RATE BASE

1.0 INTRODUCTION

This Exhibit provides the forecast of Hydro One Transmission’s rate base for the 2013 and 2014 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. 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 in 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 in Exhibit D2, Tab 3, Schedule 1 and Exhibit D2, Tab 3, Schedule 2.

Hydro One Transmission’s forecast rate base for the 2013 test year is $9,460.0 million and for the 2014 test year is $10,073.5.million. Table 1 provides a summary of the calculation of the Transmission rate base for the 2013 and 2014 test years.

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

Description	Test 2013	Test 2014
Gross Plant	14,426.6	15,329.2
Accumulated Depreciation	(4,982.8)	(5,271.0)
Net Plant in Service	9,443.9	10,058.2
Construction work in progress	0.0	0.0
Net Utility Plant	**9,443.9**	**10,058.2**
Cash Working Capital	12.7	11.9
Materials and Supplies Inventory	3.5	3.5
Total Working Capital	**16.1**	**15.3**
Transmission Rate Base	**9,460.0**	**10,073.5**

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 in Exhibit D2, Tab 2, Schedule 3.

The 2013 net plant in-service of $9,443.9 million is $688.5 million or 7.9% higher than 2012 Board-approved. The 2014 net plant in-service of $10,058.2 million is $614.3 million or 6.5% higher than 2013 Test Year. These increases reflect the Company's infrastructure investments to address asset replacement and refurbishment needs of our aging system, and to expand the system for the purposes of load growth, accommodating a

[1] 2013 and 2014 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.

modified generation mix, and expanding access to interconnected electricity markets as described in Exhibit D1, Tab 1, Schedule 2.

The accumulated depreciation balance for the test years incorporates the accepted Foster Associates' Inc. methodology. The depreciation expense is further discussed in Exhibit C1, Tab 8, Schedule 1. A continuity schedule for accumulated depreciation for the test, bridge and historical years is shown in Exhibit D2, Tab 3, Schedule 2.

2.1.1 Continuity Schedule for Fixed Assets

Table 2
Continuity of Fixed Assets Summary ($ Million)

Description	Historic			Bridge	Test	
	2009	2010	2011	2012	2013	2014
Opening Gross Asset Balance	10,481	11,081	11,928	12,687	13,975	14,879
In-Service Additions	661	843	792	1322	946	937
Retirements	(34)	(20)	(28)	(35)	(41)	(37)
Sales	0	(3)	(4)	0	0	0
Transfers	(27)	26	(2)	0	0	0
Closing Gross Asset Balance	11,081	11,928	12,687	13,975	14,879	15,780
Mid-Year Gross Asset Balance	10,781	11,505	12,308	13,331	14,427	15,329

A continuity schedule for fixed assets for the test, bridge and historical years is shown in 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 in Exhibit D1, Tabs 3.

2.2 Cash Working Capital

In 2012 Hydro One Transmission retained Navigant Consulting Inc. to undertake a lead-lag study. The provision for working capital in 2013 and 2014 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 $12.7 million for the 2013 test year and $11.9 million for the 2014 test year. The calculation of cash working capital is discussed in further detail in Exhibit D1, Tab 1, Schedule 3.

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 $3.5 million for 2013 and $3.5 million for 2014. Materials and supplies inventory is discussed in further detail in Exhibit D1, Tab 5, Schedule 1.

3.0 COMPARISON OF RATE BASE TO BOARD APPROVED

Table 3 compares 2011 costs to the 2011 Rate Base approved by the Board in their Decision on Hydro One Transmission's previous application in EB-2010-0002.

Table 3
2011 Board Approved versus 2011 Rate Base
($M)

Rate Base Component	2011	2011Board Approved	Variance
Gross Plant	12,307.5	12,263.1	44.4
Accumulated Depreciation	(4,436.5)	(4,428.4)	(8.1)
Net Utility Plant	**7,871.0**	**7,834.7**	**36.3**
Cash Working Capital[1]	7.1	7.1	0.0
Materials & Supplies Inventory	14.4	10.7	3.7
Total Rate Base	**7,892.5**	**7,852.5**	**40.0**

[1] Hydro One Transmission does not calculate actual cash working capital, thus the 2011 approved amount was used for illustrative purposes.

Total rate base was $40.0 million above the Board approved amount, a variance of 0.5%.

Table 4 compares 2012 forecast costs to the 2012 Rate Base approved by the Board in their Decision on Hydro One Transmission's previous application EB-2011-0268.

Table 4
2012 Board Approved versus 2012 Bridge Year Rate Base
($M)

Rate Base Component	2012 Bridge Year (Forecast)	2012 Board Approved	Variance
Gross Plant	13,330.7	13,443.8	(113.1)
Accumulated Depreciation	(4,703.7)	(4,688.4)	(15.3)
Net Utility Plant	**8,627.0**	**8,755.4**	**(128.4)**
Cash Working Capital[1]	5.0	5.0	0.0
Materials & Supplies Inventory	9.8	14.0	(4.2)
Total Rate Base	**8,641.8**	**8,774.4**	**(132.6)**

[1] Hydro One Transmission does not calculate actual cash working capital, thus the 2012 approved amount was used for illustrative purposes.

Total rate base was $132.6 million below the Board approved amount, a variance of 1.5%.

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 2011 – 2014 ($ M)

	2011 ISA Actuals	2011 OEB Approved	2012 - Bridge Projected	2012 - OEB Approved	Test Years 2013	Test Years 2014
Sustaining	363.8	363.0	396.6	394.5	562.1	602.7
Development	374.6	378.2	835.8	1,074.8	278.5	223.7
Operations	6.8	41.0	25.2	52.7	45.1	48.0
Other	46.7	52.3	64.5	69.9	59.7	63.1
Total	**791.8**	**834.4**	**1,322.1**	**1,591.9**	**945.5**	**937.4**

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 15, Schedule 6 for how Hydro One Transmission intends to accomplish the work program.

Primary factors behind the 2011 in-service additions being $43 million lower than the OEB approved level of $834 million include:

- Operations in-service additions are $34 million below OEB approved levels as there were delays in the Backup Control Centre investments and the Wide Area Network (WAN) project. The Backup Control Centre investment was delayed as the review of short and long term strategies is still underway and is considering new technologies and alternate approaches. The release of the WAN investments were delayed to ensure alignment with an independent review of the Telecommunication Master Plan for Hydro One Networks. Also, rather than construct additional building facilities at the Ontario Grid Control Centre to accommodate staff, the decision was taken to lease space off-site in the interim. These factors also result in the 2012 Operations in-service additions underage.

- Other in-service additions are $5 million lower than OEB approved largely due to delays in real estate projects.
- Both the Sustainment and Development in-service additions essentially match 2011 OEB approved levels (the variances are both less than 1%).

The 2012 in-service additions are $270 million lower than the OEB approved level of $1,592 million due to the following factors:

- The $239 million underage in Development in-service additions is due to the following factors:
  - The new $88 million transformer station at Hearn has been delayed until 2013 due to property acquisition issues; and, due to project commencement delays, the new transformer stations at Barwick ($15 million) and Tremaine ($10 million) have also been delayed until 2013.
  - $732 million of the new 500kV Bruce to Milton double-circuit line was scheduled to be in-service in 2012. However, in 2011, multiple stages of this project totaling $35 million were placed in-service, comprising station upgrades at Milton SS and the new circuit line from Middleport to Bruce. Project costs of $652 million will be placed in-service in 2012, with additional amounts being placed into service in the test years.
  - The $26 million new transformer station at Duart was placed in-service ahead of schedule in 2011 rather than 2012; as were $37 million of Burlington TS circuit breakers and a transformer connection (the remaining $20 million for the project is placed into service in 2012).

- Operations in-service additions are $27 million below OEB approved levels due to the same factors as outlined earlier for the 2011 underage.
- Other in-service additions are $5 million lower than OEB approved largely due to delays in Cornerstone Phase 3.
- Sustainment in-service additions essentially match OEB approved levels (the variance is less than 1%).

In-service capital additions will decrease 28% in 2013 as compared to 2012, and decrease a further 1% in 2014 as compared to 2013. The significant decrease from 2012 to 2013 is due to the main portion of the Bruce to Milton project being placed into service in 2012 as noted earlier. However, 2013 and 2014 levels of in-service additions are substantially greater than previous years. This is primarily a result of the required increases in our work program over the past few years to address asset replacement and refurbishment needs of our aging system and to expand the system to accommodate load growth and a modified generation mix.

The in-service additions in 2013 and 2014 include:

- Market Efficiency - Network Transfer Capability, a Development activity, has the following main projects coming int to service:
  - 2013 – the Shunt Capacitor installation at Pinard TS.
  - 2014 - the Reconductoring of 230kV circuits at L24L and L26L.
- Station Facility Reinvestments – a Sustaining activity, is comprised of investments replacing multiple end-of-life assets at transformer stations such as air blast circuit breakers and metalclad switchgear.
- Overhead Lines Component Refurbishment and Replacement – a Sustaining activity, replaces end-of-life components such as towers and tower foundations, shieldwire, switches and insulators.

- Power Transformers – a Sustaining activity, replaces and refurbishes various types of end-of-life station transformers.
- Protection, Control and Metering – a Sustaining activity, 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, Digital Frequency Recorders, 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, includes new lines or transformer stations that are required to increase supply and reliability. The main projects are as follows:
  - 2013 – the new Hearn TS, the 115kV Switchyard Uprate at Leaside TS, and the 115kV Switchyard Uprate at Manby TS.
  - 2014 - the new 115kV circuit line from Leaside TS to Bridgman TS, and the T11 & T12 upgrades at Keith TS.
- TS Upgrade to Facilitate Renewables - a Development activity, whose main project in 2014 is the installation of In-line Circuit Breakers #3 (Samsung Phase 2).
- Load Customer Connection - a Development activity, includes the following main projects:
  - 2013 - Barwick TS, Tremaine TS, and Nebo TS.
  - 2014 - the T1 & T2 DESN Replacement at the Nelson Yard, and installation of a third transformer at Red Lake TS.
- Major Equipment Risk Mitigation – a Development activity, has two projects in 2013, the short circuit capability uprates at Hawthorne TS and at Allanburg 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. The accepted methodology was reviewed by Navigant in 2010 and used in the the Transmission rate filing EB-2010-0002. In 2012, 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 27, 2012).

2.0 SUMMARY

Hydro One Transmission's net cash working capital requirement for the 2013 test year is $12.7 million or 2.8% of OM&A ($451.8M) expenses or 0.13% of Rate Base ($9,460.0M). Net cash working capital for 2014 is $11.9 million, which is 2.6% of OM&A ($459.7M) expenses or 0.12% of Rate Base ($10,073.5M). 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 2013 and 2014 test years' revenue, expense and HST 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 leads 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 Lead (Days)**	**Net Lag (Lead) (Days)**	**2013 Test Year Amount**	**2014 Test Year Amount**
	(A)	(B)	(C)	(D)	(E)
Expenses					
OM&A Expenses	36.15	23.01	13.14	451.8	459.7
Removal costs	36.15	24.40	11.75	35.3	41.9
Environmental Remediation	36.15	27.99	8.16	6.1	6.9
Interest on Long term debt	36.15	15.16	20.99	262.0	272.4
Income tax	36.15	58.93	(22.78)	42.7	50.9
Total				**797.9**	**831.8**
HST (see Table 2)				81.5	90.6
TOTAL AMOUNTS PAID/ACCRUED				**879.4**	**922.4**
Working Capital Required (Calculations based on above values, for each expense category, calculated using the following formula: For 2013 Col (D)*Col (C)/365 For 2014 Col (E)*Col (C)/365)					
OM&A Expenses				16.3	16.5
Removal costs				1.1	1.4
Environmental Remediation				0.1	0.2
Interest on Long term debt				15.1	15.7
Income tax				(2.7)	(3.2)
Total				**29.9**	**30.5**
HST (see Table 2)				(17.3)	(18.7)
NET WORKING CASH REQUIRED				**12.7**	**11.9**

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

HST Category	**2013 Test Year**		**2014 Test Year**	
		13% HST Projection		**13% HST Projection**
	(A)	(B)	(A)	(B)
Revenue	1,464.3	190.4	1,556.6	202.4
OM&A Expenses	148.2	(19.3)	150.8	(19.6)
Removal costs	4.1	(0.5)	4.9	(0.6)
Environmental Remediation	2.3	(0.3)	2.5	(0.3)
Capital	682.9	(88.8)	694.5	(90.3)
TOTAL		**81.5**		**91.6**

HST (Benefit) Cost	**2013 Test Year**		**2014 Test Year**	
	Expense Leads (Days)	**HST Amounts**	**Expense Leads (Days)**	**HST Amounts**
	(C)	(D)	(C)	(D)
The values shown in the Col (D) labeled “HST Amounts” are calculated using the expense leads shown in Col (C) divided by 365 and multiplied by the 13% HST projected amount in Col (B)				
Revenue	(46.17)	(24.1)	(46.17)	(25.6)
OM&A Expenses	33.58	1.8	33.58	1.8
Removal costs	20.43	0.0	20.43	0.0
Environmental Remediation	20.43	0.0	20.43	0.0
Capital	20.43	5.0	20.43	5.1
TOTAL		**(17.3)**		**(18.7)**

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

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March 27, 2012

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Section I: Executive Summary

Summary

In the EB-2006-0501 and EB-2010-0002 Decision with Reasons, the Ontario Energy Board (the "Board" or "OEB") either accepted, or accepted with modifications, Hydro One Transmission's requests for working cash allowances. In preparation for a 2013-14 Transmission Rates Filing before the Board, Hydro One retained Navigant Consulting Ltd. ("Navigant") to prepare an update to its prior studies. This report provides the results of the update and the working capital requirements of Hydro One'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 comparable with Hydro One's 2006 and 2010 transmission studies. Where there are differences, they have been identified, explained, and their impact on working capital requirements quantified;
2. The approach and methods used in the study are generally consistent with prior Hydro One studies as well as studies performed by other regulated electricity transmitters in Ontario; and,
3. Results from the lead-lag study applied to Hydro One Transmission's expenses in the test years identify that working capital amounts of $12.7M in 2013 and $11.9M in 2014 will be required. These amounts represent approximately 2.80% and 2.58% of Hydro One Transmission's Operations, Maintenance, and Administration ("OM&A") expenses. These results are a reduction from that identified in the 2006 study (3.10% and 3.02%) but a slight increase from the 2010 study (1.57% and 1.11%). Reasons for the change from the 2010 study are provided in Section VI of this report.
4. Determining the company's working capital allowance using a lead-lag study is one of the two approaches included in the Board's Filing Requirements. If the OEB's alternative approach that 15% of OM&A was applied by Hydro One, the result would have been a working capital requirement of approximately $67.8M for 2013 and $69.0M for 2014. This would further result in rate base being $55.1M and $57.1M higher in 2013 and 2014, respectively.

Organization of the Report

Section I of this report is the Executive Summary and discusses the key findings and conclusions from this study.

Section II presents the methods and assumptions used in determining the lead lag approach. Included in this section is a description of two key concepts; the mid-point method and the statutory approach for services and materials provided and expensed.

Section III of this report discusses the lags associated with Hydro One's collection of revenues. This includes a description of the sources of such revenues, how they were treated for the purposes of deriving an overall revenue lag, and how it affects Hydro One Transmission's operations.

Section IV presents a description of the various expenses and their attendant lead times. Included in this discussion are the lead times on OM&A costs, removal costs, environmental remediation costs, interest on long-term debt, capital and income taxes, and the harmonized sales tax ("HST"). 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 V presents the cash working capital requirements of Hydro One Transmission including the working capital requirement associated with the HST.

Finally, Section VI presents a summary comparison of the results from this study with results from the 2010 Hydro One Transmission study. Differences between the two have been noted, explained, and their impacts on working capital quantified. The intent of presenting the discussion in Section VI is to demonstrate that the approach used in this study is an accurate reflection of the current operations of Hydro One Transmission and that the results are reasonable when compared with the 2006 and 2010 transmission studies.

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Section II: Methodology Used to Estimate Cash Working Capital

Working capital is the amount of funds that are 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 Navigant for this purpose.

A lead-lag study analyzes the time between the date customers receive service and the date customers' payments are available to Hydro One (or "lag") together with the time between which Hydro One receives goods and services from its vendors and pays for them at a later date (or "lead")[1]. "Leads" and "Lags" are both measured in days and are generally and where appropriate dollar-weighted.[2] The dollar-weighted net lag (i.e., lag minus lead) days is 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 amount of working capital is then included as part of Hydro One Transmission's rate base for the purpose of deriving revenue requirement.

Key Concepts

Two key concepts need to be defined up-front as they appear throughout the lead-lag study described in this report:

Mid-Point Method: When a service is provided to (or by) Hydro One over a period of time, the service is deemed to have been provided (or received) evenly over the midpoint of the 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 Hydro One. In some instances, particularly for the HST, the due dates for payments are established by statute or by regulation with significant penalties in place for late payments. In these instances, the due date established by statute has been used in lieu of when payments were actually made.

Expense Lead Components: As used in this study, Expense Leads are defined to consist of two components: i) a Service Lead component (i.e., services are assumed to be provided to Hydro One evenly around the mid-point of the service period), and ii) a Payment Lead component (i.e., the time

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

[2] The notion of dollar-weighting is pursued further in the sub-section titled "Key Concepts".

period from the end of the service period to the time payment was made and the funds left Hydro One's possession.)

Dollar Weighting: Both Lags and Leads should be dollar-weighted where appropriate and where data is available to more accurately reflect the flow of dollars. To use an example, suppose that a particular transaction has a Cash Outflow Lead time of 100 days and its dollar value was $100. Suppose further that another transaction has a Cash Outflow Lead time of 30 days with a dollar value of $1M. A simple un-weighted average of the two transactions would give us a Cash Outflow Lead time of 65 days (100+30 divided by 2). On the other hand, dollar weighting the two transactions gives us a Cash Outflow Lead time that would be closer to 30 days, an answer which is more representative of how the dollars actually flowed in this example.

Methodology

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 operations, interviews with personnel within Accounts Payable, Customer Service, Wholesale Market Operations, Human Resources, Payroll, Treasury, and Tax Departments were conducted. Key questions that were addressed during the interviews included:

1. What is being sold (or bought)? If a service is being provided (purchased), over what time period was the service provided (or purchased);
2. Who are the buyers (sellers);
3. 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;
4. Are any changes expected to the terms for payment either driven by industry or internally by Hydro One? What is the basis for such changes (if any);
5. Are there any new rules and regulations governing such transactions that are expected to materialize over the time frame considered in this report; and,
6. How is payment made (e.g., cash, check, electronic funds transfer)?

Except where otherwise noted, a calendar year 2010 data set was used in the analysis. Development of the data set entailed gathering raw data from the utility's General Accounting, Accounts Payable, Customer Service, 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 or bills with data from the utility's systems to ensure accuracy.

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Section III: Revenue Lags

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

Interviews with Hydro One personnel indicate that its Transmission business receives funds from two sources:

1. The Independent Electricity System Operator (or "IESO"); and,
2. Other sources including municipalities, electricity retailers, and for miscellaneous services such as jobbing and contracting work performed by Hydro One Transmission.

Data from Hydro One's billing system for the twelve months ended May 31, 2011 indicates that payments from the IESO contributed about 94% of Hydro One Transmission's revenues. Contribution from Other Sources was about 6%. The revenue lag days and dollar-weighted average associated with each of these contributions for the 2013/2014 test years is shown in Table 1. Each source of revenue is discussed in greater detail following Table 1. Historical revenue lag days from prior studies are also shown for reference.

Table 1: Summary of Weighted Average Revenue Lag Days

Description	Un-weighted Lag Days	Amounts ($M)	Weighting Factor % of Revenues	Weighted Lag Days
IESO	35.06	$1,325.48	94.26%	33.05
Other Revenues	54.10	$80.67	5.74%	3.10
Weighted Average				**36.15**

IESO Revenue Lag

Hydro One receives revenues from Ontario's IESO monthly in a manner that is consistent with the settlement and payment procedures outlined in the IESO's tariff (i.e., 12 business days after the end of a service month). Taking this information into account and using actual dates and amounts received for the twelve months ending May 31, 2011, a revenue lag of 35.06 days was determined. The derivation is shown in Table 2 below.

Table 2: IESO Revenue Lag Days

Period Start	Period End	Payment Date	IESO Revenue Amounts ($M)	Service Lag Time Days	Payment Lag Time Days	Total Lag Time Days	Weighting Factor	Weighted Lag Time Days
06/01/10	06/30/10	07/21/10	$106.61	15.00	21.00	36.00	8.04%	2.90
07/01/10	07/31/10	08/20/10	$124.91	15.50	20.00	35.50	9.42%	3.35
08/01/10	08/31/10	09/21/10	$120.96	15.50	21.00	36.50	9.13%	3.33
09/01/10	09/30/10	010/21/10	$120.64	15.00	21.00	36.00	9.10%	3.28
10/01/10	10/31/10	11/19/10	$89.78	15.50	19.00	34.50	6.77%	2.34
11/01/10	11/30/10	12/20/10	$97.94	15.00	20.00	35.00	7.39%	2.59
12/01/10	12/31/10	01/21/11	$110.37	15.50	21.00	36.50	8.33%	3.04
01/01/11	01/31/11	02/18/11	$119.83	15.50	18.00	33.50	9.04%	3.03
02/01/11	02/28/11	03/18/11	$114.80	14.00	18.00	32.00	8.66%	2.77
03/01/11	03/31/11	04/20/11	$108.95	15.50	20.00	35.50	8.22%	2.92
04/01/11	04/30/11	05/19/11	$98.57	15.00	19.00	34.00	7.44%	2.53
05/01/11	05/31/11	06/20/11	$112.14	15.50	20.00	35.50	8.46%	3.00
Total			**$1,325.48**					**35.06**

Other Revenue Lag

The lag time associated with Other Revenues is defined as the sum of an average service lag time and a dollar-weighted payment lag time. The expectation is that Hydro One bills monthly for services such as merchandising, jobbing, and rents and leases of Hydro One property. Thus, the mid-point of a month (i.e., 15.21 days) was used as an indication of the service lag for non-energy related services provided by Hydro One Transmission to outside parties. Accounts receivable balances on Other Revenues for 2010 were reviewed to determine a dollar-weighted payment lag which was determined to be 38.89 days. Taken together, the lag time associated with Other Revenues was determined as 54.10 days.

Section IV: Expense Leads

The 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 Hydro One. Therefore, in conjunction with the calculation of the revenue lag, expense lead times were calculated for the following items:

1. OM&A Expenses;
2. Removal and Environmental Remediation Costs;
3. Interest on Long Term Debt;
4. Payments in Lieu of Taxes; and,
5. HST.

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:

1. Payroll and Benefits expenses;
2. Payments made to Consulting and Contract Staff;
3. Payments made to Inergi;
4. Lease Payments made on the Trinity Office Building;
5. Property Taxes;
6. Corporate Procurement Card payments; and,
7. Other (Miscellaneous) Operations and Maintenance related payments.

Expense lead times were calculated individually for each of the items (1) – (7) listed above and then dollar-weighted to derive a composite expense lead time of 23.01 days for OM&A expenses.

Payroll and Benefits Expenses

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

1. Four types of payroll including basic, trades, management, and board of directors payroll;
2. Three types of payroll withholdings including the Canada Pension Plan, Employment Insurance, and Income Tax withholdings;
3. Contributions made by Hydro One to the Hydro One Pension Plan;
4. Group Health, Dental, and Life Insurance related administrative fees and claims;
5. Payments made by Hydro One on account of the Employer Health Tax (or "EHT"); and,
6. Payments made by Hydro One to the Workplace Safety and Insurance Board ("WSIB").

When all payroll, withholdings, and benefits were dollar-weighted using actual payment data for calendar year 2010, the weighted average expense lead time associated with payroll and benefits was determined to be 22.24 days (see Table 3 below).

Table 3: Expense Lead Time Associated With Payroll and Benefits[3]

Payroll & Benefits	Amounts ($M)	Lead Time Days	Weighting Factor	Weighted Lead Time Days
Pensions	$141.93	54.69	14.67%	8.02
WSIB Payments	5.90	44.77	0.61%	0.27
EHT Payments	14.95	30.74	1.54%	0.47
Group Life Insurance	4.68	1.48	0.48%	0.01
Group Health & Dental - ASO	6.43	30.52	0.66%	0.20
Group Health & Dental - Claims	43.99	1.92	4.55%	0.09
Payroll				
Basic	312.16	18.48	32.25%	5.96
Construction	133.71	11.50	13.82%	1.59
Management	56.59	(0.68)	5.85%	(0.04)
Board of Directors	0.38	60.63	0.04%	0.02
Payroll Withholdings				
Basic	156.97	26.05	16.22%	4.23
Construction	56.11	19.14	5.80%	1.11
Management	33.85	8.44	3.50%	0.30
Board of Directors	0.15	71.62	0.02%	0.01
Total	**$967.80**		**100.00%**	**22.24**

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 40.62 days was determined based on a review of a sample of invoices rendered and payments made by Hydro One for the time period January 1, 2010 to May 31, 2011. As with other categories of expense, this dollar-weighted expense lead time took into account the relevant period over which services were provided to Hydro One.

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 chain management services. Hydro One generally makes payments to Inergi on or around the last day of the month for the current month. Based on a review of a sample of payments made by Hydro One for the twelve months ending April 30, 2011, and using a half month of service lead time (since payments are made monthly), a dollar-weighted expense lead time of 16.75 days was determined.

Trinity Lease Payments

Hydro One leases its office space in the Bell Trinity Square Building from an outside party. Hydro One generally makes its lease payments on or around 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 December 31, 2010, a dollar-weighted expense lag time of 11.36 days was determined. Note that since lease payments are generally required to be made before the fact, the result is an expense lag rather

[3] Note that the Total Company Payment Amounts shown in Col (B) of Table 4 is based on raw data from Hydro One's Payroll and Human Resources Systems.

than an expense lead. Again, since lease payments are made monthly, the calculated dollar-weighted expense lag time includes one half month of service lead time.

Property Taxes

Hydro One 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 installments. Using actual payment dates and amounts associated with Hydro One's transmission business for calendar year 2010, a dollar-weighted expense lag time of 18.41 days was determined. Since property tax payments are for the current year, a half year was used as indicative of the service lead time associated with property taxes.

Procurement Card Payments

Procurement (or charge) cards are used by Hydro One's employees for a variety of business 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 December 31, 2010 from Hydro One's charge card provider and payments made by Hydro One, a dollar-weighted expense lead time of 36.94 days was determined. Since Hydro One receives a monthly bill for service, the dollar-weighted expense lead time includes an additional half month of service lead time.

Other (Miscellaneous) Operations and Maintenance Expenses

This category of expense includes a sample of items from Hydro One's accounts payable system that were paid in 2010.[4] The sample was selected in a manner that reflected a reasonable mix of vendors and payments – both small and large. Based on a sample of approximately 348 invoices which included product purchases, equipment rentals, and provision of general services to Hydro One, a dollar-weighted expense lead time of 36.61 days was derived. A mid-point approach was used in the determination of the expense lead time associated with the delivery of miscellaneous services to Hydro One.

Removal Costs

Hydro One 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 Hydro One's expenditures on such removals. Hydro One estimates that 85% of total removal costs relate to Hydro One's labor and benefits; 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 24.40 days was determined.

Environmental Remediation

Hydro One incurs an expense when it is required to perform environmental remediation of its existing sites. As with removals, such remediation costs are recorded on Hydro One'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. Hydro One estimates that

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

60% of remediation costs relate to Hydro One's labor and benefits; the balance relates to materials and supplies supplied both internally and from outside vendors. Taking this information into account, an expense lead time of 27.99 days was determined for environmental remediation.

Interest Expense

Hydro One makes interest payments on its long term debt outstanding with 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, 2010, the dollar-weighted expense lead time associated with Hydro One's interest payments on its long term debt was calculated to be 15.16 days. The mid-point of a year was included as the service lead time since interest payments are made for the current year, albeit in installments.

Payments in Lieu of Taxes (or "PILs")

Hydro One makes payments in lieu of taxes in monthly installments to the relevant taxing authorities. Using payment amounts that are expected to be made in calendar year 2011, a dollar-weighted expense lead time of 58.93 days was determined for PIL's. The mid-point of a year of service lead time is included in the calculation, since payments are made for the current year in monthly installments.

Harmonized Sales Tax

The expense lead times associated with the following items that attract HST were considered in the 2012 update to the transmission lead-lag study:

1. Revenues;
2. Payments for the Corporate Credit Card;
3. Payments for the lease of the Trinity Office Building;
4. Payments to Inergi;
5. Payments for Other (Miscellaneous) Operations and Maintenance Expenses;
6. Payments made to Consulting and Contract Staff; and,
7. 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 for the 2013/2014 test years. Note that the statutory approach described at the outset was used to determine the expense lead times associated with Hydro One's remittances and disbursements of HST (i.e., both remittances and collections are generally on the last day of the month following the date of the applicable invoice)

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Table 4: Expense Lead Times Associated With HST

HST Category	Expense Lead (Lag) Time Days
HST – Revenues	(46.17)
HST - Corporate Credit Card	12.00
HST - Payments for Lease of the Trinity Building	59.83
HST - Inergi Contract	59.47
HST – Consulting and Contract Staff	36.46
HST – Miscellaneous OM&A Expenses	20.43
HST - Environmental Remediation	20.43
HST – Removals	20.43
HST – Capital	20.43

The expense lead times associated with the HST 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 HST payments made for each category. The aggregation resulted in a weighted lead time of 33.58 days and is used in the calculation of HST costs or benefits as discussed in the next section.

Section V: Hydro One Transmission – Working Capital Requirements

Using the results described under the discussion of revenue lags and expense leads, and applying them to Hydro One's proposed transmission expenses for the test years 2013 and 2014, Hydro One's working capital requirements are $12.7M in 2013 and $11.9M in 2014. These amounts represent 2.80%, and 2.58% of the transmission business' OM&A expenses respectively. A summary of Hydro One's transmission business working capital requirements is provided in Table 5. Included within the working capital amounts shown in Table 5 are HST amounts of $(17.3M), and $(18.7M) for 2013 and 2014 respectively.

Table 5: Working Capital Requirements Associated With Transmission Operations

Description	Revenue Lag Days	Expense Lead Days	Net Lag (Lead) Days	Amounts ($M)		Working Capital Requirements ($M)	
				2013	**2014**	**2013**	**2014**
OM&A Expenses	36.15	23.01	13.14	451.8	459.7	16.3	16.5
PILS	36.15	58.93	(22.78)	42.7	50.9	(2.7)	(3.2)
Interest Expense	36.15	15.16	20.99	262.0	272.4	15.1	15.7
Environmental Remediation	36.15	27.99	8.16	6.1	6.9	0.1	0.2
Removals	36.15	24.40	11.76	35.3	41.9	1.1	1.4
Sub Total				797.9	831.8	29.9	30.5
HST						(17.3)	(18.7)
Total						12.7	11.9
WCR as a % of OM&A						**2.80%**	**2.58%**

Table 6: HST Related Working Capital Requirements – Transmission Operations

HST Calculation	2013	2014
HST Rate	13.00%	13.00%
Amounts Eligible for HST ($M)		
Revenues	1,464.3	1,556.6
OM&A Expenses	148.2	150.8
Environmental Remediation	2.3	2.5
Removals	4.1	4.9
Capital	682.9	694.5
Projected HST Amounts ($M)		
Revenues	190.4	202.4
OM&A Expenses	19.3	19.6
Environmental Remediation	0.3	0.3
Removals	0.5	0.6
Capital	88.8	90.3
HST Lead Lag Days		
Revenues	(46.2)	(46.2)
OM&A Expenses (Weighted)	33.6	33.6
Environmental Remediation	20.4	20.4
Removals	20.4	20.4
Capital	20.4	20.4
HST Working Capital Factor (%)		
Revenues	(12. 7)%	(12.7)%
OM&A Expenses	9.2%	9.2%
Environmental Remediation	5.6%	5.6%
Removals	5.6%	5.6%
Capital	5.6%	5.6%
HST Amounts ($M)		
Revenues	(24.1)	(25.6)
OM&A Expenses	1.8	1.8
Environmental Remediation	0.0	0.0
Removals	0.0	0.0
Capital	5.0	5.1
Total ($M)	**(17.3)**	**(18.7)**

Section VI: Findings and Conclusions

This section compares the results from this study with Hydro One's 2010 study and explains differences where they might exist. In addition, this section demonstrates that the results from this study, while slightly higher than the results from Hydro One's 2010 transmission study, reflects the current operations of Hydro One Transmission.

