunder Bay	Hydro	1
Newpost Creek	Hydro	25
Bentley Creek	Hydro	1
Big Beaver Falls	Hydro	11
25.6 - 19.2 km from mouth	Hydro	10
Timmins South	Hydro	1
	Total	**74**
Source: OPA		

The OPA has contracted for over 350 MW of generation resources in Northern Ontario that have come into service since May 2008 or are expected to come into service by 2010. These resources will increase southbound flows on the North-South tie beyond its capability and therefore require the Reinforcement Projects to be installed by 2010.

Furthermore, the Green Energy and Green Economy Act ("GEGEA") identifies the Government's goal "to increase the availability of renewable energy in Ontario and increase the use of renewable energy sources in Ontario." The expected launch of the Feed-in Tariff ("FIT") program, a component of the GEGEA, has increased the expectation for renewable generation development across the Province, including in Northern Ontario. Generation resources contracted through the FIT program could come into service as early as 2011 or 2012 if there is available transmission capability. As described in Section 2.2, the existing transmission system between Northern and Southern Ontario is already fully utilized and therefore any additional generation will require the reinforcement of this transmission system. The Reinforcement Projects are therefore required by 2010, as scheduled, to allow the connection and utilization of new renewable resources.

4.0 CONCLUSION

In May 2008, the OPA recommended that Hydro One proceed with the Reinforcement Projects based on the capability of the existing transmission system and the generation resources expected to come into service at that time. Although some of the expected in-service dates of the generation resources have changed, the OPA expects a large amount of near-term resources to come into service that will require these transmission reinforcements. Further, the OPA anticipates that the FIT program will yield significant interest in renewable generation development in Northern Ontario. Without the Reinforcement Projects, there will not be enough transmission capability available to allow new renewable resources to come into service in the near-term through this program. Therefore, the OPA still recommends that the Reinforcement Projects should be implemented by 2010.

LETTERS OF SUPPORT FOR THE TORONTO AREA SHORT CIRCUIT UPGRADES AT HEARN SS, LEASIDE TS AND MANBY TS.

Letters are attached from the following organizations:

1. Environmental Defence
2. Enwave Energy Corporation
3. MaRS Discovery District
4. City of Toronto
5. Ontario Clean Air Alliance
6. Redpath Sugar Ltd.
7. Safety Power
8. Sunnybrook Health Sciences Centre
9. Toronto Atmospheric Fund
10. Toronto Community Housing
11. University Health Network
12. WaterFront Toronto
13. World Wildlife Fund

ENVIRONMENTAL | DEFENCE
317 Adelaide Street West Suite 705 • Toronto Ontario Canada • M5V 1P9 • tel: 416.323.9521 fax: 416.323.9301 • www.environmentaldefence.ca

March 12, 2010

Mr. Allan Cowan
Director, Transmission Applications
Hydro One Networks Inc.
South Tower, 8th Floor
483 Bay Street
Toronto M5G 2P5

Dear Mr. Cowan:

Re: Hydro One's proposed short circuit capacity upgrades for its Hearn, Leaside & Manby Transformer Stations

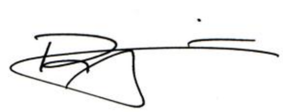
We are writing to express our support for Hydro One's proposal to remove the short circuit constraints at its transformer stations that serve downtown and central Toronto. We believe that eliminating the current short circuit limits at Hydro One's Hearn, Leaside and Manby Transformer Stations will provide multiple benefits for the City's residents, businesses and institutions.

In particular, by dramatically increasing the capacity of the Toronto Hydro distribution system to accommodate distributed generation projects, these Hydro One upgrades will help to increase the City's security of electricity supply, open the way for the development of more robust emergency power systems at hospitals and other critical facilities, and provide new economic opportunities, both for power system suppliers and for facilities interested in supplying power to the grid.

A number of organizations in Toronto have already expressed strong interest in developing combined heat and power or renewable energy projects in the area currently constrained by these short-circuit limits. We believe Hydro One's efforts to rectify this situation will quickly result in reliable and cost-effective projects that can help our city gain greater energy security. These projects will also help institutions and companies to increase their energy efficiency and lower their environmental and climate impact.

In conclusion, we strongly support Hydro One's proposal to upgrade its transformer stations to permit the connection of renewable and combined heat and power to the Toronto Hydro distribution grid in downtown and central Toronto.

Yours truly,



Rick Smith, Ph.D.
Executive Director, Environmental Defence

enwave
ENERGY CORPORATION

March 12, 2010

Mr. Allan Cowan
Director, Transmission Applications
Hydro One Networks Inc.
South Tower, 8th Floor
483 Bay Street
Toronto ON M5G 2P5

Dear Mr. Cowan:

Re: Hydro One's proposed short circuit capacity upgrades for its Hearn, Leaside, and Manby Transformer Stations

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In conclusion, we strongly support Hydro One's proposal to upgrade its transformer stations to permit the connection of renewable and combined heat and power to the Toronto Hydro distribution grid in downtown and central Toronto.

Yours truly,

Dennis Fotinos
President & CEO

ENWAVE ENERGY CORPORATION
P.O. Box 105, 17th Floor, 181 University Avenue, Toronto, Ontario M5H 3M7 Tel: (416) 392-6838 Fax: (416) 363-6052

March 10, 2010

MaRS

Mr. Allan Cowan
Director, Transmission Applications
Hydro One Networks Inc.
South Tower, 8th Floor
483 Bay Street
Toronto M5G 2P5

Dear Mr. Cowan:

Re: Hydro One's proposed short circuit capacity upgrades for its Hearn, Leaside & Manby Transformer Stations

We are writing to express our support for Hydro One's proposal to remove the short circuit constraints at its transformer stations that serve downtown and central Toronto. We believe that eliminating the current short circuit limits at Hydro One's Hearn, Leaside and Manby Transformer Stations will provide multiple benefits for the City's residents, businesses and institutions.

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In conclusion, we strongly support Hydro One's proposal to upgrade its transformer stations to permit the connection of renewable and combined heat and power to the Toronto Hydro distribution grid in downtown and central Toronto.

Yours truly,

MaRS DISCOVERY DISTRICT

Randal Froebelius, P.Eng
Vice-President, Real Estate

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Charitable Registration Number: 876682717-RR0001

Mayor
DAVID MILLER

February 18, 2010

Honourable Brad Duguid
Minister of Energy and Infrastructure
Hearst Block
4th Floor
900 Bay Street
Toronto, ON M7A 2E1

Re: Clean Cogenerated Energy

Dear Minister Duguid:

It is my understanding that the Ontario Power Authority is considering an appropriate policy and program for purchasing clean cogenerated energy (i.e. generating heat and electric power at the same time from the same energy source) in Ontario. I strongly encourage you to support this initiative, which can provide multiple benefits to the City of Toronto and the Province of Ontario.

According to the July 28, 2009 report by Navigant Consulting for the OPA and Toronto Hydro, steps must be taken to address electricity reliability challenges that will become serious in the 2015 – 2017 timeframe in order to "mitigate against low probability but high impact events." Clean cogenerated energy (along with energy conservation and other distributed energy initiatives) is a more cost-effective and less disruptive way to address electricity reliability than building a third transmission line to supply the City at a cost of approximately $600 million through many City neighbourhoods.

Projects that utilize waste heat and pressure, will be key to reducing our greenhouse gas emissions, an important objective for the City of Toronto and the Province of Ontario. Not only does efficient clean cogenerated energy emit 80 percent less greenhouse gases than coal, it can serve an essential and flexible backstop for the intermittency of renewable energy supply such as solar and wind. Clean cogenerated energy has the additional benefit, when sited at hospitals and extended care facilities, of providing full backup generation capacity, even during a prolonged blackout; a much better air quality option than diesel generation.

Despite the favourable conditions and support for additional clean cogenerated energy within Toronto, the amount of generation that can be readily installed in Toronto is limited by the current short circuit ratings of transformer stations located in Toronto and owned by Hydro One. The Ontario Energy Board previously mandated Toronto Hydro to conduct a study to facilitate the incorporation of up to 300 MW of distributed generation within Toronto. Only 90 MW can presently be installed in Toronto due to limitations caused by short circuit capacity. It is therefore essential that the limitations of the short circuit capacity be addressed and corrected to allow the full potential of clean cogenerated energy to be realized in Toronto.

TORONTO

City Hall • 100 Queen Street West • 2nd Floor • Toronto, Ontario M5H 2N2
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As Canada's largest city, Toronto is well-positioned for clean cogenerated energy, with potential proponents, including hospitals and other institutions, commercial buildings, and industrial facilities throughout downtown/central Toronto and in our many employment areas. A standard offer program, in the form of a feed-in tariff, would permit a number of excellent clean cogenerated projects to proceed in Toronto, when and where the power is needed. Examples include:

- The MARS Discovery District which would like to develop a 20 megawatt (MW) cogeneration and district energy system to meet the needs of the Hospital for Sick Children, Toronto General Hospital, Princess Margaret Hospital, Mt. Sinai Hospital, Toronto Rehabilitation Hospital and the University of Toronto Medical School;

- Sunnybrook Health Sciences Centre would like to install a 5.7 MW cogeneration system to close the gap between its current emergency power supply and its actual peak demand;

- St. Michael's Hospital would like to install a 6 MW cogeneration unit in their proposed new 18 storey tower at Queen and Victoria Street;

- Toronto Community Housing Corporation would like to install a 6 MW cogeneration system as part of their Regent Park redevelopment;

- Waterfront Toronto would like to install a 5 MW cogeneration system in the West Don Lands for the 2015 Pan Am Games;

The City of Toronto recently approved an energy plan, titled "The Power to Live Green: Toronto's Sustainable Energy Strategy", which outlines a range of policies and programs to improve energy efficiency and deploy renewable and distributed energy, including the use of clean cogenerated power. I have every confidence that once the OPA establishes a fair price and a simple process that is accessible for all potential CHP hosts, the market will respond and deliver viable, well-designed projects for the OPA's consideration.

Yours truly,

David Miller

Mayor David Miller
City of Toronto

c Colin Andersen, Chief Executive Officer, Ontario Power Authority
Anthony Haines, President and CEO, Toronto Hydro
Joe Pennachetti, City Manager, Toronto
Richard Butts, Deputy City Manager, Toronto
Bruce Bowes, Chief Corporate Officer, Toronto
Lawson Oates, Director, Toronto Environment Office

ONTARIO
CLEAN AIR
ALLIANCE

March 12, 2010

Mr. Allan Cowan
Director, Transmission Applications
Hydro One Networks Inc.
South Tower, 8th Floor
483 Bay Street
Toronto M5G 2P5

Dear Mr. Cowan:

Re: Hydro One's proposed short circuit capacity upgrades for its Hearn, Leaside & Manby Transformer Stations

We are writing to express our support for Hydro One's proposal to remove the short circuit constraints at its transformer stations that serve downtown and central Toronto. We believe that eliminating the current short circuit limits at Hydro One's Hearn, Leaside and Manby Transformer Stations will provide multiple benefits for the City's residents, businesses and institutions.

In particular, by dramatically increasing the capacity of the Toronto Hydro distribution system to accommodate distributed generation projects, these Hydro One upgrades will help to increase the City's security of electricity supply, open the way for the development of more robust emergency power systems at hospitals and other critical facilities, and provide new economic opportunities, both for power system suppliers and for facilities interested in supplying power to the grid.

A number of organizations in Toronto have already expressed strong interest in developing combined heat and power or renewable energy projects in the area currently constrained by these short-circuit limits. We believe Hydro One's efforts to rectify this situation will quickly result in reliable and cost-effective projects that can help our city gain greater energy security. These projects will also help institutions and companies to increase their energy efficiency and lower their environmental and climate impact.

In conclusion, we strongly support Hydro One's proposal to upgrade its transformer stations to permit the connection of renewable and combined heat and power to the Toronto Hydro distribution grid in downtown and central Toronto.