Comparison with Hydro One's 2010 Transmission Study

While the results from this study (2.80% and 2.58% for 2013 and 2014) are slightly higher than what was calculated in the previous 2010 transmission study (1.57% and 1.11% for 2011 and 2012), the results are generally consistent. Table 7 below compares the major items included within Hydro One's 2010 transmission study as well as in the current study. The discussion following provides the rationale for each of the differences where significant.

Table 7: Comparison of 2010 and 2012 Transmission Studies

	2010 Study (Days)		2012 Study (Days)		Impact ($M)	
	2011	2012	2013	2014	2013-2011	2014-2012
Lead/Lag Days						
Revenues	36.40	36.40	36.15	36.15	$5.2	$5.2
OM&A Expenses	21.73	21.73	23.01	23.01	$(1.6)	$(1.6)
PILS	16.51	16.51	58.93	58.93	$(5.0)	$(5.9)
Interest Expense	52.87	52.87	15.16	15.16	$27.1	$28.1
Environmental Remediation	34.84	34.84	27.99	27.99	$0.1	$0.1
Removals	30.02	30.02	24.40	24.40	$0.5	$0.7

Revenue Lag

As shown in Table 7 above, the overall revenue lag has decreased slightly from 36.40 days in the 2010 study to 36.15 days in the current 2012 study. The effect of this reduction in revenue lag days would generally decrease the amount of working capital required if all other variables were held constant. However the net effect of the revenue lag decrease in conjunction with a decrease of HST-related working capital changes associated with OM&A expenses, Environmental Remediation, Removals, and Capital expenditures, is that there is an **increase** of the otherwise applicable working capital requirements of $5.2M and $5.2M in 2013 and 2014. The key drivers for the changes within the HST lead time component relate to lower net remittance lead days in the current 2012 study than in the prior 2010 study.

Operations, Maintenance, and Administrative Expenses

The expense lead time associated with OM&A expenses has increased slightly from 21.73 days in the 2010 study to 23.01 days in the current 2012 study. Factors driving this change from the prior study are primarily attributed to the increased lead times for Miscellaneous OM&A and Payments to Inergi, offset by a smaller decrease in lead time for Consulting and Contract Staff. The net effect of these changes in expense lead times is that it **decreases** the otherwise applicable working capital requirements of Hydro One by $1.6M and $1.6M in 2013 and 2014.

Payments in Lieu of Taxes

The expense lead time associated with PILs has increased from 16.51 days in the 2010 study to 58.93 days in the current 2012 study. This increase is driven primarily by a $15M true-up payment made in February 2011 for the prior 2010 calendar year. This has a significant change to the PILs expense lead time as this true-up payment is significantly in arrears of the prior year ending. Interviews with Hydro One staff indicate that this true-up payment will happen every year and is a part of company operations going forward. Further, the 2010 study includes lead times for Capital Taxes, which has not been included in the current 2012 study since Hydro One no longer incurs these expenses. The net impact of this change in expense lead time is that it **decreases** the otherwise applicable working capital requirements by $5.0M and $5.9M in 2013 and 2014.

Interest on Long Term Debt

The expense lead time associated with the interest on long term debt has decreased from 52.87 days in the 2010 study to 15.16 days in the 2012 study. The key driver of the difference is an enhancement in the study methodology which better reflects the Cash Working Capital required to support these payments. The 2010 study calculated the interest lead times based upon the assumption that interest is evenly incurred throughout the year which follows an accrual approach. The 2012 study has revised the methodology and calculated the expense lead based upon when the coupon payments for each bond occur. Navigant believes the change is an improvement in the methodology and consistent with interest lead time calculations for other utilities across Ontario. The net impact of this change is that it **increases** Hydro One's working capital requirements by $27.1M and $28.1M in 2013 and 2014.

Environmental Remediation

The expense lead time associated with environmental remediation related activities has decreased from 34.84 days in the 2010 study to 27.99 days in the current 2012 study. The driver of the difference is due to the prior 2010 study basing the environmental remediation lead days solely on the miscellaneous OM&A lead days since the data for environmental remediation was not available for the prior 2010 study. The current 2012 study takes into account Hydro One internal and external labour costs in addition to the miscellaneous OM&A costs. The net weighted lead times with these additional factors decrease the environmental remediation lead days, which consequently **increases** Hydro One's otherwise applicable working capital requirement by $0.1M and $0.1M in 2013 and 2014.

Removals

The expense lead time associated with removals related activities has decreased from 30.02 days to 24.40 days. The driver of the difference is due to an updated percentage allocation of labour and miscellaneous OM&A lead times. This allocation is deemed to be a more accurate depiction of Hydro One's transmission business practice going forward and the net impact of this change is that it **increases** Hydro One's otherwise applicable working capital requirement by $0.5M and $0.7M in 2013 and 2014.

Conclusions

The consolidated results from this study are generally consistent with the prior two studies, with working capital as a percentage of OM&A remaining less than 3% for both 2013 and 2014. The drivers of the changes from the prior study are explained in the passages above with the major drivers accounting from the changes in methodology for the calculations of interest expense, HST lead days, in addition to a true-up payment for PILS. Current operations of Hydro One's transmission business are fully captured in the methodology and data incorporated into this updated study. Table 8 below summarizes the working capital requirements for the 2006, 2010 and current 2012 study.

Table 8: Comparison of Hydro One Transmission Requests for Working Capital

	2012 Study		2010 Study		2006 Study	
Test Year	**2013**	**2014**	**2011**	**2012**	**2007**	**2008**
WCR as a % of OM&A	**2.80%**	**2.58%**	**1.57%**	**1.12%**	**3.10%**	**3.02%**

From a review of the information in Table 9, it is clear that the items considered in the 2012 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 electricity transmission company's operations or to the operations of an electric company for that matter.

Table 9: Comparison of Hydro One 2012 Transmission Study With Other Canadian Studies

Name of Utility	Jurisdiction	Type of Service	Customer/Retail Revenues	IESO/ISO Revenues	Other Revenues	Payroll & Withholdings	Employee Benefits	Cost of Power	Cost of Other Fuels	Other OM&A	Income & Related Taxes	GST/HST	Interest Expense
Hydro One Networks	Ontario	Electric Transmission	N/A	Yes	Yes	Yes	Yes	N/A	N/A	Yes	Yes	Yes	Yes
Great Lakes Power	Ontario	Electric Transmission	N/A	Yes	Yes	Yes	Yes	N/A	N/A	Yes		Yes	
Hydro Ottawa Ltd.	Ontario	Electric Distribution	Yes	Yes	Yes	Yes	Yes	Yes	N/A	Yes	Yes	Yes	Yes
Horizon's Utilities Corp.	Ontario	Electric Distribution	Yes	Yes	Yes	Yes	Yes	Yes	N/A	Yes	Yes	Yes	Yes
Ontario Power Generation	Ontario	Electric Generation	N/A	Yes	Yes	Yes	Yes	N/A	Yes	Yes	Yes	Yes	
Enbridge Distribution	Ontario	Natural Gas Distribution	Yes	N/A		Yes	Yes	N/A	Yes	Yes		Yes	
Union Gas	Ontario	Natural Gas Distribution	Yes	N/A		Yes	Yes	N/A	Yes	Yes		Yes	
AltaLink	Alberta	Electric Transmission	Yes	Yes	Yes	Yes	Yes	Yes	N/A	Yes	Yes	Yes	Yes
FortisAlberta	Alberta	Electric Distribution	Yes	Yes	Yes	Yes	Yes	N/A	N/A	Yes	Yes	Yes	Yes
ATCO	Alberta	Natural Gas Distribution	Yes	N/A	Yes	Yes	Yes	N/A	Yes	Yes	Yes	Yes	Yes
BC Hydro	British Columbia	Vertical Electric				Yes	Yes		Yes	Yes		Yes	
FortisBC	British Columbia	Vertical Electric	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Terrasen Gas	British Columbia	Natural Gas Distribution	Yes	N/A	Yes	Yes	Yes	N/A	Yes	Yes	Yes	Yes	
Manitoba Hydro	Manitoba	Vertical Electric				Yes	Yes		Yes	Yes		Yes	
Newfoundland Power	Newfoundland	Vertical Electric	Yes	N/A	Yes	Yes	Yes	Yes	N/A	Yes	Yes	Yes	

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".

The rates used in calculating AFUDC for the bridge and test years were derived using the ten year Government of Canada forecast plus the October 2011 spread between the average actual ten year Government of Canada bond yield and the average DEX Mid-Term Corporate Bond Index Yield. The source for the ten year Government of Canada bond yield was taken from October 2011 Consensus Forecast. The historical years 2009 to 2011 reflect the average quarterly prescribed interest rate.

Table 1
Allowance for Funds Used During Construction

Year	AFUDC Rate	AFUDC ($ millions)
2009	5.9%	45.7
2010	4.3%	44.4
2011	4.2%	46.2
2012	4.2%	48.8
2013	4.7%	44.0
2014	5.7%	57.5

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 15, Schedules 3 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**	
	2009	**2010**	**2011**	**2012**	**2013**	**2014**
Sustaining	300.1	356.3	337.1	426.7	636.5	656.0
Development	515.9	523.1	415.9	412.1	314.2	312.5
Operations	20.0	7.6	8.8	47.9	47.5	56.5
Shared Services Capital	81.8	49.1	48.4	75.0	72.1	63.5
TOTAL	**917.8**	**936.1**	**810.2**	**961.7**	**1,070.4**	**1,088.5**

The Transmission Capital requirements continue to grow over the 2012 to 2014 period to address asset replacement and refurbishment needs of Hydro One’s 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.

The increase in Sustaining expenditures is primarily due to the continued growth in the number of assets that are beyond their expected service life and have been identified as either in poor condition and at end of life, obsolete with no spare parts available, or requiring replacement in order to satisfy changes in the regulations that govern the transmission business.

Investment Summary Documents in support of capital projects with cash flows in excess of $3.0 million in either 2013 or 2014 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 4, Schedules 1 through 5.

6.0 COMPARISON OF CAPITAL COSTS TO BOARD APPROVED

Table 2 provides a comparison between the 2011 actual capital expenditures and the 2011 expenditures approved by the Board in its Decision on Hydro One Transmission's previous application in Proceeding EB-2010-0002.

Table 2
2011 Board Approved versus 2011 Actual Capital Expenditures

Capital Category	**2011 Board Approved** ($ million)	**2011 Actuals** ($ million)	**Variance** ($ million)
Sustaining	412.1	337.1	(75.0)
Development	609.4	415.9	(193.5)
Operations	43.5	8.8	(34.7)
Shared Services	58.4	48.4	(9.9)
Total	**1,123.4**	**810.2**	**(313.2)**

Hydro One Transmission's capital expenditures in 2011 were approximately $313 million lower than the level approved by the Board due to the following offsetting work program factors:

- The Sustaining under-expenditure was driven by delays in the System Re-investment program, due to the complexity of a number of projects resulting in more time required for planning and engineering as well as resolution of stakeholder issues (primarily Beck #1 SS); a Toronto underground cable replacement project due to unexpected difficulties with obtaining land easements; and the Protection & Control program, due to complexities encountered in several projects in the detailed engineering phase. This was partially offset by the acceleration of power transformer replacements due to unit failures and to mitigate the risk of further failures due to the poor condition of specific units.

- The Development program variance is primarily due to delays in customer projects, Tremaine and Barwick TS, delays in the Toronto Area projects, Leaside and Hearn due to outage scheduling and land acquisition issues, as well as several of the SVC projects coming into service under budget.
- The Operations program is under spent primarily due to delays in the Back-up Control Centre facility costs and the Wide Area Network (WAN) program costs.
- Shared Services actual capital expenditures were lower than approved primarily due to lower Facilities and Real Estate and fleet spending initially planned for 2011 that was ultimately deferred. This is partially offset by the shift of Cornerstone savings which were netted out against the Cornerstone spend in 2011 Board approved; the 2011 actuals reflect the Cornerstone savings within Sustaining, Development and Operations as well as Shared Services program/project spending.

Table 3 provides a comparison between the 2012 projected capital expenditures and the 2012 expenditures approved by the Board in their Decisions in Proceedings EB-2010-0002 and EB-2011-0268.

Table 3
2012 Board Approved versus 2012 Projected Capital Expenditures

Capital Category	**2012 Board Approved** ($ million)	**2012 Bridge Year** ($ million)	**Variance** ($ million)
Sustaining	431.3	426.7	(4.5)
Development	448.8	412.1	(36.7)
Operations	56.4	47.9	(8.4)
Shared Services	44.8	75.0	30.2
Total	**981.3**	**961.7**	**(19.6)**

Hydro One Transmission's projected capital expenditures in 2012 are $20 million below the expenditure levels approved by the Board in EB-2010-0002 and EB-2011-0268 due to the following work program factors.

- Sustaining expenditures are less than OEB approved levels due to Cornerstone savings.
- The Development program is under spent primarily due to the new Bruce to Milton project coming into service under budget, the impact of the 2011 project delays cascading into 2012, as well as the suspension of some of the Green Energy projects identified in proceeding EB-2010-0002.
- The Operations program is under spent primarily due to the delays in the Back-up Control Centre and the WAN project. The WAN implementation is underway but will have lower spending in 2012 than originally forecast.
- The increased Shared Services capital costs are due to the shift of Cornerstone savings which were netted out against the Cornerstone spend in 2012 Board Approved; the bridge year forecast reflects the Cornerstone savings within Sustaining, Development and Operations as well as Shared Services program/project spending. There is also an increase in Facilities and Real Estate spending to accommodate the need to acquire new office space, and associated tenant improvements initially planned for 2011 but deferred in part to 2012.

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 2013 and 2014 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, 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 15, Schedules 3 to 5, 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 1 provides an outline of the sustainment investment structure and linkages. Exhibit C, Tab 2, Schedule 2 provides an investment overview for the most significant assets including asset demographics, asset performance data and outlines the rationale for program direction for the key transmission assets. Appendix A of Exhibit C, Tab 2, Schedule 2 contains a detailed description of the transmission assets.

Over the long term, an adequately maintained transmission system that performs to the level of its original design is in the best interest of Hydro One and its customers. As outlined in Exhibit C1, Tab 2, Schedule 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 operational risks to manage and cost pressures to respond to an increasing number of assets requiring replacement. Capital expenditures proposed in this exhibit address the needs identified in the test years also considering to the increases in future asset needs which will continue as a result of the aging asset base. It must be recognized that any reductions applied to the test years spending will have a compounding effect on cost pressures in the future, and the ability to complete the required work, both in capital replacements and corrective maintenance as well as asset and system reliability and safety.

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	
	2009	**2010**	**2011**	**2012**	**2013**	**2014**
Stations	224.1	284.7	266.5	355.1	504.2	519.9
Lines	76.0	71.6	70.6	71.6	132.4	136.2
Total	**300.1**	**356.3**	**337.1**	**426.7**	**636.5**	**656.0**

The overall Sustaining Capital investment for the test year 2013 is approximately 50% greater than the 2012 bridge year. This is primarily due to the number of assets that are beyond their expected service life and have been identified as either in poor condition and at end of life, obsolete with no spare parts available, or requiring replacement in order to satisfy changes in the regulations that govern our business.

As demonstrated in Exhibit C1, Tab 2, Schedule 2, asset demographics continue to create a challenge in managing the transmission system. The design of the Hydro One transmission system and effectiveness of Hydro One’s maintenance programs have minimized the impact of aging assets on our customers. However, equipment performance and condition trends reveal the necessity for increased investment to maintain the historic levels of risk. Unless this is actively addressed in a timely manner, as more asset types are at risk, the likelihood of coincident events occurring increases and there’s a greater certainty of impacting customers.

One notable difference in the test year spending is the number of larger, integrated projects in both the Stations and Lines asset families. With many asset types beyond their expected service life and showing signs of the need for replacement, larger scale Station or Line refurbishment projects are an effective option to deal with the specific assets and in many cases make modifications that would not otherwise be practical. This may include moving assets to more optimal locations such as relocating the circuit breakers from Abitibi Canyon SS to Pinard TS, standardizing the configuration at Wallaceburg TS, or removing oil filled cable systems in Toronto with the H2JK/K6J Cable Replacement (Riverside Jct. x Strachan TS) project. The air blast breaker replacement projects are one example with significant benefits. These breakers are typically installed at critical stations, and once replaced, the equipment reliability is expected to improve by a factor of 5 and the replacement breakers will result in a 90% savings in maintenance.

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

- There would be a marked reduction in reliability (equipment and Customer performance) at transmission stations as a result of increased transformer failures, inoperable breakers and switches, and potential misoperation of protection systems.
- Risk of non-compliance with Ministry of Environment regulations concerning adequate drainage and oil spills, and lack of progress against PCB phase out plans mandated by Environment Canada.
- 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 in 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. This includes disconnect switches, circuit switchers, capacitor banks, surge arrestors, low voltage cables and potheads, instrument transformers and insulators;

- 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 Capital ($ Millions)

Description	**Historic Years**			**Bridge Year**	**Test Years**	
	2009	**2010**	**2011**	**2012**	**2013**	**2014**
Circuit Breakers	16.6	29.6	29.2	17.6	25.0	25.3
Station Re-investment	34.6	17.9	36.4	110.2	179.6	190.2
Power Transformers	48.7	106.8	81.1	57.0	87.4	104.8
Other Power Equipment	13.1	13.9	16.2	18.3	22.3	25.6
Ancillary Systems	6.0	13.3	13.5	16.5	19.9	22.0
Station Environment	3.0	4.0	7.0	6.6	11.6	11.0
Protection, Control, Monitoring, and Telecommunications	82.0	66.8	61.6	107.6	128.5	108.3
Transmission Site Facilities and Infrastructure	20.1	32.3	21.7	21.2	30.0	32.7
Total	**224.1**	**284.7**	**266.5**	**355.1**	**504.2**	**519.9**

The overall Stations Capital investment for the test year 2013 is approximately 40% greater than the 2012 bridge year. These expenditures reflect the increased asset replacement rates required to maintain reliability and risks levels on an on-going basis. At the same time, the Sustaining Stations OM&A expenditures outlined in Exhibit C1, Tab 3, Schedule 2 are broadly consistent with historic expenditures. The primary drivers for capital increases include:

- Stations Re-investment test year expenditures are primarily focused on replacing air-blast circuit breakers and executing integrated station rebuilds at load delivery stations.
- There are a growing number of power transformer replacements as well as increased expenditures in the areas of Protection, Control, Monitoring and Telecommunications

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

- Power transformer expenditures are increasing to deal with increasing risk associated with degrading fleet condition and compounding demographic pressures.

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 4,490 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 gas insulated switchgear (GIS), as replacements of this type involve a broader scope than just a "one for one" replacement. This being the case, ABCB and GIS are typically replaced on a project basis under Stations Re-investment, as discussed in 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 required to conduct equipment assessments and determine solutions.

Hydro One has planned replacements in the four categories of breakers as outlined below.

S1: Oil Circuit Breaker (OCB) Replacements

Hydro One is managing a population of over 1,900 oil circuit breakers that are no longer manufactured. Replacement parts are becoming increasingly expensive and harder to source. An ongoing replacement program is required to manage the large population of obsolete breakers in a cost effective manner. In many cases they cannot be economically repaired and if not replaced will impact on Hydro One Transmission's ability to supply reliable power. The program focuses primarily on technically obsolete and poor performing breakers. Capital spending for the test years 2013 and 2014 equals $9.0 million and $8.6 million respectively and will result in 29 OCB's being replaced. Test year expenditures are generally in-line with historic years, with some variation one year to the next due to the mix of units and timing of cashflows.

Many of these circuit breakers are at or approaching their expected service lives (refer to Exhibit C1, Tab 2, Schedule 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 annual replacement rate of approximately 0.8% of the OCB fleet in the test years is expected to increase in the future, as larger numbers of breakers approach their expected service lives and leading reliability indicators show degradation.

S2: SF6 Circuit Breaker Replacements

Hydro One manages approximately 1376 SF6 circuit breakers, the first of which were installed in the late 1960s and newer designs remain as one of the utility standards for circuit breaker installations. Three quarters of the test year replacements are focused on breakers in capacitor and reactor switching positions, which are subjected to the most severe application. These breakers have exceeded the number of design operations, are demonstrating poor performance, and require on-going costly corrective maintenance if not replaced. Another significant area of replacement is focus on early generation SF6 breakers with poor design characteristics, high leak rates and that are now technically obsolete. Capital spending for test years 2013 and 2014 equals $11.0 million and $11.1 million respectively which will result in the replacement of 40 SF6 circuit breakers.

The annual replacement rate of approximately 1.5% of the SF6 breaker fleet in the test years is expected to increase gradually in the future, as larger numbers of breakers exceed their expected service lives, reliability risks increase, and replacement becomes a more appropriate solution versus preventive and corrective maintenance.

Other Projects and Programs

Hydro One Transmission is replacing individual metalclad breakers and vacuum breakers due to known design deficiencies, poor performance and technical obsolescence. 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 29 breakers are planned for replacement during the test years. This category of expenditure also funds the purchase of operating spare circuit breakers and the demand costs to replace failed units. Total capital spending for these other projects and programs, for the test years 2013 and 2014, equals $5.0 million and $5.6 million respectively.

3.1.3 Summary of Expenditures

The spending level for test year 2013 and 2014 is $25.0 million and $25.3 million respectively and is in line with historic expenditures. 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. Circuit breakers currently contribute account for 26% of the station equipment-caused delivery point interruptions. 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 circuit breaker reliability from that of other Canadian transmitters. Refer to Exhibit C1, Tab 2, Schedule 2 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 > $3 Million in Test Year 2013 or 2014 ($ Millions)

Ref #	**Description**	**Cash Flow Test Years**		**Total Cost**
		2013	**2014**	
S1	Oil Circuit Breaker Replacements	9.0	8.6	17.6
S2	SF6 Circuit Breaker Replacements	11.0	11.1	22.1
	Other Projects/ Programs < $3M	5.0	5.6	10.6
	Total Cost	**25.0**	**25.3**	
	Capital Contributions	**0.0**	**0.0**	
	Net Capital Cost	**25.0**	**25.3**	

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. Stations re-investment work complements other individual component replacement programs within Sustaining Capital.

3.2.2 Investment Plan

Investment decisions are based on historical information, maintenance reports, and detailed asset condition information. 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.

Projects with test-year cashflows have been grouped into similar types of work and are summarized in Table 4 below. Individual project summary information follows and details are contained within ISDs in Exhibit D2, Tab 2, Schedule 3.

Table 4
Stations Re-Investment Summary
Capital Projects > $3 Million in Test Year 2013 or 2014 ($ Millions)

Description	Cash Flow Test Years 2013	Cash Flow Test Years 2014	Total Cost	Capital Contribution	Net Capital Cost
Metalclad Switchgear Replacements	17.3	25.3	52.9	18.0	39.1
Air Blast Circuit Breaker Replacements	65.1	44.6	206.0	5.8	200.2
End of Life Station Reconfigurations	34.0	18.9	230.4	2.0	228.4
GIS Replacements	4.9	0.0	11.0	0.0	11.0
Integrated DESN Investments	68.7	104.1	172.8	0	172.8
Other Projects/Programs <$3M	0.2	1.6	16.6	0.0	16.6
Future Projects Beyond Test Years	0.0	4.6	134.5	0.0	134.5
Total Cost	**190.2**	**199.0**			
Capital Contributions	**10.6**	**8.8**			
Net Capital Cost	**179.6**	**190.2**			

Metalclad Switchgear Replacement Projects: S3, S4, S5

Hydro One Transmission has a number of metalclad switchgear lineups, typically at indoor stations in urban areas. Replacement programs are established to replace switchgear beyond their expected service lives. Several installations are from the 1950s and have safety concerns, are technically obsolete, and are important to maintaining customer reliability in Toronto, Hamilton, and Ottawa. In the case of Toronto, a multiyear program is underway to replaced aged infrastructure in coordination with Toronto Hydro Electric System Limited (THESL). Prioritization has been done in coordination with THESL, allowing both utilities to leverage resources and construction outages. Expenditures for test years 2013 and 2014 are $17.3 million and $25.3 million respectively, as part of the replacement of 12 metalclad line ups. A portion of this work is recoverable from THESL.

Air Blast Circuit Breaker Replacement Projects: S6 - S12

Air blast circuit breakers (ABCBs) are the poorest performing breakers in the Hydro One system. They are not produced anymore and many models have little-to-no support for parts and technical expertise. Typically ABCBs are installed at critical network locations and were originally installed with the 1970's build of the Ontario transmission system. ABCBs have the highest operating cost of any breaker technology, due to their high-pressure air systems with sensitive components that need frequent maintenance. The breakers planned for replacement have been problematic and are in need of replacement due to performance, obsolescence, and system criticality. See Exhibit C1, Tab 2, Schedule 2 for additional information on ABCB fleet.

In the test years expenditures are planned at Orangeville TS, Richview TS, Pickering A SS, Hanmer TS, Bruce A TS, Beck #2 TS and Burlington TS. The replacements will include the removal of the high-pressure air systems and adjoining equipment determined to be at end of life. The breakers will be replaced with modern SF6 type with 90% lower life-cycle OM&A costs and approximately 5 times improved reliability. Expenditures at all seven stations total $65.1 million for test year 2013 and $44.6 million for test year 2014, which excludes an anticipated $5.8 million capital contribution expected from OPG for work at Pickering A SS replacing dual use assets.

ABCB projects at Orangeville TS, Hanmer TS, and Pickering A SS were all included in EB-2010-0002 as S7, S9, and S10 respectively. These projects have all received internal Hydro One approval and are in various stages of implementation, details are provided in the ISDs in Exhibit D2, Tab 2, Schedule 3. The Richview TS ABCB replacement was included in the EB-2010-0002 proceeding as project S8, and is currently undergoing detailed design and engineering; the 2013 and 2014 test year expenditures will allow construction work to begin on the project with a total project in-service date of 2016.

<u>End of Life Station Reconfiguration Projects: S13 - S16</u>

Consistent with the integrated strategy of Station Reinvestments, end of life station reconfiguration projects address many assets and components that are in need of replacement at a single station. These projects stem from typical Sustainment end-of-life replacement needs, but the solutions employed also have a significant element of station reconfiguration. For example, Wallaceburg TS had two of its four power transformers fail within six months of each other. Following consultation with various internal stakeholders and with the IESO, it was determined that it was best to rebuild the station into a standard DESN (dual element spot network) switchyard with two standardized larger transformers, a modern low-voltage switchyard, and associated protection, control, telecom and metering equipment. Synergies in design, construction and procurement can be best realized by executing an integrated project of this nature when all major station infrastructure is in need of replacement within the same general timeframe.

Expenditures of $34.0 million in 2013 and $18.9 million in 2014 are planned at Abitibi Canyon SS / Pinard TS, Wallaceburg TS, Gage TS, and Beck #1 SS. $1.0 million is planned as a customer contribution from OPG for demerger work as part of the project, reducing the net capital cost to $33.0 million in 2013.

Abitibi Canyon SS / Pinard TS reconfiguration was identified in EB-2010-0002 as project S5. Test year cashflows and project timeline were based on preliminary planning assumptions during the previous proceeding. The project has since undergone detailed engineering and estimating, and has received approval from the Hydro One Board of Directors. The project is proceeding with a planned 2013 in-service date.

Beck #1 SS Reconfiguration was identified in EB-2010-0002 as project S4. Cashflows and project timeline were based on preliminary planning assumptions during the previous proceeding. The project had not yet undergone detailed engineering and estimating. More detailed engineering and estimating has since been completed, including coordination with OPG and the IESO, and the costs were significantly higher than the EB-2010-0002 preliminary estimate. A pause was taken so that further alternatives could be assessed prior to the project being recommended for approval. Personnel safety risks have been controlled by establishing exclusion zones at Beck #1 SS until such time a preferred alternative is selected and approved. It is anticipated the project will proceed with an in-service date of 2016 or 2017. As such $2.0 million has been included in 2014 for front-end project costs.

Merivale GIS Replacements: S17

Gas Insulated Switchgear (GIS) has a smaller physical footprint than its alternative air-insulated switchgear (AIS) and is typically installed where space is a constraint. Replacement of early vintage GIS bus duct at Merivale TS continues as previously identified as S11 in EB-2010-0002. This GIS installation is a known poor performer and significant contributor to provincial SF6 emissions. The project cashflows and in-service have shifted by approximately 6 months since the EB-2010-0002 due to delays in procurement of this custom equipment. Total project cost has come down slightly. Expenditures for test year 2013 are $4.9 million.

Integrated DESN Investments: S18 – S19

Projects within this grouping are targeted at replacing multiple assets within DESN (dual element spot network) stations, which facilitate power transformation from the bulk supply stations to load customers, typically at 44kV, 28kV, and 14kV. The underlying force for the investment is typically multiple transformers that are in need of replacement, at which point opportunities are sought after to replace assets such as spill containment, protections, disconnect switches and surge arresters at the same time in an integrated manner. Combining multiple elements into a single work package allows additional efficiencies to be realized during the design, construction, and commissioning stages of the work.

Work is planned at 14 stations within the 2013 and 2014 test years with expenditures of $68.7 million and $104.1 million respectively. Additional details can be found in the project ISDs provided within Exhibit D2, Tab D2, Schedule 3.

Future Projects beyond Test Years

Due to their complexity, Station Reinvestment projects typically take 3-5 years from the conceptual planning stage until they are constructed and placed in-service. Some 2014 expenditures are required to conduct preliminary engineering and estimating for projects beyond the test year. Planned capital expenditure for the 2014 test year is $4.6 million.

3.2.3 Summary of Expenditures

The spending level for test years 2013 and 2014 is $179.6 million and $190.2 million respectively. This represents a substantial increase from the 2012 bridge year and even more so over historic years. The increases are the result of the need to replace a greater number of end of life assets with projects that have a larger scope, predominantly air blast circuit breakers (ABCB) and integrated DESN investments. 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.

Station Re-Investment capital investment work total project cost in excess of $3 million and cashflows in the test years are provided in Table 5. Additional details for these programs are provided in the Investment Summary Documents in Exhibit D2, Tab 2, Schedule 3.