Yours sincerely,

Jack Gibbons

Jack Gibbons
Chair

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A subsidiary of American Sugar Refining, Inc.

March 12, 2008

Mr. Allan Cowan
Director, Transmission Applications
Hydro One Networks Inc.
South Tower, 8th Floor
483 Bay Street
Toronto M5G 2P5

Dear Mr. Cowan:

Re: Hydro One's proposed short circuit capacity upgrades for its Hearn, Leaside & Manby Transformer Stations

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In conclusion, we strongly support Hydro One's proposal to upgrade its transformer stations to permit the connection of renewable and combined heat and power to the Toronto Hydro distribution grid in downtown and central Toronto.

Yours truly,

Jonathan Bamberger
President

safety POWER

clean essential energy

Robert M. Stelzer
Chairman
Direct Line – (416) 477-2709 ext.22
Cell Phone – (416) 458-4341
Fax – (416) 477-2709
bob.stelzer@safetypower.ca

March 8, 2010

Mr. Allan Cowan
Director, Transmission Applications
Hydro One Networks Inc.
South Tower, 8th Floor
483 Bay Street
Toronto M5G 2P5

Dear Mr. Cowan

Re: Hydro One's proposed short circuit capacity upgrades for its Hearn, Leaside & Manby Transformer Stations

We are writing to express our support for Hydro One's proposal to remove the short circuit constraints at its transformer stations that serve downtown and central Toronto. We believe that eliminating the current short circuit limits at Hydro One's Hearn, Leaside and Manby Transformer Stations will provide multiple benefits for the City's residents, businesses and institutions.

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safety POWER

clean essential energy

In conclusion, we strongly support Hydro One's proposal to upgrade its transformer stations to permit the connection of renewable and combined heat and power to the Toronto Hydro distribution grid in downtown and central Toronto.

Yours truly,

Bob Stelzer
Chairman

RMS/ac

Sunnybrook
HEALTH SCIENCES CENTRE

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March 12, 2008

Mr. Allan Cowan
Director, Transmission Applications
Hydro One Networks Inc.
South Tower, 8th Floor
483 Bay Street
Toronto M5G 2P5

Dear Mr. Cowan:

Re: Hydro One's proposed short circuit capacity upgrades for its Hearn, Leaside & Manby Transformer Stations

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In conclusion, we strongly support Hydro One's proposal to upgrade its transformer stations to permit the connection of renewable and combined heat and power to the Toronto Hydro distribution grid in downtown and central Toronto.

Yours truly,

Michael Young
Executive Vice President

TORONTO Atmospheric Fund

Julia Langer
Executive Director

75 Elizabeth Street
Toronto, Ontario M5G 1P4

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Fax: 416-338-0616
jlanger@tafund.org
www.toronto.ca/taf

March 10, 2008

Mr. Allan Cowan
Director, Transmission Applications
Hydro One Networks Inc.
South Tower, 8th Floor
483 Bay Street
Toronto, ON M5G 2P5

Dear Mr. Cowan:

Re: Proposed short circuit capacity upgrades of Hydro One's Hearn, Leaside & Manby Transformer Stations

Toronto Atmospheric Fund (TAF) strongly supports Hydro One's proposal to remove the short circuit constraints at its transformer stations that serve downtown and central Toronto. We believe that eliminating the current short circuit limits at the Hearn, Leaside and Manby Transformer Stations will provide multiple benefits for the City's residents, businesses and institutions.

By dramatically increasing the capacity of the Toronto Hydro distribution system to accommodate distributed generation projects, these Hydro One upgrades will help to increase the our city's security of electricity supply and will be a key to meeting Toronto's ambitious sustainable energy and climate change targets.

TAF and a number of other organizations have already expressed strong interest in having combined heat & power and renewable energy projects developed in Toronto, and recognize that these are currently constrained by these short-circuit limits. We believe Hydro One's initiative to rectify this situation will open the door for reliable, cost-effective public and private sector projects that supply power to the grid and improve our city's energy security, help institutions and companies lower their environmental and climate impact and create and reap new economic opportunities.

We look forward to Hydro One completing the proposed upgrades of these three transformer stations, which will permit the connection of distributed electricity projects to the Toronto Hydro distribution grid in downtown and central Toronto.

Sincerely,

Julia Langer
Executive Director

Toronto Community
Housing Corporation
931 Yonge Street
Toronto, ON
M4W 2H2

Toronto Community Housing

March 9, 2010

Mr. Allan Cowan
Director, Transmission Applications
Hydro One Networks Inc.
South Tower, 8th Floor
483 Bay Street
Toronto M5G 2P5

Dear Mr. Cowan:

Re: Hydro One's proposed short circuit capacity upgrades for its Hearn, Leaside & Manby Transformer Stations

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In conclusion, we strongly support Hydro One's proposal to upgrade its transformer stations to permit the connection of renewable and combined heat and power to the Toronto Hydro distribution grid in downtown and central Toronto.

Yours truly,

Mitzie Hunter
Chief Administrative Officer

University Health Network

Toronto General Hospital Toronto Western Hospital Princess Margaret Hospital

Mr. Allan Cowan
Director, Transmission Applications
Hydro One Networks Inc.
South Tower, 8th Floor
483 Bay Street
Toronto M5G 2P5

March 15, 2010

Re: Hydro One's proposed short circuit capacity upgrades for its Hearn, Leaside & Manby Transformer Stations

Dear Mr. Cowan:

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In conclusion, we strongly support Hydro One's proposal to upgrade its transformer stations to permit the connection of renewable and combined heat and power to the Toronto Hydro distribution grid in downtown and central Toronto.

Regards,

Ed Rubinstein
Manager, Energy & Environment
University Health Network
416-340-4800x6190
edward.rubinstein@uhn.on.ca

Copy: Michael Sheeres, Executive Director, Infrastructure, University Health Network

WATERFRONToronto

20 BAY STREET, SUITE 1310
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Fax: 416.214.4591

www.towaterfront.ca

March 12, 2010

Mr. Allan Cowan
Director, Transmission Applications
Hydro One Networks Inc.
allan.cowan@HydroOne.com

BY EMAIL ONLY

Dear Mr. Cowan:

Re: Combined Heat and Power Projects in Downtown Toronto

We are writing to express our strong interest in developing CHP projects in downtown Toronto.

Waterfront Toronto is the master developer of the precincts along Toronto's waterfront known as West Don Lands (home of the Pan Am Athlete's Village), East Bayfront, and the Lower Don Lands. These precincts will have eventual residential, commercial and institutional GFA well in excess of 20 million square feet.

Fundamental to our corporate vision is environmental sustainability. Our work on the Lower Don Lands, one of seventeen founding projects in the Clinton Climate Initiative, seeks to be climate positive – to secure below zero greenhouse gas emissions. To this end, we are currently developing a district energy system in West Don Lands and East Bayfront, for eventual expansion into the Lower Don Lands. We plan to develop CHP as part of that system to the extent we can.

For this reason, we support efforts by Hydro One to facilitate further development of CHP projects in downtown Toronto.

Yours truly,

John Campbell
President & CEO

WWF for a living planet®

WWF-Canada

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wwf.ca

March 15, 2008

Mr. Allan Cowan
Director, Transmission Applications
Hydro One Networks Inc.
South Tower, 8th Floor
483 Bay Street
Toronto M5G 2P5

Dear Mr. Cowan:

Re: Hydro One's proposed short circuit capacity upgrades for its Hearn, Leaside & Manby Transformer Stations

We are writing to express our support for Hydro One's proposal to remove the short circuit constraints at its transformer stations that serve downtown and central Toronto. We believe that eliminating the current short circuit limits at Hydro One's Hearn, Leaside and Manby Transformer Stations will provide multiple benefits for the City's residents, businesses and institutions.

In particular, by dramatically increasing the capacity of the Toronto Hydro distribution system to accommodate distributed generation projects, these Hydro One upgrades will help to increase the City's security of electricity supply, open the way for the development of more robust emergency power systems at hospitals and other critical facilities, and provide new economic opportunities, both for power system suppliers and for facilities interested in supplying power to the grid.

A number of organizations in Toronto have already expressed strong interest in developing combined heat and power or renewable energy projects in the area currently constrained by these short-circuit limits. We believe Hydro One's efforts to rectify this situation will quickly result in reliable and cost-effective projects that can help our city gain greater energy security. These projects will also help institutions and companies to increase their energy efficiency and lower their environmental and climate impact.

In conclusion, we strongly support Hydro One's proposal to upgrade its transformer stations to permit the connection of renewable and combined heat and power to the Toronto Hydro distribution grid in downtown and central Toronto.

Yours truly,

Keith Stewart

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OPERATIONS CAPITAL

1.0 INTRODUCTION

Operations Capital funds enhancements and replacements to the facilities required to operate the Hydro One Transmission system within the requirements established by the reliability authorities, operating agreements and the market rules. The process to develop capital investments for Operations assets is discussed in Exhibit A, Tab 12, Schedule 4.

The planned investments enable Hydro One Transmission to meet its regulatory obligations as a transmission owner and operator and align with Hydro One Transmission's vision as a leading transmission company by employing "best in breed" commercially available operations systems and equipment that provide adequate monitoring and control to maintain system and customer reliability at required levels, and maintain public and worker safety.

Operations capital investments are required to sustain assets that are at their end of life or need major refurbishment and to implement, enhance and modify the physical infrastructure, systems and tools necessary for transmission operations. These investments deliver improvements to transmission system performance in the form of reduced outage duration, improved system utilization and improved information to asset managers and customers.

Failure to sustain the Network Operating systems and tools would lead to increased business and operational risk as they become less reliable and require more maintenance over time. Network Operating system and/or tool failures may negatively impact customer service, system reliability and regulatory compliance.

The Operations Capital program for the test years is divided into two categories:

- Grid Operations Control Facilities, which funds enhancements to, and replacement of, the computer tools and systems that support the transmission operating functions at the Ontario Grid Control Centre (OGCC) and the back-up centre.
- Operating Infrastructure, which funds enhancements or modifications to the physical infrastructure outside of the control centres, required for the operation of the transmission system.

The required funding for the test years, along with the spending levels for the bridge and historic years is provided in Table 1 for each of these categories.

Table 1

Operations Capital ($ Millions)

Description	**Historic**			**Bridge**	**Test**	
	2007	**2008**	**2009**	**2010**	**2011**	**2012**
Grid Operations Control Facilities	2.0	16.8	11.3	8.8	22.6	18.5
Operating Infrastructure	2.7	6.3	8.7	1.4	21.7	38.9
Total	**4.7**	**23.1**	**20.0**	**10.1**	**44.3**	**57.4**

Planned spending in 2011 is $44.3 million as compared to the 2010 level of $10.1 million. This increase is required to provide a Wide Area Network for protection and control of the grid as well as to address OGCC and Back-up Centre building space needs, as discussed in Sections 4.3.3 and 3.3 respectively. Planned spending in 2012 of $57.4 million is a 30% increase over the 2011 level resulting from the higher necessary spending levels for the Wide Area Network Project.

A brief description of the primary systems used to manage Hydro One Transmission's system is provided in Section 2.0 below. This is followed by the description and details of, and the year-to-year changes in, the two individual Operations Capital investment categories.

2.0 DESCRIPTION OF THE SYSTEMS AND TOOLS

Hydro One Transmission operates and controls the entire Hydro One Transmission system from the OGCC. Backup facilities are also provided at a separate location in the event that the OGCC is unavailable. A suite of centralized systems and tools, supported by province wide telecommunication and station control infrastructure is used to carry out the monitoring and control of the transmission assets and system, the planning and scheduling of transmission equipment outages, and the provision of transmission system performance information. Hydro One Transmission continually assesses and implements technologies to improve the performance and efficiency of its transmission operating function. The operating function faces growing challenges:

- The efficient scheduling and real time management of an increasing number of equipment outages required to support the growing Sustainment and Development work programs
- Challenges associated with adjusting to the changing conditions of aging assets that require closer management of operating limits and equipment de-ratings. This results in increasing workload to plan and manage equipment outages.
- New impacts on transmission operation resulting from the connection of large amounts of renewable generation directly tapped to transmission lines or connected to the distribution systems. Many of these require controls and monitoring to manage system impacts, performance and customer requirements.

2.1 Grid Operation and Control Facilities

The primary systems used in the monitoring and control of the transmission system are:

- **The Network Management System ("NMS")** is the transmission network monitoring and control tool which performs the following functions: data acquisition, supervisory control, real-time and study mode network analysis, and training simulation. It provides the real time voltage and loading on the transmission system as well as monitoring and control of the status of the switches and breakers connecting the equipment to the integrated network for the purpose of safe and reliable operation of the transmission system. The NMS also provides predictive assessment tools which help in providing situational awareness to the operator.
- **Operations Support Tools** enable the integration of outage management, utility work protection code and electronic logging functions, each of which is described below:
    a. **Network Outage Management System ("NOMS")** is the transmission outage management tool that is used for planning, scheduling, assessing and executing transmission equipment outages and for transmitting outage requests, via a direct communication link, to the Independent Electricity System Operator (IESO) for approval.
    b. The **Utility Work Protection Code System** is used by Hydro One Transmission to establish conditions which, when combined with appropriate work practices, procedures and work methods will provide employees with a safe work area. This electronic work permit forms system contains the necessary information to support the development of required Work Protection documentation.
    c. **Electronic Logging** is the records system for the control room daily activity. It has automated features to capture operations using the NMS, including operator actions such as opening and closing breakers, and automatic operations resulting

from power system faults. The staff also manually record all other pertinent information to create the chronological record of the daily activity. Electronic logging provides system data for asset management and system planning.

- The **Transmission and Station Operating Diagrams** are used by field crews and by the OGCC to provide detailed information on the configuration of the transmission system and the connectivity of the transmission station equipment. This information is essential in ensuring the safe and reliable operation of the transmission system.
- The **OGCC Integrated Voice System** is designed to allow OGCC Operations to effectively manage voice communications between the OGCC, IESO, transmission connected customers and field staff. This system provides the interface to multiple communication media, such as the public telephone network, public cell phone network and Hydro One Transmission's provincial mobile radio system.
- The **OGCC Emergency Services Information System** provides verified up-to-date contact numbers for all emergency response services (e.g. police, fire, ambulance, ministry of environment, gas utilities, etc.) across the Province. This system is designed to enable OGCC staff to quickly and effectively contact emergency personnel.

2.2 Operating Infrastructure

The Operating Infrastructure comprises the systems and telecommunications required to connect the OGCC and Back-up centre to the transmission stations, to support real time field operations and to fulfill Hydro One's obligations for real time telemetry under the Market Rules and Transmission System Code. Specifically, the Operating Infrastructure includes:

- **Gateway Systems** that connect legacy station control systems at the approximately 460 transmission switchyards to modern systems used at the OGCC and Back-up

Centres and to the systems at the IESO. There are 110 gateway systems located at 37 sites, referred to as Hub Sites, across the province. The station control systems themselves, also generally referred to as Remote Terminal Units (RTUs), are considered part of the station asset and not Operating Infrastructure.

- The **Wide Area Telecommunications Network** that ensures multiple independent paths, including by satellite, to all stations that are of critical importance to the operation of the grid and restoration following any major disturbance event. This network also carries real time data that Hydro One is obliged to provide to Transmission Connected Customers from the OGCC or Back-up Centre to local points of presence for these customers.
- The **Fault Locating Systems** which are new systems being deployed to promptly identify the location of failures on transmission circuits. This will save cost and time for restoring circuits to service.
- The **Provincial Mobile Radio System** is the means by which both the OGCC and the field operations centres maintain continuous contact with field crews. It is designed to be reliable in the event of a widespread blackout and capable of accessing all remote locations where field crews would be dispatched to provide crews with an assured means of communication in case of emergency.
- **Underground Cable Monitors** which are probes that monitor the surface temperature and soil temperature gradients in order to ensure the healthy and optimum operation of cables which are critical to the supply of large downtown load centres.
- **Geomagnetically Induced Current Monitors** which detect currents flowing through the transmission system induced by the earth's magnetic field during solar disturbances. These currents can disrupt protection systems and cause outages.
- **Weather Stations** to acquire location specific weather data required for determining accurate operating limits on equipment, or other key condition information of vital

importance to grid operation such as accumulation of insulator contamination and ice build up.

3.0 GRID OPERATIONS CONTROL FACILITIES

3.1 Overview

Grid Operations Control Facilities provide critical capabilities to support transmission operations at OGCC and the back-up centre. This program funds enhancements to, and capital sustainment of, the computer tools and systems to maintain equipment performance at appropriate levels, thereby maintaining the overall reliability and service quality while satisfying all regulatory requirements.

Computer and network systems are short lived assets typically requiring renewal every five years. Grid Operations Control Facilities requiring upgrade are at the end of their normal life cycle and are subject to reduced reliability and increased support and maintenance requirements.

The Operations Capital projects for the Grid Operations Control Facilities are provided in Table 2 below.

Table 2
Grid Operations Control Facilities
Capital Projects ($ Millions)

Description	**Historic**			**Bridge**	**Test**	
	2007	**2008**	**2009**	**2010**	**2011**	**2012**
Network Operations Buildings Expansion	0	0	0	0.5	12.1	11.0
NMS Upgrade & Enhancements	1.2	16.0	9.2	3.6	3.8	4.0
Transmission Operating Facilities Sustainment	.5	.4	.6	3.0	6.5	3.5
Operations Support Tools (NOMS, UWPC, Electronic Logging)	0	0.3	1.5	1.7	0	0
Miscellaneous	.3	.1	0	0.0	0.2	0
Total	**2.0**	**16.8**	**11.3**	**8.8**	**22.6**	**18.5**

3.2 Description of Investments

Table 3
Grid Operations Control Facilities
Capital Projects > $ 3 Million in Test Year 2011 or 2012 ($ Millions)

Ref #	Description	Cash Flow Test Years 2011	Cash Flow Test Years 2012	Total Cost	Removal Cost	Capital Cost
O1	Network Operations Buildings Expansion	12.1	11.0	23.1	0	23.1
O2	NMS Enhancements	3.8	4.0	7.8	0	7.8
O3	Transmission Operating Facilities Sustainment	6.5	3.5	10.0	0	10.0
	Other Projects/ Programs < $3M	0.2	0.0	0.2	0	0.2
	Total Cost	**22.6**	**18.5**	**41.1**	**0**	**41.1**
	Removal Cost	**0**	**0**	**0**		
	Capital Cost	**22.6**	**18.5**	**41.1**		

3.3 O1 Network Operations Buildings Expansion

This is a new investment required to ensure adequate building facilities, including back office, computer rooms and backup centre control rooms. The investment deals with both the primary control facility, the Ontario Grid Control Centre located in the Barrie area, and the back up control facility located in the Toronto area.

3.3.1 Ontario Grid Control Centre (Primary Control Facility)

Growing business requirements are driving increases both in staff numbers and expansion of the operating support systems. To date, all possible measures have been implemented at the OGCC to use all available space. Office space has been optimized and computer hardware facilities have been expanded to maximum capability.

Moving staff to “overflow” locations or decentralizing various operating departments would increase costs due to the resulting lost staff time for travel, inefficiencies and space leasing costs. Experience since the consolidation of operations into the OGCC has demonstrated that it is most effective to accommodate operations staff and support facilities at one centre.

The best solution is to expand the OGCC facility either directly or by building a new facility adjacent to the original.

3.3.2 Backup Control Centre

The Backup Control Centre is required should an extreme contingency disable the OGCC. Existing Backup Control Centre computer rooms are currently stretched to capacity in terms of physical space, power supplies and environmental controls. As a result, full redundancy of all systems is not currently available and some systems are currently housed in substandard overflow locations, constituting a risk to the reliability of transmission operating facilities.

A review of the Back up Centre is in progress which is taking a broader assessment considering total life-cycle cost and the current and future operating needs of the existing back-up control centre facilities. Analysis shows that relocating to a new back-up centre with expansion capacity is the best option.

3.4 O2 NMS Enhancements

Additional tools are required to enable operators and outage planning staff to manage increasing workload required to execute the growing sustainment and development work programs.

During 2011 and 2012, new commercially available NMS applications will be implemented to provide better information on the status and condition of field equipment, better information on the power system and to automate routine tasks. As well, standard vendor supplied applications will replace custom applications thereby reducing ongoing support costs.

3.5 O3 Transmission Operating Facilities Sustainment

This investment provides capital sustainment of the computer tools and systems that support the Control Room and back office transmission operating functions at the OGCC and the back-up centre. Many of these systems have about a 5-year life.

During 2011 and 2012, the Control Room telephone system, NMS workstations and displays, and Control Room display wallboards will reach end of life and will require replacement.

The risk of not proceeding with these replacements will include increased support costs and increasing failures of systems essential for the smooth function of the control room.

3.6 Operations Support Tools

This capital investment provides for the replacement of the existing NOMS, Utility Work Protection Code (UWPC) Forms and Electronic Logging programs with an integrated solution. The enhanced integrated system will bundle all of the transmission equipment outage planning tools in a complete solution and provide interfaces to asset management work program systems, thereby improving the outage planning process. The centralized system will also streamline the effort to ensure the accuracy of the work protection permits and switching orders – an important contribution to the provision of a safe working area to employees.

This capital investment is expected to be in-service by the end of 2010 and therefore it has no impact on the Operations Capital expenditures during the test years.

3.7 Miscellaneous Projects

The investment in Dynamic Transformer Ratings ($0.2 million total for 2011) continues funding of an existing project to investigate, verify and prove the accuracy of Dynamic Transformer Ratings (DTR). DTR has the potential to increase the efficiency of transformer usage under various operating conditions.

4.0 OPERATING INFRASTRUCTURE

4.1 Overview

This program funds enhancements, expansion and end of life replacement of the physical infrastructure required for the operation of the Transmission System.

Table 3
Operating Infrastructure Capital
($ Millions)

Description	Historic			Bridge	Test	
	2007	2008	2009	2010	2011	2012
Hub Site Management Program	0.1	5.3	5.3	1.0	2.9	4.3
Telemetry Expansion Program	0.2	0	0	0.1	3.4	3.5
Wide Area Network	0	0.3	0.1	0.3	11.0	26.1
Miscellaneous	2.4	0.7	3.3	0.0	4.4	5.1
Total	**2.7**	**6.3**	**8.7**	**1.4**	**21.7**	**38.9**

The spending level for this program is driven by the ongoing program requirements combined with discrete projects undertaken in any given year or period of years. The spend in 2010 is below trend due to an intentional slowing of some programs and delays to projects in order to re-assess their scope and priorities in the face of major emerging new requirements associated with the green energy initiatives such as distributed generation and Smart Grid and the future evolution of NERC Cyber Security requirements. The proposed plan is the result of that reassessment. The increase in 2011 and 2012 funding levels are mainly attributable to the telecommunication requirements for generation connections, smart grid, security (both cyber and physical) and enterprise efficiency and increasing the rate of the telemetry expansion program. The telecommunication requirements are expected to continue to grow over the next decade. While the funding between 2011 and 2013 for the initial telecommunication infrastructure build represents a one-time cost, relatively small ongoing incremental expansion costs will continue in future years. Combined with telemetry expansion, ongoing hub site management and end of life replacements, the future funding levels for Operating Infrastructure Capital will be higher than historic and likely in range of 60% above the 2008 to 2009 average spend.

4.2 Summary of Need

The key drivers for the expenditures in operating infrastructure are:

- Growth in the grid increasing the number of assets and system elements that need to be monitored and controlled
- New compliance requirements
- The need to provide improved open access to the grid for connection of generation
- The need to achieve improved efficiency and performance in order to execute expanded sustainment and development programs.
- Other challenges such as the need for improved physical security at stations

During the test years, and years following, there will be an unprecedented combination of all these factors requiring expansion to the operating infrastructure.