Table 5
Station Reinvestment
Test Year Expenditures for Capital Projects > $ 3 Million Total

Ref#	Description	Cash Flow Test Years 2013	Cash Flow Test Years 2014	Total Cost	Contribution	Net Capital Cost
Metalclad Switchgear Replacement Projects		**17.3**	**25.3**	**52.9**	**18.0**	**39.1**
S3	GTA Metalclad Switchgear Replacements	12.0	12.0	52.3	18.0	34.3
S4	Albion TS Metalclad Replacement	5.1	7.0	12.3	0.0	12.3
S5	Kenilworth TS Metalclad Replacement	0.2	6.3	13.2	0.0	13.2
Air Blast Circuit Breaker Projects		**65.1**	**44.6**	**206.0**	**5.8**	**200.2**
S6	Hanmer TS – 500kV ABCB	7.5	0.0	26.1	0.0	26.1
S7	Orangeville TS – 230kV ABCB	8.2	0.0	29.6	0.0	29.6
S8	Pickering A SS – 230kV ABCB	5.4	1.4	11.6	5.8	5.8
S9	Richview TS – 230kV ABCB	14.6	15.0	61.2	0.0	61.2
S10	Beck #2 TS – 230 kV ABCB	3.8	12.4	34.4	0.0	34.4
S11	Bruce A TS- 230kV ABCB	20.0	14.0	35.0	0.0	35.0
S12	Burlington TS – 230kV ABCB	5.8	1.9	8.1	0.0	8.1
End of Life Station Reconfiguration Projects		**34.0**	**18.9**	**230.4**	**2.0**	**228.4**
S13	Abitibi Canyon SS / Pinard TS: Reconfigure and Demerge	24.0	0.0	47.0	1.0	46.0
S14	Beck #1 SS - Build New Switchyard	0.0	2.0	83.4	1.0	82.4
S15	Wallaceburg: TS – Reconfigure to Address Failed Transformers	9.8	0.0	26.4	0.0	26.4
S16	Gage TS EOL Asset Replacement Project	0.2	16.9	73.6	0.0	73.6
S17	**Merivale GIS Bus Replacement**	**4.9**	**0.0**	**11.0**	**0.0**	**11.0**
Integrated DESN Investments		**68.7**	**104.1**	**172.8**	**0.0**	**172.8**
S18	NRC TS Rebuild	10.7	10.0	21.6	0.0	21.6
S19	Integrated DESN Investments	58.0	94.1	152.1	0.0	152.1
Future Projects Beyond Test Years		**0.0**	**4.6**	**134.5**	**0.0**	**134.5**
Other Projects/Programs <$3M		**0.2**	**1.6**			
	Total Cost	**190.2**	**199.0**			
	Capital Contributions	**10.6**	**8.8**			
	Net Capital Cost	**179.6**	**190.2**			

3.3 Power Transformers

3.3.1 <u>Introduction</u>

In total, Hydro One has 719 large transmission class 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 connects 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 are not included in this figure. A complete description of the transformer types can be found in Exhibit C1, Tab 2, Schedule 2, Appendix A.

3.3.2 <u>Investment Plan</u>

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

Transformer replacements and purchases under this program are provided below.

<u>End of Life Transformer Replacements: S20 and S21</u>

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. Fleet-wide information and assessment is provided in Exhibit C1, Tab 2, Schedule 2, which also outlines the underlying rationale for increased replacement in the test years. Increased replacements are required to mitigate impacts to reliability, the environment, customer impacts, and safety. Expenditures for test years 2013 and 2014 are $68.3 million and $84.9 million respectively, which will result in the replacement of 25 power transformers.

Approximately $3.5 million of the 2013 test year spend is associated with the replacement of a specific family of CGE transformers previously identified in EB-2010-0002 under S14. Hydro One chose to advance the replacement of more transformers in 2011 and 2012 to that previously planned to mitigate customer delivery reliability risks. As such, the 2013 expenditure will be the final amount required for this specific population.

<u>S22: Operating Spare Transformer Purchases</u>

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. Transmission operating spare complement is at the modeled requirement and this funding is budgeted to replenish inventory that will be drawn down for future failures. The specific transformers are not known until the time of failure. Expenditures for test years 2013 and 2014 of $12.7 million and $13.1 million respectively, and are in-line with historic expenditures.

Other Programs and Projects

- Replacement of station service transformers that have reached end of life. Station Service transformers step down primary voltages, i.e., 230 kV, 115 kV, 44 kV, 28 kV or 14 kV to secondary voltages of 600/120V AC to supply station auxiliary equipment such as battery chargers, transformer cooling and tap changers, and station heaters.
- Estimated capitalized demand work on failed transformers.
- Installation of online monitoring and diagnostic equipment to provide real-time condition data that impacts both the day-to-day operation of the transformers and the longer term Sustaining capital replacements.

Total capital spending for other projects and programs for the test years 2013 and 2014, is $6.4 million and $6.8 million respectively and is in-line with historic amounts.

3.3.3 Summary of Expenditures

The planned expenditure for 2013 is $87.4 million and $104.8 million for 2014, which in total is about the same as was spent in 2010 and 2011. The number of transformers planned for replacement is in fact significantly higher than recent years which is attributable to a large degree on unit price reductions gained through design standardization and bulk purchasing. The variation in spending between 2009 and 2014 is primarily attributed to variations in specific timing of project costs.

The primary reason for the increase in test year spending over the previous decade is attributed to a greater number of transformers determined to be at end of life. Reductions in the required funding will amplify the compounding demographic pressures and result in further degradation of fleet condition. Within a five year timeframe this will likely have significant impact upon delivery reliability as transformer failures will increase to levels not seen since the 1990s.

Power Transformer capital investment programs requiring in excess of $3.0 million in either test year 2013 or 2014 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
Power Transformers
Capital Projects > $ 3 Million in Test Year 2013 or 2014 ($ Millions)

Ref #	**Description**	**Cash Flow Test Years**		**Total Cost**
		2013	**2014**	
S20	End of Life CGE Transf. Replacements	3.5	0.0	3.5
S21	End of Life Transformer Replacements	64.8	84.9	149.7
S22	Operating Spare Transformer Purchases	12.7	13.1	25.8
	Other Projects/ Programs < $3M	6.4	6.8	13.2
	Total Cost	**87.4**	**104.8**	
	Capital Contributions	**0.0**	**0.0**	
	Net Capital Cost	**87.4**	**104.8**	

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.

S23: Disconnect 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. Test year expenditures are focused primarily on replacing problematic switches with a known safety issue, which has resulted in some switches failing and falling closed which is a considerable risk for the power system and staff relying on switches as guaranteed isolating point for work protection. Capital expenditures for test years 2013 and 2014 are $7.7 million and $9.3 million respectively, which will replace 140 switches over the two test years. This is a significant increase from the 83 in the EB-2010-0002 proceeding, and will result in approximately 0.5% of the in-service fleet being renewed in each test year.

S24 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 feedback from preventive and corrective maintenance programs and is generally correlated with asset age. Expenditures for test years 2013 and 2014 are $3.7 million and $5.1 million respectively, which will replace 10 capacitor banks found to be at end of life.

S25 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. Some replacements are required as part of Hydro One Transmission’s PCB removals program to meet regulatory deadlines set by Environment Canada. Expenditures for test years 2013 and 2014 are $3.1 million and $3.2 million respectively, which will replace 160 instrument transformers.

S26: Insulator Replacement Program

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 replaced both under planned and demand conditions within this program. Insulators are visually inspected to determine their condition and those that meet end of life criteria are replaced. Insulator failures lead to forced outages, which is one of the primary methods of defect detection. 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 2013 and 2014, plans are in place to replace approximately 2,500 unreliable insulators as part of this program. Insulator failures cause equipment outages (potentially load interruptions), pose a safety risk to personnel, and can result in damage to other equipment that is exposed to the fault. Spending for this program for the tests years 2013 and 2014 is $4.8 million and $5.0 million respectively.

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, infrared scans and correlation between known problematic terminations. Capital spending for test years 2013 and 2014 are $1.2 million and $1.3 million respectively, which will replace 48 cable potheads.

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. Surge arrestors protect transformers and other power equipment from damage and therefore reduce equipment outages. Hydro One Transmission has over 1,800 sets of surge arrestors within the system. Planned expenditures for test years 2013 and 2014 are $ 1.6 million and $1.8 million respectively and will replace 42 sets of surge arresters.

3.4.3 Summary of Expenditures

The spending requirement for test year 2013 is $22.3 million, which is an increase of 21% over the bridge year 2012. The increase in spending is mainly attributed to an increased focus on replacing poor performing high voltage disconnect switches that have in inherent safety risk associated with them. The spending requirement for test year 2014 is $25.6 million, which is an increase of 15% over the test year 2013. The increase is primarily driven by disconnect switch replacements. 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 be negatively impacted. Continued replacements will manage risks associated with equipment failure, such as customer interruptions, impacts to other planned work, and safety risks.

Other Power Equipment capital investment programs requiring in excess of $3.0 million in either test year 2013 or 2014 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
Other Power Equipment
Test Year Expenditures for Capital Projects > $ 3 Million ($ Millions)

Ref #	**Description**	**Cash Flow Test Years 2013**	**Cash Flow Test Years 2014**	**Total Cost**
S23	Disconnect Switch Replacements	7.7	9.3	17.0
S24	Capacitor Bank Replacements	3.7	5.1	8.8
S25	Instrument Transformer Replacements	3.1	3.2	6.3
S26	Insulator Replacements	4.8	5.0	9.8
	Other Projects/ Programs < $3M	3.0	3.0	6.0
	Total Cost	**22.3**	**25.6**	
	Capital Contributions	**0.0**	**0.0**	
	Net Capital Cost	**22.3**	**25.6**	

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.

S27: Station Service Replacements

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 availability of spare parts. Capital spending for test years 2013 and 2014 are $11.1 million and $12.5 million respectively to replace 11 station service schemes.

Station Battery & Rectifier Replacements

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 of Hydro One's transmission stations are provided with at least one DC system, comprised of 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 2013 and 2014 are $2.5 million for each of the test years to replace 88 battery/rectifier systems.

S28: Station Grounding System Replacements

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 technical details obtained through testing programs. Capital spending for test years 2013 and 2014 are $4.9 million and $5.5 million respectively to replace deficient grounding systems at 10 transmission stations.

Other Ancillary System Expenditures

Spending for test years 2013 and 2014 is $1.4 million and $1.5 million respectively. This will address deficient HPA system components, and will implement new AC station service metering requirements mandated by the IESO.

3.5.3 Summary of Expenditures

The spending requirement for test years 2013 and 2014 is $19.9 million and $22.0 million respectively. The average test year spending represents approximately a 25% increase from the 2012 bridge year of $16.5 million. This increase from bridge year expenditures is primarily attributed to the need to address inadequate grounding at stations in response to safety issues and prevent damage to equipment. These become increasing risks with aging infrastructure, both grounding systems themselves and the assets they protect, as aged assets may have a reduced ability to handle fault duty imposed on them.

Continued investment in ancillary systems will maintain back-up and safety systems such as DC station service and grounding systems, while replacing AC station service schemes that cannot be relied upon to perform critical operations, often during switching or contingencies on the power system to avoid customer interruptions.

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

Table 8
Ancillary Systems
Test Year Expenditures for Capital Projects > $ 3 Million ($ Millions)

Ref #	Description	Cash Flow Test Years 2013	Cash Flow Test Years 2014	Total Cost
S27	Station Service Replacements	11.1	12.5	23.6
S28	Station Grounding Replacements	4.9	5.5	10.4
	Other Projects/ Programs < $3M	3.9	4.0	7.9
	Total Cost	**19.9**	**22.0**	
	Capital Contributions	**0.0**	**0.0**	
	Net Capital Cost	**19.9**	**22.0**	

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 or replacements or installation of new systems. 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, an estimated 50 - 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 these spill containment systems are 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. In some cases, a C of A is granted for the station to allow replacement of one or more spill containment systems with a condition of bringing the others up to modern standards within a predefined period, typically five years. During the 2013 and 2014 test years Hydro One Transmission will be replacing or installing 27 spill containment systems.

3.6.3 Summary of Expenditures

The spending requirement for test years 2013 and 2014 is $11.6 million and $11.0 million respectively. The spending increase over historic years is primarily attributable to increased C of A requirements from the MOE 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 are provided in Table 9 below. Additional details for these programs are provided in the Investment Summary Documents in Exhibit D2, Tab 2, Schedule 3.

Table 9
Station Environment
Test Year Expenditures for Capital Projects > $ 3 Million ($ Millions)

Ref #	Description	Cash Flow Test Years		Total Cost
		2013	**2014**	
S29	Spill Containment Refurbishment & Installation	11.6	11.0	22.6
	Total Cost	**11.6**	**11.0**	
	Capital Contributions	**0.0**	**0.0**	
	Net Capital Cost	**11.6**	**11.0**	

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, Remote Terminal Units (RTUs), Sequence of Event Recorders (SERs), Digital Fault Recorders (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 10 below.

Table 10
Station - Protection, Control, Monitoring and Telecommunications Capital ($ Millions)

Description	Historic			Bridge	Test	
	2009	2010	2011	2012	2013	2014
Protection, Control and Metering	40.7	53.4	44.4	69.0	80.2	70.2
Auxiliary Telecommunication Equipment	19.2	8.5	14.7	26.1	24.5	18.5
Cyber Security	22.1	4.9	2.4	12.5	23.7	19.6
Total	**82.0**	**66.8**	**61.6**	**107.6**	**128.5**	**108.3**

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, disruption of 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. It is critical to ensure that assets which were installed over a short period of years, with well-defined replacement criteria, are all replaced before the onset of failures or rapidly increasing maintenance costs. Should a large population of assets essential to the operation of the grid begin failing simultaneously in large numbers the results could be potentially disastrous. 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 failure.

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 of all primary relays
- NERC and NPCC standards
- Nature and scope of defects

Selections of systems for replacement are based on:

- Analysis 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.

Specific planned replacement projects and programs are described below:

S30: Bruce Special Protection System (BSPS) Replacement

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 scheme is required even after the new Bruce to Milton 500kV line is constructed and placed in service. For the test year 2013 spending of $20.7 million is required.

This investment has been previously included in the EB-2010-0002 proceeding as project S22, and at that time the test years cash flows and schedule were based on preliminary planning assumptions. Since then more detailed engineering has been completed. The project has received internal Hydro One approval and is being implemented with an in-service date of the second half of 2013.

S31: Interprovincial Transmission Company (ITC) - Line Protection Replacements

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 in 2013 and 2014 is $ 2.5 million per year.

This investment has been previously included in the EB-2010-0002 proceeding as project S23, and at that time test years cash flows and schedule were based on preliminary planning assumptions. Since the protection upgrades on one of the interconnection circuits (B3N) have been completed, future planned upgrades of the remaining interconnection circuits while still based on preliminary planning assumptions are estimated to require similar investments.

S32: 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 while adding additional protection and telecom facilities not previously anticipated. Both NYPA and Hydro One Transmission need to replace the protections at their respective line terminals to ensure compatibility between the two systems. Spending in the test years 2013 and 2014 is $ 10.1 million and $ 1.0 million respectively.

This investment has been previously included in the EB-2010-0002 proceeding as project S24, and at that time test years cash flows and schedule were based on preliminary planning assumptions. Since then more detailed engineering has been completed and the project has received internal Hydro One approvals and is being implemented for an in-service date of 2015.

S33: Station P&C Replacements – PCT in a Box

All protection and control and telecom systems (PCT) 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. This design has been termed as “PCT in a Box”. 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 panel by panel replacement of individual protection systems. Hydro One has identified over 30 load supply stations at which most of the P&C systems have reached or are approaching end of life. Nine of these will be replaced in 2013 and 2014 with spending of $15 million and $30 million respectively.

S34: 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 C1, Tab 2, Schedule 2. Considering the importance of these systems, protection schemes are identified for replacement based on system criticality, its performance (mean time to failure), and health indices. Currently Hydro One Transmission has identified about 1,800 protections that need to be replaced over the next five years. Spending for test years 2013 and 2014 is $19.3 million and $22.1 million respectively

S35: RTU Replacements

Remote Terminal Units (RTUs) 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). One hundred old vintage RTUs are presently in service. These old vintage RTU's utilize manufacturers' proprietary communication protocols which adds unnecessary complexity and challenges to their operation and maintenance; consequently they have been targeted for replacement over the next 8 years. Fourteen RTUs will be replaced in each of the years 2013 and 2014 under this program, plus an additional 9 under the Station P&C replacement program, for a total of 37. Spending for this program in 2013 and 2014 is $8.4 million.

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:

- Demand corrective program deals with end of life protection and control issues that are causing significant customer or system impacts and require priority attention.
- Programmable Synchrocheck Relays (PSRs) 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 PSRs which are being custom repaired/rebuilt as they fail. Our long term strategy is to replace them by a standard “off-the-shelf” IED based solution (Intelligent Electronic Device – microprocessor based relays), but as of now no suitable product is available for this application.
- Sequence of Event Recorders (SERs) are one type of monitoring system. Hydro One Transmission has a population of over 110 stand alone SERs. The SER capability is built-in in the new generation of RTUs and is being enabled when new RTUs are deployed at stations with dedicated old SER cabinets. Based on the current RTU replacement program schedule we plan to replace 10 of these SER devices during the test years 2013 and 2014.
- The Bridgman Relay Building and Protections Replacement is addressing the issue of poorly performing protections at a Toronto supply station. As a result of space constraints in the existing relay building (no staging space) and the resulting inability

to deploy a modular PCT in a Box solution, a new relay room and protections are being constructed there. The project is scheduled for completion in 2013.

- Under Frequency Load Shedding (UFLS) protections replacement are undertaken in response to NPCC Directory 12 requirements which came into effect in 2009. Existing UFLS installations have to be either modified or upgraded in order to allow for specific load shedding at different system frequency thresholds. Full compliance with Directory 12 requirements is expected at the completion of this work currently scheduled for 2017 in accordance with the implementation plan submitted to NPCC by the IESO.

In total, spending for the work listed above for test years 2013 and 2014 is $7.3 million and $6.2 million respectively.

3.7.1.3 Summary of Expenditures

The spending level for test year 2013 and 2014 is $80.2 million and $70.2 million respectively. The spending in the test year 2013 is increasing by 16% over the 2012 bridge year. This additional spending is required to increase the replacement rate of end of life protections to ensure that these critical system elements do not deteriorate further. As well, 2013 will see an intense continuing effort on a number of key facilities, e.g., the Bruce Special Protection System (BSPS) and the interconnection tie lines with neighboring US utilities as discussed earlier. The spending for the test year 2014 is decreasing by 12% compared to the 2013 test year primarily due to substantial completion of work associated with the BSPS replacement 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 are provided in Table 11. Additional details for these programs are provided in the Investment Summary Documents in Exhibit D2, Tab 2, Schedule 3.

Table 11
Protection, Control and Monitoring Equipment
Capital Projects > $ 3 Million in Test Year 2013 or 2014 ($ Millions)

Ref #	Description	Cash Flow Test Years		Total Cost	Contribution	Net Capital Cost
		2013	2014			
S30	BSPS Replacement of End-of-Life Equipment	20.7	0.0	35.8	0.0	35.8
S31	ITC – Line Protections Replacements	2.5	2.5	7.5	0.0	7.5
S32	NYPA Tie Lines – Beck Line Protections Replacements	10.1	1.0	16.3	5.5	10.8
S33	2013 – 2014 Station P&C Replacement	15.0	30.0	45.0	0.0	45.0
S34	2013-2014 Protection Replacements	19.3	22.1	41.4	0.0	41.4
S35	2013-2014 RTU Replacement	8.4	8.4	16.8	0.0	16.8
	Other Projects/ Programs < $3M	7.3	6.2	13.5	0.0	13.5
	Total Cost	**83.2**	**70.2**			
	Contribution	**3.0**	**0.0**			
	Net Capital Cost	**80.2**	**70.2**			

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

S36 and S37: 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. Telecom carriers 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 only during normal working hours (no Telco service personnel is available to resolve issues during evening and night hours and on the weekends). As a result, the average restoration time has risen about tenfold from the levels of 10 years ago (the average restoration time in the early years of the last decade was 12 hours). When a DC circuit is out of service, the design supply redundancy of a load supply station is lost and any subsequent contingency will result in load loss (i.e. a direct customer impact). In 2003 Hydro One Transmission embarked on a DC signaling replacement program, to replace over 529 DC telecom signaling channels and associated relaying which are at end of life. Of these, 205 will be replaced by the end of 2012. An additional 50 will be replaced during the 2013 and 2014 period. This will leave 274 to be replaced in subsequent years. Expenditures for test years 2013 and 2014 are $8.2 million and $5.9 million respectively.

S38: 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 about 220 have been replaced. In the 2013 and 2014 period another 40 will be replaced. The remaining 110 are expected to be replaced before 2020. For maximum efficiency, work is coordinated with protections replacement activities.

Hydro One has assigned highest priority to sustaining the reliability of those protections due to the risk associated with failures and the fact that they are subject to NPCC and NERC Reliability Standards. Expenditures for test years 2013 and 2014 are $5.0 million in each year.

S39: ITMC refreshment/reconditioning.

The telecom management centre at Richview has been in operation for nearly 15 years and is in need of rehabilitation. Hardware and control room layout, together with auxiliary systems that support the logistics of the Integrated Telecommunication Management Centre (ITMC) control room will be examined and upgraded as required. Monitoring of telecom facilities that support protection and control of the provincial grid make possible optimized maintenance activities (extended maintenance intervals) allowable by regulatory bodies such as NPCC and IESO. Expenditures for test years 2013 and 2014 are $2.9 million and $1.1 million respectively.

<u>Other Projects and Programs</u>

Included in this category are all projects and programs where spending during test years 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 power to telecommunication systems.
- 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 Integrated Telecommunication Management Centre (ITMC) 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.

In total, spending for the work listed above for the test years 2013 and 2014 is $8.4 million and $6.5 million respectively.

3.7.2.3 Summary of Expenditures

The spending level for the 2013 and 2014 test years is $24.5 million and $18.5 million respectively. The 2013 test year spending is 6% lower than the 2012 bridge year due to completion of DC signaling work in the Hamilton and Windsor areas combined with completion of work on replacements of power line carrier (PLC) systems. The 2014 spending declines by 24% as a result of completion of work on DC signaling replacements at load stations in the northeastern GTA area. To keep pace with asset aging of other telecommunications devices, end of life replacements are kept relatively flat over the test years period.

Execution of these projects and programs will ensure that the load supply reliability and transmission system reliability is maintained at current levels or slightly improved. Extending the use of DC cable facilities rather than replacing them will lead to a higher number of outage events primarily attributable to the frequency and duration of DC circuit outages. Furthermore, field P&C resources will have to be dispatched to troubleshoot these events and restore services hence ability to deploy them to perform planned sustainment and development work will be either inefficient or seriously compromised. Delaying the replacement of end of life tone channels 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 the test years are provided in Table 12. Additional details for these programs are provided in the Investment Summary Documents in Exhibit D2, Tab 2, Schedule 3.

Table 12
Auxiliary Telecommunications Equipment
Capital Projects > $3 Million in Test Year 2013 or 2014 ($ Millions)

Ref #	Description	Cash Flow Test Years 2013	Cash Flow Test Years 2014	Capital Cost
S36	DC Signaling (Remote Trip) Replacements	4.8	5.0	9.8
S37	DC Signaling Replacements (Toronto North & East)	3.4	0.9	4.3
S38	Protection Tone Channel Replacements	5.0	5.0	10.0
S39	ITMC Refreshment	2.9	1.1	4.4
	Other	8.4	6.5	14.9
	Total Cost	**24.5**	**18.5**	
	Contribution	**0.0**	**0.0**	
	Net Capital Cost	**24.5**	**18.5**	

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 in December 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

S40: Telecom Device Control Network (TDCN) 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. The spend on this project in 2011 was much lower than planned due to rescheduling of this project to align with the WAN project (see Exhibit D1, Tab 3, Schedule 4, pages 21 and 22). Due to the integrated nature of the two projects, the S40 project is proceeding in coordination with the WAN project.

S41: NERC CIP V5 Readiness

This initiative addresses the requirements for compliance with Version 5 of the NERC Critical Infrastructure Protection (CIP) set of standards. These are expected to be approved by the US Federal Energy Regulatory Commission in late 2012. Under this new version, it is expected that the total number of devices that will need to be secured will increase by about 40%. Funding is required for the additional hardware and system expansion required to meet the anticipated requirements.

S42: Cyber Security for Load Supply Stations

Once design standards, Security Management systems and processes are in place and matured for meeting the evolving NERC standards, it is prudent to apply these to expand beyond the existing station standards to protect stations supplying major cities and industrial load centres. Hydro One plans to develop a program to do this starting in 2014.

S43: Cyber Systems Life Cycle Management

The deployment of Security Management systems started in 2008. A new program is required to address obsolescence in some of these systems starting in 2013. Security management systems can require shorter upgrading cycles due to the “cat and mouse” aspect of the security function and the need for evolving counter-measures to new forms and avenues of attacks.

Other Projects

Other Cyber Security investments in 2013 and 2014 are required to address cyber vulnerabilities that are uncovered periodically, and to implement improved security on the devices used by field staff to access and maintain Critical Cyber Assets. In total, spending for these other projects in test years 2013 and 2014 is $4.0 million and $1.0 million respectively.

3.7.3.3 Summary of Expenditures

The 2013 test year spending of $23.7 million is above the 2012 bridge year expenditures. This is attributed to the start of the new project to prepare for the requirements of the NERC Version 5 cyber security standards. The 2014 test year level declines by $4.1 million, as compared to 2013, due primarily to the completion of the Telecom Device Control Network (TDCN) Cyber Security project.

Cyber Security capital investment programs requiring in excess of $3 million in either test year 2013 or 2014 are provided in Table 13 . Additional details for these programs are provided in the Investment Summary Documents in Exhibit D2, Tab 2, Schedule 3.

Table 13
Cyber Security Compliance Readiness
Capital Projects > $3 Million in Test Year 2013 or 2014 ($ Millions)

Ref #	**Description**	**Cash Flow Test Years 2013**	**Cash Flow Test Years 2014**	**Total Cost**	**Capital Cost**
S40	TDCN Cyber Security	6.7	0.0	10.4	10.4
S41	NERC CIP V5 Readiness	10.0	9.0	19.0	19.0
S42	Cyber Security of Load Stations		6.6	11.7	11.7
S43	Cyber Systems Life Cycle Management	3.0	3.0	6.0	6.0
	Other Projects/ Programs < $3M	4.0	1.0	5.0	5.0
	Total Cost	**23.7**	**19.6**		
	Capital Contribution	**0**	**0**		
	Net Capital Cost	**23.7**	**19.6**		

3.8 Transmission Site Facilities and Infrastructure

3.8.1 Introduction

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

3.8.2 Investment Plan

Site Drainage

Transmission stations require functional drainage systems for worker safety and to prevent damage to property and electrical equipment. Condition assessment, investigations and studies identify sites that require major modifications in order to bring the site drainage to acceptable standards. Spending to restore adequate drainage for 2013 and 2014 are $ 2.2 million and $ 2.5 million respectively.

<u>S44: Station Fences and Security Infrastructure</u>

Expenditures within Transmission Station Fences and Security Infrastructure are established 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. Perimeter fences replacements and upgrade also help to keep wildlife out of stations, as animal contacts are a significant contributor to delivery point interruptions. 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.

Continued improvement of Hydro One's security perimeters is imperative to ensure public and employee safety, and also reduce and combat instances of theft from Hydro One stations. Security breaches can have not only an effect on safety and lost productivity while repairing or replacing stolen components, but can also have significant impacts to local or system reliability. This was demonstrated during an event on January 21, 2012 where a member of the public tripped several elements in the Scott TS switchyard after having gained unauthorized access to the station. The result was a loss of 160MW of load to the local LDC and transmission-connected industrial customers in the Sarnia area. The impact to the process-based industrial customers and the economies they contribute to are significant upon loss of supply. Hydro One recognizes the need to provide secure perimeters to the station facilities to reduce the likelihood of these types of events.

Spending levels for the test years 2013 and 2014 of $8.9 million and $10.8 million respectively is required to add and modify station security to reduce theft and unauthorized entry onto transmission station premises.

Station Power System Asset Infrastructure Investments

Expenditures in this category are targeted at refurbishing or replacing components and systems within the transmission stations that are designed to support or protect power system equipment. Assets included are such things as support structures (concrete footings or steel/wood structures within the station), fire protection system/deluge replacements, refurbishment of deteriorated cable trays carry control and power cables, yard gravel, and repair to access roads in the station. Expenditure levels for the test years are 2013 and 2014 of $10.4 million and $10.9 million respectively.

Building Infrastructure Investments

Expenditures in this category are targeted at refurbishing or replacing building components within transmission stations typically designed to house Hydro One staff, and in some cases electrical assets (i.e. protection, control, and telecom components). Types of work included are building roof replacement, replacement of Heating Ventilation and Air Conditioning (HVAC) systems, water supply upgrades, or other building refurbishments or enhancements. Expenditures for the 2013 and 2014 test years are $8.5 million and $8.5 million respectively.

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.

3.8.4 Summary of Expenditures

The spending level for test years 2013 and 2014 are $30.0 million and $32.7 million respectively and are about one-third above the average historic and bridge year spending.

The test years spending has increased over prior years primarily due to the required refurbishment and hardening of transmission station perimeter security.

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 million in either test year 2013 or 2014 are provided in Table 14 below. Additional details for these programs are provided in the Investment Summary Documents in Exhibit D2, Tab 2, Schedule 3.

Table 14
Transmission Site Facilities and Infrastructure
Test Year Expenditures for Capital Projects Over $ 3 Million ($ Millions)

Ref #	Description	Cash Flow Test Years		Total Cost
		2013	**2014**	
S44	Station Fences and Security	8.9	10.8	19.7
	Other Programs <$3 million	21.1	21.9	43.0
	Total Cost	**30.0**	**32.7**	
	Capital Contributions	**0.0**	**0.0**	
	Net Capital Cost	**30.0**	**32.7**	

4.0 LINES

Hydro One's Transmission system consists of approximately 29,000 circuit km of overhead transmission lines and 292 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 the end of their service life. 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 end of life. 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 expected end of life. It also funds completely recoverable secondary land use projects, where Hydro One Transmission is required to relocate its facilities to accommodate new roads or other infrastructure changes.
- Underground Transmission Line Refurbishment and Replacement, which funds the capital investments to refurbish or replace cable sections and components that have reached end of life. 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 15 for each of these categories.

Table 15
Lines Sustaining Capital ($ Millions)

Description	**Historic**			**Bridge**	**Test**	
	2009	**2010**	**2011**	**2012**	**2013**	**2014**
Overhead Lines Refurbishment and Component Replacement	56.8	54.0	52.4	55.5	70.6	68.3
Transmission Lines Re-investment	15.2	16.2	17.1	10.3	37.9	37.8
Underground Lines Cables Refurbishment and Replacement	4.1	1.4	1.0	5.9	23.9	30.0
Total	**76.0**	**71.6**	**70.6**	**71.6**	**132.4**	**136.2**

The spending requirement for the 2013 test year is $132.4 million which is an 85% increase from 2012. The spending level for 2014 is 3% more than the 2013 test year spending.

The increase in the test years spending is partially due to the need to replace two 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 each over 5 km in length and located in downtown Toronto. The year over year costs for underground cable replacement can vary significantly due to the large costs associated with individual projects. Expenditures in 2011 and 2012 were low as a plan to replace the above circuits was deferred due to unexpected difficulties with obtaining the necessary land easements to begin work.

Other increases under the Lines programs are due to an increase in conductor replacement and line refurbishment projects. Results of recent conductor samples and testing on older circuits in corrosive areas have identified a number of circuits that require re-investment. The average life expectancy of conductors is estimated to be 70 years, based upon a study carried out by the former Ontario Hydro. The conductors from the six line sections included for conductor replacement and line refurbishment projects during the test years have all undergone laboratory tests to confirm the need to replace; the combined average age of these circuits is 74 years. About 16% of the overall conductor population is over 70 years of age and this number will double during the next 10 years, making it important to increase this program in order to maintain the performance and safety related to these assets. One of the line sections mentioned above contains a problematic self-damping conductor design that requires replacement and is only 34 years old.

A significant increase is also required in the refurbishment of steel towers. Coating structures presents the lowest life cycle costs to extend the life of these assets, but there is an optimum time to coat, and should this be exceeded, then these structures would have to be replaced at some point in the future at a significantly higher cost. Currently there are about 1600 structures that require coating during the next 5 years and 700 structures will be coated during the test years, with an additional 8 structures replaced which have exceeded the optimum time to coat and are no longer structurally sound.

4.1 Overhead Lines Refurbishment and Component Replacement

4.1.1 <u>Introduction</u>

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, switches, and refurbishment/replacement of corroded towers, as well as providing funding for other projects such as 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 the end of its life, the project takes on a much larger scope than individual component replacement with an emphasis to replace all components nearing end of life, thereby re-instating the condition of the line to like new. Conductor replacement projects are addressed under the Transmission Line Re-Investment Program, which is discussed in Section 4.2.