Operating Infrastructure is subject to demanding requirements for reliability, performance and cyber security and is architected and designed accordingly. It is essential that this infrastructure continue to operate during extreme events such as severe weather or a wide-spread blackout, that it be continuously monitored for, and impervious to, cyber attack and that it can handle the large volumes of data that need to be sent to the control centre during a system disturbance affecting multiple transmission stations.

4.3 Description of Investments

Table 4
Operating Infrastructure
Capital Projects > $ 3 Million in Test Year 2011 or 2012 ($ Millions)

Ref #	Description	Cash Flow Test Years 2011	Cash Flow Test Years 2012	Total Cost	Removal Cost	Capital Cost
O4	Hub Site Management Program	2.9	4.3	7.2	0	7.2
O5	Telemetry Expansion	3.4	3.5	6.9	0	6.9
O6	Wide Area Network	11.0	26.1	37.1	0	37.1
	Other Projects/ Programs < $3M	4.4	5.1	9.5	0	9.5
	Total Cost	**21.7**	**38.9**	**60.6**	**0**	**60.6**
	Removal Cost	**0**	**0**	**0**		
	Capital Cost	**21.7**	**38.9**	**60.6**		**60.6**

4.3.1 O4 Hub-Site Management Program

This program is needed to continuously expand the gateways systems located at 37 hub sites across the province to provide capacity for monitoring and control of new assets, stations and generators that are connecting to the system. As new asset are built, the additional telemetry required increases the utilization of the gateways. When a gateway approaches capacity, additional gateways and hub sites need to be added. After a period of about 5 years, the gateway boxes need to be replaced due to obsolescence. The hub site management program continually manages these factors optimally to ensure the capacity and reliability of the grid control infrastructure is in place to meet the needs of the development, load connection and generation connection programs.

This program was introduced in 2007 about 4 years after most of the gateways went into service for the creation of the OGCC. From 2007 to 2009 many gateway systems were upgraded to larger systems to address full capacity utilization problems of many systems. By 2011 it is projected that grid expansion and generation connections will require an increased rate of gateway expansion and hub site separations.

Additional detail for this program is provided in the Investment Summary Documents in Exhibit D2, Tab 2, Schedule 3.

4.3.2 O5 Telemetry Expansion Program

This program is required to eliminate unnecessary equipment outages and inefficient use of the time of field staff, and to better manage aging assets. This will contribute to improved grid reliability and also reduce impediments to accomplishing the growing sustainment and development work programs.

The key deliverables of this program are the splitting of critical bundled alarms and the addition of more detailed monitoring of station equipment. This will enable OGCC operators to make immediate determination of the cause of an alarm and the appropriate response and will eliminate the need for unnecessarily removing equipment from service and costly urgent field staff callout to the stations. The removal of any piece of equipment from service can place load supply at risk and will likely result in delaying other outages required to complete sustainment or development work. Delay or cancellation of outages can be very disruptive to the execution of work affecting both schedules and costs.

Additional detail for this program is provided in the Investment Summary Documents in Exhibit D2, Tab 2, Schedule 3.

4.3.3 O6 Telecom Wide Area Network

Hydro One projects a fourfold increase in requirement for telecom capacity over the next five years. This is to meet the needs of protection and control for new generation, smart grid, cyber security, enterprise systems and monitoring for physical site security.

The Telecom Wide Area Network project will install telecom facilities that will allow Hydro One to make optimum use of its existing extensive network of fibre optic cable installed onto its transmission lines to meet these requirements. Studies have shown that this investment will pay back in five years through reduced future telecom lease costs beyond the test years.

Additional detail for this program is provided in the Investment Summary Documents in Exhibit D2, Tab 2, Schedule 3.

4.3.4 Other Miscellaneous Projects

A number of other smaller projects totaling $4.4 million in 2011 and $5.1 million in 2012 make up the balance of the Operating Infrastructure expenditures. These projects are briefly described below:

Telecommunication Performance Improvement: This investment ($2.9 million total for 2011 and 2012) will fund improvements to Hydro One Transmission's grid control network to resolve telecommunication reliability and performance problems. There are a number of stations that improvements to reliability and redundancies are required due to telecom problems. It is particularly serious if the telecommunication fails as a result of power loss. This program addresses those by providing an alternate independent path or by addressing infrastructure problems which allow common mode failure issues.

Fault Locating: This program ($1.5 million total for 2011 and 2012) funds facilities required to accurately compute and promptly transmit the location of transmission line failures (faults) from the line terminal stations to the control room operators. Monitoring devices are now in place in most stations which have the ability to collect raw information that can be used to compute the fault location on transmission lines emanating from the station. This information is presently communicated verbally to the OGCC by protection and control staff once they have travelled to the station, interrogated the devices and performed the necessary calculations manually. This investment will allow for much faster determination of the location of the problem and faster restoration. It will also result in improved efficiency and reduced carbon footprint as the "windshield" time spent looking for a fault will be largely eliminated. Priority is given to long circuits in remote locations as these have both the longest travel times and the higher rates of faults. This investment receives information from the network connections installed at transmission stations as outlined on page 44 of Exhibit D1, Tab 3, Schedule 2.

Grid Control Network Sustainment: This program ($2.6 million total for 2011 and 2012) funds upgrades and end of life replacement of telecom equipment used in the Grid Control Network.

Real Time Data Service to Customers: This program ($1.0 million total for 2011 and 2012) funds maintenance, upgrades and enhancements to the Real Time Data Service. Hydro One is required under the Transmission System code to provide real time data to transmission connected customers. A system has been in operation from the OGCC and Back-up to provide this service and is well subscribed.

Weather Station Replacement: This project ($0.9 million total for 2011 and 2012) will fund end of life replacement of weather stations. Hydro One has a number of meteorological data collection systems at stations throughout the grid which provide important data for determining real time equipment limits, track build up of contamination on insulators, and detecting ice accretion.

Underground Cable Monitoring: This project ($0.6 million total for 2011 and 2012) will complete the installation of monitors on underground cable supplying downtown Toronto. These monitors will help ensure the health of the cables while allowing the best possible operating limits.

SUMMARY OF SHARED SERVICES CAPITAL

Capital expenditures under the Shared Services program support the Sustainment, Development, and Operations work programs of Hydro One Networks Inc. As such they consist of assets that are largely shared by both the Transmission and Distribution businesses. Shared assets include information technology (IT) installations such as applications software and computer equipment, buildings, office equipment, transportation and work equipment (“T&WE”), tools, and service equipment.

The following table provides an overview of the various cost categories for the period 2007 through 2012, highlighting the total capital spending for Shared Services.

Table 1
Total Shared Services & Other Capital 2007-2012 ($ Millions)

Description	Historic			Bridge	Test	
	2007	**2008**	**2009**	**2010**	**2011**	**2012**
Information Technology	31.6	19.1	21.0	41.6	37.8	29.1
Cornerstone Initiative	63.5	107.2	90.9	24.1	7.0	7.3
Facilities & Real Estate	9.6	7.1	17.1	48.4	44.8	35.2
Transport & Work Equipment	41.1	52.0	46.5	61.0	74.1	60.2
Service Equipment	7.9	11.7	6.6	12.0	8.8	5.9
Other (including Distribution Line Loss and CDM)	15.2	3.3	2.5	0.0	0.0	0.0
Total	**168.9**	**200.4**	**184.7**	**187.1**	**172.5**	**137.6**

Table 2 is a summary of the Transmission portion of the Shared Services Capital over the Historic, Bridge and Test years.

Table 2
Shared Services & Other Capital Allocated to Transmission 2007-2012 ($ Millions)

Description	Historic			Bridge	Test	
	2007	2008	2009	2010	2011	2012
Information Technology	13.3	9.2	9.2	17.0	18.9	14.4
Cornerstone	35.2	59.1	50.9	11.1	2.0	0.2
Facilities & Real Estate	3.2	3.5	6.3	25.8	23.9	19.1
Transport & Work Equipment	9.9	12.5	11.2	14.6	17.8	14.4
Service Equipment	3.4	5.0	2.8	5.1	3.8	2.5
Other	7.1	0.5	1.1	0.0	0.0	0.0
Total	**72.2**	**89.8**	**81.5**	**73.6**	**66.4**	**50.6**

Exhibit C1, Tab 5, Schedule 3 outlines the appropriate cost allocation drivers that have been utilized to derive the Transmission allocation of this capital.

The increase in IT capital for 2011 and 2012 relative to the 2009 historic test year is driven by the IT strategy that includes the upgrade or replacement of several of the current large information systems as they reach their end-of-life. Exhibit D1, Tab 3, Schedule 6 details the capital requirements for IT.

The Cornerstone initiative is a major business transformation initiative that deals with end-of-life replacement issues and also provides a platform for further effectiveness and efficiency gains at Hydro One (see Exhibit A, Tab 16, Schedule 1 for further details). The costs for 2007 through to 2009 relate to the initiation and then completion of Phases 1 and then 2 of the Cornerstone initiative. Once Cornerstone's SAP platform is fully deployed, it is followed by the gradual completion of Cornerstone Phase 3 in the latter years. Exhibit D1, Tab 3, Schedule 7 details the capital requirements for the Cornerstone initiative.

Shared Services capital is primarily driven by the need to support a larger work program. This in turn requires increased Facilities & Real Estate as space for a larger workforce is required. In 2011 and 2012 the Facilities & Real Estate capital increases, relative to the 2009 historic year, are to accommodate the need to acquire new head office space, and anticipated associated tenant improvements. Exhibit D1, Tab 3, Schedule 8 details the capital requirements for Facilities and Real Estate.

Additional T&WE are also needed to support growth in work programs. T&WE costs show an increase for 2011 and 2012, relative to the 2009 historic year, primarily due to the significant increase in workload due to the new connections required for the *Green Energy and Green Economy Act, 2009*. Moreover, as the end-of-life is reached for fleet vehicles, such as line trucks, utility vehicles and helicopters, replacement is required. Exhibit D1, Tab 3, Schedule 9 details the capital requirements for T&WE.

Service Equipment year-over-year changes are largely the result of end-of-life replacement of specific items of large mobile equipment, spending related to corporate Health and Safety initiatives, and general cost increases associated with purchases of new and replacement equipment. Exhibit D1, Tab 3, Schedule 9 details the capital requirements for Service Equipment.

Other capital normally consists of accruals and adjustments, including adjustments for over/under recovery for burdened rates that are attributable to capital, but had not been applied to a specific program. There are no anticipated adjustments in the test years 2011 and 2012.

SHARED SERVICES CAPITAL - INFORMATION TECHNOLOGY

1.0 INTRODUCTION

Information Technology (“IT”) refers to computer systems (hardware, software and applications) that support business processes used by employees throughout Hydro One. IT infrastructure includes the voice and data telecommunication networks; data centre installations; and computer equipment (servers, computers, data storage devices, and printers). Staff access software applications and systems from offices, field locations and mobile devices using Hydro One’s wide area network, local area networks or through Hydro One’s virtual private network.

IT capital expenditures include hardware and software for projects and programs that each in total cost more than $2 million. IT investments are made in accordance with approved business strategies, follow the IT Governance process described in Exhibit C1, Tab 2, Schedule 9, and are subject to a formal review process.

2.0 IT CAPITAL EXPENDITURES

Table 1
Total IT Capital Expenditures ($ Millions)

Description	Historic			Bridge	Test		TX Allocation	
	2007	2008	2009	2010	2011	2012	2011	2012
Software Refresh & Maintenance	11.9	9.3	8.0	12.8	10.9	8.0	6.1	4.5
Minor Fixed Asset Program*	14.4	9.3	9.0	18.1	18.0	14.2	7.8	6.1
Development Programs	5.4	0.5	4.0	10.6	9.0	6.9	5.0	3.9
Total	**31.7**	**19.1**	**21.0**	**41.6**	**37.9**	**29.1**	**18.9**	**14.4**

* Cornerstone capital is shown in Exhibit D1, Tab 3, Schedule 7

Capital IT expenditures are undertaken as projects or programs to meet business requirements. Capital expenditures fall into 3 categories:

- Software Refresh and Maintenance programs ensure continued operations of the installed IT application infrastructure, and include costs related to upgrading existing operating systems.
- Minor Fixed Assets (MFA) programs ensure the continued operations of the installed IT hardware infrastructure. Expenses in this category address equipment needs generated by the growth in demand for IT services, capacity limitations and the replacement of end-of-life IT equipment and in the Telecom network. MFA includes desktop/notebook computing equipment, field tablet computers, mainframe and storage devices, servers, and peripherals and telecommunication infrastructure including switches, computer-telephony interfaces, etc.
- Development Programs ensure the replacement and/or upgrade of older and end-of-life applications and include investments in new applications. Replacement of applications occurs when the applications have become inadequate for current functional needs or where the version is no longer supported by the vendor. Upgrades are undertaken to address legislative changes or market driven initiatives or to modify the application to better support an evolving business capability. New applications are added to address business needs and to support existing or new business processes.

Hydro One has established general architecture principles for all of its applications. These are:

- Applications will be “off the shelf” and will be maintained in a vendor supported version. Existing custom applications will be migrated to “off the shelf” solutions wherever possible.
- There will be fewer applications rather than more.
- Middleware, such as Oracle’s BEA enterprise service bus, will be used as appropriate to facilitate application interconnectivity. Hydro One has already invested in creating this middleware or Service Oriented Architecture (“SOA”) to enable data integration within and between applications.

- Systems architecture and chosen applications will be:
  a. robust (generally understood to mean unlikely to fail, but rapid response if it does)
  b. secure (generally understood to mean server-hardened, monitored, fire-walled and password protected)
  c. flexible service oriented architecture (generally accepted as the most appropriate and efficient data integration method).
- System hardware will be upgraded as required to support new applications and will be vendor supported.
- Costs will be managed on a total cost of operations basis.

IT has also developed and is implementing an Enterprise Strategy to replace the existing best of breed and customized enterprise applications which are approaching end of life. The strategy envisions an integrated suite of applications which allow for interconnectivity and interflow of financial and operations data (Cornerstone) which can then be used by the business to support work processes. Applications will be implemented "off the shelf" and applications will be maintained up to date to allow the business to make use of vendor enhancements and improvements. New applications will, wherever practical, interface with the Enterprise systems to allow for the transfer of data and to ensure cross-corporate data visibility.

The major planned IT capital projects which will be funded in 2010, 2011 and 2012 are described below.

2.1 Software Maintenance and Refresh Programs

Table 2
Software Refresh and Maintenance Program Capital Expenditures
($ Millions)

Description	Historic			Bridge	Test		TX Allocation	
	2007	2008	2009	2010	2011	2012	2011	2012
Software Refresh & Maintenance	11.9	9.3	8.0	12.8	10.9	8.0	6.1	4.5
Total	**11.9**	**9.3**	**8.0**	**12.8**	**10.9**	**8.0**	**6.1**	**4.5**

Hydro One utilizes just over 970 software applications in order to equip its employees with the required technologies to perform their tasks efficiently and safely. The software refresh and maintenance program provides the needed software vendors' releases, periodic version upgrades, and replacements of activity-focused applications that each meet the total capital threshold of $2 million aggregated. Included in these costs are applications and operating systems that support integrated enterprise systems such as OMS, WEP, SAP, etc.

Applications are replaced or upgraded with the line of business involvement to ensure applications remain compatible with current IT platforms and other interfacing applications. In this manner, vendor support is maintained to help fix breakdowns or other issues that may occur with the application. Funding decisions are made based on software lifecycles, vendor schedules, reliability requirements, and experience with similar initiatives/projects.

The cost increase in 2010 is mainly attributed to required upgrades and/or modifications to a number of legacy applications due to the Haromized Sales Tax (HST) regulation that comes into effect in July 2010. Included in 2011 are the implementation of enterprise content management and collaboration tools, further IT security access control and monitoring capabilities, upgrading the desktop operating system to Windows 7, anti-virus software upgrades and improvements to the disaster recovery platform. In 2012, planned costs include: working towards a Microsoft Office 2010 rollout, Windows Server 2012 rollout, IT security additions to centralized logging and event management; expansion of event detection capabilities; and further investment in BEA middleware components for integration of SAP and other applications.

2.2 Minor Fixed Assets

Minor Fixed Asset investments are for IT hardware and include specific programs to refresh aging hardware such as personal computers, servers and mainframes. Equipment is refreshed based on its age and the nature of the applications running on the hardware. Equipment may be upgraded, or improvements may be made to extend hardware functionality. Hydro One's strategy is to minimize the costs of ownership, ensure operations risk is kept at an acceptable level, and to maintain functionality and security. Planned funding is based on equipment lifecycles. This work is broken down into the categories shown in Table 3 below.

Table 3
Minor Fixed Asset Program Capital Expenditures
($ Millions)

Description	Historic			Bridge	Test		TX Allocation	
	2007	2008	2009	2010	2011	2012	2011	2012
IT Mainframe, Servers and Storage	8.4	1.6	2.1	4.3	7.5	6.8	3.3	2.9
IT Desktops, Laptops, Tablets, Printers and Plotters	4.8	5.2	3.4	5.8	6.2	4.2	2.7	1.8
Telecom Networks and PBX/Voicemail	1.2	2.5	3.5	8.0	4.3	3.2	1.8	1.4
Total	**14.4**	**9.3**	**9.0**	**18.1**	**18.0**	**14.2**	**7.8**	**6.1**

2.2.1 MFA: IT Mainframe, Servers and Storage Sustainment program

This investment is required to respond to and manage annual growth in demand for additional IT processing and storage capacity and to address end of life issues with the existing Unix and Wintel servers.

Infrastructure servers are used to run business applications, networks, web services and email. Data storage devices are used by business applications and email to store and retrieve data. Servers and storage devices reach capacity over time and reach their vendor's end-of-support-life at which time they require upgrading or replacement to increase capacity or to ensure cost efficient maintenance that minimizes or eliminates down time. In determining when systems require replacement, the functionality and operating and maintenance costs are assessed. Hardware upgrades are needed to maintain reliable service for business applications.

The funding for the mainframe, servers and storage refresh program varies year to year depending upon hardware lifecycles and business requirements for increased processing capacity.

IT servers follow a four to five year lifecycle. In 2006/2007, the Microsoft XP Upgrade project required the replacement of a large quantity of servers that are now targeted for lifecycle refresh in 2011. This will accommodate the lifecycle refresh of end of life servers and the anticipated growth in demand for new server resources. The lifecycle refresh continues in 2012 with an additional 25% of Wintel servers and an estimated 15% of Unix servers.

2.2.2 MFA: IT Desktops, Laptops, Tablets, Printers, and Plotters Sustainment Program

Desktop and laptop computers are used by most Hydro One staff for office productivity applications such as email, word processing, spreadsheet, presentation, and personal databases, and for business applications. Rugged tablet computers are used by field staff. Tablets are used with Geospatial Information Systems ("GIS") applications for undertaking systems design work and for asset condition assessments. Plotters are used by Hydro One engineering and operations staff for design work and to plot systems maps.

Hardware upgrades are required to accommodate new software requirements, to replace end of life equipment, to address warranty considerations and to maintain hardware reliability. Personal computer purchases also reflect projected increases in headcount.

Properly planned equipment refresh can maintain or reduce maintenance costs. Hardware costs tend to increase with age, especially when the hardware is no longer supported under vendor warranty. Hydro One's practice is to replace desktop and laptop computers every three to five years, and printers and plotters every four to five years. The renewal timeline is consistent with industry practice as identified by Gartner industry benchmarking studies. In practice, the refresh cycle has been slightly longer but has been consistent with maintaining functionality and minimizing maintenance costs.

The funding for desktops, laptops, tablets, printers, and plotters varies year to year depending upon hardware lifecycles, business needs and forecasted headcount increases. 2011 costs also include increased hardware requirements to accommodate the planned upgrade to Microsoft Windows 7 and the upgrade of Microsoft office tools. The hardware spend in 2010 and 2011 is to bring the current client technology hardware (laptops, desktops, tablets, etc) inline to support the migration to the Microsoft Windows 7 upgrade, reducing the refresh demands for the 2012 year.

2.2.3 <u>MFA: Telecom Networks and PBX/Voicemail Sustainment program</u>

The telecom assets of Hydro One are varied and have a large range of install dates, and lifecycle dates. The business telecom network is used to transmit data required to run business applications, for email, and for web sites. Voice or data network improvements or replacements are undertaken as part of an ongoing network management program. The objective is to improve network efficiency and to ensure equipment is current and supported by third party vendors.

Voice and data communications are used by the business daily to plan and carryout work and are especially important during storm periods. Projects regularly undertaken include rewiring local area networks ("LAN"), replacing end of life data network switches and routers, upgrading telephone Private Branch Exchange ("PBX") switches, replacing un-interruptible power source ("UPS") system, and upgrading the security solutions for external interfaces.

PBX/Voicemail hardware includes PBX and key set telephone switches, and voice mail equipment used to provide business telephone services to Hydro One employees at central and field locations throughout the province. Investments vary depending on the opening, closing or consolidation of offices.

Within the Hydro One voice and data network there are more than 800 routers/switches and hubs that connect to 74 PBX's and 35 Norstar/BCM smaller multi-line office sets that support more than 155 locations across the province. A majority of the routers/switches and hubs are reaching end of life.

The investment in Networks and PBX/Voicemail is undertaken to replace end-of-life assets and to maintain service reliability and security. The strategy is to replace equipment that is no longer supported by vendors. For network equipment the refresh occurs about every five years for network related hardware and about every ten years for PBX/Voicemail equipment.

The funding for Networks and PBX/Voicemail varies year to year depending upon hardware lifecycle refreshes, business needs for increased bandwidth and available market resources.

2010 planned costs include: growth in the telecom infrastructure; initiation of a 4 year voice system upgrade which includes migration of 25% of the end of life Meridian Mail systems to Call Pilot; local area network wireless expansion; branch office router upgrades; Telecom Disaster/Recovery enhancements; and GTA network upgrades. On a year-to-year comparison, the higher 2010 costs in this category are attributed to the branch office router upgrades which begin and end in 2010 and upfront costs associated with the voice system IP telephony upgrades. 2011 and 2012 costs represent the continuation of the second and third year upgrade to these programs along with the commencement of a corporate local area network 4-year (2010-2014) refresh program.

2.3 Development Projects

As previously noted, development projects include the cost for new applications or the replacement of end of life applications. Costs for IT development projects are detailed in Table 4 below.

Table 4
IT Development Projects Capital Expenditures
($ Millions)

Description	**Historic**			**Bridge**	**Test**		**TX Allocation**	
	2007	**2008**	**2009**	**2010**	**2011**	**2012**	**2011**	**2012**
CIS/CSS Hybrid Upgrades/CRM	2.9	0.3	0.2	-	-	-	-	
CTI Upgrades	0.7	(0.3)[1]	-	-	-	-	-	
ACPi/WEP	0.9	0.0	-	-	-	-	-	
IREIS	-			-	-	-	-	
Mobile IT	-		1.0	2.5	3.0	2.0	1.7	1.1
Asset Mgmt & Data Collection	0.9	-	-	-	-		-	
Warehouse Bar Coding	-	0.0	0.4	1.0	-		-	
eCustomer Self-Service Web Site	-	-	1.9	1.5	-		-	
Enterprise GIS Program	-	-	-	5.4	6.0	4.9	3.3	2.8
DX Asset Information System	-	0.5	0.5	0.2	-		-	
Total	**5.4**	**0.5**	**4.0**	**10.6**	**9.0**	**6.9**	**5.0**	**3.9**

[1]: represents vendor credit

2.3.1 Mobile IT

Mobile IT (total of $5.0 million to be spent over 2011 through 2012) is intended to equip field staff with the tools required to access current asset data applications including SAP, GIS and work order dispatch applications. This project supports the Company's response to staff and vehicle location safety needs, Smart Grid and Smart Metering initiatives and supports the implementation of "off the shelf" data collection tools for SAP and other enterprise systems which require data to be collected and reported from the field.