4.1.2 <u>Investment Plan Process</u>

Hydro One considers asset condition assessment results, regulatory compliance requirements, 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 the end of their life are prioritized based on risk (e.g. safety, reliability) and scheduled for refurbishment or replacement.

S45: Wood Pole Replacement Program

Hydro One's Transmission system contains approximately 42,000 wood pole structures. Wood poles are determined to be at end of life based on the results of wood pole tests and inspections, at which point they are scheduled for replacement.

Historic replacements have averaged about 800 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 in part 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 2000 remain that still have the defective arm that requires upgrading. The remaining upgrades are planned to be completed over the next 5 years with approximately 850 per year taking place during the test years. Once the defective Gulfport structures are eliminated from the network, replacement levels are expected to decrease. 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 2013 and 2014 is $28 million and $28.8 million respectively.

S46: Steel Structure Coating Program

Hydro One's Transmission system includes about 50,000 steel towers and about 14% are older than 80 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 targeted in corrosive areas have shown that more than 700 structures on several line sections have, to a large part, lost their galvanized coating and need to have the corrosion protection re-instated during 2013 and 2014. Spending for the tower coating program in test years 2013 and 2014 is $10.0 million and $10.9 million respectively.

S47: 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 maintains an on-going 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 300 km of shieldwire will be replaced during 2013 and 2014, at the cost of $5.6 million and $5.7 million respectively.

S48: Transmission Lines Emergency Repairs

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/cross-arms, towers, insulators, conductor, shieldwire and hardware. Funding is based on recent historic costs and it is estimated that $7.1 million and $7.9 million will be required in 2013 and 2014 respectively to address emergency work.

S49: Insulator Replacement Program

This program replaces transmission lines' insulators that have reached or are reaching the end of their service life. Insulator failures result in outages and at times allow energized conductor to fall to the ground creating safety hazards. Transmission line insulators' expected life varies, depending on the type, design, manufacturer and their installed environment. Due to this large variation in the life expectancy some insulators require replacement well before the circuit reaches end-of-life. This program deals with insulators that have reached end of life as well as unforeseen insulator issues such as known insulator design or manufacturing issues for different insulator types.

Insulator test results indicate that there are currently about 400 strings of insulators on the 115 kV and 230 kV network that have reached end-of-life. In addition to these locations, there are about 1800 strings of insulator on the 500 kV system that require replacement due to a high failure rate. Theses insulators are from a particular manufacturer and were installed between 1968 and 1982 and are known to become defective over time, suffering from a condition known as cement growth. As such, they have been under surveillance through testing programs and now need to be replaced. These are deemed very critical since they are part of the 500kV system. Funding to address this work for the test years 2013 and 2014 will be $7.3 million and $3.3 million respectively.

S50 and S51: Steel Structure Replacements

Once the galvanized coating on a steel structure has been depleted, the bare steel becomes exposed to the environment and begins to corrode at a much faster rate. In many cases, the steel has been found to corrode up to 25 times faster than when protected by the zinc. If the tower is not painted with a galvanized coating and corrosion is allowed to continue, steel members will begin to lose strength and eventually fall below Hydro One design standards. Once a structure is identified as being in poor condition through visual inspection and sample zinc coating measurement, a detailed corrosion assessment is conducted to determine whether it is possible to replace a portion of the steel members and coat the remaining structure to protect it from corrosion or whether it is more economical to replace the entire structure. 16 structures on the S2B circuit are exhibiting metal loss based on a detailed engineering analysis and require replacement. This work is starting in 2012 and will continue into the 2013 test year, with a cost of $1M in 2013. Additionally, 8 other steel structures have exceeded the optimum time to coat and have now reached a point where they have fallen below their required design strength and will be replaced during the test years 2013 and 2014 at cost of $3.6M in each year.

Other Projects/ Programs <$3 million

Other component replacements include replacement of switches, right of way access components and aviation lights that have reached end of life. Replacements of these components 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’s Transmission 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 increase clearances to that required. In total, spending for these component replacements, refurbishment of foundations and electrical clearance corrections for test years 2013 and 2014 is $8.0 million and $8.1 million respectively.

4.1.3 Summary of Expenditures

The spending requirement for the test year is $70.6 million which is 27 % greater than the bridge year 2012 and the $68.3 million spending level for 2014 is 23% greater than the 2012 bridge year. This increase is attributed to an increased need for tower coating as well as an increase in insulator replacement to address problematic insulators on the 500kV system.

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 could 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 safety issues as they arise.

Overhead lines refurbishment and component replacement programs requiring in excess of $3.0 million in either test year 2013 or 2014 are provided in Table 16. Additional details for these programs are provided in the Investment Summary Documents in Exhibit D2, Tab 2, Schedule 3.

Table 16
Overhead Lines Refurbishment and Component Replacement
Capital Projects > $ 3 Million in Test Year 2013 or 2014 ($ Millions)

Ref #	Description	Cash Flow Test Years 2013	Cash Flow Test Years 2014	Total Cost
S45	Wood Pole Replacement Program	28.0	28.8	56.8
S46	Steel Structure Coating Program	10.0	10.9	20.9
S47	Shieldwire Replacement Program	5.6	5.7	11.3
S48	Transmission Lines Emergency Restoration	7.1	7.9	15.0
S49	Insulator Replacement Program	7.3	3.3	10.6
S50	S2B Steel Structure Replacements	1.0	0	7.2
S51	Steel Structure Replacement Program	3.6	3.6	7.2
	Other Projects/ Programs < $3M	8.0	8.1	16.1
	Total Cost	**70.6**	**68.3**	
	Contribution	**0.0**	**0.0**	
	Net Capital Cost	**70.6**	**68.3**	

4.2 Transmission Lines Re-Investment

4.2.1 <u>Introduction</u>

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 re-investment program addresses the need to rebuild sections of transmission line based primarily on conductors reaching end of life. The work also includes the replacement of other components at or nearing the end of their life.

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 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.

Hydro One is now beginning to see from conductor samples and testing program on aged conductors that many are approaching their end of life. Based on the current demographics of the overhead conductors, it is expected that this trend will continue in the future. Field sampling and testing of conductors, although a very accurate way to determine conductor condition, is time consuming, destructive and dependent on outages. Hydro One is therefore currently investigating the use of a new tool that can be used on an energized line to non-destructively assess the general condition of the conductor. This will help to more efficiently prioritize and limit the amount of destructive testing required for determining remaining life of the large number of conductors that are beginning to reach the end of their expected service. Any delay in not proceeding with the following conductor and line re-investment projects will result in safety and reliability risks as well as a build-up of work that may not be practical to achieve in the future as other candidate lines are expected to be identified for re-investment.

S52 C25H Line Refurbishment

Expenditures are included in 2014 for the refurbishment of a transmission line between Chats Falls SS x Havelock TS. This involves a 170 km line with the conductor currently installed being 84 years old. Conductor tests reveal that the tensile strength and ductility has deteriorated to an extent that the conductor is at end of life. Furthermore, the insulators, hardware and shieldwire on this line require replacement.

S53 D1A Line Refurbishment

This investment is required to address the condition of the conductors on the 115kV circuits D1A/D3A from Decew Falls SS to St. Johns Valley Jct (4.2 km). The circuit is 69 years old and the conductor has deteriorated to the point where the strength and ductility characteristics are below established criteria.

S54 H27H Line Refurbishment

This investment is required to address the condition of the conductors on the 230 kV circuit H27H from Bannockburn Jct to Havelock TS (29 km). The conductor has deteriorated to the point where the strength and ductility characteristics are below established criteria indicating end of life. Furthermore, the insulators, hardware and shieldwire on this line are also approaching end of life and require replacement.

S55 V73R/V74R Self-Damping Conductor Replacement

This investment is required to address the condition of the conductors on the 230 kV circuits V73R/V74R from Claireville TS to Richview TS (9.6 km). These circuits contain a problematic self-damping conductor which is proven to be unable to adequately control aeolian vibration. An inadequate vibration control system would lead conductors to fatigue and ultimately fail prematurely, hence the need to replace.

S56 H24C Line Refurbishment

This investment is required to address the condition of the conductors on the 230kV circuit H24C from Marine JCT to Oshawa North JCT (54 km). The conductor has deteriorated to the point where the strength and ductility characteristics are below established criteria signifying end of life. Furthermore, the insulators, hardware and shieldwire on this line require replacement.

S57 C27P Line Refurbishment

This investment is required to address the condition of the conductors on the 230 kV circuit C27P from Chats Falls SS to Galetta JCT (6.5 km). The conductor has deteriorated to the point where the strength and ductility characteristics are below established criteria signifying end of life. The conductor on C27P from Chats Falls SS to Galetta JCT is 80 years old.

S58 Ottawa - Hwy 417 Interchange (Recoverable)

This project is 100% recoverable and involves relocating our overhead facilities to accommodate the HWY 417 interchange work. The estimated cost for this work in the test years is $ 3.2 million.

S59 Keith TS Hwy 401 Expansion (Recoverable)

This project is 100% recoverable and involves relocating our overhead facilities to accommodate the HWY 401 expansion. The estimated cost for this work in the test years 2013 and 2014 is $11.4 million and $8.9 million respectively.

S60 Toronto-TTC Maintenance Facility (Recoverable)

This project is 100% recoverable and involves relocating 2 of our underground transmission cables at a cost of $8 million in 2013.

S61 Sudbury-Maley Drive Extension/Widening (Recoverable)

This project is 100% recoverable and involves raising and/or relocating steel transmission towers due to a new major arterial road in the City of Greater Sudbury. Estimated cost for this work in the test years is $1.2 million.

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, as well as removal of transmission lines that are no longer required. Projected expenditures for secondary land use projects are required to accommodate upcoming highway expansion plans. Test year expenditures are $4.4 million in 2013 and $0.3 million during 2014.

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 failures present unacceptable risk to public safety and to the reliability of the electrical system, and as such need to be avoided. 16% of conductors are beyond their expected service life of 70 years and this number is forecasted to double over the next 10 years. The current assessment data has identified that a number of line re-investment projects are required, and based on the aging demographic this trend is expected to continue into the future.

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

Table 17
Transmission Line Re-Investment Capital Projects > $ 3 Million

Ref #	Description	Cash Flow Test Years		Total Cost	Capital Contribution	Net Capital Cost
		2013	**2014**			
S52	C25H Line Refurbishment	0.0	15.0	52.5	0	52.5
S53	D1A Line Refurbishment	3.2	0.0	3.2	0	3.2
S54	H27H Line Refurbishment	7.5	7.0	14.5	0	14.5
S55	V73R/V74R Self Damping Conductor Replacement	7.0	2.0	9.0	0	9.0
S56	H24C Line Refurbishment	12.2	13.5	25.7	0	25.7
S57	C27P Line Refurbishment	6.2	0.0	6.2	0	6.2
S58	Ottawa - Hwy 417 Interchange (Recoverable)	3.2	0.0	4.3	4.3	0.0
S59	Keith TS Hwy 401 Expansion (Recoverable)	11.4	8.9	29.7	29.7	0.0
S60	Toronto-TTC Maintenance Facility (Recoverable)	8.0	0.0	20.7	20.7	0.0
S61	Sudbury-Maley Dr Extension/Widening (Recoverable)	1.2	0	3.7	3.7	0.0
	Other Projects/ Programs < $3M	4.4	0.3	4.7	2.6	2.1
	Total Cost	**64.3**	**46.7**			
	Contribution	**26.4**	**8.9**			
	Net Capital Cost	**37.9**	**37.8**			

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.

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 other risk considerations. 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 an underground cable and or cable components at end-of-life 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.

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. 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.

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.

<u>S62: H2JK/K6J Underground Cable Replacement (Riverside Jct. x Strachan TS)</u>

This project will replace two paper insulated oil filled 115 kV cables that are each 5.6 km in length and have reached end of life due to chronic oil leaks caused by a corroded lead sheath. They are located in downtown Toronto along the western waterfront area. The replacement cables will be operated at 115kV but designed to 230kV standards to allow for future transmission applications. The costs for this project are estimated to be $22.5 million in 2013 and $24.5 million in 2014. This project was previously planned as project S39 in the EB-2010-0002 proceeding, and approved by the Board to proceed in 2011 and 2012. The project start has been deferred due to unexpected difficulties with obtaining land easements. Hydro One is currently working with the City of Toronto to finalize the easement agreements and it is anticipated that all the required rights will be in place to begin construction in 2012.

Other Projects

Networks plans to replace a high pressure oil pumping plant that provides oil pressurization to two cable circuits in Ottawa at Riverdale TS in 2014. Pumping plants are critical to provide the necessary oil pressure to pipe-type cable circuits in order for them to operate at their required voltage level. The system security depends greatly on the integrity of the pumping equipment and this particular facility was modified in the early 1990's with parts which are no longer commercially available, making it very difficult to maintain and repair.

4.3.3 Summary of Expenditures

Underground Cables capital expenditure for test years 2013 & 2014 is substantially more than the investment for bridge year 2012. This is due to the need to replace two 5.6 km circuit lengths of 115 kV oil filled cable that have reached end of life in Toronto.

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. 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 Capital Projects > $ 3 Million in Test Years ($ Millions)

Ref #	Description	Cash Flow Test Years 2013	Cash Flow Test Years 2014	Total Cost
S62	H2JK/K6J Underground Cable Replacement (Riverside Jct. x Strachan TS)	22.5	24.5	53.1
	Other Projects/ Programs < $3M	1.4	5.5	6.8
	Total Cost	**23.9**	**30.0**	
	Contribution	**0**	**0**	
	Net Capital Cost	**23.9**	**30.0**	

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 Hydro One's Transmission system.
- Connect load customers (load connections) and generating stations (generation connections) to Hydro One Transmission's system.
- Carry out necessary mitigation measures to minimize high impact risk and ensure safe, secure and reliable operation of Hydro One Transmission's system in accordance with the Market Rules, TSC and other mandatory industry standards such as NERC and NPCC.
- 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.

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 ("ORTAC") when conducting System Impact Assessments ("SIA") for new transmission facilities. In particular, Hydro One is 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 15, Schedule 3. A more detailed explanation of the planning for each different type of investment (i.e. Network Upgrades, Local Area Supply, Load Connection, Generation Connection, Protection and Control for Enablement of Distribution Connected Generation, Protection and Control Modifications for Consequences of Connected Distribution Generation, Performance Enhancement, Risk Mitigation and Smart Grid) is provided in Sections 2.2.1 to 2.2.8 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 3.7.

2.2.1 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 neighboring 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:

- 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.
- Hydro One Transmission monitors the IESO's SIA reports for load and generation projects. If any SIA suggests that network upgrades may be required, Hydro One Transmission undertakes additional studies to assess alternatives for the upgrades and to identify recommended transmission solutions. In performing these assessments, Hydro One consults with the IESO, the OPA, and the customer where appropriate.

- 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.

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.

2.2.2 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 subsystem 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:

- Hydro One Transmission monitors the transmission system and identifies concerns about equipment overloading, system performance constraints, or restricted operating and maintenance flexibility.

- 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. In performing these assessments, Hydro One consults with the LDCs and the OPA, where appropriate.
- The OPA recommends local area supply initiatives aimed at ensuring regional and local area reliability.

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.

2.2.3 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.

2.2.4 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.

2.2.5 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 ensure the reliability and capacity of the distribution system feeders and maintain protection of transmission assets. The need for them is determined as part of the Connection Impact Assessment process.

However, the required changes do not have a one-to-one correspondence with individual DG projects. Instead, specific changes will support different groupings of generators at the station. They become necessary at certain thresholds of aggregate DG capacity at a feeder, at a bus, and at the entire station. In accordance with the Transmission System Code the costs must be recovered from the generator whose actual connection requires the investment. Thus cost recovery is based on the sequence of actual connection and not, as with the Distribution System Code, the sequence in which the capacity was reserved. When the Connection Impact Assessment is done, the actual connection sequence is not known and hence neither is the specific generator that will cross the threshold and be the target for cost recovery. Consequently, all generators connecting to the station, even those with very small capacity, must be allocated these full costs at time of Connection Impact Assessment. As these costs will be prohibitive to smaller generators, Hydro One is also implementing a system to rebate the first generator to actually cross the threshold, from the funds collected from other generators that connect after the threshold has been crossed. This rebating needs to be tracked at four grouping levels:

a. all generators connecting to an individual feeder beyond the point at which feeder protection directioning is required.
b. all generators connecting to a station bus after the bus protection needs to be directioned
c. all generators connecting to a station that require transfer trip
d. all generators connecting to a transmission line that require transfer trip

This is a very complex and costly process to implement. Databases and necessary staffing are being put into place to track the actual connection sequences and cost incurred for the protection modifications at these levels and to ensure the costs are allocated as fairly as possible to all generators.

2.2.6 Planning for Protection and Control for Consequences of Distribution Connected Generation

Hydro One tries to identify all costs associated with the connection of generators to the distribution system at the time of the connection impact assessment so that they can be recovered from the generators as a condition for obtaining the connection. However, there are two categories of costs for which this is not possible:

a. Occasionally some consequences of generation connection are not foreseen
b. Some costs can be anticipated but the exact timing of their need cannot be. These are cost associated with protection and control systems that span all, or large portions, of the grid network. The exact threshold when they will be required depends on factors which are not always predictable such as changes in load patterns and real time generation patterns.

When unforeseen consequences arise, Hydro One experts analyze the problem to determine the underlying cause and then determine the scope of remedial program required. For the anticipated consequences, Hydro One monitors trends and tries to determine the most likely timing of need in order that resources and standards can be in place to achieve a planned and cost-effective implementation.

2.2.7 Planning for Smart Grid

The planning for smart grid system deployment in Transmission Stations is based on developing long-term innovative strategies to offer value to Hydro One Transmission's LDC customers through improvements in protection and control systems at Transmission Stations to interface with, and support the objectives of LDCs' Smart Grid systems.

In developing its Transmission Station Smart Grid interface systems, Hydro One Transmission is learning from the strategies for smart grid being evaluated in Hydro One Distribution's Smart Zone pilot. These range from implementing and testing automatic fault isolation and restoration systems, managing reactive power with a DVAR controller at transformer stations with high DG penetration, enhancing monitoring and control of DG's at transformer stations, and installing new technologies and next generation intelligent electronic devices (IEDs) at transformer stations that employ the open standards best suited for interfacing with Distribution System Smart Grid equipment.

2.2.8 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, Protection and Control for Enablement of Distributed Generation, Protection and Control Modifications for Consequences of Connected Distribution 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**	
	2009	**2010**	**2011**	**2012**	**2013**	**2014**
Inter Area Network Transfer Capability	344.0	392.8	269.3	135.0	155.8	184.9
Local Area Supply Adequacy	93.7	58.8	64.0	141.6	117.8	61.2
Load Customer Connection	70.8	44.6	68.1	121.6	85.9	95.4
Generation Customer Connection	9.7	7.0	11.3	60.5	144.5	131.5
Station Equipment Upgrades & Additions to Facilitate Renewables *(Government Instruction)*	0.2	13.8	16.0	34.2	0.0	0.0
Protection and Control Modifications for Enablement of Distribution Connected Generation	3.3	6.4	14.1	39.6	23.5	28.5
Protection and Control Modifications for Consequences of Connected Distribution Generation	0	0	0	1.4	2.8	11.0
Smart Grid	0.0	0.0	5.8	7.0	2.0	2.0
Performance Enhancement	2.2	1.4	1.2	5.3	2.5	2.5
Risk Mitigation	17.0	18.7	17.9	24.3	23.9	7.8
Gross Capital Total	**540.9**	**543.5**	**467.7**	**570.5**	**558.7**	**524.8**
Capital Contributions as per TSC	(25.1)	(20.5)	(51.8)	(158.4)	(244.5)	(212.3)
Net Capital Total	**515.8**	**523.0**	**415.9**	**412.1**	**314.2**	**312.5**

The overall gross spending on Development Capital work in the test years is comparable to historical levels. However the net spending on Development Capital work in the test years is below the historical levels. The primary reason for the higher gross but lower net levels is that the vast majority of the capital expenditures for the generation connection projects are recoverable through capital contributions. Further details for each Investment Type are provided in Sections 3.1 to 3.8 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 (2013 or 2014) 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 (2013 or 2014), 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 <u>Description of Inter-Area Network Transfer Capability Investments</u>

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 2013 and 2014 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 in the Test Years is less than Historical spending. The primary reason is that most major projects identified in EB-2010-0002 in this category will be in-service before 2013 and the number of new projects (as outlined in Appendix A, Table 2) of comparable expenditure levels has decreased.

Projects that were placed in service in 2011 or are scheduled for in-service in 2012 include:

- Detweiler TS: Install 230 kV, 350 MVar Static Var Compensator
- Nanticoke TS: Install 500 kV, 350 MVar Static Var Compensator
- Porcupine TS: Install 230 kV, -100 MVar / +300 MVar Static Var Compensator
- Kirkland Lake TS: Install 115 kV, 200 MVar Static Var Compensator
- Porcupine TS: Install two 230 kV, 100 MVar Shunt Capacitor banks
- Essa TS: Install 230 kV, 245 MVar Shunt Capacitor bank
- Hanmer TS: Install 230 kV, 192 MVar Shunt Capacitor bank
- New Bruce to Milton 500kV double circuit line.

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 are non-discretionary (as defined in the OEB Filing Requirements for Transmission and Distribution Applications).

Project D1: ***New 500 kV 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.

The current cost estimate of this project totals $715M which is approximately $38M less then the $753M outlined in Proceeding EB-2010-0002 Exhibit A, Tab 11, Schedule 5. The primary reason for the decrease is attributable to: favourable weather permitting an accelerated lines civil work construction, decreasing interest rates over the construction period, and a 6 month early completion contributing to additional interest savings.

The above cost includes an additional $28M expected to be spent over the 2013-18 period. An expenditure in the amount of $9M will be required in 2013 for the removal of temporary access roads on agricultural land, right-of-way mitigation as per the Environmental Approval commitments, and biodiversity work. There is also the potential for expenditures in the amount of $14M to be incurred in 2013 and 2014 to address expropriation of lands; which was approved by the OEB under Section 99 of the OEB Act in its Decision and Order dated March 15, 2011 under Proceeding EB-2010-0023. It is expected that an additional $5M of real estate costs will be incurred from 2015 to 2018.

Projects D2, D3, D4: ***Clarington TS: Build new 500/230kV Station and Installation of Shunt Capacitor Banks at Cherrywood TS***

These projects are required to reinforce the 230kV supply capability in the east GTA following the upcoming retirement of the Pickering Nuclear Generating Station. It comprises the installation of a new 500/230kV autotransformer station just east of the City of Oshawa in the Municipality of Clarington. It also includes the installation of shunt capacitor banks at Cherrywood TS to provide additional reactive capacity. OPA letters dated October 3, 2011 and January 11, 2012 asking Hydro One to initiate work on these project together with supporting evidence entitled "OPA Information on the Description of Need and Rationale for Oshawa Area TS (Clarington TS) by 2015" are attached in Appendix B to this exhibit. Project D2 is classified as Category 2. Projects D3 and D4 are classified as Category 3 as the in-service date is beyond the test years although significant funding is required within the test years.

Project D5: ***Installation of Static Var Compensator at Milton SS.***

This project comprises the installation of a 350 MVar static var compensator (SVC) at Milton SS, as outlined in the Ontario Long Term Energy Plan (LTEP), to improve reactive support and increase transmission capability out of the Bruce Area to support increased generation in the area. Hydro One has received a letter of support for this project from the OPA dated October 3, 2011. Hydro One has also received further evidence for this project from the OPA entitled "Southwestern Ontario Reactive Compensation – Milton SVC". This document is attached in Appendix C to this exhibit. This project is classified as Category 3 as the in-service date is beyond the test years although significant funding is required within the test years.

Project D6*: Reconductor the Lambton TS to Longwood TS 230kV Circuits.*

This project comprises the reconductoring of the existing 230kV double-circuit transmission line between Lambton TS#2 and Macksville Junction (near Longwood TS) as outlined in the LTEP. The project is required to address the inadequate transmission capacity to transmit renewable generation and gas-fired generation in the west of London area. Hydro One has received a letter of support for this project from the OPA dated June 30, 2011 which is attached in Appendix D to this exhibit. This project is classified as Category 4 since approval is being sought in a Section 92 application (EB-2012-0082) submitted on March 28, 2012.

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. These investments typically affect many customers over a significant period of time and the benefits cannot be allocated in a practical and fair manner to specific customers.

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 in the local area.
- System constraints that restrict the ability of new renewable or high efficiency generation to be connected.

Funding levels for 2013 and 2014 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 overall spending in Local area Supply projects has a decreasing trend over the Test Years. The primary reason is that four of the major projects identified in this category are coming into service within the first Test Year (2013) and the two new projects identified in this category will not commence construction until after all approvals are obtained; hence significant spending will not be incurred until beyond the Test Years.

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.

Projects D7, D8: ***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. These projects were approved by the OEB in its Decision and Order dated December 23, 2010 under Proceeding EB-2010-0002, and are classified as Category 1.

The current cost of these projects is approximately $24M lower than outlined in Proceeding EB-2010-0002. The primary reason for the decrease is attributable to a reduction in project scope. Detailed engineering work determined that a portion of the P&C facilities did not require modifications at this time and replacement could be deferred. The in-service date for Leaside TS is delayed from the initial in-service date of Dec. 2012 due to difficulty in obtaining outages in the City of Toronto to stage the station upgrade work.

Project D9: ***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 was approved by the OEB in its Decision and Order dated December 23, 2010 under Proceeding EB-2010-0002, and is classified as a Category 1.

The current cost is approximately $19M greater than outlined in Proceeding EB-2010-0002. The primary reason for the increase is due to higher costs for the turn key GIS station following the tendering process and increased costs for protection and control modifications and facilities. The delayed in-service date for Hearn from the initial in-service date of December 2012 is due to a one year delay in acquiring property for the new switchyard. It was initially anticipated that the land acquisition could be completed by late Fall 2010; however, property purchase negotiations took longer than expected and the required property could not be secured until late October 2011.

Project D10: ***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 was approved by the OEB under Section 92 of the OEB Act in its Decision and Order dated June 17, 2010 under Proceeding EB-2009-0425, and is classified as Category 1.

The current cost is approximately $8M greater than outlined in Proceeding EB-2009-0425. The primary reason for the increase is attributable to a combination of higher construction costs and costs associated with delays in obtaining project approvals. The in-service date was delayed due to additional time required for local consultations and to secure the approvals for the underground portion of the work.

Projects D11/D12: ***Guelph Area Transmission Reinforcement and Preston TS Transformation***

These projects are planned to provide reliable transmission supply capacity for load growth in the South-Central Guelph Area and the Kitchener/Cambridge Area. These projects are required as the transmission system is inadequate to meet the local area's existing demand and forecast load requirements. Hydro One has received a letter of support for this project from the OPA dated March 8, 2011. This document is attached in Appendix E to this exhibit. Project D11 at Preston TS is classified as Category 3 as the in-service date is beyond the test years; and Project D12 for Guelph Reinforcement is classified as Category 4 as further approvals from the Board in the form of a Section 92 application will be required.

In addition to the above projects Hydro One is currently participating with the OPA, the IESO and the local LDC's on a number of joint Regional Supply studies including York Region, Kitchener-Waterloo-Cambridge-Guelph, Essex-Leamington, the City of Ottawa and the City of Toronto. Work identified as a result of these studies will be included in future submissions to the Board. For example, alternatives are being assessed for additional switching facilities at Holland TS to address load security and increased supply capability.

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 2013 and 2014 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-2010-0002.
- Addition of new line connection and capacity increase projects being initiated by customers.

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**
D13: Tremaine TS D14: Barwick TS	D15: Nebo TS D16: Orleans TS D17: Bremner TS D18: Chalk River CTS D19: Nelson TS		

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 typically addressed by radial connection facilities; however, in some cases other modifications may be required to Hydro One's local area connection or network facilities in order to incorporate the generation into the system.

Since mid-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 Renewables Request for Proposals ("RFPs"), Clean Generation RFPs, Combined Heat and Power RFPs, the FIT program, and other project procurements.

With the signing of the Green Energy Investment Agreement with the Korean Consortium in January 2010, and the release of 25 large-scale renewable energy projects under Ontario's Clean Energy Feed-In Tariff program in July 2011; the generation connection activity continues to grow rapidly.

The consequences of not proceeding with these investments include:

- Failure to connect generators which have been contracted by the Ontario Government or 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
- Failure to meet Hydro One Transmission's obligation to connect new generators under its Transmission License and the TSC.

Funding levels for 2013 and 2014 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 overall spending level on Generation Customer Connection projects, compared to historical levels, is primarily due to:

- Further project definition following connection assessments and preliminary engineering work on many of the projects from the first two phases of the FIT contract awards in April 2010 and February 2011.
- The release of 25 new large-scale renewable energy projects in July 2011, through Ontario's Clean Energy Feed-In Tariff program, to take advantage of the additional transmission capacity enabled by the new Bruce to Milton line.

- The signing of power purchase agreements with the Korean Consortium to develop wind and solar projects; in accordance with the Ontario government's plan for a clean energy economy.

3.4.2 Summary of Generator Customer Connection Projects

The following is a summary listing of the new generator projects for which cashflow details are provided in Table 5. These projects have been either contracted by the Ontario Government or the OPA, and are considered substantially advanced (in terms of negotiations and/or implementation), so that they require allocation of funding in excess of $3M for transmission upgrades within the test year periods.

- D20: South Kent Wind Farm (270 MW)
- D21: Lower Mattagami Generation Connections (450 MW)
- D22: Niagara Region Wind Corporation Generation Connection (230 MW)
- D23: Armow Wind Generator Connection (180 MW)
- D24: K2 Wind Generator Connection (270 MW)
- D25: Adelaide/Bornish/Jericho Wind Energy Centres (284 MW)

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. Now that the FIT program review is completed, it is expected that additional projects will be identified by the OPA to meet the LTEP renewable energy targets.

These projects are categorized as "Customer Driven" because they are requested by the customer to accommodate new generation and connection facilities are normally 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 Protection and Control Modifications for Enablement of Distribution Connected Generation

3.5.1 Description of Protection and Control Modification Investments for Enablement of Distribution Connected Generation

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 reliability and loading capability of the feeders, to protect loads and generators from islanding, to preserve the proper function of station protections and to minimize disruption to the operation of the generators.

The consequences of not proceeding with these programs include:

- Severe restriction on the amount of generation that can be connected to distribution systems.
- Lost production periods for station generator customers as a result of planned or forced transmission conditions for which transfer trip protections are not valid

Funding levels for 2013 and 2014 for Protection and Control Modification 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. 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 6 are provided in the Investment Summary Documents in Exhibit D2, Tab 2, Schedule 3.

3.5.2 Summary of Protection and Control Modifications for Enablement of 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.

3.5.2.1 Transmission Station P&C Upgrades for Distribution Connected Generation

Certain upgrades to or replacements of the Protection and Control (P&C) systems at Transmission Stations are required in order to accommodate generation connected to distribution systems supplied from the TS. These costs are fully recovered through customer contribution and the Net Total Cost will be nil.

3.5.2.2 Transfer Trip Signaling Enhancement

The CIA that is done for a generator connection is explicitly based on normal operating conditions. The requirements to allow operation during planned or forced outage conditions on the transmission system are not considered. Consequently, during outages at the TS or on the transmission lines to the TS, DG facilities requiring transfer trip must shutdown or severely curtail their operation.

Enhanced Transfer Trip Signaling will allow the generators to continue normal operation during many of these outages. Enhanced Transfer Trip Signaling will be offered to generators at their cost.

Additional details about these projects are provided in the Investment Summary Documents in Exhibit D2, Tab 2, Schedule 3.

3.6 Protection and Control Modifications for Consequences of Connected Distribution Generation

3.6.1 Description of Protection and Control Modification Investments for Consequences of Connected Distribution Generation

As the connection of generation to the Distribution Systems supplied from the Hydro One Transmission System accumulates, certain consequences can emerge that require further investment to address. Some of these are consequences that are unforeseen, others can be anticipated but the exact threshold when they will be required depends on factors which are not always predictable such as load growth and changes to generation patterns.

The consequences of not proceeding with these programs include:

- 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 Protection Schemes.
- Power quality problems for distribution load customers

- Deterioration in reliability and performance of system control functions
- Inability to manage operation during planned or forced outage conditions

Funding levels for 2013 and 2014 for Protection and Control Modification projects for the Consequences of Distributed Generation, along with the spending levels for the bridge and historic years, are provided in the attached Table 7 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 7. 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 7 are provided in the Investment Summary Documents in Exhibit D2, Tab 2, Schedule 3.

3.6.2 Summary of Protection and Control Modifications for Consequences of Connected Distribution Generation Projects

The following is a summary listing of the investments identified under the Protection and Control for Consequences of Connected Distribution Generation program. All of these programs are non-discretionary.

3.6.2.1 Under Frequency Load Shedding and Load Rejection Modifications for DG

Some contingencies on the interconnected transmission system can cause a loss of generation. The resulting imbalance between generation and load will cause a downward trend in the system frequency. If this trend is not corrected, other generation will trip and a widespread blackout would result. To prevent this, NERC and NPCC mandate under frequency load shedding (UFLS) schemes which disconnect load from the system automatically until the generation load imbalance is corrected. Hydro One has about 130 Transmission Stations equipped for under frequency load shedding. The loads are shed by tripping feeder breakers. As generation connects to the feeders, the number of feeder breakers that trip only load is being reduced and alternate arrangements will need to be implemented to maintain required UFLS capability.

Special Protection Schemes (SPS's) initiate tripping of generation, load or both, in response to contingencies on the transmission system, to prevent overloads or system instability. As with UFLS, the tripping of load is accomplished by tripping of the feeder breakers at Transmission Stations. With generation connected to the feeders, the amount of load available for rejection is reduced and alternate arrangements will need to be implemented to maintain required SPS capability.

These are system driven schemes associated with the transmission network. They are not connection assets and are not for connection purposes. Consequently, these costs will be allocated to the network pool.

3.6.2.2 Transmission work to mitigate distance limitation

This encompasses the protection work required on transmission assets which are required to address the power-distance limitation problems observed at connected projects. This work was approved in the OEB proceeding EB-2010-0229 (Hydro One's exemption application). The OEB approved $44M for power-distance correction work for specific distribution connected projects connected by Hydro One. About $7M of the $44M will be spent on required modifications to transmission assets. For example, in the case where a DG is relocated to a shorter feeder the cost of installing transfer trip and other protection modifications on the shorter feeder will be a Transmission cost incurred to mitigate power-distance limitations.

Additional details about these projects are provided in the Investment Summary Documents in Exhibit D2, Tab 2, Schedule 3.

3.7 Smart Grid

3.7.1 Description of Smart Grid Investments

The major portion of Hydro One's Smart Grid investments are on the development of the Advanced Distribution System (ADS). However, a portion of the investments are for the upgrading of the Protection and Control (P&C) systems in the Transmission Stations to make them capable of the necessary interactions with the intelligent devices on the distribution systems (Hydro One's or those of other LDC's) supplied from those stations.

The main objective of the Smart Grid transmission investments are to test the implementation and integration of new P&C technologies that are best suited to interfacing with, and supporting the functions planned for, ADS implementations. Hydro One Networks needs to establish standards that will support the ADS implementations of many distributors. Development Capital will provide the funding for work in the following key areas:

- Implement and evaluate a peer-to-peer, publisher-subscriber P&C architecture using IEC 61850 Standards at the Owen Sound TS. This architecture is ideally suited for interacting with intelligent devices located out across the distribution systems.
- Field pilot(s) to test new protection and control techniques including:
    1. improved and lower cost transfer trip signaling for generators
    2. voltage controller to coordinate the control of reactive power management devices inside the TS with those out on the distribution system. This is expected to be beneficial or required for distribution systems with large numbers of connected generators.

3. control of DG output to allow fullest possible use of feeder capacity for connecting generators.
4. automated switching for faster restoration through alternate paths where possible.

The consequences of not proceeding with this investment include:

- Inability to develop smart grid technologies that will allow the connection of distributed generation to be maximized as advocated through the Ontario Government's GEGEA;
- Insufficient testing and understanding of the IEC 61850 Standards for use to support ADS objectives. This testing and understanding is essential to driving the evolution of those standards in the direction required to enable low-cost ADS deployment. Furthermore, integrated testing, evaluation, and validation of various smart devices including communication interfaces are needed prior to major deployment.

The field pilots will also allow Hydro One to study and evaluate costs and benefits appropriate to a large rural electrical network.

3.7.2 Summary of Smart Grid Investments

The smart grid capital expenditures in 2013 and 2014 represent the costs associated with the Smart Zone Pilot only. Based on the findings from this pilot work, new programs may be created in the future. The Transmission Smart Grid pilot planned in 2013 and 2014 will evaluate the following functions:

1. New P&C architecture using IEC-61850 standards at Owen Sound TS ($1.3M total in 2013 and 2014)

2. Low cost transfer trip signaling to generators using licensed wireless technology from Owen Sound TS ($1.2M total in 2013 and 2014)
3. A controller at Owen Sound TS to manage power output from a group of DG's connected to a TS ($0.8M total in 2013 and 2014)
4. A TS voltage controller at Owen Sound TS that coordinates with voltage control devices out on the distribution system ($0.7M total in 2013 and 2014)

Funding levels for 2013 and 2014 for Smart Grid projects, along with the spending levels for the bridge and historic years are provided in Table 8 in Appendix A to this exhibit.

3.8 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:

3.8.1 <u>Performance Enhancement</u>

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 to customers 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 or when the reliability performance of the delivery point is worse than the historical baseline of a group of delivery points in the same load category (0-15MW, 15-40MW, 40-80MW and greater than 80 MW).

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 2013 and 2014 for Performance Enhancement projects, along with the spending levels for the bridge and historic years, are provided in Table 9 in Appendix A to this exhibit.

3.8.2 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 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. Two current examples of such projects to address reliability are the 115kV breaker upgrades at Hawthorne TS and Allanburg TS, projects D30 and D31 respectively. High short circuit levels have required interim operating measures to reduce the short circuit levels. These operating measures involve opening bus tie breakers and splitting the bus at the 115kV stations which substantially reduces the capability and the redundancy of these stations to supply their respective areas. Completing the breaker upgrades at Hawthorne TS and Allanburg TS will restore the reliability back to levels prior to the deployment of the interim measures.

Two other projects under this category to address equipment and safety risk are the addition of reactors at Basin TS and the high voltage breakers at Main TS, projects D32 and D33 respectively. These investments are required to address risk of damage to cables due to excessive temporary overvoltages in the 115kV downtown Toronto system.

Funding levels for 2013 and 2014 for Risk Mitigation projects, along with the spending levels for the bridge and historic years are provided in Table 10 in Appendix A to this exhibit. Additional details on those projects 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]	
						2009	2010	2011	2012	2013	2014				
D01	New 500 kV Bruce to Milton Double Circuit Transmission Line	Development, Non-Discretionary	Category 1	Completed	Completed	150.0	173.2	204.1	106.8	16.6	7.3	715.0	0.0	715.0	Q2 2012
D02	Installation of Shunt Capacitor Banks at Cherrywood TS Phase 1	Development, Non-Discretionary	Category 2	Not Required	Not Required	0.0	0.0	0.0	0.3	6.0	1.0	7.3	0.0	7.3	Q4 2014
D03	Installation of Shunt Capacitor Banks at Cherrywood TS Phase 2	Development, Non-Discretionary	Category 3	Not Required	Not Required	0.0	0.0	0.0	0.3	3.0	3.0	7.3	0.0	7.3	Q2 2015
D04	Clarington TS: Build new 500/230kV Station	Development, Non-Discretionary	Category 3	Required	Not Required	0.0	0.0	0.0	17.0	70.0	105.0	270.0	0.0	270.0	Q2 2015
D05	Installation of Static Var Compensator at Milton SS	Development, Non-Discretionary	Category 3	Required	Not Required	0.0	0.0	0.0	0.0	30.0	40.0	100.0	0.0	100.0	Q2 2015
D06	Reconductor the Lambton TS to Longwood TS 230kV Circuits	Development, Non-Discretionary	Category 4	Required	Required	0.0	0.1	1.6	1.5	17.0	18.0	40.0	0.0	40.0	Q4 2014
	Other Capital Projects (<$3M) with 2013-14 Cashflows[4]					0.0	0.0	0.1	5.9	13.2	10.6	744.0 [6]	0.0	744.0	
	Other Historical Projects (pre-2013)[5]					194.0	219.5	63.5	3.2	0.0	0.0	766.1	3.0	763.1	
	Total					**344.0**	**392.8**	**269.3**	**135.0**	**155.8**	**184.9**				

Notes

Note 1: **Gross Total Cost:** of the plan cost, including the sum of the cash flows in the years before 2013 and after 2014 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 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 2013 or 2014.
Note 5: 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 2013 or 2014.
Note 6: The Gross Total Cost consists of several major multi-year projects under consideration for beyond 2014, which have some minimal cashflow in 2013 and/or 2014 in order to perform preliminary studies and engineering.

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]	
						2009	2010	2011	2012	2013	2014				
D07	Toronto Area Station Upgrades for Short Circuit Capability: Leaside TS Equipment Uprate	Development, Non-Discretionary	Category 1	Not Required	Not Required	0.0	0.0	6.7	8.3	9.1	2.3	26.6	0.0	26.6	Q4 2013
D08	Toronto Area Station Upgrades for Short Circuit Capability: Manby TS Equipment Uprate	Development, Non-Discretionary	Category 1	Not Required	Not Required	0.0	0.1	0.2	2.7	12.5	2.0	17.5	0.0	17.5	Q4 2013
D09	Toronto Area Station Upgrades for Short Circuit Capability: Re-build Hearn SS	Development, Non-Discretionary	Category 1	Completed	Not Required	0.3	1.6	3.6	35.0	59.4	4.0	103.9	0.0	103.9	Q4 2013
D10	Midtown Transmission Reinforcement Plan	Development, Non-Discretionary	Category 1	Completed	Completed	0.9	2.7	13.1	51.9	26.7	19.2	114.8	46.2	68.6	Q3 2014
D11	Preston TS Transformation	Development, Non-Discretionary	Category 3	Not Required	Not Required	0.0	0.0	0.0	0.0	0.0	6.0	20.0	0.0	20.0	Q2 2016
D12	Guelph Area Transmission Reinforcement	Development, Non-Discretionary	Category 4	Required	Required	0.2	0.4	0.1	1.0	3.0	20.0	65.0	0.0	65.0	Q2 2016
	Other Capital Projects (<$3M) with 2013-14 Cashflows[4]					2.5	21.8	18.3	29.7	7.1	7.7	384.3[6]	5.3	379.0	
	Other Historical Projects (pre-2013)[5]					89.8	32.2	22.0	13.0	0.0	0.0	364.3	15.6	348.7	
	Total					**93.7**	**58.8**	**64.0**	**141.6**	**117.8**	**61.2**				

Notes

Note 1: **Gross Total Cost:** of the plan cost, including the sum of the cash flows in the years before 2013 and after 2014 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 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 2013 or 2014.
Note 5: 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 2013 or 2014.
Note 6: The Gross Total Cost consists of several major multi-year projects under consideration for beyond 2014, which have some minimal cashflow in 2013 and/or 2014 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]	
						2009	2010	2011	2012	2013	2014				
D13	Tremaine TS: Build New Transformer Station	Development, Non-Discretionary	Category 1	Completed	Not Required	0.3	0.9	3.6	22.2	3.3	0.0	30.5	11.7	18.8	Q1 2013
D14	Barwick TS: Build new Transformer Station	Development, Non-Discretionary	Category 1	Completed	Not Required	0.4	0.4	2.6	13.3	7.1	0.0	23.8	0.0	23.8	Q4 2013
D15	Nebo TS: Increase Capacity of 230/27.6kV DESN	Development, Non-Discretionary	Category 2	Not Required	Not Required	0.0	0.0	0.2	7.0	12.0	0.0	19.2	9.2	10.0	Q4 2013
D16	Orleans TS: Build new Transformer Station	Development, Non-Discretionary	Category 2	Not Required	Not Required	0.0	0.0	0.1	7.1	7.3	19.0	33.4	20.2	13.2	Q2 2014
D17	Bremner TS: Build Line Connection for Toronto Hydro	Development, Non-Discretionary	Category 2	Completed	Not Required	0.0	0.0	0.2	2.6	20.2	37.0	60.0	60.0	0.0	Q4 2014
D18	Chalk River CTS: Build 115kV Switching Facilities and connect new Customer Station	Development, Non-Discretionary	Category 2	Not Required	Not Required	0.0	0.0	0.0	1.0	4.0	5.0	10.0	10.0	0.0	Q2 2014
D19	Nelson TS: Replace T1/T2 DESN with new DESN	Development, Non-Discretionary	Category 2	Not Required	Not Required	0.0	0.0	0.3	2.0	12.0	15.5	29.8	14.8	15.0	Q4 2014
	Other Capital Projects (<$3M) with 2013-14 Cashflows[4]					0.9	1.0	11.5	23.8	20.0	18.9	369.7 [6]	143.4	226.3	
	Other Historical Projects (pre-2013)[5]					69.2	42.3	49.6	42.6	0.0	0.0	327.0	63.7	263.3	
	Total					**70.8**	**44.6**	**68.1**	**121.6**	**85.9**	**95.4**				

Notes

Note 1: **Gross Total Cost:** of the plan cost, including the sum of the cash flows in the years before 2013 and after 2014 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 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 2013 or 2014.
Note 5: 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 2013 or 2014.
Note 6: The Gross Total Cost consists of several major multi-year projects under consideration for beyond 2014, which have some minimal cashflow in 2013 and/or 2014 in order to perform preliminary studies and engineering.

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) Historical 2009	Historical 2010	Historical 2011	Bridge 2012	Test 2013	Test 2014	Gross Total Cost[1]	Capital Contribution[2]	Net Total Cost[3]	In-Service Years
D20	Samsung South Kent Wind Farm (270 MW) (Formerly Chatham Wind Generation Connection)	Development, Non-Discretionary	Category 2	Not Required	Not Required	0.0	0.0	0.2	6.5	4.1	0.0	10.7	10.7	0.0	Q2 2013
D21	Lower Mattagami Generation Connections	Development, Non-Discretionary	Category 2	Completed	Completed	0.1	0.1	0.8	11.1	15.9	2.4	30.9	29.3	1.7	Q4 2013
D22	Niagara Region Wind Corporation Generation Connection (230 MW)	Development, Non-Discretionary	Category 2	Required	Not Required	0.0	0.0	0.0	1.0	25.0	25.0	51.0	51.0	0.0	Q2 2014
D23	Armow Wind Generation Connection (180 MW)	Development, Non-Discretionary	Category 2	Required	Not Required	0.0	0.0	0.0	2.0	1.0	22.0	25.0	3.0	22.0	Q2 2014
D24	K2 Wind Generator Connection (270 MW)	Development, Non-Discretionary	Category 2	Required	Not Required	0.0	0.0	0.0	10.0	20.0	25.0	55.0	55.0	0.0	Q4 2014
D25	Adelaide/Bornish/Jericho Wind Energy Centres (284 MW)	Development, Non-Discretionary	Category 2	Required	Not Required	0.0	0.0	0.0	10.0	25.0	20.0	55.0	55.0	0.0	Q4 2014
	Provision for Unforeseen Projects	Development, Non-Discretionary	Category 2	Required	Not Required	0.0	0.0	0.0	2.0	10.0	10.0	56.0	56.0	0.0	
	Other Capital Projects (<$3M) with 2013-14 Cashflows[4]					0.0	0.0	0.4	14.7	43.5	26.1	90.9	90.6	0.3	
	Other Historical Projects (pre-2013)[5]					9.6	6.9	9.9	3.2	0.0	1.0	135.5	61.2	74.3	
	Total					**9.7**	**7.0**	**11.3**	**60.5**	**144.5**	**131.5**				

Notes

Note 1: **Gross Total Cost:** of the plan cost, including the sum of the cash flows in the years before 2013 and after 2014 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 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 2013 or 2014.
Note 5: 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 2013 or 2014.

Table 6
Protection and Control Modifications for Enablement of Distribution Connected Generation
Summary of Development Capital Projects in Excess of $3 Million

Item #	Investment Description	Classification as per OEB Filing Guideline	Cash Flow ($ Millions)					
			Historical			Bridge	Test	Test
			2009	2010	2011	2012	2013	2014
D26	Transfer Trip Signaling Enhancement	Development Non-Discretionary	0	0	0	2.0	5.0	8.0
D27	Transmission Station P&C Upgrades for DG	Development Non-Discretionary	2.4	6.1	12.1	37.6	18.5	20.5
	Other Capital Projects (<$3M) With 2013-14 Cashflows[4]		0	0	0	0	0	0
	Other Historical Projects (pre-2013)[5]		0.9	0.3	2.0	0.0	0.0	0.0
	Total Gross Capital		**3.3**	**6.4**	**14.1**	**39.6**	**23.5**	**28.5**
	Capital Contributions		*2.4*	*4.2*	*11.1*	*39.6*	*23.5*	*28.5*
	Total Net Capital		**0.9**	**2.1**	**3.1**	**0.0**	**0.0**	**0.0**

Notes

Note 4: 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 2013 or 2014.
Note 5: 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 2013 or 2014.

Table 7
Protection and Control Modifications for Consequences of Connected Distribution Generation
Summary of Development Capital Projects in Excess of $3 Million

Item #	Investment Description	Classification as per OEB Filing Guideline	Cash Flow ($ Millions)					
			Historical			Bridge	Test	Test
			2009	2010	2011	2012	2013	2014
D28	Transmission Work to Mitigate Distance Limitation	Development Non-Discretionary	0	0	0	1.2	2.8	3.0
D29	UFLS and Load Rejection Modification	Development Non-Discretionary	0	0	0	0.0	0.0	5.0
	Other Capital Projects (<$3M) With 2013-14 Cashflows[4]		0	0	0	0.2	0.0	3.0
	Other Historical Projects (pre-2013)[5]		0	0	0	0.0	0.0	0.0
	Total Gross Capital		**0**	**0**	**0**	**1.4**	**2.8**	**11.0**
	Capital Contributions		*0*	*0*	*0*	*0*	*0*	*0*
	Total Net Capital		**0**	**0**	**0**	**1.4**	**2.8**	**11.0**

Notes

Note 4: 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 2013 or 2014.
Note 5: 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 2013 or 2014.

Table 8
Smart Grid: Summary of Development Capital Programs

Item #	Investment Description	Classification as per OEB Filing Guideline	Gross Cash Flow ($ Millions)					
			Historical			Bridge	Test	Test
			2009	2010	2011	2012	2013	2014
	Smart Grid	Development Non-Discretionary	0.0	0.0	5.8	7.0	2.0	2.0
	Total		**0.0**	**0.0**	**5.8**	**7.0**	**2.0**	**2.0**

Table 9
Performance Enhancement: Summary of Development Capital Programs

Item #	Investment Description	Classification as per OEB Filing Guideline	Gross Cash Flow ($ Millions)					
			Historical			Bridge	Test	Test
			2009	2010	2011	2012	2013	2014
	Various lines and TSs outliers-inliers	Development Non-Discretionary	2.2	1.4	1.2	5.3	2.5	2.5
	Total		**2.2**	**1.4**	**1.2**	**5.3**	**2.5**	**2.5**

Table 10
Risk Mitigation: Summary of Development Capital Programs

Item #	Investment Description	Classification as per OEB Filing Guideline	Gross Cash Flow ($ Millions)						In-Service Years
			Historical			Bridge	Test	Test	
			2009	2010	2011	2012	2013	2014	
D30	Hawthorne TS: Uprate Short Circuit Capability	Development, Non-Discretionary	0.0	0.0	0.2	5.1	5.6	1.0	Q4 2013
D31	Allanburg TS: Uprate Short Circuit Capability	Development, Non-Discretionary	0.0	0.0	1.9	10.3	4.8	2.0	Q4 2013
D32	Basin TS: Add Reactors	Development, Non-Discretionary	0.0	0.0	0.0	2.0	4.0	0.0	Q4 2013
D33	Main TS: Add Breakers	Development, Non-Discretionary	0.0	0.0	0.0	2.0	4.7	0.0	Q4 2013
	Other Capital Projects (<$3M) With 2013-14 Cashflows[4]		0.0	0.0	0.2	1.9	4.8	4.8	
	Other Historical Projects (pre-2013)[5]		17.0	18.7	15.6	3.0	0.0	0.0	
	Total		**17.0**	**18.7**	**17.9**	**24.3**	**23.9**	**7.8**	

Notes

Note 4: 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 2013 or 2014.
Note 5: 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 2013 or 2014.

Description of Need and Rationale for "Oshawa Area" TS by 2015

1 Summary and Purpose

Pickering Generation Station ("GS") is a critical local generation source for reliable supply of the eastern part of the Greater Toronto Area (East GTA), providing about 3,100 MW of capacity to the local area. A significant source of new transmission or generation capacity will be required to maintain reliable supply to electricity users in East GTA when Pickering GS retires.

Ontario Power Generation Inc. ("OPG"), who owns and operates Pickering GS, is considering extending the life of the nuclear station to 2020 however, there is a possibility it could be completely out of service by early 2015. The reliability consequence of Pickering GS retiring by 2015, without a new source of capacity in place, is the loss of about 750 MW of load within the East GTA, following a single contingency event. This level of load loss for a single contingency event is 5 times higher than the current planning criteria allows for planning transmission facilities in Ontario.

Installation of a new 500-230 kV Transformer Station ("TS") called "Oshawa Area" TS is the only feasible solution to address retirement of Pickering GS and to mitigate the risk of early retirement. The solution was also outlined in the Ontario Power Authority ("OPA") - 2011 IPSP Planning and Consultation Overview document dated May 2011 (pages 5-11)

http://www.powerauthority.on.ca/sites/default/files/page/IPSP%20Planning%20and%20Consultation%20Overview.pdf as well as in the Transmission Planning component of the IPSP 2011 Stakeholder Consultation Presentation (slides 38 and 39) http://www.powerauthority.on.ca/sites/default/files/page/Transmission%20Presentation.pdf.

"Oshawa Area" TS also includes new switching facilities that provide improved load restoration capabilities to the Pickering, Ajax, Oshawa and Clarington areas. Existing supply facilities serving these areas are not capable of meeting existing load restoration requirements specified within the Ontario Resources and Transmission Assessment Criteria ("ORTAC") document issued by the Independent Electricity System Operator ("IESO"). "Oshawa Area" TS would enable meeting the requirements specified in ORTAC.

Since there is some risk of inadequate supply by as early as 2015, the OPA believes that it is prudent to prepare for implementing "Oshawa Area" TS by the 2015 date for the following reasons:

1. The consequence of not being prepared would expose customers in the eastern portion of the GTA to an unacceptable level of risk to reliability by 2015 (exposure to about 750 MW of load rejection for a single contingency event).
2. Transmission facilities currently serving the Pickering, Ajax, Oshawa and Clarington areas are not currently capable of meeting load restoration criteria specified in ORTAC. "Oshawa Area" TS provides facilities which rectify this situation.

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3. "Oshawa Area" TS is also the recommended solution for the scenario where the operation of Pickering GS is extended to 2020. The cost impact of installing "Oshawa Area" TS in 2015 as opposed to installing the station in 2020 is $60 million. It is necessary to make expenditures now to mitigate the reliability risks mentioned above given that a decision on the retirement date of Pickering GS is still forthcoming.

To provide for the timely implementation of this recommended solution the OPA has requested that Hydro One develop a flexible implementation plan. This implementation plan should be designed to ensure that the 2015 in service date can be met to mitigate the risk to reliability should Pickering retire in 2015, while at the same time providing appropriate technical and commercial off-ramps, to minimize cost exposure should it be confirmed by OPG that at least 2 units will be available at Pickering beyond the 2015 date and there is an opportunity to defer some expenditures for this project. Two letters from the OPA to Hydro One on this subject are attached in Appendix 1.

The purpose of this document is to update the analysis that considered viable alternatives and provide the rationale for the recommended solution to address the retirement of Pickering GS.

2 System Needs

2.1 Supply sources for East GTA 230 kV system

Pickering GS, which includes six units with total output capacity of 3,100 MW, is a critical local generation source for supplying East GTA. Pickering GS reduces the required power transfers from the 500 kV bulk transmission system through the 500-230 kV autotransformers at Cherrywood TS (with four autotransformers) and Parkway TS (with two autotransformers).

Information received from Ontario Power Generation Inc., who owns and operates Pickering GS, indicates that there is a possibility that Pickering GS could be shut down completely by early 2015. OPG is considering options to extend the operating life of Pickering GS to the year 2020. The extended operation is not a certainty as it is dependent on the successful outcome of studies to confirm the technical feasibility and obtaining the necessary approvals. The results of these studies and receipt of approvals are not expected to be known before the latter part of this year or possibly next year.

System studies performed for the Ontario Power Authority by the IESO indicated that a minimum of two Pickering units are required to be in service to maintain reliable supply for the area during peak load periods. The existing six 500-230 kV autotransformers at Cherrywood TS and Parkway TS would not have sufficient capacity to supply the load in East GTA reliably with less than two Pickering GS units in operation.

The studies further indicated that, with no Pickering units in-service, loss of one of the four 500-230 kV autotransformers at Cherrywood TS would result in a serious overload on one of the three remaining autotransformers at Cherrywood TS. Load interruptions of about 750 MW would be required to reduce

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the loading on the overloaded transformer to be within its equipment rating. This level of load loss is five times higher than the current planning criteria allows for planning transmission facilities in Ontario.

Given the above circumstances, OPA believes that there is a possibility that the electricity users in East GTA cannot be supplied reliably in 2015. A solution is therefore required to mitigate this risk.

Even if the operating life of Pickering GS is extended, the solution to address Cherrywood TS 500-230 kV autotransformer overloads is required by no later than year 2020 when Pickering GS would be retired. In addition to the above mentioned need, Pickering GS also provides approximately 1,000 MVar of reactive power to support the East GTA area system voltages. In the absence of Pickering GS, an alternate source for this reactive power would also be required.

2.2 Supply Reliability Needs of Pickering, Ajax, Oshawa and Clarington Areas

The 230 kV step-down stations supplying Local Distribution Company loads east of Cherrywood TS (in Pickering, Ajax, Oshawa and Clarington areas) are supplied by long 230 kV circuits emanating eastward from Cherrywood TS. The total load supplied in this area is forecast to be about 750 MW with about 300 MW supplied by H24C and H26C circuits and about 450 MW supplied by M29C and B23C circuits. These circuits are on a four circuit transmission line. The terminal stations to the east are far from the area, as shown in Figure 1 below.

In the event of a permanent fault affecting either of these pair of circuits, it would not be possible to supply load from the eastern end of these circuits due to the long distance involved. The existing transmission facilities supplying the loads in this area are inadequate for the purpose of meeting the IESO's load restoration criteria under ORTAC. New transmission or generation facilities are required to provide the required reliable supply.

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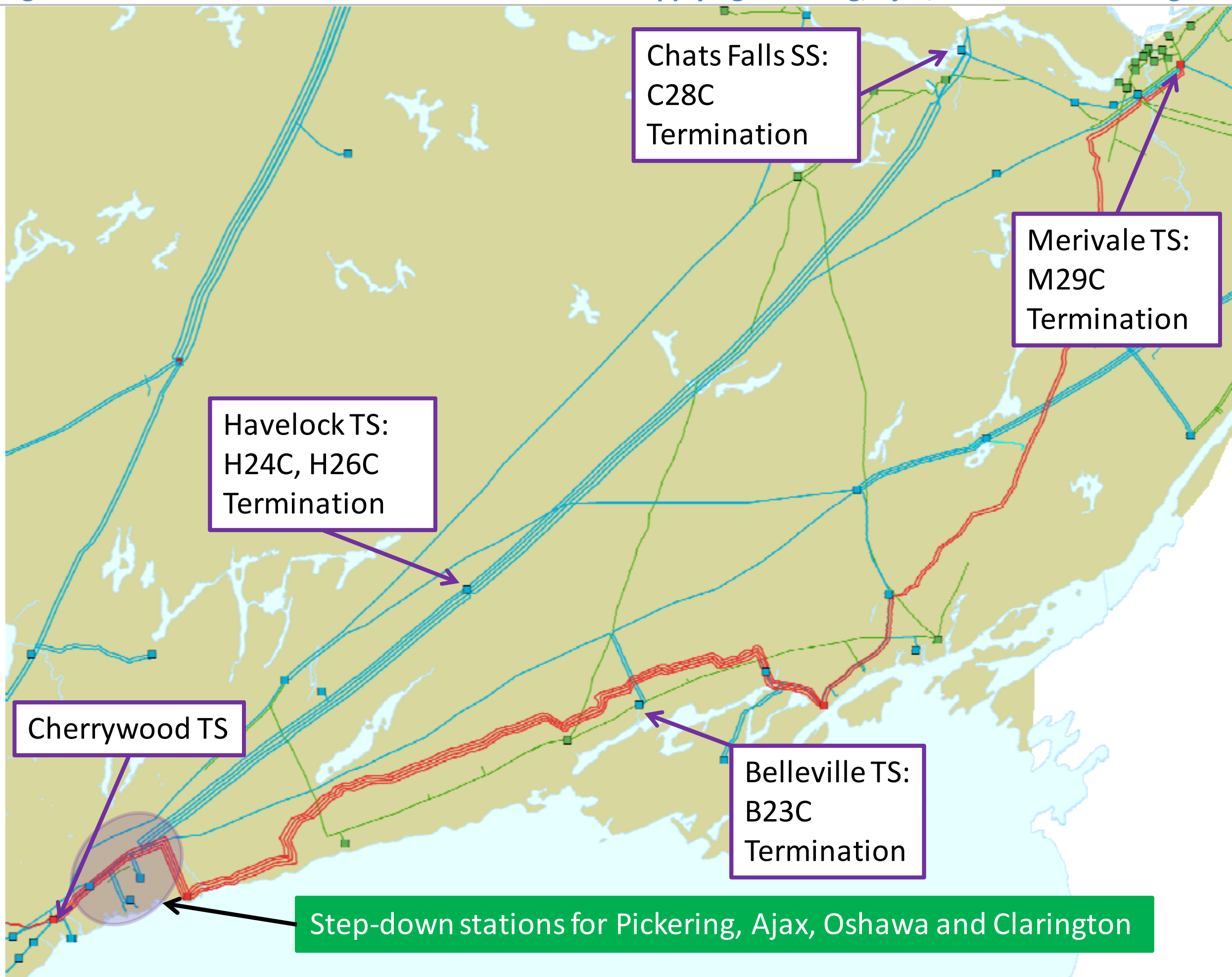
Figure 1: Terminal stations for transmission circuits supplying Pickering, Ajax, Oshawa and Clarington



Source: OPA

2.3 New Generation at Darlington

Ontario's Long-Term Energy Plan indicates that new nuclear generation totalling up to 2,000 MW at Darlington will be needed by the early 2020's. Therefore, any alternatives that would meet the above mentioned needs must also be compatible with the facilities required for the incorporation of new nuclear units at Darlington GS. Previous system studies indicated that a new double circuit 500 kV transmission line between Darlington GS and Cherrywood TS would be required for the incorporation of new nuclear units at Darlington.