Hydro One is implementing a mobile software application which will be the standard enterprise mobile tool for data collection and work status reporting and will also interface with the GIS and SAP systems. The applications will work in a connected (real time) or disconnected mode depending on the nature of the work being performed. The intent is to be able to make this information available to the enterprise systems for asset data and work status record updating and further analysis. The application was selected in 2009 and system as well as business process integration is spanning 2010 through 2012 in manageable phases. The first phase includes enabling Stations Maintenance crews to collect their inspection data for loading into SAP to enable reliability-centered maintenance. Enablement within Customer Operations will follow to support their ongoing asset management and data collection

2.3.2 Warehouse Bar Coding

This investment is required to provide an enterprise wide solution for automating the inventory management activities for the Barrie warehouse, central maintenance shop and the meter shop to ensure accuracy of data collection and reduction in manual data entry. Improvements in accuracy and timeliness of entry will result in more accurate inventory records, and fewer inventory adjustments.

2.3.3 eCustomer Self Service Web Site

This investment will improve and enhance the existing self service web site applications including the ability for customers to: sign-up for pre-authorized payments in accordance with the Canadian Payments Association new regulations; make payment arrangements when in arrears; sign-up for pre-authorized payments; complete high bill enquiry walkthroughs; connect directly to an Agent for further assistance; receive a callback via the Virtual Hold function.

This electronic communication channel enables customers to serve themselves when electricity usage data becomes available on a daily basis with the implementation of automated meter reading and time of use ("TOU") billing. This investment will allow for the alignment of smart metering and TOU requirements using a solution that is seamless to the end user.

2.3.4 Enterprise GIS Program

Geospatial technology is a key infrastructure that enables a variety of business processes including design, transmission and distribution planning, outage management, work management, real estate and others. Geospatial technology and the underlying connected network model is also a key component required to support the benefits achieved from smart grid initiatives.

This program will result in a single system of record comprising the location and connectivity of both transmission and distribution assets (GIS is the only technology that fully supports both logical connectivity and physical location of assets) as well as properties. It will: facilitate planning and outage management; support mobile workforce management through intelligent crew routing and automated vehicle location ("AVL"); manage real estate records and Hydro One property; and provide the underpinnings of smart grid applications such as FLISR (fault location, isolation and service restoration, which minimizes the outage impact to customers) and VVO (volt var optimization, which provides a consistent quality of service while achieving efficiency through voltage reduction).

The GIS Program will also enable integration to other critical business systems such as SAP, distribution planning with CYME, outage management with ORMS, or next-generation DMS. It entails completing the conversion of Dx asset data, reconciling the data and business processes, and updating the GIS infrastructure, particularly software applications.

2.3.5 DX Asset Information System

The objective of this investment is to establish technology and infrastructure allowing for collection of the data related to Dx Assets, migration of this data to the GIS environment and post-migration editing of the data in order to build connectivity, populate missing attributes and verify reliability of the data. This is a multi-year process, the purpose of which is to create a complete and reliable spatial dataset supporting crucial business initiatives such as Outage Management, Work Program Planning, etc.

SHARED SERVICES CAPITAL - CORNERSTONE

1.0 OVERVIEW

The Cornerstone Project is part of the overall information technology ("IT") strategy to replace several of Hydro One's key enterprise information systems as they reach their 'end of life'. The Cornerstone Project is also a major business process transformation initiative that provides a platform for further effectiveness and efficiency gains at Hydro One. The Cornerstone Project is to be carried out in four phases as summarized below:

Phase 1 (Completed June 2008): Replaced end of life Passport application and functionality associated with work management, supply chain, procurement, accounts payable and asset registry with a modern Enterprise Asset Management ("EAM") solution using SAP. This phase was completed successfully in June 2008.

Phase 2 (Majority Completed August 2009, minor items to be completed in 2010): Replaced end of life PeopleSoft application for Finance / Human Resources / Payroll processing with functionality provided by SAP that is integrated with the EAM solution installed in Phase 1. The phase 2 implementation also addressed the analytical and reporting business needs for work management, finance, investment management, HR and Pay and requirements for International Financial Reporting Standards ("IFRS") compliance. Additional releases will be required in 2010 to address the most recent requirements for IFRS and final phase 2 reporting and analytical requirements.

Phase 3 (In-Service 2010-2012): Enhance integrated planning, Enterprise Asset Management / Enterprise Resource Planning systems, tools and processes by expanding Hydro One's SAP solution and integrating key systems/technologies and specialized packaged point solutions to drive additional business value, improve end-to-end process efficiency and improve asset lifecycle management analytics/decisions. This includes adding SAP functionality by turning on new SAP modules; integrating specialized software applications for reliability centred maintenance & optimization, scheduling & dispatch enhancements; interfacing key enterprise systems (e.g. geospatial information system ("GIS"), operating, fleet, telecom, protection & control, etc); incorporating new assets into the asset registry (e.g. IT assets, real estate assets, metering assets, etc); integration with enterprise mobile technology, enhancing functionality for HR, Finance, Work Management and Supply Chain and consolidating end-user databases/applications.

Phase 4 (2016): Replace end of life customer information system ("CIS"). Core product is Customer-1 application with numerous best of breed and custom applications fulfilling the remaining functionality of the CIS.

Table 1 below identifies the capital expenditures and savings for the Cornerstone program for the period 2007 to 2012.

Table 1
Cornerstone Capital 2007 – 2012 ($ Millions)

	Historic			**Bridge**	**Test**		**TX Allocated**	
	2007	**2008**	**2009**	**2010**	**2011**	**2012**	**2011**	**2012**
Minor Fixed Assets	3.2	7.2	0.2	2.0	1.5	2.1	0.6	0.9
Development Projects	60.4	99.9	90.8	32.9	19.4	27.2	10.9	15.2
Total Capital Cost	63.6	107.1	91.0	34.9	20.9	29.3	11.5	16.1
Savings	0	0	*	(10.8)	(13.9)	(22.1)	(9.5)	(15.9)
Net Capital Cost	**63.6**	**107.1**	**91.0**	**24.1**	**7.0**	**7.2**	**2.0**	**0.2**

* 8.0 million in savings realized in 2009

The Cornerstone capital expenditures consist of Minor Fixed Assets and Development Costs. The latter include all the costs to acquire, install and place into service the new Cornerstone systems. Cornerstone capital expenditures support the Sustainment, Development, and Operations work programs of Hydro One Networks Inc. As such they consist of assets that are largely shared by both the Transmission and Distribution businesses. The differences in year to year expenditures are the result of the phasing of Cornerstone implementation. This table also shows the forecast capital savings arising from Cornerstone process improvements and the result of netting these savings against the total capital costs. These savings are discussed later in this schedule.

The Cornerstone Project O&M spending and the percent allocation to Transmission over the Historic, Bridge, and Test years are shown in Exhibit C1, Tab 2, Schedule 10. In Exhibit C1, Tab 5, Schedule 3 the appropriate cost allocation drivers that have been utilized to derive the Distribution allocation of the Cornerstone Project are shown.

2.0 BACKGROUND

The capital work program for Cornerstone commenced in 2007. Phase 1 of the project was successfully completed in June 2008. The majority of Phase 2 was completed in August 2009. Work has begun on Phase 3. The four phases of the Cornerstone Project are discussed below:

Phase 1 – Enterprise Asset Management Core Functionality (Completed June 2008)

The EAM initiative replaced the existing Passport applications with a modern EAM solution in June 2008. The result is an integrated EAM application that has enabled more effective information transfer within the Company and provided the basis for connectivity with other core systems as they are replaced or upgraded.

Hydro One started Phase I after obtaining Hydro One Board of Director approval in February, 2007 and successfully implemented ("go-live") Phase 1 on June 30, 2008. Phase 1 delivered an EAM solution that replaced legacy Passport functionality; provided additional enhancement/capability to facilitate business process improvements; established data governance and data structure for ongoing data collection and management activities; addressed Bill 198 and other regulatory compliance requirements; and provided the basis for future phases of the project by turning on and utilizing additional modules within the same application suite.

The benefits from Phase 1 are based upon a complete understanding of the benefits from the SAP application. These benefits are derived from three key value levers underpinned by Cornerstone Phase 1 application, process and organizational changes. These value levers are:

- Centralizing to a single asset registry with a uniform hierarchy and selective integration to legacy databases;
- Providing greater process transparency, integration and collaboration (enabled through the application and process changes) across Hydro One's lines of business ("LOB"); and,
- Enhancing compliance to the underlying processes and data requirements.

Phase 1 savings (both Transmission and Distribution) total $200 million over a seven year period starting in 2009 to 2015. Total savings of $60.4M are expected in the test years 2011 and 2012 as shown in Table 2.

Table 2
Total Cornerstone Phase 1 Savings ($M) (Transmission & Distribution)

	2011	**2012**
OM&A	16.5	19.0
Capital	11.6	13.3
Total	28.1	32.3

The bulk of the total savings are through the following:

- Optimize O&M and Capital spend through enhanced asset analysis and maintenance by managing operational risks over the asset life cycle (Expected Savings $50.3M).
- Enhanced crew productivity due to better materials availability through more efficient forecasting, planning and execution. The contribution to improvement in crew productivity results from having the right materials available at the right time and the right location (Expected Savings $35.5M).
- Improve internal & supplier contract compliance through reduction in non – Purchase Order spend for direct purchase of materials and services. This benefit is derived from all users purchasing standardized materials and services off negotiated contracts at agreed prices and terms (Expected Savings $35M).

Each of the future phases build on the foundation set by Phase 1. Each of Phases 1, 2 and 3 will utilize the interconnected SAP application platform. Each phase is stand-alone to the extent that each will add its own benefits to the overall Cornerstone program.

Phase 2 – Replaced PeopleSoft Finance / Human Resources / Payroll Functionality (Majority Completed August 2009, minor items to be completed in Q1-Q3 2010)

In August, 2009, Phase 2 replaced existing end-of-life PeopleSoft Finance, Human Resources ("HR") and Payroll processing with functionality provided by SAP that is integrated with the EAM solution installed in Phase 1. Phase 2 also addressed analytical and reporting business needs and helped to fulfill the requirement to be compliant with International Financial Reporting Standards by January 1, 2011 as discussed in the project investment justification document shown in Exhibit D2, Tab 2, Schedule 3. Additional releases are currently underway to address additional changes in IFRS requirements and final reporting and analytical requirements.

The PeopleSoft Finance, HR and Payroll processing modules were installed in 1998 and the HR module was upgraded in 2002 and subsequently customized. These systems were core to Hydro One's financial reporting and human resource management capability.

Cornerstone Phase 2 expanded Hydro One's SAP solution footprint by replacing PeopleSoft; providing one integrated system of record for all finance, HR and asset data and bring a greater proportion of Hydro One's core business systems under vendor support. The scope also covered the following:

- replaced the in-house application, Business, Regulatory Planning & Reporting ("BRPR"), which tracked the release of work from Asset Management to the field, with SAP investment management functionality;
- replaced legacy data warehouse applications and databases with a single SAP business data warehouse and the business objects reporting suite, to provide one source of reliable business data; and

- Addressed International Financial Reporting Standards ("IFRS") requirements to accommodate IFRS compliance by January 1, 2011. A parallel IFRS Project has been carried out to review Hydro One accounting policies/practices and recommend changes to meet IFRS compliance requirements. Many of these recommendations were incorporated into the Phase 2 SAP solution while others will be addressed in subsequent releases of SAP, to address any late changes in IFRS requirements so as to provide full IFRS compliance before the January 1, 2011 deadline. A full discussion of IFRS is provided in Exhibit A, Tab 13, Schedule 1.