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3 Alternative Solutions

3.1 Generation Alternatives

Installing new generation totaling 1,000 MW close to Cherrywood TS would be necessary to meet the required supply reliability in East GTA. The planning criteria within ORTAC requires that this 1,000 MW be comprised of at least two generating units (500 MW each), or a number of smaller units within the area. This multiple generating unit requirement provides the diversity needed to ensure supply reliability. To meet the need, these generation facilities are required to be installed prior to spring 2015, to address the early retirement of Pickering GS. There has been interest for generation projects in the area through the OPA's - Combined Heat & Power ("CHP") procurement program. However, the total amount of interest is about 300 MW and it is not sufficient to meet the need even if they could be installed by March 2015. The OPA has other generation procurement programs such as FIT, microFIT and CESOP with interest in the area, but the total amount would not be sufficient to meet the need, even when combined with the CHP interest.

Given that it will take longer than the 2015 need date to incorporate a sufficient amount of new generation in this area, the generation option has been determined to be infeasible.

3.2 Transmission Alternatives

<u>Alternative 1: "Oshawa Area" 500-230 kV TS (the recommended solution)</u>

Hydro One owns a property at the border of Oshawa and Clarington, north of Winchester Road / Concession 7 between Grandview Street and Enfield Road. This is a location where the 500 kV lines and the 230 kV lines in the area converge, and it has been planned for installation of 500-230 kV autotransformers and switching facilities for the long 230 kV circuits in the area. Figure 2 below shows the location of "Oshawa Area" TS. The following is a high level description of this alternative.

At "Oshawa Area" TS install:

- Two 500-230 kV, 750 MVA auto-transformers each connecting to one of the four 500 kV Bowmanville to Cherrywood circuits using 500 kV circuit breakers;
- Switching facilities for the existing five long 230 kV circuits emanating east from Cherrywood TS; and
- Two 230 kV - 150 MVAR shunt capacitor bank.

At Cherrywood TS install:

- Two 230 kV - 300 MVAR shunt capacitor banks.

This option would meet the 500-230 kV autotransformer capacity and reactive power requirements outlined in Section 2.1, as well as the regional supply reliability needs of the area.

In addition to meeting the required needs, this alternative provides the following additional benefits:

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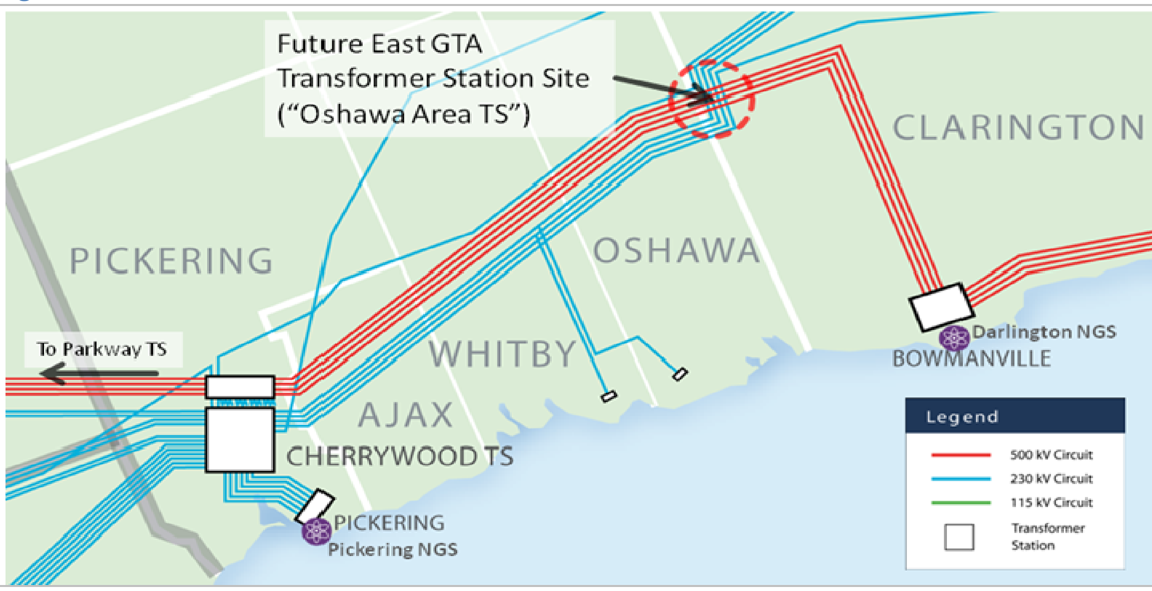
- The new transformer station would provide a new load supply point in an area where growth is expected. This would reduce the reliance on Cherrywood TS as the only major supply source for the East GTA.
- A new 500 kV double circuit line from Bowmanville SS (Darlington) west ward towards the GTA is expected to be required for incorporation of Darlington B units. The “Oshawa Area” TS would obviate the need for a 27 km line section between Cherrywood TS and “Oshawa Area” TS. In addition, two circuits from the new 500 kV line between Bowmanville SS and “Oshawa Area” TS would not require additional 500 kV circuit breakers at “Oshawa Area” TS, whereas additional 500 kV breakers would be needed if these lines terminated at Cherrywood TS.

Figure 2: Oshawa Area TS



Source: OPA

<u>Alternative 2: Expand Cherrywood TS</u>

There are four 500-230 kV autotransformers at Cherrywood TS, which are connected to two separate 230 kV switchyards. These two switchyards are not interconnected due to the fact that this connection arrangement would exceed the short circuit levels of the major equipment. Studies conducted by the IESO, at the OPA’s request, have confirmed that, given this connection arrangement, installing two additional 500-230 kV autotransformers at Cherrywood does not help to alleviate the potential overload situation under the criteria specified within ORTAC. The IESO studies indicate that the two switchyards would need to be interconnected to be effective. Since the interconnection of the 230 kV switchyards would result in short circuit levels beyond the capabilities of the existing 230 kV breakers, even when all Pickering units are retired, this option is considered infeasible. The short circuit level would also be higher than the capability of new 230 kV breakers even if the existing breakers could be replaced in time.

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In addition, the above facilities also do not address the regional supply reliability needs of Pickering, Ajax, Oshawa and Clarington areas, outlined in Section 2.2. Four new transmissions circuits extending east from Cherrywood TS would still be required to address the area supply reliability needs.

<u>Alternative 3: Expand Parkway TS</u>

Parkway 500-230 kV TS is located west of Cherrywood TS. There are currently two 500-230 kV autotransformers at Parkway TS. IESO studies, conducted at the request of the OPA, have confirmed that installing two additional 500-230 kV autotransformers at Parkway TS would not provide sufficient reduction on the autotransformers at Cherrywood TS. Options were investigated to determine if another solution could be found for reducing the loading on the Cherrywood 500-230 kV autotransformers, given the significant impact (the loss of 3,100 MW of local generation within the East GTA) when Pickering retires. It was found that the installation of four new 230 kV circuits connecting Parkway TS to the existing 230 kV circuits between Richview TS and Cherrywood TS, on the Finch transmission corridor, would be necessary to achieve the required loading relief on the 500-230 kV autotransformers at Cherrywood TS.

This alternative was determined to be infeasible from an implementation perspective for the following reasons:

- The area where the four 230 kV circuits connections are to be located has been fully developed for a number of years, as shown in Figure 3. It would be very difficult to obtain a new right of way or expand the existing right of way for the four new 230 kV circuits. There is a significant risk of not being able to obtain the necessary right of way in a timely manner.
- IESO studies indicate the improvement in the supply capability provided by this alternative is significantly inferior to that from "Oshawa Area" TS.

In addition, the above facilities also do not address the regional supply reliability needs of Pickering, Ajax, Oshawa and Clarington areas, outlined in Section 2.2. Four new transmission circuits extending east from Cherrywood TS would still be required to address the area supply reliability needs.

Therefore, this option is not considered further.

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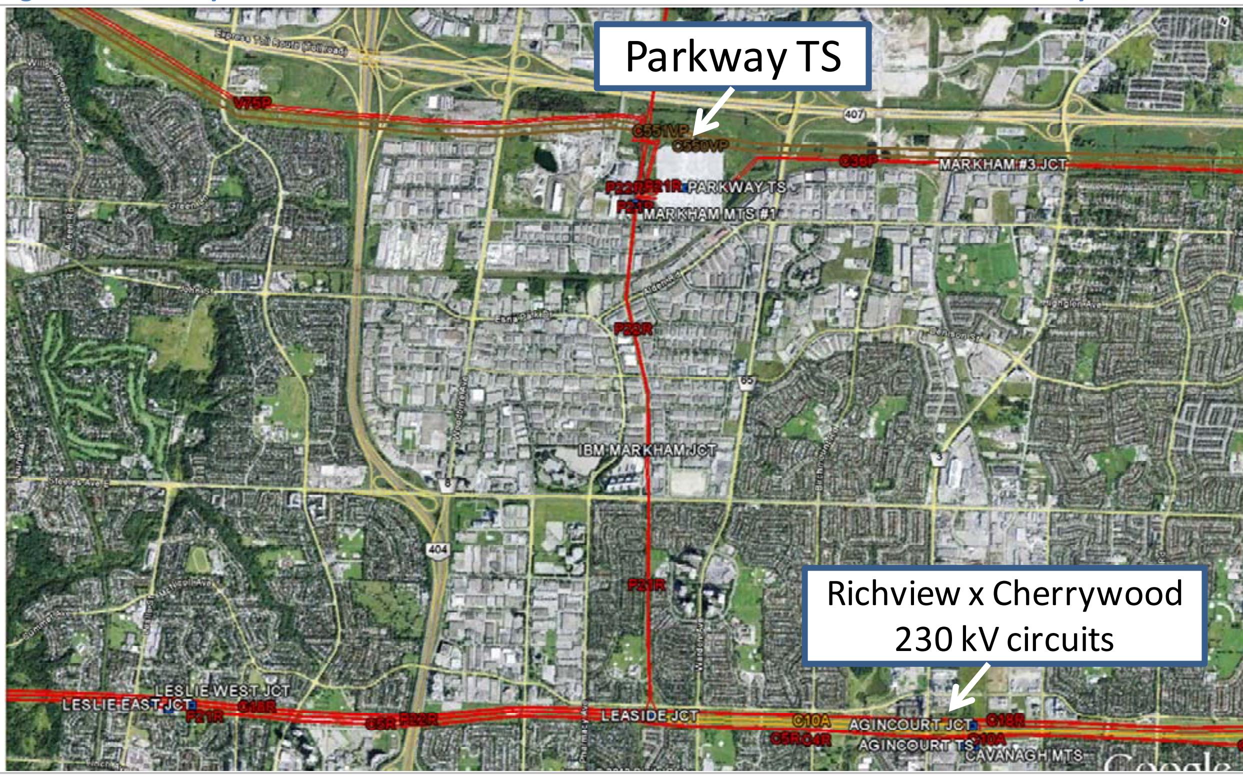
Figure 3: Parkway TS and Finch 230 kV transmission line between Richview TS and Cherrywood TS



Source: OPA

4 Conclusion

The transmission Alternative 1 (installation of “Oshawa Area” 500-230 kV TS) is the recommended alternative because it is the only alternative that meets all of the identified needs and can be implemented in time to address the risk of early retirement of Pickering GS. Implementation of “Oshawa Area” TS by 2015 represents an advancement of the project which would be required by 2020 assuming OPG is successful in extending the life Pickering GS.

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October 3, 2011

Mr. Carmine Marcello
Executive Vice President, Strategy
Hydro One Networks Inc.
483 Bay Street
Toronto, ON
M5G 2C9

Dear Carmine:

Need for an implementation plan to incorporate additional 500-230 kV auto-transformation capacity in the east GTA by spring of 2015 given risk of early retirement of Pickering GS

Summary

The purpose of this letter is to recommend that Hydro One develop an implementation plan and initiate the necessary work for installing additional 500-230 kV autotransformer capacity within the east GTA by the spring of 2015. The implementation plan should be designed to provide sufficient flexibility to meet the possible need date of 2015, while minimizing costs to rate payers should a decision be made in 2012 to extend the life of Pickering GS beyond the spring of 2015. Extending the life of at least 2 generating units at Pickering beyond 2015 delays the need for the additional autotransformer capacity in the east GTA, for as long as the 2 generating units are available.

The preferred location for these transformation facilities is at a new 500-230 kV autotransformer station provisionally named "Oshawa Area" TS located on a property owned by Hydro One. The property is located at the border of Oshawa and Clarington, north of Winchester Road / Concession 7 between Grandview Street and Enfield Road. The need and timing for "Oshawa Area TS" was publically communicated during the IPSP - 2011 stakeholder consultation session conducted on May 31, 2011 (reference slides 38 to 41 of May 31, 2011 stakeholder presentation). No stakeholder comments were received on the information communicated.

Rationale

An implementation plan to incorporate additional autotransformer capacity within the east GTA is required because Pickering GS could be completely out of service by as early as the spring of 2015. Under this scenario, technical studies performed by the OPA and IESO indicate that the 500-230 kV autotransformers at Cherrywood TS would not have sufficient capacity to reliably supply load in the east GTA.

Ontario Power Generation Inc. (OPGI) is exploring extended operation of Pickering GS to 2020. However, the extended operation is not a certainty since it depends on the outcome of studies to confirm the technical feasibility as well as the conclusion of related commercial agreements and the receipt of required regulatory approvals. The results of these investigations are not expected to be known until sometime in 2012. Given the material impact to the reliable supply to the east GTA under the scenario of no generating units at Pickering GS and the lead time for incorporating 500-230 kV autotransformers at "Oshawa Area TS" the OPA considers it prudent for Hydro One to:

1. Develop an implementation plan to install "Oshawa Area" TS by the spring of 2015, with consideration for the decisions surrounding extended operation of Pickering GS and their timing.

2. Work with the OPA and the IESO to develop stop gap measures, such as installing additional 500-230kV autotransformation capacity at either Cherrywood TS or Parkway TS, should Hydro One's implementation planning work indicate that providing facilities at "Oshawa Area" TS has a significant risk of being delayed beyond spring 2015.

The implementation plan should be designed to provide sufficient flexibility to meet the possible need date of 2015, while minimizing costs to rate payers should a decision be made in 2012 to extend the life of Pickering GS to the year 2020. The OPA will continue working with Hydro One to achieve this balance by providing input on the minimum facilities required at the station in the near term. Hydro One should also utilize other risk mitigation techniques to minimize near terms costs, such as the use of technical and commercial off ramps, where they are deemed to be appropriate.

Background

Pickering GS, with two A units and four B units connected to the 230 kV system, provides critical local generation for reliable supply of the east GTA. System studies indicate that either a minimum of two Pickering units are required in service or additional autotransformer capacity in the east GTA is needed to maintain reliable supply for the area.

There are scenarios where Pickering GS is shut down as early as by the spring 2015. Since such scenarios have material impact to the reliable supply to east GTA, the OPA considers it prudent for Hydro One to begin work that will provide the 500 - 230 kV autotransformer capacity within the east GTA, to meet the spring 2015 need date.

Current information indicates that Pickering GS is not expected to operate beyond 2020 under the extended operation scenarios. Thus, the new autotransformer capacity is expected to be required by 2020 in any case.

The OPA will keep Hydro One apprised of the status of decisions related to the operating schedule of generating units at the Pickering GS which could have impact on the 2015 need date for additional 500-230 kV transformation capacity in the area.

Specifics of the Preferred Solution

The preferred solution to relieve the 500-230 kV Cherrywood autotransformers was outlined within the first Integrated Power System Plan (EB-2007-0707) in Exhibit E Tab 4 Schedule 1, which is attached for convenience. This solution remains valid and is composed of establishing a new 500-230 kV station within the east GTA, at the site known as "Oshawa Area TS". An alternative to install two additional transformers are Cherrywood TS instead of "Oshawa Area TS" was determined technically infeasible due to short circuit capability limits of existing 230 kV equipment.

The need and timing for "Oshawa Area TS" was publicly communicated during the IPSP - 2011 stakeholder consultation session conducted on May 31, 2011.

Installation of "Oshawa Area TS", which includes 500-230 kV transformation facilities, provides the required relief to the Cherrywood TS 500-230 kV auto-transformers and a new supply point in an area that is experiencing significant growth. This new bulk system station would also improve supply reliability to the area by providing a new switching point for several long 230 kV circuits emanating east from Cherrywood TS. The new bulk station also reduces the reliance on Cherrywood TS, which is currently the only major supply source for the east GTA.

The OPA is working with the IESO to refine the station facility requirements, including reactive compensation needs, and will provide further details as soon as they become available.

Conclusion

Given the information currently available on the status of the units at Pickering GS and the need to ensure reliable service in the east GTA, the OPA believes that it is prudent for Hydro One to develop an implementation plan and initiate the work necessary to ensure "Oshawa Area" TS can be available by the spring of 2015. The implementation plan should provide flexibility, where possible, to minimize costs should the life extension of Pickering GS proceed.

The OPA recognizes that the timelines to build Oshawa Area TS are challenging and will work with Hydro One and the IESO to establish a staged approach where feasible for providing the minimum facilities needed to mitigate the near-term risk, while minimizing costs.

The OPA is prepared to provide evidence in support of the need, rationale and prudence associated with this request. Please feel free to contact us should you require any clarification or additional information.

Yours truly,

Amir Shalaby
Vice-President, Power System Planning
Ontario Power Authority

cc. Kim Warren, the IESO

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January 11, 2012

Mr. Carmine Marcello
Executive Vice President, Strategy
Hydro One Networks Inc.
483 Bay Street
Toronto, Ontario, M5G 2C9

Dear Carmine:

Update on the need for "Oshawa Area" TS to address potential early retirement of Pickering GS

This is further to our letter of October 3, 2011 outlining the need for Hydro One Networks to develop an implementation plan to incorporate additional 500-230 kV auto-transformation capacity at "Oshawa Area" TS by the spring of 2015.

Based on our discussions at the Hydro One - Transmission Steering Committee meeting of November 23, 2011 and recent work that has been completed by the OPA working with Hydro One Networks, the Independent Electricity System Operator (IESO) and ongoing discussions with Ontario Power Generation (OPG), the following is a summary of the status of key factors related to the subject project:

- Pickering GS has a license that allows it to operate only until March 2015. The current outlook for the number of in-service units at Pickering is 6 currently, 5 after May 2014, 4 after November 2014 and none after March 2015. Thus, if this outlook holds, by spring of 2015, additional 500-230 kV auto-transformation capacity would be required. There is work underway that explores the possibility that the plant can continue to operate until mid 2019, and there are significant technical, economic and regulatory issues yet to be concluded before this can be counted on. This letter is to prepare the system for a March 2015 end of life in case that becomes the outcome.

- An assessment has been made to "manage" the life of the last 4 units at Pickering GS for an additional 14 months beyond the end of life date. Although economic assessments conducted by the OPA show this to be economically viable if the life were continued to 2019, at this point they do not support this option for a 2015 end of life date. The OPA assessment results for the 2015 end of life date hold true even with the potential deferral of the additional 500-230 kV auto-transformer capacity required in the area, taken into account.

- OPA continues to work with OPG to pursue a number of proposals around Pickering. The merits of the options depend on a large number of factors that are subject to change. This work is done in a broader context of integrated planning.

- OPA understands that, barring any major unforeseen approvals issues, Hydro One is capable of meeting a spring 2015 in service date for "Oshawa Area" TS, as outlined in the attached single line diagram.

- OPA also understands that to meet a spring 2015 in-service date, Hydro One may need to incur or commit substantive expenditures in the 2012 - 2013 period, which the company will seek to recover in an appropriate regulatory proceeding. Hydro One will check with OPA on status and outlook before major expenditures are made.

- Joint studies with Hydro One Networks, the IESO and the OPA confirm that stop gap measures such as adding 500-230 kV autotransformers at Cherrywood TS or Parkway TS are of limited effectiveness and need not be pursued further. The effective option is Oshawa Area TS.

In light of these circumstances, the OPA recommends that Hydro One continue to work toward the objective of incorporating additional 500 / 230 kV auto-transformation capacity at "Oshawa Area" TS for a spring 2015 in service date.

Going forward, the OPA also recommends the following actions:

- OPA will make Hydro One aware of changes that it believes will affect the need date for "Oshawa Area" TS, as soon as the information becomes available.

- Hydro One will inform OPA before any major expenditure is undertaken, so that the expenditure decision can be assessed with the best information available at that time.

- OPA will provide the necessary evidence to support the need, scope and timing for the Oshawa Area TS project.

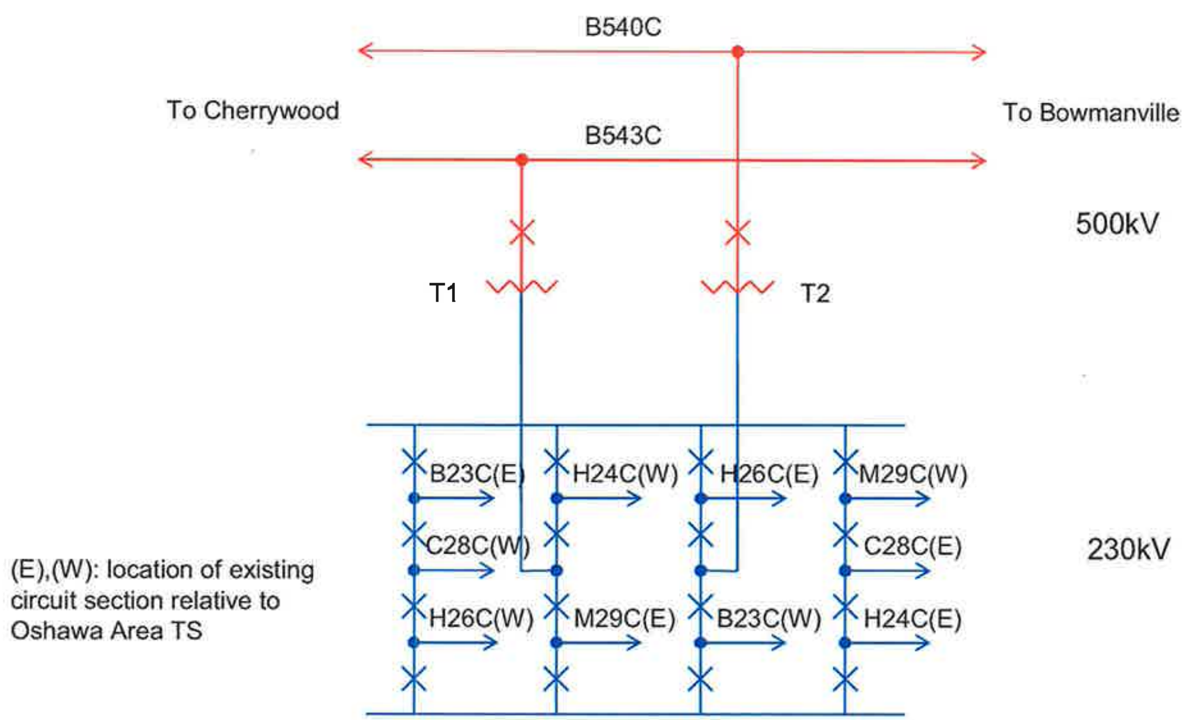
The above process will ensure the best available information is factored into decisions affecting costs to Ontario rate payers, while addressing the reliability risk to electricity users from potential early retirement of Pickering GS

I look forward to continuing our effective working relationship on this project.

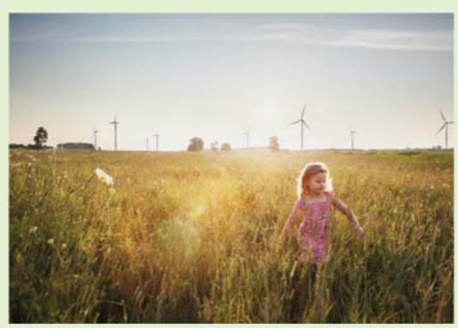
Yours truly,

Amir Shalaby
Vice-President, Power System Planning
Ontario Power Authority

cc: Kim Warren, Independent Electricity System Operator



"Oshawa Area" TS: Single line diagram



Southwestern Ontario

Reactive Compensation Milton SVC

March, 2012

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Southwestern Ontario Reactive Compensation – Milton SVC

1 Summary and Purpose

This document provides information from the OPA with respect to the Southwestern Ontario Reactive Compensation project (Milton SVC) as proposed in Hydro One's 2013-2014 Transmission Rate Application.

The OPA recommends that Hydro One install a static var compensator ("SVC") with a capacitive capacity of 350 MVAr at the Milton switching station ("SS"). The purpose of the project is to support the Government's policy objectives relating to renewable resource incorporation and provide local voltage support and regulation to the west GTA area.

This project was also referenced in the Ontario Government's Long Term Energy Plan ("LTEP") and Supply Mix Directive ("SMD") as one of five priority transmission projects required for, among other things, renewable generation incorporation; and directed the OPA to define and make recommendations on the scope and timing of this upgrade.

2 The Bruce Electric System

Existing Transmission System in the Bruce Area

The existing bulk transmission system in the Bruce area consists of a 500 kV network connecting the Bruce Nuclear Complex and the Greater Toronto Area ("GTA"), and an underlying 230 kV network, as shown in Figure 1 below. The 500 kV network consists of two main transmission paths: one between the Bruce Nuclear Complex and the Milton SS in the western part of the GTA (which will include the new double-circuit 500 kV Bruce-to-Milton transmission line expected to be in service by the end of 2012) and another connecting the Bruce Nuclear Complex to the GTA via the Longwood transformer station ("TS") near London, the Nanticoke TS on the shore of Lake Erie, and the Milton SS. The 230 kV network consists of three double-circuit transmission lines between the Bruce Nuclear Complex and the Kitchener, Orangeville, and Owen Sound areas, and provides connection points for many of the individual generation projects in the Bruce area.

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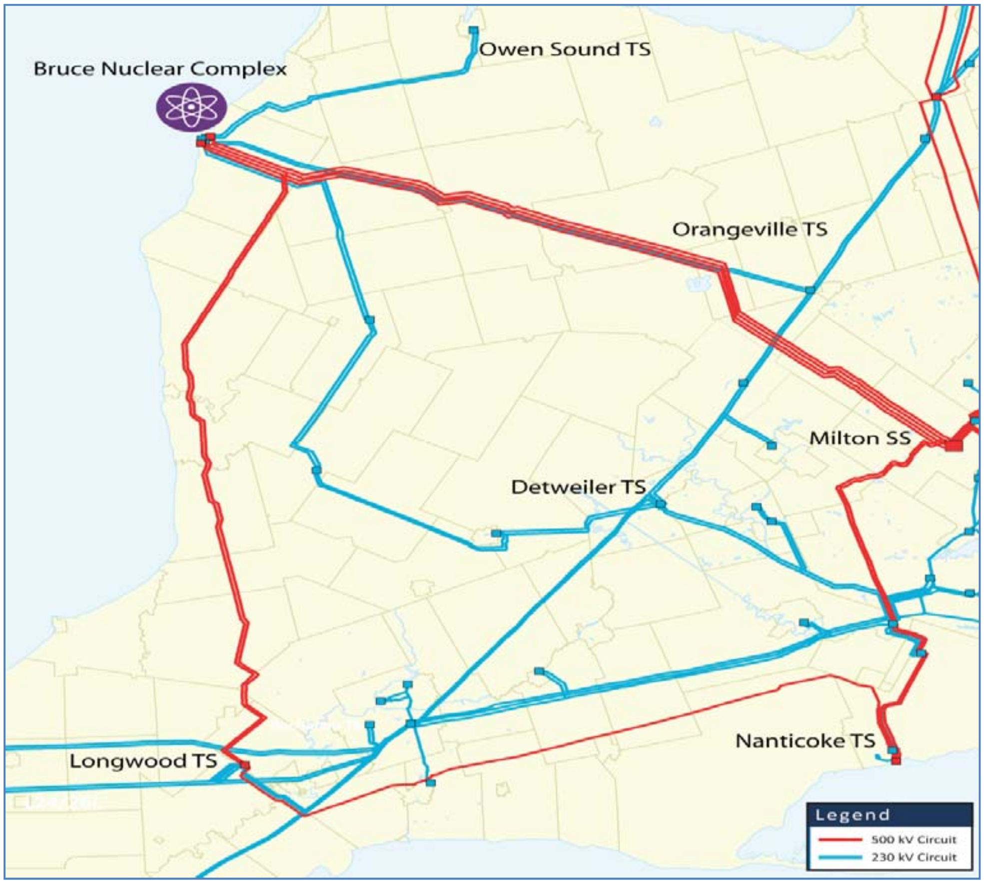
Figure 1: Bruce Area Transmission System



Source: OPA

Existing Bruce Area Resources

The Bruce area is a resource-rich area with significant electricity generation capacity. The area includes the Bruce nuclear complex, located on the shore of Lake Huron. Today, the Bruce nuclear complex has the capacity to generate approximately 5,000 MW. This capacity will increase to approximately 6,500 MW once the remaining refurbished units return to service in 2012.

The Bruce area also contains significant renewable generation resources (predominantly wind). To date there are approximately 1,700 MW of existing and contracted wind generation projects in the Bruce area. Figure 2 provides an overview of the installed resources based on existing and contracted generation.

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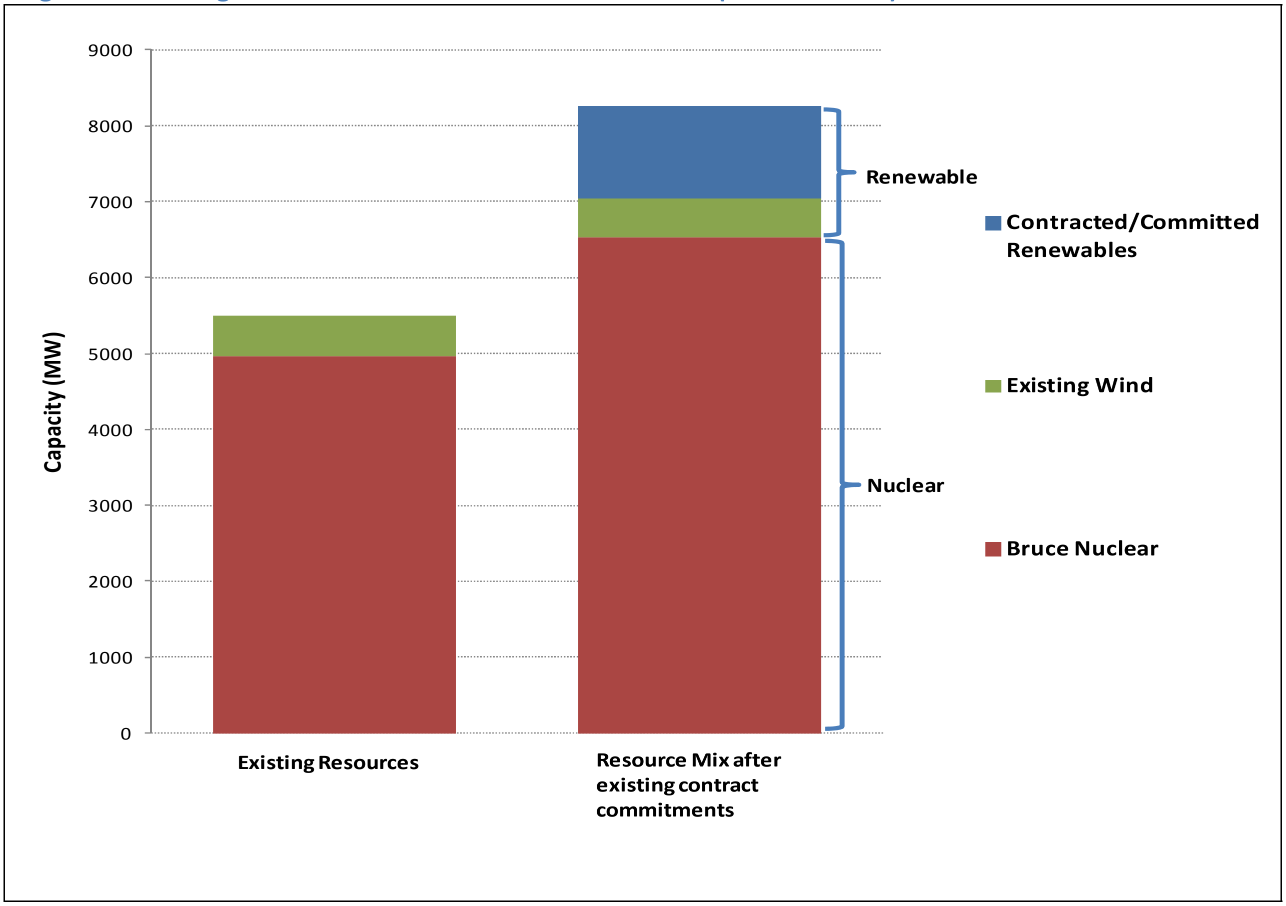
Figure 2: Existing and Contracted Bruce Area Generation (Installed MW)



Source: OPA

3 Need Assessment

Policy Objectives and Renewable Potential in the Bruce Area

The LTEP and SMD established goals for the level of installed generation resources in the Province, which includes a target for non-hydroelectric renewable generation (i.e. wind, solar, and bioenergy) by 2018. This target stated that "the OPA shall plan for 10,700 MW of renewable energy capacity, excluding hydroelectric, by 2018".[1]

The OPA estimates that approximately 3,300 MW of additional non-hydroelectric renewable generation will be required in order to achieve the 10,700 MW target. Further, the OPA expects that this remaining 3,300 MW will be satisfied in part through the Feed-in Tariff ("FIT") program (approximately 1,900 MW) and in part through the implementation of the remaining three phases of the Government's agreement with the Korean Consortium (approximately 1,400 MW).

[1] February 17, 2011 Supply Mix Directive issued to the OPA by the Minister of Energy

The Ontario wind atlas indicates a great density of high wind speeds in the Bruce area. Given the high quality wind resources and the significant FIT interest expressed in the region, it is anticipated that the Bruce area will play an important role in meeting the 10,700 MW non-hydroelectric renewable generation target.

Need to Enhance Transfer Capability out of the Bruce Area

After accounting for existing and contracted generation, the existing Bruce system will be nearly fully utilized, with about 200 MW of transmission transfer capability remaining. The amount of additional generation that can be accommodated in the Bruce area will be limited by the potential voltage instability that could occur on the Bruce transmission system following the outage of one of the double-circuit Bruce to Milton 500 kV lines.

Because the Bruce capability is limited by the voltage stability issue, reactive compensation is needed to enhance the transfer capability out of the Bruce area and enable the accommodation of additional generation in the area.

Need to Provide Voltage Support to the west GTA

With a large amount of power transferring from the Bruce area to the GTA, reactive power support is needed to maintain voltage stability. Currently there is gas generation located in the Milton/west GTA, (Sithe-Goreway GS and Halton Hills GS) which can provide reactive support when they are generating. However, when this local generation is not available, such as during off-peak periods or when they are on maintenance, alternate reactive compensation is needed for maintaining voltage regulation and system stability in the western part of the GTA.

4 Alternative Evaluation and Recommendations

Assessment of Options for Reactive Compensation to enhance transfer capability out of the Bruce area

The OPA assessed two industry standard technologies for providing reactive compensation: static var compensation and series compensation. Either of these technologies may be implemented to provide reactive compensation in the Bruce area.

Static var compensators are dynamic capacitors that automatically adjust to system conditions to regulate the voltage at a pre-set point on the system; they are typically installed at an existing station. SVCs are a proven technology that has been implemented in Ontario at Nanticoke TS, Detweiler TS, and in northern Ontario. Several locations in southwestern Ontario have been studied with respect to the installation of SVCs. The results indicate that installing SVCs at Milton SS would provide maximum capability to accommodate generation and also provide the added benefit of providing local voltage support and regulation to the west GTA.

Series compensation involves the insertion of static capacitors along a transmission line to regulate voltage. Like SVCs, series compensation is a proven technology that has been applied in Ontario. Series

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compensation options on the Bruce-to-Longwood and Longwood-to-Nanticoke circuits are being considered as options to provide reactive compensation in the Bruce area. Unlike SVCs, series compensation would require development of a new site to host the equipment. Interaction between series capacitors and nearby turbine generators could also result in sub-synchronous resonance, creating vibrations that could damage equipment.

Based on the above technologies, the OPA identified five alternatives for consideration. These alternatives, which are summarized in Table 1 below, were evaluated based on the incremental capacity they would add and their estimated cost.

Table 1: Southwestern Ontario Reactive Compensation Alternatives

Alternatives	Alternatives Description	Incremental Capacity (MW)	Cost Estimates (M$)
1	**350MVar SVC at Milton**	**250**	**100**
2	**30% Series Compensation on B562/563L and N582L**	**210**	**150**
3	**350MVar SVC at Milton + 30% Series Compensation on B562/563L**	**260**	**200**
4	**350MVar SVC at Milton + 30% Series Compensation on N582L**	**330**	**150**
5	**350MVar SVC at Milton + 30% Series Compensation on B562/563L and N582L**	**410**	**250**

Source: OPA

Recommendation of the Milton SVC Project

Based on cost effectiveness, land use, and technical considerations, the OPA identified the Milton SVC as the recommended project. Moreover, as described above, the addition of SVCs does not create sub-synchronous resonance issues and, as they would be installed at an existing station, this option would minimize adverse impact on transmission system and land-use/environmental impacts.

This project will increase the capability of the Bruce transmission system by approximately 250 MW, depending on where future projects may be connected.

As Milton SS is located in the west GTA area, adding an SVC into the station will also provide local voltage support and regulation to this area. When both Sithe-Goreway GS and Halton Hills GS are not available, there is a need to replace the voltage support and regulation functions of those local

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generating units with other types of reactive power sources. The proposed SVC at Milton SS provides these capabilities.

In October 2011, the OPA provided Hydro One with a recommendation for the scope and timing of the Southwestern Ontario Reactive Compensation upgrade project in accordance with Hydro One's licence conditions. The recommended project consists of adding an SVC with a capacitive capacity of 350 MVAr and connecting to the 500 kV voltage level at the Milton station. Based on discussions with Hydro One, an in-service date of spring 2015 has been established for this project.

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June 30, 2011

Mr. Mike Penstone
Vice President, Transmission Project Development
Hydro One Inc.
483 Bay Street
Toronto, Ontario M5G 2P5

Dear Mike,

Re: West of London Transmission Upgrade Priority Project

In its Decision and Order dated February 28, 2011, the Ontario Energy Board (OEB) amended the transmission license of Hydro One Networks Inc. (Hydro One) in accordance with the Minister's Directive, dated February 17, 2011, to the Ontario Energy Board. The transmission license amendment includes, among other things, a requirement that Hydro One develop and seek approvals for an upgrade of one or more existing transmission lines west of the City of London. The Directive further stated that Hydro One was to "immediately work in co-operation with the Ontario Power Authority (OPA) to establish the scope and timing on the projects identified…", and that "the scope and timing of the projects shall be in accordance with the recommendations of the OPA".

The purpose of this letter is to provide Hydro One with a recommendation on the scope and timing of the west of London transmission line upgrade project. As stated in the government's Long Term Energy Plan (LTEP), this project is needed to add renewable generation to the grid, in order to meet the LTEP target of 10,700 MW of installed non-hydroelectric renewable capacity by 2018. The Supply Mix Directive received by the OPA on February 17, 2011 states that the OPA shall include this project in the Integrated Power System Plan.

The existing bulk transmission system in the west of London area consists of three double circuit 230 kV transmission lines connecting Sarnia, Lambton and Chatham respectively with the Longwood and Buchanan transformer stations near London. There are also 230 kV circuits connecting Sarnia and Lambton, Lambton and Chatham, and Longwood and Buchanan. This system is shown in Figure 1.

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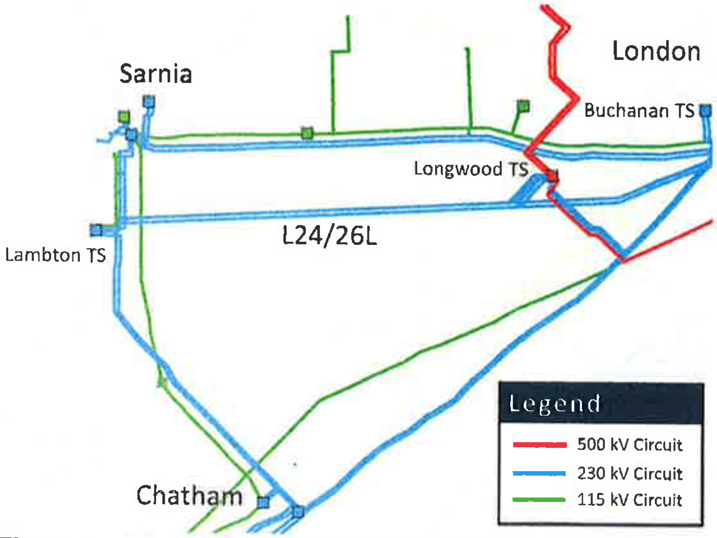

Figure 1 - West of London Transmission System

Power transfer into the London area from the west is limited by the thermal capability of the three transmission lines connecting the London area stations with Sarnia, Lambton and Chatham. Once the new Bruce-Milton transmission line comes into service, these circuits will limit the amount of additional renewable generation that can be connected in the west of London area. Upgrading one of the three circuits will increase transfer capability, and enable the connection of additional renewable generation. The upgrade project will maximize the capability of the system and require less lead time than a new transmission line.

The OPA recommends that Hydro One Networks Inc. proceed with reconductoring approximately 70 km of the two 230 kV circuits (L24/26L) from Lambton to Longwood with a higher ampacity conductor rated approximately 1700-1900 A (LTE capability at 35˚C, 4km/hr wind speed). The upgrade project will enable the connection of approximately 300-500 MW of additional renewable generation in the west of London area, depending on such factors as generators' locations and system conditions. The required in-service date for the upgrade is December 2014. The OPA will continue working regularly with Hydro One to review progress and provide any further assistance in order to enable the successful project completion by the required in-service date.

The OPA's studies indicate reconductoring the Lambton to Longwood transmission line will provide the greatest capability to incorporate additional renewable generation west of London. The OPA has also worked closely with Hydro One's staff over the past several months to review the cost and feasibility of reconductoring alternatives. Based on this information, the OPA has identified this reconductoring project as the best alternative to meet the upgrade requirements, including the LTEP target in-service date of 2014. Should the final project specifications determined by Hydro One result in a conductor rating outside the 1700 - 1900 A range, Hydro One will seek the OPA's confirmation of the suitability of the rating for meeting project objectives.

Regards,

A Shalaby

Amir Shalaby
Vice President, Power System Planning
Ontario Power Authority

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March 8, 2012

Mr. Mike Penstone
Vice President, Transmission Project Development
Hydro One
483 Bay Street
Toronto, Ontario M5G 2P5

Dear Mike:

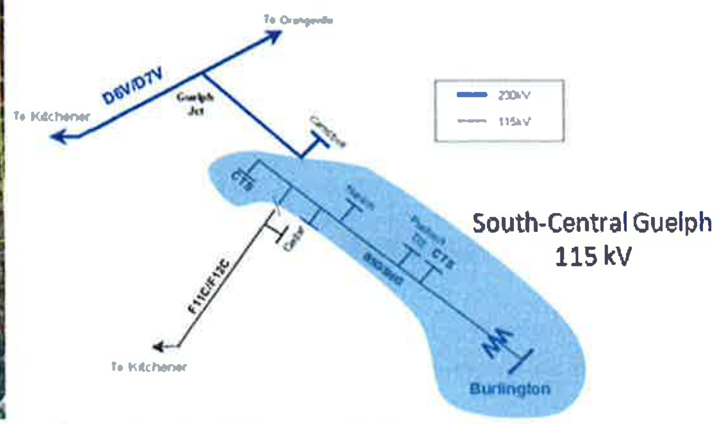
Continuing with the Project Development Work for the Guelph Area Transmission Refurbishment Project

The purpose of this letter is to recommend continuing with the project development work for the Guelph Area Transmission Refurbishment project, including completion of the necessary environmental and regulatory approval processes.

In 2009, Hydro One Networks Inc. (Hydro One) began the necessary environmental approvals for the upgrading of an existing 115 kV transmission line, approximately 5 km in length, from Cedar TS to near Campbell TS along the Hanlon Expressway in the City of Guelph, and the installation of transformers at either Cedar TS or Campbell TS. This project is referred to as the Guelph Area Transmission Refurbishment (GATR) project. Two public information centers were held in Guelph to present the need and options for this project and to solicit feedback from the public. Since then, Hydro One has been developing study estimates for a number of transmission alternatives and working with the OPA and Guelph Hydro Electric Systems to determine the preferred option for the GATR project. As well, a broader regional planning study, initiated in 2010, examined and confirmed the need for the GATR project as part of the 20-year study, in consideration of updated demand forecast and recent conservation and distributed generation developments.

The purpose of the GATR project is to reinforce the electricity supply to a portion of the City of Guelph, as well as the neighboring town of Puslinch, known as South-Central Guelph, as shown in Figure 1. This area has experienced significant growth in electricity demand and is forecast to continue to grow over the next 20 years. Continuing development of the Hanlon Industrial Park is one of the key contributors to this growth.

Source: OPA
Figure 1: South-Central Guelph



Source: Hydro One Networks and OPA
Figure 2: South-Central Guelph Transmission System

The existing electricity supply to the South-Central Guelph area is primarily through a double circuit 115 kV transmission line from Burlington, B5G/B6G, as shown in Figure 2 above. This transmission line was originally built starting in 1910, and for planning purposes, has a supply capacity of approximately 100 MW. In the summer of 2011 peak demand in the South-Central Guelph area was about 115 MW, which exceeded the capability of the supply circuits for planning purposes.

Over the past several months the OPA has worked closely with Hydro One staff to review the cost and feasibility of options for reinforcing the supply to South-Central Guelph. Based on technical considerations, it is the OPA's recommendation that the preferred option is comprised of the following:

- two 230/115 kV autotransformers at Cedar TS;
- revitalization of the existing 115 kV transmission line between Campbell TS and CGE Junction near Cedar TS (approximately 5 km) to 230 kV;
- connection of the existing F11C/F12C and B5G/B6G 115 kV circuits at Cedar TS; and
- initial switching facilities at Guelph North Junction to facilitate sectionalization of the existing D6V/D7V 230 kV circuits.

This recommendation has the support of the Kitchener-Waterloo-Cambridge-Guelph (KWCG) area working group.

The proposed arrangement of Cedar TS, as well as the proposed transmission upgrade, are shown in Figure 3 and Figure 4 below.

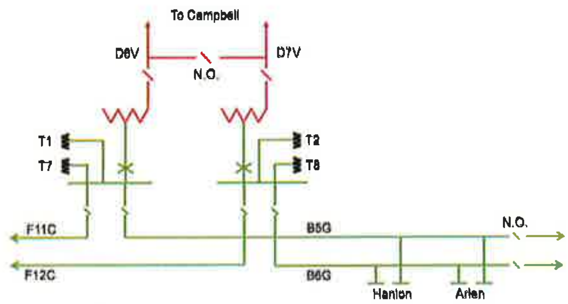


Figure 3 Proposed Cedar TS Arrangement

Figure 4 Map of Proposed Transmission Upgrade

Upon completion, Cedar TS will become an additional strong source of supply within the KWCG region, providing improved supply capability to both South-Central Guelph as well as neighbouring Kitchener. Additionally, it will provide an opportunity to improve the reliability of supply to customers in the Cambridge area. Hence, the addition of a second 230/115 kV autotransformer at Preston TS in Cambridge will also be required.

The above recommendation is subject to the outcome of the project's environmental assessment.

It is our understanding that the GATR project will take approximately 3-4 years to complete, including the necessary environmental and regulatory approvals. The OPA recommends Hydro One proceed with the project's development work.

We look forward to the opportunity to continue working with Hydro One to further develop these options.

Regards,

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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 15, Schedule 3.

The planned investments enable Hydro One to meet its regulatory obligations as a transmission owner and operator and align with its vision as a leading transmission company by employing “best in class” commercially available operations systems and equipment that provide monitoring and control to maintain top-quartile system reliability, customer satisfaction, 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 strive to deliver improvements to transmission system performance in the form of improvements to reduced outage duration, system reliability, system utilization and information.

Failure to sustain the Network Operating systems and tools would lead to increased business and operational risk as aging assets become less reliable, require more maintenance and no longer have vendor support. Network Operating system and/or tool failures may negatively impact customer service, system reliability and regulatory compliance. It is important to our customers, the province of Ontario and our interconnected neighbors’ that Hydro One Transmission Operations prudently undertake these investments necessary to operate the transmission system so that the service provided is efficient, safe and reliable.

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**	
	2009	**2010**	**2011**	**2012**	**2013**	**2014**
Grid Operations Control Facilities	11.3	3.6	3.7	12.5	15.1	15.5
Operating Infrastructure	8.7	4.1	5.1	35.4	32.4	41.1
Total	**20.0**	**7.7**	**8.8**	**47.9**	**47.5**	**56.6**

The increase in Grid Operations Control Facilities from historic to the test years is attributed to the planned end of life replacement of the Network Management System (NMS) system, and the continued Network Outage Management System (NOMS) integration project. Planned spending in Operating Buildings and Operating IT

Infrastructure also adds to this increase, described in further detail in section 3.0 Grid Operations Control Facilities.

The increase in Operating Infrastructure from historic to the bridge and test years is due primarily to the Wide Area Network, Station Local Area Networks and the Frame Relay Replacement Projects growing in 2014 due to the Fault Locating System and Hub Site Management programs.

Planned spending in 2013 is $47.5 million as compared to the 2012 level of $47.9 million. This represents a slight decrease due to $6.3M decreased spending requirement for the Wide Area Network project in that year offset by an increase in Cable Monitoring Infrastructure, Communication Tower Reinforcement and Telemetry Expansion. Planned spending in 2014 of $56.6 million is an increase over the 2013 level resulting from the higher spending levels for the Wide Area Network project in that year and the Network Management System (NMS) upgrade project.

The funding levels for the bridge and test years have increased substantially from historic years due to several projects planned for 2011 being deferred to the bridge and test years, along with an increase in planned spending on the Wide Area Network project and the NMS upgrade. Projects that were deferred to the bridge and test years include;

- Network Operations Buildings Expansions (OGCC/BUCC) – Interim solutions discussed in section 3.4 Network Operations Buildings have been implemented and have deferred the required investments at the OGCC. The back-up control centre assessment continues to progress in light of new technologies, alternatives and business needs.

- Transmission Operations Facilities Sustainment - Control Room telephone systems, NMS workstations and displays, and Control Room display wallboards have all been delayed with anticipated in-service of 2012 and early 2013.

A major NMS enhancement has been deferred, as a pilot of the tool proved that implementation was premature. The tool is in its infancy and requires a substantial amount of tailoring to provide the intended benefits in the control room.

A brief description of the primary systems used to manage Hydro One's Transmission 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 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 rendered 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 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.
- Continued impacts on transmission operations resulting from the government's Green Energy & Green Economy Act and the FIT program. This has resulted in 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 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. NOMS Version II (NOMS V2) was implemented September 2010 and continues to be developed in order to integrate Hydro One's SAP system of record, Utility Work Protection Code (UWPC), and Electronic Logging (EL) (described in further detail below) into a single integrated application.

b. The **Utility Work Protection Code System** is used by Hydro One 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. Operators in the control room also manually record all other pertinent information including utility work protection, 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 developed, modified and 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 ("IVS")** is designed to allow OGCC Operations to effectively manage voice communications between the OGCC, IESO, interconnected utilities, transmission connected customers, emergency services and field staff. This system provides the interface to multiple communication media, such as the public telephone network, satellite phone systems and Hydro One'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** (WAN) that provides multiple independent paths, on Hydro One's Fibre Optic system, on third part leased telecom, and by various wireless media, to all stations that are of critical importance to the operation of the grid and its 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 on costs 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 high reliability contact with field crews. It is designed to be reliable in the event of localized or widespread blackouts and capable of accessing all remote, and electrically noisy, locations where Hydro One field crews would be dispatched. For health and safety and operational reasons, it is essential to provide crews with an assured means of communication in case of emergency.
- **Underground Cable Monitors** which are probes that monitor the surface temperature of the cable jacket, soil temperature gradients and cathodic protection voltages 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 the OGCC and back-up centre. This program funds enhancements to, and capital sustainment of, computer tools and systems to maintain equipment performance at required 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 upgrades are at the end of their normal life cycle and are subject to reduced reliability and increased support and maintenance requirements.

The 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**	
	2009	**2010**	**2011**	**2012**	**2013**	**2014**
Network Operations Buildings*	0.0	0.0	0.2	3.4	2.6	1.5
NMS Upgrade & Enhancements	9.2	1.2	0.1	1.5	7.8	12.2
Transmission Operating IT Infrastructure**	0.6	0.6	2.9	5.6	2.4	1.8
Operations Support Tools (NOMS, UWPC, Electronic Logging)	1.5	1.8	0.5	2.0	2.3	0.0
Miscellaneous	0.0	0.0	0.0	0.0	0.0	0.0
Total	**11.3**	**3.6**	**3.7**	**12.5**	**15.1**	**15.5**

* In EB-2010-0002, this investment was specific to planned buildings expansions; however this category now represents planned investments in the OGCC and the Backup Control Centre. **In EB-2010-0002, Transmission Operating IT Infrastructure was referred to as Transmission Operating Facilities Sustainment.

3.2 Description of Investments

Table 3
Grid Operations Control Facilities
Capital Projects > $ 3 Million in Test Year 2013 or 2014 ($ Millions)

Ref #	Description	Cash Flow Test Years 2013	Cash Flow Test Years 2014	Total Cost	Removal Cost	Capital Cost
O1	NMS Upgrade	7.3	11.7	19.0	0	19.0
	Other Projects/ Programs < $3M	7.8	3.8	11.6	0	11.6
	Total Cost	**15.1**	**15.5**	**30.6**	**0**	**30.6**
	Removal Cost	**0**	**0**	**0**	**0**	**0**
	Capital Cost	**15.1**	**15.5**	**30.6**	**0**	**30.6**

3.3 O1 Network Management System Upgrade (ISD)

This investment upgrades the current Network Management System (NMS) software, associated server hardware, and the operating system currently in-service at the Ontario Grid Control Centre and the Backup Control Centre.

The NMS is the mission critical operating tool used for monitoring and control of the Hydro One Transmission System. The reliable operation of the Ontario Power System is dependent on the continued availability and high performance of the NMS. This investment will also ensure continued NERC Cyber Security compliance.

The NMS must be upgraded due to the impending end of life software and hardware components. The operating system must also be upgraded to ensure compatibility. In late 2014, the current application software, Alstom (formerly Areva) Energy Management System (EMS) 2.5, will be two releases out of date and will reach end of life. Vendor support will also be withdrawn during this time. The server hardware has been in continuous operation since 2008 and is therefore reaching end of life between 2013 and 2015.

The Investment Summary Document for the NMS Upgrade is filed under Exhibit D2, Tab 2, Schedule 3.

3.4 Network Management System (NMS) Enhancements

These investments provide enhanced tools in the NMS to improve operator situational awareness, efficiencies and work flow in the face of increasing operational complexities and workload.

Approved funding for 2011 and 2012 planned NMS enhancements was and will continue to be under spent.

A pilot of a planned NMS enhancement to improve situational awareness was conducted in 2011. Functionality of this version of the tool did not meet the business requirements and did not provide the intended benefits. This investment has been deferred and will be reviewed at a later date, as the tool continues to be developed.

The Special Protection System application is currently a custom in-house application for modeling various Special Protection Systems. The vendor continues to develop this application that is to be included in subsequent NMS versions as a standard offering and thus has been deferred.

The remaining NMS enhancements have been implemented, albeit with spends much lower then the approved funding levels.

3.5 Network Operations Buildings

This investment is required to sustain operational readiness of building facilities, including office space and computer rooms at the Ontario Grid Control Centre ("OGCC") and the backup control centre ("BUCC").

Approved funding for Network Operations Buildings Expansions (now Network Operations Buildings) was largely under spent in 2011 as the planned investments in buildings and infrastructure were deferred. Rationale for deferment of these investments is provided in the following sections.

3.5.1 Ontario Grid Control Centre (Primary Control Facility)

Current business requirements are having a significant impact on office and computer room space availability, as well as the associated infrastructure. In particular the OGCC's cooling system has reached its capacity. In late 2010, leased office space was acquired in the Barrie area (Barrie Corporate Office) to address the office space shortage at the OGCC as well as other Hydro One locations in Barrie. This is an interim solution that has alleviated the office space congestion and has reduced cooling system load. A modular non-production computer room was also implemented in 2011 as an interim solution to alleviate computer room space and further decrease cooling system load. The abovementioned interim measures have deferred the planned investment for 2011 and 2012 for new building facilities at the OGCC.

In 2012 through to 2014, investments will be made in the air conditioning (HVAC) systems at the OGCC to resolve cooling limitations. These investments will ensure that critical equipment and infrastructure continue to be properly maintained.

3.5.2 Backup Control Centre

The Backup Control Centre is required should an extreme contingency disable the OGCC and is a regulatory requirement of the North American Electric Reliability Corporation (NERC). Existing Backup Control Centre computer rooms are currently at design limits in terms of physical space, power supplies and environmental controls. As a result, full redundancy of all systems is not currently available and the reliability of transmission operating facilities is reduced.

Previous analysis indicated that relocating to a new back-up control centre with expansion capacity was the best option and constituted the majority of the planned investments in 2011 and 2012 under Network Operations Buildings Expansion. This investment has been deferred pending a review of the Backup Control Centre strategy in consideration of the current and future back-up needs of all Hydro One's real time operating functions, and in light of new technologies and the need to seek greatest possible efficiencies.

A short term strategy will be implemented to address the constraints currently being experienced. It will ensure reliable operation of the backup control centre and computer room while also providing flexibility and time to complete a thorough analysis of the entire backup strategy.

The long term strategy will take three to five years to implement, thus will not affect the Operations Capital expenditure in the test years.

The costs for the investments in Network Operations Buildings consist of $2.6M in 2013 and $1.5M in 2014.

3.6 Transmission Operating IT Infrastructure

These investments provide 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.

A short description of the planned investments for the bridge and test years is provided below:

3.6.1 Voice Communications System Upgrades

The Integrated Voice System ("IVS") (formally: control room telephone system) is reaching end of life. This investment will provide for the planned 2012 to 2013 system replacement.

3.6.2 Control Room Display Wallboard Upgrade

The control room and training simulator display wallboard technologies assessment is currently underway, evaluating the potential solutions and alternatives. The wallboards have been in continuous operation since 2004 and are at end of life. Maintenance work is compromised due to the difficulty in procuring replacement parts.

3.6.3 Control Room Workstations Upgrade

The existing control room console operating system "2001 released – Windows XP" is end of life and requires replacement. Microsoft will no longer provide Window XP service packs or upgrades which places the existing infrastructure in a critical state.

Windows 7 with the 64 bit architecture is required for console application program upgrades planned for the test years. This investment is expected to be in-service by the end of 2012; therefore it has no impact on the Operations Capital expenditures in the test years.

3.6.4 Computing Facility Storage

The OGCC computing facility storage and Storage Area Network (SAN) infrastructure hardware is nearing end of life and needs to be replaced in order to maintain its viability. This system supplies computer storage to mission critical applications such as the NMS and NOMS. This system will be replaced with a newer model that has a projected life expectancy of five years. The newer model will be sized to support current loads and anticipated capacity for the life of this asset. This investment is expected to be in-service in mid 2012 and therefore it has no impact on the Operations Capital expenditures in the test years.

The risk of not proceeding with these replacements will include increased support costs and increasing failures of systems essential for the reliable function of the control room.

The costs for these investments in the test years consist of $2.4M in 2013 and $1.8M in 2014.

3.7 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. The NOMS system was replaced in September 2010 by NOMS Version II, phase one. The scope of this investment has been enhanced by taking the opportunity to provide consistent, accurate, timely exchange of data between applications to minimize redundant data entry, tighter integration of SAP (enterprise software to manage business operations and customer relations) work management functionality, and true alignment of work, outage planning and scheduling processes. These enhancements to scope are expected to reduce projected annual short notice outage requests by approximately 7 %. Due to unforeseen scope and scheduling changes, the investment is still on-going and is expected to be completed by October 2013.

The costs for this investment in the bridge and test years consist of $2.0M in 2012 and $2.3M in 2013.

4.0 OPERATING INFRASTRUCTURE

4.1 Overview

This program funds enhancements, expansion and end of life replacement of the physical infrastructure, beyond the walls of the OGCC and back-up centre, required for the operation of the Transmission System.

Table 4
Operating Infrastructure Capital
($ Millions)

Description	Historic			Bridge	Test	
	2009	2010	2011	2012	2013	2014
Hub Site Management Program	5.3	1.9	0.8	3.2	3.2	3.3
Telemetry Expansion Program	0.1	0.1	1.2	1.6	2.3	2.3
Wide Area Network Project	0.1	0.1	0.8	17.0	10.9	19.3
Frame-Relay Replacement Project	0	0	0	5.3	5.0	0.0
Fault Locating Program	0	0.5	0.5	1.0	1.0	5.0
Station LAN Infrastructure Program	0	1.0	1.0	4.0	4.0	4.0
Miscellaneous	3.2	0.5	1.8	3.3	6.2	7.1
Total	**8.7**	**4.1**	**5.1**	**35.4**	**32.4**	**41.1**

The spending level for this program is driven by the ongoing program requirements combined with discrete projects undertaken in a specific year or period of years. The spend in 2011 was below the approved amount due to a continued intentional slowing of some programs and delays to projects in order to re-assess their scope and priorities in the face of emerging new requirements associated with the green energy initiatives such as distributed generation and Smart Grid, the future evolution of NERC Cyber Security requirements and a renewed focus on business efficiencies. The proposed plan is the result of that reassessment. The increase in 2013 and 2014 funding levels are mainly attributable to the WAN project to meet telecommunication requirements for generation connections, smart grid, security (both cyber and physical) and enterprise efficiency, and other projects and programs to achieve design, maintenance and operating efficiencies. The telecommunication (WAN) requirements are expected to continue to grow over the next decade. Consequently, while the funding between 2012 and 2014 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, rollout of station LAN and data extraction infrastructure, ongoing hub site management and end of life replacements, the future funding levels for Operating Infrastructure Capital will continue at elevated levels relative to the historic average..

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 manage and 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 continues 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 needs to be sent to the control centre during a system disturbance affecting multiple transmission stations.

4.3 Description of Investments

Table 5
Operating Infrastructure
Capital Projects > $ 3 Million in Test Year 2013 or 2014 ($ Millions)

Ref #	Description	Cash Flow Test Years 2013	Cash Flow Test Years 2014	Total Cost	Removal Cost	Capital Cost
O2	Hub Site Management Program	3.2	3.3	6.5	0	6.5
O3	Telemetry Expansion Program	2.3	2.3	4.6	0	4.6
O4	Wide Area Network Project	10.8	19.3	30.1	0	30.1
O5	Frame Relay Replacement Project	5.0	0	5.0	0	5.0
O6	Fault Locating Program	1.0	5.0	6.0	0	6.0
O7	Station LAN Infrastructure Program	4.0	4.0	8.0	0	8.0
	Other Projects/ Programs < $3M	6.2	7.1	13.3	0	13.3
	Total Cost	**32.4**	**41.1**	**73.5**	**0**	**73.5**
	Removal Cost	**0**	**0**	**0**	**0**	
	Capital Cost	**32.4**	**41.1**	**73.5**		**73.5**

4.3.1 O2 Hub-Site Management Program

This program is needed to continuously expand the gateway 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 transmission system. As new assets 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 6 years, the gateway boxes need to be replaced due to obsolescence. The Hub-site management program continually manages these factors to ensure the capacity and reliability of the grid control infrastructure is in place to meet the needs of the development, load connection and transmission 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, grid expansion and generation connections had pushed 6 Hub-sites beyond design limits. The plan to begin addressing these in 2011 was delayed due to a review of the overall protection and control (P&C) architecture in the context of the selected WAN technology, to ensure alignment with evolving Cyber Security standards, to meet the Advanced Distribution System ("ADS") interface requirements and to negotiate a more optimum arrangement for telemetry provision to the IESO.