Phase 2 of Cornerstone was undertaken following a competitive RFP selection in late 2007 / early 2008 and the discovery process completed in 2008, which was used to confirm cost and scope. Hydro One started Phase 2 discovery work after obtaining Hydro One Board approval in May, 2008 and continued project delivery after successfully completing Phase 1 in June 2008.

As in Phase 1, the main objective was not only to install an off-the-shelf solution, but also to adopt industry-standard practices. Integration of the new finance and HR application with the modules installed in Phase 1 has enhanced reporting capabilities. This was done by providing Business Intelligence / Business Warehouse capability in Phase 2. Business intelligence is the capability of collecting and analyzing internal and external data to generate knowledge and value for the organization. Business Warehouse is making information readily accessible and available for analysis.

Inergi worked closely with Hydro One, in its role as outsource business service provider and as an end user of the applications and revised business processes. Inergi and its parent company, Cap Gemini, worked with Accenture, the system integrator, to ensure the solution delivered met Hydro One's needs. Accenture, SAP and Cap Gemini/Inergi committed to delivering the required solution and working in a collaborative and open process. Governance over the project included oversight by a sub committee of the Hydro One Board of Directors, Executive and project level reviews and an ongoing Quality Assurance /Quality Control process implemented by Accenture.

The Phase 2 benefits built on the benefits derived from three key value levers underpinned by the Cornerstone Phase 1 application for technology, process and organizational changes. The Phase 2 savings total approximately $50 million with expected savings of about $5.5 million in the test year 2011 and $7.0 million in 2012 as shown in Table 3 below.

Table 3
Total Cornerstone Phase 2 Savings ($M) (Transmission & Distribution)

	2011	**2012**
OM&A	3.2	4.1
Capital	2.3	2.9
Total	5.5	7.0

The Phase 2 savings are based upon the following benefits identified over a seven year period starting in 2010:

2.1 Replacement of the core Finance / Investment Management / Time Reporting / Human Resources / Payroll Functionality

Expected Benefits $20M:

- Provide efficiency improvements that are driven by having a standardized platform for business process, technology and reporting and an integrated system of record within SAP for all asset and financial data;
- Improve IT security and internal control; and

- Avoid costs associated with maintaining and reconciling two separate financial system applications and having to implement IFRS compliance requirements in both (the SAP financials implemented with Phase 1, and the legacy PeopleSoft application.).

2.2 Business Intelligence/Business Warehouse

Expected Benefits $30M:

- Provide field supervisors with key operational data, standard reports and analytical tools to enable further workforce productivity improvements;
- Provide the centralized Asset Management group with a common and single source for information and better analytical tools to improve asset investment decisions; and
- Provide the Company with a tool to help realize and measure progress in realizing the business benefits of Cornerstone.

Phase 3 (In-Service 2010-2012): Enhance Integrated Planning

Phase 3 will enhance integrated planning and Enterprise Asset Management / Enterprise Resource Planning systems, tools and processes by expanding Hydro One's SAP solution and integrating key systems/technologies and specialized packaged point solutions to drive additional business value, improve end-to-end process efficiency and improve asset lifecycle management analytics/decisions. This includes adding SAP functionality by turning on new SAP modules; integrating specialized software applications for reliability centred maintenance & optimization, scheduling & dispatch enhancements; interfacing key enterprise systems (e.g. geospatial information system ("GIS"), operating, fleet, telecom, protection & control, etc); incorporating new assets into the asset registry (e.g.

IT assets, real estate assets, metering assets, etc); integration with enterprise mobile technology and enhancing functionality for HR, Finance, Work Management and Supply Chain and consolidating end-user databases/applications.

Hydro One business information consists of many different components that reside in many different sources even after completion of Phases 1 and 2. The key is to integrate these sources to allow for asset and other business data to be captured once and used consistently throughout the Company to provide asset and asset work information from a variety of perspectives e.g. system performance, asset condition, labour, cost (historical and forecasted), work accomplishment, performance and work metrics, customer reliability, outage management, etc. This facilitates breaking down the information silos and driving enterprise integration and improvements via process, people and technology. An essential element of this vision is to provide seamless integration of data between the asset registry, work orders, scheduling/dispatch and GIS system with mobile integration. This phase enhances and streamlines end-to-end business processes by expanding and leveraging the SAP application functionality to implement workflow for process control, consolidate and eliminate duplicative and disparate end-user databases/applications to increase the assets being managed in SAP and integrating/interfacing key systems (e.g. operating, real estate, fleet, protection & control, telecom, metering, etc) to provide a centralized asset repository and single source of truth across all lines of business.

Phase 3 will also integrate SAP to the enterprise GIS system and to operating scheduling/ dispatch leveraging enterprise mobile technology that is deployed to field staff across the province. It will integrate legacy historical information with current SAP data to facilitate trend analysis and performance forecasts and integrate new reliability centred maintenance optimization software to provide ongoing analysis of preventative maintenance results, validation of asset models, and facilitate strategic/scenario planning that is focused on improving asset lifecycle management decisions.

Phase 3 will be completed late in 2011 and savings are not expected to be realized until 2012. Hydro One expects savings from improved processes, elimination of duplicative data systems and improved transparency across the organization. The Phase 3 expected savings total approximately $130 million over a seven year period with expected savings of $14.1 million starting in 2012 as shown in table 4.

Table 4
Total Cornerstone Phase 3 Savings ($M) (Transmission & Distribution)

	2011	**2012**
OM&A	0.0	8.2
Capital	0.0	5.9
Total	0.0	14.1

Phase 4 (In-Service 2016) - Replace Customer Information System Functionality

The CSS or Customer-1 application was purchased in 1997 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 supports the application.

To obtain full functionality with the newer systems, and to improve workflow and improve customer satisfaction, the intent of Phase 4 is to replace the existing Customer-1 system with a more integrated application which would interface with the application suite implemented in Phases 1, 2 and 3.

SHARED SERVICES CAPITAL - FACILITIES & REAL ESTATE

1.0 INTRODUCTION

This exhibit addresses Facilities and Real Estate's ("F&RE") capital expenditures to acquire (own or lease) and maintain Hydro One Networks Inc.'s office space and service centres.

2.0 SHARED SERVICES - FACILITIES & REAL ESTATE

Table 1 presents total F&RE capital expenditures for the Historic, Bridge and Test Years as well as the 2011 and 2012 Transmission amounts.

Table 1

Total Facilities and Real Estate Capital Expenditures ($ Millions)

Description	Historic			Bridge	Test		TX Allocation	
	2007	2008	2009	2010	2011	2012	2011	2012
Major	6.5	6.1	16.0	38.0	35.8	29.6	20.0	16.7
MFA	3.1	1.0	1.1	10.4	9.0	5.6	3.9	2.4
Total	9.6	7.1	17.1	48.4	44.8	35.2	23.9	19.1

The primary driver for the increase in costs is the need to provide suitable space to accommodate staff resources and equipment. These expenditures encompass the refurbishment, acquisition and/or development of field facilities, and provide for additional administrative workspace and improvement of head office space.

The F&RE major capital program allows for the provision of workspace for head office facilities, the Ontario Grid Control Centre in Barrie, and field administrative and service centre facilities.

Key Program work activities include:

- addressing Company accommodation requirements in terms of new buildings, buildings additions and major facility renovations;
- replacement of major building components including roof structures, windows, heating, ventilating and air conditioning ("HVAC") systems and other structural elements and building systems;
- dealing with environmental issues that may arise such as mold;
- water treatment upgrades to improve quality and reliability of water supply, including conversions to municipal supply.

2.1 Field Facilities Accommodations Requirements

Table 2
Total Field Facilities Capital Expenditures ($ Millions)

Description	Historic			Bridge	Test		TX Allocation	
	2007	2008	2009	2010	2011	2012	2011	2012
Major	5.4	5.8	16.0	24.3	22.8	16.6	12.8	9.3
MFA	1.5	0.0	0.8	3.1	3.0	3.0	1.3	1.3
Total	6.9	5.8	16.8	27.4	25.8	19.6	14.1	10.6

This capital work program includes improvements and additions to existing facilities, acquisition of new facilities in line with the Company's operational requirements and responding to work program space demands. This program also focuses on ensuring critical facility structural and other building improvements to enhance the life of assets.

The capital investment is required for field facilities in order to continue to provide adequate workspace accommodation for various types of staff resources (e.g. regular, temporary) and accommodate lines of business operating requirements. The investment need is driven by the following key factors:

- aging facilities asset base that are near the end of life;
- emerging accommodation needs from lines of business' expanding work programs and changing business requirements.

The Company experiences work program growth across the Province which affects all field facilities. Main factors taken into consideration during investment decisions include: existing facilities' conditions including facilities that are near the end of their life and/or which were historically experiencing operating deficiencies including health and safety issues, facilities that are inadequate for changing, and increasing business needs (this includes providing accommodation for additional staff and/or work equipment). Ultimately the accommodation needs of lines of business are examined in terms of short and long term needs, logistics and geographic proximity to service areas, work sites and corresponding acceptable accommodation alternatives available in the local real estate markets. Based on these considerations decisions are made to build new facilities, conduct major renovations including building additions, or consider limited lease options. In addition, structural and other building improvements are conducted on a priority basis to existing facilities as a result of asset condition assessments. The level of the capital sustainment spending may vary from year to year depending on business circumstances.

The facilities infrastructure base is dominated by buildings and associated systems and components that are at or reaching the end of their asset life cycle. Approximately 40% of administrative and service centre facilities are estimated to be more than 40 years old. The aging facilities asset base, in conjunction with work program demands and operational needs of the business units, requires capital investment in order to continue to provide adequate workspace accommodation. These requirements will be addressed on a priority basis and/or as opportunities emerge at an estimated cost of $25.8 million and $19.6 million in 2011 and 2012 respectively.

2.2 Head Office and GTA Facilities Accommodations Requirement

Table 3

Total Head Office and GTA Facilities Capital Expenditures ($ Millions)

Description	**Historic**			**Bridge**	**Test**		**TX Allocation**	
	2007	**2008**	**2009**	**2010**	**2011**	**2012**	**2011**	**2012**
Major	1.1	0.3	0.0	13.7	13.0	13.0	7.3	7.3
MFA	1.6	1.0	0.3	7.3	6.0	2.6	2.6	1.1
Total	2.7	1.3	0.3	21.0	19.0	15.6	9.9	8.4

Capital investment of $19.0 million is required in test year 2011 and $15.6 million in test year 2012. This investment will provide for head office accommodation improvements.

Hydro One Networks has completed an eleven year lease renewal for 483 Bay Street in Toronto, effective February 1, 2010, to serve its ongoing head office requirements. Within the recently completed lease renewal, Hydro One was successful in obtaining the commitment of the Landlord to upgrade base building systems/infrastructures, allowances for tenant improvements and swing space to execute improvements over a two year period, which created both the opportunity and incentive to complete head office related improvements at this time.

Leading to the decision to renew the lease for 483 Bay Street through a competitive process, a commercial real estate firm was retained to assist Hydro One with the identification, evaluation and negotiations for office space requirements. The retained firm undertook to directly investigate through a formal RFP process with landlords and real estate brokers leasing opportunities, which included advertisement through a major newspaper, to meet Hydro One Networks' objectives within the Greater Toronto area. Of the eleven office space proposals received, a comparative analysis process was undertaken of five short listed options.

The comparative analysis covered a wide set of criteria which included price; transit access; LEED/environmental accreditation; telecommunications; barrier free access; amenities; floor plate configuration and efficiency; elevators; growth opportunities; security; and building services. Ultimately the process identified two Downtown Toronto options with landlords that were well suited to meet Hydro One Networks' requirements. Hydro One Networks pursued parallel negotiations with the respective landlords including validation of the lease terms and pricing in the market place at that point in time.

The head office capital investment consists of both leasehold improvements and replacement furniture systems which will commence in the bridge year 2010 and are expected to continue throughout the test years and end in 2013. In 2011 the gross leasehold improvements and the furniture systems funding requirements are estimated to be $13.0 million and $6.0 million respectively. In 2012 the gross leasehold improvements are estimated to be $13.0 million and the furniture systems funding requirements are estimated to be $2.6 million. The planned improvements are necessary as major head office building infrastructure elements are now at the end of their life and require replacement. (This includes the raised flooring, which presents a health and safety issue with an increasing number of tripping hazards.) The project costing reflects continuance of the open office environment, completion to standard commercial finishes and commitment to LEED certification. Similarly, furniture systems acquired from the previous tenant and refurbished, are also now considered to be at end of life. The planned tenant improvements are part of the newly negotiated lease agreement.

3.0 MINOR FIXED ASSETS ("MFA")

Office workstations and furniture are beyond the end of their normal service life and need to be replaced. Table 1 shows the estimated MFA expenditures in 2011 and 2012. This includes replacement of furniture and office equipment in conjunction with the head office accommodation that will continue throughout test years 2011 and 2012 and furniture systems related to new and renovated space accommodation requirements.

SHARED SERVICES CAPITAL – TRANSPORT, WORK AND SERVICE EQUIPMENT

1.0 INTRODUCTION

This exhibit identifies the Transport and Work Equipment ("TWE") and Service Equipment capital expenditures for the period 2007 to 2012.

TWE and Service Equipment provide vehicle and specialized equipment support to the growing levels of the transmission and distribution, sustainment, development, and operations work programs. Some of the high-level activities driving upward pressure on TWE and Service Equipment capital in 2011 and 2012 are:

- The increased focus on the transmission and distribution, capital and OM&A sustainment and development work programs;
- Customer Operations – Additional staffing requirements, driven by the requirements of the Provincial Lines and Forestry Apprenticeship Programs;
- The replacement of core end-of-life Fleet and equipment; and,
- Vegetation Management – Hydro One Distribution is proposing increases in accomplishment levels to move maintenance toward an 8-year cycle. As recently as 2006, maintenance was on a 10-year cycle and efforts to reduce the cycle have been underway since that time. During this cycle transition, the impact on labour and equipment resources is significant.

2.0 TRANSPORT AND WORK EQUIPMENT

The increase in capital expenditures of $13.1 million in 2011 as shown in Table 1, is directly tied to the planned level of activities in the overall work programs, driven by:

core Fleet replacement, additional staffing, changes to the Forestry and Provincial Lines Apprenticeship Programs, as well as supporting the growing levels of the transmission and distribution capital and OM&A sustainment, and development work programs, including the initiatives outlined in the Transmission and Distribution Green Energy Plans. In 2012, capital expenditures decrease by $13.9 million as a result of delays to fulfilling some of the equipment and staffing requirements, as well as Forestry and Provincial Lines Apprenticeship Programs. The majority of these expenditures are associated with the Hydro One Distribution business.

Hydro One has approximately 5,700 units with an original capital value ("OCV") of $400 million. Approximately 500 units are scheduled for replacement. Fleet capital requirements are primarily based on industry standards (manufacturer's recommendations) for life cycle expectancy, the remaining capital value, and operating cost drivers. Light vehicles are replaced after 6 years or 180,000 km, service trucks are replaced after 6 years or 200,000 km, and work equipment is replaced after 8 to 10 years or 330,000 km.

Table 1

Capital Expenditures From 2007 – 2012 ($ Millions)

Description	Historic			Bridge	Test		TX Allocation	
	2007	2008	2009	2010	2011	2012	2011	2012
Total Cost	41.1	52.0	46.5	61.0	74.1	60.2	17.8	14.4

The objective of the TWE Replacement Program is to promote an orderly system of purchasing and funding a standardized fleet replacement process, to plan for future transportation requirements as well as identify the need to increase overall fleet size based on staffing requirements. The TWE Replacement Program annually analyzes 5-year cycles for capital investment requirements and maintains a safe and efficient fleet. It is critical to evaluate and forecast spending requirements to minimize fluctuating spending patterns and to stabilize long term capital investment. The fleet capital program, on an annual basis, is evaluated against the business plan and is subject to the work program prioritization and forecasting process.

Business cases for the program are prepared and approved and the equipment is strategically procured through a tendering process.

The TWE Replacement Program reviews:

- Equipment capital forecast;
- Equipment productivity, functionality, and future requirements;
- Equipment standards, equipment age, mechanical condition, kilometers traveled and cost per kilometer, downtime, and repair time;
- Safety/risk;
- Work programs, evaluating staff and equipment complement;
- Tendered procurement process;
- Fleet's Original Capital Value and Net Book Value;
- Historical and future utilization;
- Strategic procurement; and
- Cost versus 5-year business plan.

The guidelines for vehicles considered for replacement are based on vehicles meeting predetermined criteria including, but not limited to: manufacturer's life expectancy, average cost per kilometer, regulated maintenance standards and safety/risk. Hydro One takes advantage of discounts by establishing purchasing cycles with manufacturers. As vehicles reach the targeted criteria, a vehicle maintenance evaluation is performed and, in some cases, the unit may be reassigned to other functions with "low usage" requirements. The replacement program measures the age and value of the fleet and meets the requirements and due diligence of a typical utility fleet.

The benefits of our replacement program include:

- Maximum safety, productivity and utilization;
- Minimum downtime, repair time, and fleet complement;
- Reduced operating costs.

2.1 2007 to 2012 Period Analysis

As noted in Exhibit C1, Tab 4, Schedule 1 (Costing of Work), the overall size of Hydro One Networks Inc.'s fleet was adjusted to approximately 5,700 vehicles and other equipment in 2010 to match the work program requirements. TWE expenditures are forecasted to be $ 74.1 million in 2011 and $60.2 million in 2012 based on the number of vehicles and equipment requirements to achieve the planned level of transmission and distribution capital and OM&A, sustainment and development work programs, core end-of-life fleet and equipment replacement, and additional staffing requirements.

The increase in capital requirements in 2008 over 2007 was directly related to the increases in the Forestry and Provincial Lines Apprenticeship Programs in anticipation of regular staff retirements. This will be readjusted when staff complement is right-sized. Of the $52.0 million, $7.2 million was required for Provincial Lines to accommodate the increase in work program to offset rental requirements and to support the Lines Apprenticeship Program, and $4.8 million was directly related to additional large equipment requirements for Forestry in order to facilitate changes in the Apprenticeship Program.

In 2009, the capital expenditure primarily reflects the amount required to maintain core Fleet requirements. Of the $46.5 million, approximately $7.0 million was required to support the Forestry and Provincial Lines apprenticeship programs and additional staffing requirements, and $37.9 million for core Fleet and equipment replacements. Similarly, TWE capital expenditure is forecasted to be $61.0 million in 2010 based on the planned work program levels ($37.9 million), additional equipment requirements for the Provincial Lines and Forestry Apprenticeship Programs and additional staff ($12.5 million), as well as $10.6 million for the internal Transmission and Distribution work requirements to accomplish the initiatives of the Green Energy Act.

In 2011, the forecasted TWE capital expenditures of $74.1 million includes - $39.7 million requirements for core Fleet replacements, as well as $34.4 million towards the transmission and distribution capital and OM&A, sustainment and development work activities. In 2012, TWE capital expenditures are forecasted to be $60.2 million. This includes $42.0 million for the core end-of-life Fleet and equipment replacement program, and $18.2 million for necessary equipment, and staffing requirements associated with the Provincial Lines and Forestry Apprenticeship Programs.

2.2 Capital vs. Operating Leases

The evaluation of leasing as a financial alternative to the approved capital program has been evaluated in the past. The evaluation included the review of both capital and operating leases and the total operating costs. The risks and benefits generated by leasing were evaluated and it was decided the risks outweighed the modest benefits. The results therefore indicated that leasing was not cost effective.

The requirement for short term rentals (as distinct from long term rentals) is recognized and is included with our operating expenses in Exhibit C1, Tab 5, Schedule 1.

2.3 Procurement Initiatives

In order to achieve cost reductions over the next five years, Fleet Services follow capital procurement objectives for material and service acquisitions which include:

- Profile the commodities, collect and analyze cost drivers;
- Analyze the supply market;
- Develop a strategy for sourcing;
- Select the suppliers through a rigorous RFP process;
- Conduct negotiations.

These procurement initiatives have allowed Hydro One Networks Inc. to lock in pricing for 3 year terms with preferred vendors.

2.4 Environmental Management

In 2010, Hydro One received a gold rating for environmental management of its fleet. Canada's Energy Environment and Excellence Group based their gold rating on the reduction of 156,675 KG of carbon dioxide through reduced fleet idling, the tire smart campaign, use of hybrids, buying more fuel-efficient vehicles as well as overall reduced consumption of gasoline and diesel fuel. All aspects of Hydro One's fleet management strategy were reviewed, to ensure the 5,700 pieces of equipment, ranging from ATVs to helicopters, operate with green standards in mind.

3.0 SERVICE EQUIPMENT

Table 2 identifies the expenditures for Service Equipment for the 2007 to 2012 period.

Table 2
MFA Service Equipment 2006 – 2011 ($ Millions)

Description	Historic			Bridge	Test		TX Allocation	
	2007	2008	2009	2010	2011	2012	2011	2012
Total Cost	7.9	11.7	6.6	12.0	8.8	5.9	3.8	2.5

Minor fixed assets for service equipment consists of capital items of $2,000 or more, required by Hydro One staff to carry out construction and maintenance work programs. Capital items less than $2,000 are expensed to OM&A. Minor fixed asset expenditures for service equipment are required to replace equipment at end of life, replace technologically obsolete service equipment when new standards and safer work practices come into effect, and provide for sufficient levels of new service equipment consistent with work program expansion and increasing staffing levels.

Purchases in this category include specialized transportation equipment for off-road work sites and mobile equipment required to carry out a variety of work.

Specialized transportation equipment used for both Transmission and Distribution includes items such as all-terrain vehicles, boats, barges, snowmobiles and related accessories. Generally, Service Equipment largely used for both transmission and distribution related work includes: mobile cranes, stringing equipment, Schnabel cars, and float trailers.

Mobile equipment includes oil tankers, de-gassifiers, and dry air machines required for transformer maintenance, SF6 gas carts required for the maintenance of SF6 breakers, and a variety of other equipment necessary to analyze, test, and carry out construction and maintenance associated with the transmission work program.

Capital requirements related to health, safety and the environment have slightly increased year-over-year. We continue to invest in AED (defibrillator) devices, for example, to enhance basic life support capability at Hydro One workplaces, including offices and vehicles.

ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION

The interest rate used for construction work in progress (CWIP), referred to as Allowance for Funds Used During Construction (AFUDC), reflects the Board's Decision in proceeding EB-2006-0117. This Decision required that the interest rate to be used for CWIP would be the Scotia Capital All-Corporates Mid-Term Average Weighted Bond Yield, as published on the Bank of Canada website and updated quarterly. Per the OEB's website, since July 2007, "the source reference for the CWIP interest rate, the Scotia Capital Inc. All-Corporates Average Weighted Yield Mid-Term, has not been publicly available via the Bank of Canada's website". This bond yield has been renamed as the "DEX Mid-Term Corporate Bond Index". For the 2010 bridge year, as well as, for the 2011 and 2012 test years Hydro One Transmission has used the ten year Government of Canada forecast plus the November 2009 spread between the average actual ten year Government of Canada bond yield and the average DEX Mid-Term Corporate Bond Index Yield. For the historical years, 2007 reflects the average of the approved embedded cost of debt (Q1) and the prescribed quarterly interest rates (Q2 to Q4), while 2008 and 2009 reflect the average quarterly prescribed interest rate.

Table 1
Allowance for Funds Used During Construction

Year	AFUDC Rate	AFUDC ($ millions)
2007	5.2%	18.6
2008	5.3%	26.9
2009	5.9%	45.7
2010	4.9%	73.6
2011	5.6%	54.4[1]
2012	6.1%	63.2[1]

[1] Excludes CWIP for project included in rate base as discussed in Exhibit A, Tab 11, Schedule 5.