Additional detail for this program is provided in the Investment Summary Document in Exhibit D2, Tab 2, Schedule 3.

4.3.2 O3 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 urgent costly field staff callouts 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.

The plan had been to expand telemetry at 10 stations in 2011 and 2012 for a total spend of $6.9 M. The actual spend will be $2.8M. The reason for the reduced spending is due to more efficient execution of the work by integrating with the RTU Replacement Program and Station P&C Replacement Program (see Exhibit D1, Tab 3, Schedule 2 pages 44 and 45). As a result of this integration, the work in 2010 and 2011 progressed more slowly, and cost less, than planned. This program will continue to accept slower execution in favor of the efficiency gained from the integrated approach. Consequently, the funding levels for 2013 and 2014 are reduced by about 33% relative to those identified in EB-2010-0002.

Additional detail for this program is provided in the Investment Summary Document in Exhibit D2, Tab 2, Schedule 3.

4.3.3 O4 Telecom Wide Area Network

Hydro One projects a fivefold increase in the 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. Existing/future leased telecom service costs will be reduced/avoided resulting in a present value saving of $23.3M over ten years. Although we have projected growth to 3500Mbps by 2015, an independent review has projected growth to 7100Mbps resulting in a present value saving of $58.6M over ten years.

The plan had been to release the WAN in fall of 2010 and begin expenditures on the WAN project in second quarter of 2011 after the equipment procurement process would have been completed. However, the release of the project was delayed by six months to allow for independent review of the benefits and to ensure scheduling alignment with other projects having large telecommunication requirements. Additional detail for this program is provided in the Investment Summary Document in Exhibit D2, Tab 2, Schedule 3.

4.3.4 O5 Frame Relay Replacement

In May of 2010, Hydro One received notification from Bell Canada that Frame-Relay (FR) services will cease in December, 2013. Hydro One must transfer all of its services running on the FR circuits over to new circuits using current technology. Not transferring all circuits has the potential to significantly impact the reliability of the grid, as OGCC risks losing redundant communication links, and in some cases, even complete communication to major hub-sites and a large number of major and minor stations.

Additional detail for this program is provided in the Investment Summary Document in Exhibit D2, Tab 2, Schedule 3.

4.3.5 O6 Fault Locating

This program 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. Digital protection and 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 determination of the location of the problem in almost real time. This will allow faster restoration and will result in improved efficiency and reduced cost and carbon footprint as the time spent in vehicle and helicopters searching for the fault will be greatly reduced. This program has been delayed to modify data extraction systems for compliance with NERC Cyber Security Standards.

Additional detail for this program is provided in the Investment Summary Document in Exhibit D2, Tab 2, Schedule 3.

4.3.6 O7 Substation LAN Infrastructure

Modern digital protection, control and monitoring devices located in a Transmission Station have the ability to be networked together. The networking of these devices provides many benefits in the form of reduced cabling costs, reduced cost for primary measuring devices or transducers, reduced design costs, and the ability to achieve business efficiencies by remote interrogation of the devices for fault locating, event analysis and asset utilization information.

This program installs a standardized LAN infrastructure, appropriate to the class of station, which incorporates Cyber Security, remote monitoring and has the capacity, or expandability, to meet all forecast needs.

Additional detail for this program is provided in the Investment Summary Document in Exhibit D2, Tab 2, Schedule 3.

4.3.7 Other Miscellaneous Projects

A number of other smaller projects totaling $6.2 million in 2013 and $7.1 million in 2014 make up the balance of the Operating Infrastructure expenditures. These projects are briefly described below:

Telecommunication Performance Improvement: This investment ($1 million total for 2013 and 2014) will fund improvements to resolve reliability and performance problems with third party telecommunications Hydro One uses to control some Transmission Stations. There are a number of stations where improvements to reliability is required due to recurring “last mile” telecom problems. It is particularly serious if the telecommunication fails as a result of power outage and control is lost just when it is most needed. This program addresses those issues by providing an alternate independent path or by addressing infrastructure problems which allow common mode failure issues.

Grid Control Network Sustainment: This program ($1.1 million total for 2013 and 2014) funds upgrades and end of life replacement of telecom equipment used for the monitoring and control of the grid.

Weather Station Replacement: This project ($0.4 million total for 2013 and 2014) 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 weather data used for determining real time equipment thermal ratings, tracking build-up of contamination on insulators, and detecting ice accretion.

Underground Cable Monitoring: This project ($2.8 million total for 2013 and 2014) will complete the installation of monitors on underground cables supplying downtown Toronto. These monitors will help ensure the health of the cables while allowing the best possible operating limits.

Optical Guard Wire (OPGW) Build Out with Guardwire Replacement: This program ($2.5 million total for 2013 and 2014) uses the opportunity provided by the guardwire replacement program to expand the Hydro One fibre optic network where need is projected to exist. The guardwire is a wire that runs along the top of the transmission towers to protect the conductors below from lightning strikes. OPGW is a form of guardwire that contains a bundle of optical fibres in its core. Most of Hydro One's fibre optic network is OPGW. Guardwire is replaced on a 50 to 100 year cycle. The guardwire replacement program presents a low incremental cost opportunity to upgrade to OPGW for expansion of the fibre optic network.

Provincial Mobile Radio System Replacement: This project ($3.0 million total for 2013 and 2014) will refresh end-of life Provincial Mobile Radio System (PMRS) base stations. The PMRS base station radio equipment is reaching end of life and needs to be replaced over the next 5 years. A study is underway in 2012 to examine possible replacement technologies and integration strategies. Rollout of replacement radios is planned to ramp up in 2013 and reach full project replacement rates in 2014. Completion is planned by 2016.

Communication Tower Reinforcement: This program ($2.5 million total for 2013 and 2014) will enhance the structural integrity of certain communication towers located in Transmission Stations to allow attachment of additional radio equipment. There is a need to attach additional radio equipment to certain communication towers in support of the wireless infrastructure planned for the smart grid and some transmission applications. A survey was conducted in 2011 which determined that 20 towers will need reinforcing in 2013 and 2014.

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 2009 through 2014, highlighting the total capital spending for Shared Services.

Table 1
Total Shared Services & Other Capital 2009-2014 ($ Millions)

Description	**Historic**			**Bridge**	**Test**	
	2009	**2010**	**2011**	**2012**	**2013**	**2014**
Information Technology	21.0	32.7	37.9	33.7	28.5	33.7
Cornerstone Initiative	90.9	19.2	70.7	127.9	26.8	10.0
Facilities & Real Estate	17.1	22.5	25.9	45.1	44.0	44.0
Transport & Work Equipment	46.5	64.5	42.8	44.1	43.3	44.5
Service Equipment	6.6	3.8	6.7	9.9	9.3	9.9
Other (including Distribution Line Loss and CDM)	2.9*	(0.8)	(2.6)	0.6	0.6	0.6
Total	**185.0**	**141.9**	**181.4**	**261.3**	**152.5**	**142.7**

*Correction made to Other in historical year 2009 from EB-2010-0002.

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 2009-2014 ($ Millions)

Description	Historic			Bridge	Test	
	2009	2010	2011	2012	2013	2014
Information Technology	9.2	14.0	17.7	18.2	15.0	15.2
Cornerstone	50.9	10.7	15.2	13.7	15.2	5.7
Facilities & Real Estate	6.3	7.6	3.9	25.6	25.0	25.0
Transport & Work Equipment	11.2	15.5	10.3	11.5	11.3	11.6
Service Equipment	2.8	1.6	2.9	5.7	5.4	5.6
Other*	1.4	(0.2)	(1.5)	0.3	0.3	0.3
Total	**81.8**	**49.2**	**48.5**	**75.0**	**72.2**	**63.4**

*Correction made to Other in historical year 2009 from EB-2010-0002.

Exhibit C1, Tab 7, Schedule 3 outlines the appropriate cost allocation drivers that have been utilized to derive the Transmission allocation of this capital.

The decrease in IT capital for the test years relative to the 2011 historic test year is driven by the reduction in the software replace and maintenance program as Hydro One continues to reduce the number of business software programs utilized, as well there is a reduction in hardware replacement for servers and laptops etc. due to previous year refresh programs. Exhibit D1, Tab 4, Schedule 2 details the capital requirements for IT.

Cornerstone capital expenditures consist of Minor Fixed Assets and Development Costs. The latter includes all the costs to acquire, install and place into service the new systems. Phase 1, 2 & 3 consist of assets that are largely shared by both the Transmission and Distribution businesses with Cornerstone Phase 4 being allocated solely to Hydro One Distribution. The differences in year to year expenditures are the result of the phasing of the Cornerstone implementation. Exhibit D1, Tab 4, Schedule 3 details the capital requirements for Cornerstone.

Facilities & Real Estate capital increases, relative to the 2011 historic year, are to accommodate the need to acquire new office space, and associated tenant improvements. This work was initially planned for 2010 and 2011 however was ultimately deferred given consideration to capital reductions made by the Board in the last Transmission Decision and the economic situation in Ontario. This work can be put off no longer as major head office building infrastructure elements are now at the end of their life which also poses a health and safety issue for staff, due to tripping hazards etc. This is also true for the current furniture systems, which again are at end of life. Exhibit D1, Tab 4, Schedule 4 details the capital requirements for Facilities and Real Estate.

T&WE test year costs remain relatively stable, relative to the 2011 historic year, with a slight increase to address the requirements of the Core Vehicle Replacement Program. Exhibit D1, Tab 4, Schedule 5 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 4, Schedule 5 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 is slight anticipated adjustment in the test years 2013 and 2014.

SHARED SERVICES CAPITAL - INFORMATION TECHNOLOGY

1.0 OVERVIEW

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 and as part of the overall business plan.

Table 1
Total IT Capital Expenditures ($ Millions)

Description	Historic			Bridge	Test		TX Allocation	
	2009	2010	2011	2012	2013	2014	2013	2014
Software Refresh & Maintenance	8.0	6.6	14.4	10.6	9.2	11.9	5.2	6.7
Minor Fixed Asset Program	9.0	14.6	17.4	12.8	12.5	11.8	7.2	6.8
Development Programs	4.0	11.5	6.1	10.3	6.8	10.0	2.6	1.7
Total	**21.0**	**32.7**	**37.9**	**33.7**	**28.5**	**33.7**	**15.0**	**15.2**

Capital IT expenditures are undertaken as projects or programs to meet business requirements. Capital expenditures fall into 3 categories:

1.1 Software Refresh and Maintenance

Software Refresh and Maintenance programs ensure continued operations of the installed IT application infrastructure, and include costs related to upgrading existing systems.

1.2 Minor Fixed Assets (MFA)

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.

1.3 Development Programs

Development Programs ensure the replacement and/or upgrade of end-of-life applications and include investments in new applications to meet business objectives. Replacement of applications occurs when applications have become inadequate for current functional needs; where the platform is no longer supported by the vendor; to address legislative changes or market driven initiatives; or to significantly 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 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.

IT has also developed and is implementing an Enterprise Core Business System Replacement Strategy to replace the existing customized enterprise applications which are approaching end of life. For details, refer to Exhibit D1, Tab 4, Schedule 3, Shared Services – Cornerstone.

The major planned IT capital projects which will be funded in 2012, 2013 and 2014 are described below.

2.0 SOFTWARE MAINTENANCE AND REFRESH PROGRAMS

Table 2
Software Refresh and Maintenance Program Capital Expenditures
($ Millions)

Description	Historic			Bridge	Test		TX Allocation	
	2009	2010	2011	2012	2013	2014	2013	2014
Software Refresh & Maintenance	8.0	6.6	14.4	10.6	9.2	11.9	5.2	6.7
Total	**8.0**	**6.6**	**14.4**	**10.6**	**9.2**	**11.9**	**5.2**	**6.7**

Hydro One utilizes approximately 855 (year ending 2011) business software applications in order to equip its employees with the required technologies to perform their work functions. 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.

Applications are replaced or upgraded 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.

Included in 2011 are the implementation of enterprise content management and collaboration tools, Sharepoint 2010 implementation, further IT security access control and monitoring capabilities, upgrading the desktop operating system to Windows 7 and the MS-Office 2010 suite organization-wide, the completion of the Exchange 2010 transition, implementation of Microsoft Office Communicator 2007 and subsequent uplift to Microsoft Lync 2010, and improvements to the disaster recovery platform.

In 2012, 2013 and 2014, planned costs include the continuation of the Windows 7 and MS Office 2010 upgrade, and commencing Windows Server 8 upgrades to keep data center infrastructure vendor supported. Costs also include a migration from 32-bit processing to a 64-bit computing environment on both client and server platforms to accommodate the evolution of enterprise applications to 64-bit operating system platforms.

3.0 MINOR FIXED ASSETS

Minor Fixed Asset investments include specific programs to refresh aging hardware such as personal computers, servers and storage. 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 lifecycle. Hydro One’s strategy is to minimize the costs of ownership, ensure operations risk is kept at an acceptable level, and to maintain function 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	
	2009	2010	2011	2012	2013	2014	2013	2014
Servers and Storage	2.1	5.9	9.1	3.6	4.0	6.4	2.3	3.7
IT Desktops, Laptops, Tablets, Printers and Plotters	3.4	5.5	6.1	4.0	3.3	3.6	1.9	2.1
Telecom Infrastructure	3.5	3.2	2.2	2.2	3.2	1.8	1.8	1.0
Smart Grid				3.0	2.0	0.0	1.2	0.0
Total	**9.0**	**14.6**	**17.4**	**12.8**	**12.5**	**11.8**	**7.2**	**6.8**

3.1 Servers and Storage

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 servers and storage refresh program varies year to year depending upon hardware lifecycles and business requirements for increased processing capacity.

2010 and 2011 represented a cycle of refresh of Wintel and Unix servers to maintain vendor supported levels. It also included ancillary hardware upgrades, and capacity upgrades for core access control and middleware environments in anticipation of increased data processing with SAP-driven processing. In 2012 and 2013, the cost decreases due to hardware replacements in previous years. The replacement cycle ramps up again in 2014 with a focus on data storage frame replacement.

3.2 IT Desktops, Laptops, Tablets, Printers, and Plotters

Desktop and laptop computers are used by most Hydro One staff for office productivity applications such as email, word processing, spreadsheet, presentation, 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.

Equipment refresh maintains or reduces 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, and business needs. 2011 and 2012 costs include increased hardware requirements to accommodate the planned upgrade to Microsoft Windows 7 and the upgrade of Microsoft Office suite. The hardware spend in 2011 and 2012 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 2013 and 2014.

3.3 Telecom Infrastructure

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. Voice or data network improvements or replacements are undertaken to improve network efficiency and to ensure equipment is current and supported by third party vendors.

Projects regularly undertaken include rewiring local area networks, replacing end of life data network switches and routers, upgrading telephone Private Branch Exchange (PBX) switches, replacing un-interruptible power source system, and upgrading the security solutions for external network interfaces.

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, and business needs for increased bandwidth.

3.4 Smart Grid

To support the investment in the Smart Grid program there is also necessary investments in server infrastructure to support the applications and tools required to manage and monitor the Grid. The associated documentation for this initiative is filed under Exhibit D1, Tab 3, Schedule 3, specifically in Sections 2.2.8 and 3.9.1.

4.0 DEVELOPMENT PROJECTS

In support of the business technology roadmap, Development Projects deliver expanded business capability through the introduction of new enabling technologies as well as protecting our current technology investments by addressing end of life replacements of business applications. The business technology roadmap identifies the sequencing and timing of key IT projects and the spend in year varies in line with that overall strategy. 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	
	2009	2010	2011	2012	2013	2014	2013	2014
CRM	0.2							
CTI Upgrades[1]						5.0		
Mobile IT	1.0	3.6	2.2	4.5		1.0		0.6
Warehouse Bar Coding	0.4	1.1	1.4					
HST Implementation		2.5	(0.0)					
HOLMS Replacement						1.0		0.6
eCustomer Self-Service Web Site[1]	1.9	1.1				2.0		
Enterprise GIS Program		3.1	2.5	5.8	6.8	1.0	2.6	0.5
DX Asset Information System[1]	0.5	0.1						
Total	**4.0**	**11.5**	**6.1**	**10.3**	**6.8**	**10.0**	**2.6**	**1.7**

[1]These projects are Hydro One Distribution related only.

4.1 CTI Upgrades

Hydro One's current Computer Telephony Interface (CTI) platform will require replacement to accommodate tighter integration between CTI and the Work force optimization scheduling tool sets. This integration will provide improved customer service as calls will be routed, scheduled and dispatched in a more efficient manner. The existing CTI platform was installed in 2005 with minor lifecycle upgrades performed in the interim. The platform will be migrated to voice over internet protocol (VOIP) which will offer enhanced function and reliability.

Computer telephony integration is used at Hydro One for:

- call information display caller's number and screen population on answer;
- automatic dialing and computer controlled dialing (fast dial, preview, and predictive dial.);
- coordinated phone and data transfers between two parties, call center phone control. after-call work notification;
- advanced functions such as call routing, reporting functions, automation of desktop activities, and multi-channel blending of phone, e-mail, and web requests; and
- agent state control and all control for Quality Monitoring/call recording software.

4.2 Mobile IT

Mobile IT in 2012 will build upon the existing investments from 2010 and 2011 which focused on enabling mobile data collection for station and other asset inspection. This project 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 continues to leverage its investment in mobile software which is a standard enterprise mobile tool for data collection and work status reporting and will also interface with the GIS and SAP systems. The applications work in a connected (real time) or disconnected mode depending on the nature of the work being performed and the availability of telecommunications connectivity. The mobile work plan for 2012 focuses on uplifting existing data collection forms to the new standard and mobile platform as well as incorporating the ability to record images from the field as part of an asset record.

In 2014 there is a lifecycle refresh project to keep the investment in the Enterprise Mobile platform vendor supported.

4.3 HOLMS Replacement

This project will replace our existing Hydro One Learning Management System (HOLMS) that handles input, scheduling, delivery, tracking of training for all employees. The intent is to use native SAP function and decommission the current application. It will eliminate the need for interfaces that currently exist between SAP and the current learning management system. Similar to Cornerstone Phases, the scope consists of and is restricted to doing what is required to turn on the SAP product and make it work as designed in the business requirements, with no SAP software customizations or unnecessary enhancements.

4.4 eCustomer Replacement

This project is a complete re-design of how we interact with our customers online. Currently Hydro One leverages a customer portal for customers to access account information details and history. While a secure portal for customers to access is an important part of the experience, it is also important that we become more accessible to turn around inquiries and more effectively direct them to the correct resource for resolution. Improved analytics can be used to anticipate customer needs and update FAQ pages with the end goal being a lower overall cost of interacting with customers while providing a better customer experience.

4.5 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.

The 2012 to 2014 work plan for Geospatial Information Systems includes a major upgrade of Hydro One’s primary spatial technologies, the consolidation of multiple spatial repositories into a single spatial container and the creation of an automated interface that will synchronize the asset registry in SAP with the physical location of the assets in GIS.

Hydro One's GIS system is based on ESRI ArcGIS, Telvent ArcFM and Rolta OnPoint platforms which integrate with other enterprise applications. The production version 9.2 GIS software was released in 2006 and is nearing the end of its support cycle along with much of the supporting hardware operating systems & application development platforms. The proposed upgrade to 10.x GIS software is planned be completed in 2013.

At the present time, there is no single system of record for spatial data; it is managed in silo databases and business processes across Hydro One. Consumers of spatial data are required to maintain their own spatial repositories, which do not necessarily reflect the current state of the network. The Final Destination initiative will consolidate these silos into a single spatial repository by 2013.

Hydro One's asset data is primarily recorded in two systems: SAP Enterprise Asset Management (EAM) and ESRI Geographic Information System (GIS). Each of these systems has a unique view of the same assets: EAM holds the financial and work-oriented view, while GIS holds the spatial and connectivity view. The integration of SAP and GIS in 2012 will achieve a synchronized, composite asset register, including distribution and transmission assets, comprised of the Hydro One's major asset management systems.

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 being 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.

Phase 2 (Majority Completed August 2009, minor items completed in 2010): Replaced end of life PeopleSoft application for Finance / Human Resources / Payroll processing with functionality provided by SAP Enterprise Resource Planning ("ERP") 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 using SAP's Business Intelligence ("BI") platform.

Phase 3 (In-Service 2011-2014): Enhance integrated planning, Enterprise Asset Management / Enterprise Resource Planning / Business Intelligence 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 and enhancing SAP functionality for asset analytics, business planning, planning/scheduling/dispatch and supply chain optimization as well as integrating specialized software applications for asset investment planning, geo-spatial analytics and engineering & design. The in-service dates for this phase have been extended over the period of 2011-2014 due to the advancement of the Cornerstone Phase 4 initiative. Supply Chain optimization work was completed successfully in June 2011. Asset Analytics, Business Planning & Consolidation, Asset Investment Planning and Engineering Design projects are currently underway. Planning, Scheduling and Dispatch improvements are targeted for 2013/2014.

Phase 4 (2011-2013): Replace end of life Customer Information System ("CIS") including customer/account services, billing, settlements, and open market systems. The CIS project is currently replacing the legacy CIS systems with a unified platform based primarily on SAP's industry leading billing application – Customer Relationship & Billing (CRB). In addition to SAP, the project is implementing an Itron application to facilitate integration to and from the IESO for billing of Time Of Use residential customers as well as perform meter data management for interval billed commercial and industrial customers. This implementation will upgrade numerous capabilities across the organization from customer interaction to customer demand management to service order processing to device management. This initiative will also integrate CIS into the current SAP core, which will provide benefits due to tighter integration with the Work Management and Finance applications. This phase supports only Hydro One Distribution and no costs are reflected in the Hydro One Transmission revenue requirement.

Table 1 below identifies the capital expenditures for the Cornerstone program for the period 2009 to 2014.

Table 1
Cornerstone Capital 2009 – 2014 ($ Millions)

	Historic			Bridge	Test		TX Allocated	
	2009	**2010**	**2011**	**2012**	**2013**	**2014**	**2013**	**2014**
Minor Fixed Assets	0.2	0.3	11.0	2.4	-	-	-	-
Development Projects	90.7	18.9	59.7	125.5 *	26.8	10.0	15.2	5.7
Total Capital Cost	90.9	19.2	70.7	127.9 *	26.8	10.0	15.2	5.7

* 2012 - $103.8M is directly allocated to DX only for Cornerstone Phase 4 (CIS)

The Cornerstone capital expenditures consist of Minor Fixed Assets and Development Costs. The latter includes all the costs to acquire, install and place into service the new systems. Capital expenditures support the Sustainment, Development, and Operations work programs of Hydro One Networks Inc. As such, Phase 1, 2 & 3 consist of assets that are largely shared by both the Transmission and Distribution businesses with Cornerstone Phase 4 being allocated solely to Hydro One Distribution. The differences in year to year expenditures are the result of the phasing of the Cornerstone implementation. The Cornerstone Project OM&A spending is shown in Exhibit C1, Tab 4, Schedule 05.

<u>Cornerstone Value Realization (Benefits):</u>
Hydro One has implemented the first two phases of the program and is realizing value across the following four value areas: Productivity, Cost Effectiveness and Process Efficiency; Better Decisions; Compliance; and Employee Engagement. The Cornerstone program is continuing to drive forward on the next phases and will extend and expand upon these same value areas as the program rolls out across new business functions. Additional detail for how Cornerstone aligns to these value areas is as follows:

- Productivity, Cost Effectiveness and Process Efficiency

  Cornerstone has addressed business operation inefficiencies through the adoption of industry standard processes. Hydro One has not customized the business systems to accommodate current business processes; rather, Hydro One has replaced current business processes with industry standard practices that are fully supported by our new business systems. Cost effectiveness is achieved with the reduction in material costs and material handling costs as well as IT application operating costs. Process efficiency generates value by streamlining business operations.

- Better Decisions

  Better decision making arises from leveraging better information to optimize decisions on asset investments, system reliability and customer needs. To aid in enabling this objective, Cornerstone has provided an integrated system of record and business intelligence reporting and analytics platform for asset and business data which allows for easier access to reliable data for developing investment strategies.

- Compliance

  Cornerstone has facilitated improved adherence to the internal controls framework. Hydro One can now better adapt to changing conditions and promote internal efficiency, and more easily ensure the reliability of financial statements and compliance with laws and regulations.

- Employee Engagement

  Cornerstone supports the corporate Human Resources strategy by securing employee commitment through: cultivating staff ownership of processes and information; pride in achieving enhanced productivity; and confidence in compliance with standardized procedures.

Through this program delivery approach, the Cornerstone Program is well positioned to achieve the value targets from Phases 1, 2, 3 and 4. As each of the phases are built upon the SAP foundation, the achievement of the savings from these investments is being tracked together as a part of the overall Cornerstone program. Table 2 provides a summary of the realized savings from 2009-2011 as well as a summary of the savings projected for 2012-2014. The overall value of the Cornerstone Project is tracking to plan.

Table 2
Allocated Cornerstone Value Realization 2009 – 2014 ($ Millions)

	Realized – Total Program			**Planned – Total Program**		
	Historic			**Bridge**	**Test**	**Test**
	2009	**2010**	**2011**	**2012**	**2013**	**2014**
TX OM&A	6.3	13.1	15.7	15.7	17.4	18.4
TX Capital	4.5	9.7	12.4	12.4	18.7	24.0
Total TX	10.8	22.8	28.1	28.1	36.1	42.4
DX OM&A	4.2	6.7	7.2	7.2	21.4	27.9
DX Capital	3.1	4.1	6.0	6.0	8.4	10.2
Total DX	7.3	10.8	13.2	13.2	29.8	38.1
Total	**18.1**	**33.6**	**41.3**	**41.3**	**65.9**	**80.5**

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 is well underway for both Phase 3 and Phase 4. The first three phases of the Cornerstone Project are discussed below:

Phase 1 – Enterprise Asset Management ("EAM") 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. Phase 1 savings (both Transmission and Distribution) total $200 million over a seven year period beginning in 2009. Total savings of $62.2M are expected in the test years 2013 and 2014 as shown in Table 3 and have been incorporated into the current business plan.

Table 3
Total Cornerstone Phase 1 Savings ($M) (Transmission & Distribution)

	2009	**2010**	**2011**	**2012**	**2013**	**2014**
OM&A	8.9	16.0	18.2	18.2	18.2	18.2
Capital	6.4	11.1	12.9	12.9	12.9	12.9
Total	**15.3**	**27.1**	**31.1**	**31.1**	**31.1**	**31.1**

As Phase 1, Phase 2 and in-service portions of Phase 3 have been implemented within an integrated SAP solution of EAM, ERP and BI; savings are tracked based on the integrated solution. Phase 1 and Phase 2 Savings have a cumulative LTD value of $90.6M and an end target of $250M over 7 years. Phase 3 has a LTD value of $2.5M and an end target in the range of $160-$200M of savings. These savings are being realized across 3 primary areas: Strategic Sourcing and Discount Capture; Headcount reductions relative to the EB-2010-0002 filing; and through the rationalization of legacy IT systems.

<u>Strategic Sourcing and Discount Capture:</u>

Through improved collaboration across the business units and better visibility through SAP, the supply chain organization is able to execute a go-to-market strategy consisting of an approved set of standardized ratings with firm volume commitments resulting in significant reductions in the unit pricing with the vendors. The net result is a reduced material cost for projects and programs within the work program. In addition, through better analysis and management of contractual terms, the supply chain organization is better able to define payment terms and achieve discounts through timely approvals. These reduced material costs are reflected in the in-year actuals as well as for the test years. Graph 1 represents the value realized from the strategic sourcing value area.

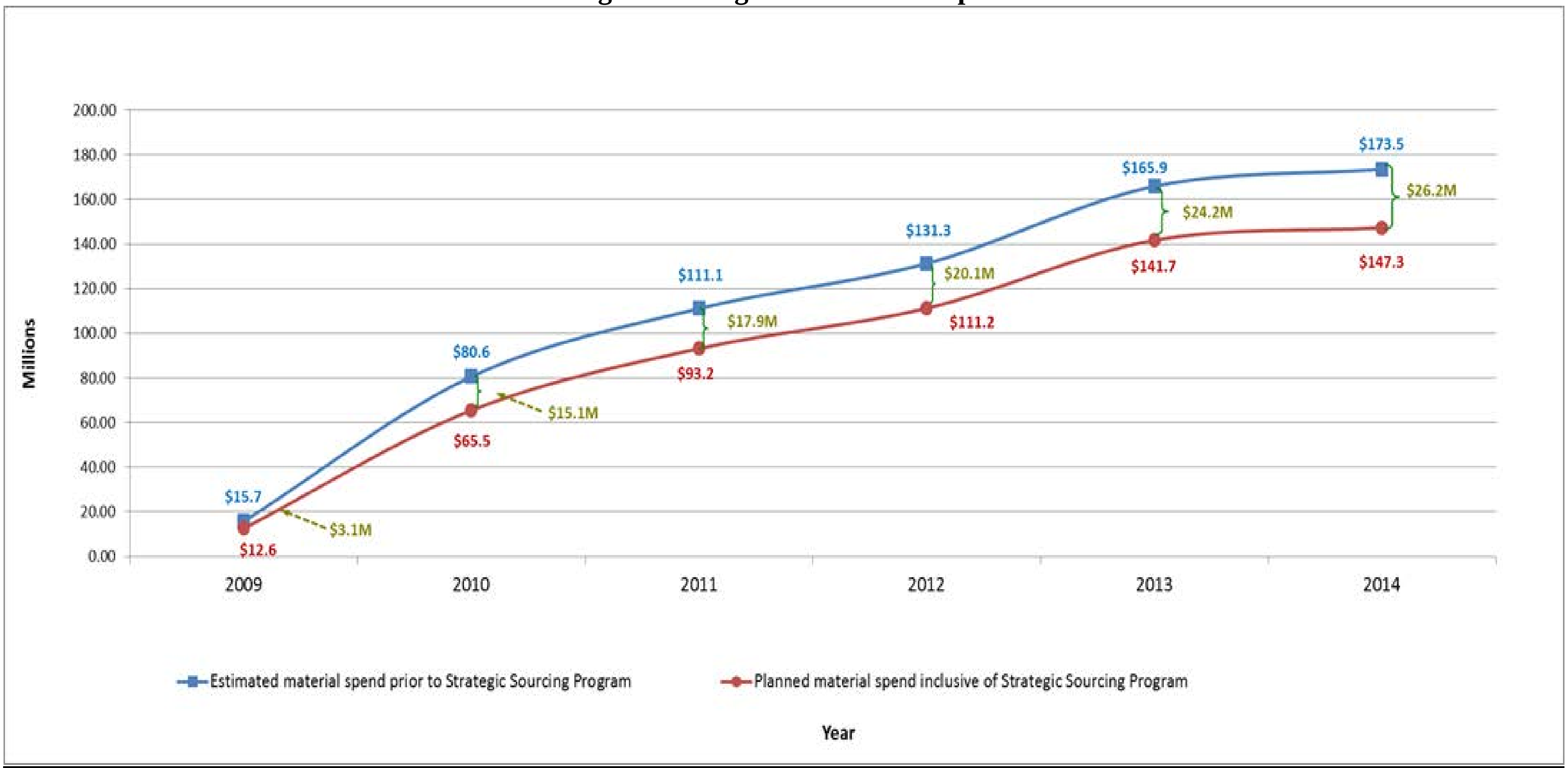
Process Efficiencies enabling Headcount Reductions:

Through improved business processes enabled by SAP functionality and workflow, access to the right information at the right time through SAP Business Intelligence and improved collaboration across the business units, all lines of business were able to reduce their headcount requirements relative to the EB-2010-0002 filing. The net result is a labour savings for projects and programs within the work program. This reduced labour cost is reflected in the in-year actuals as well as for the test years. Graph 2 represents the value realized from the process efficiency value area.

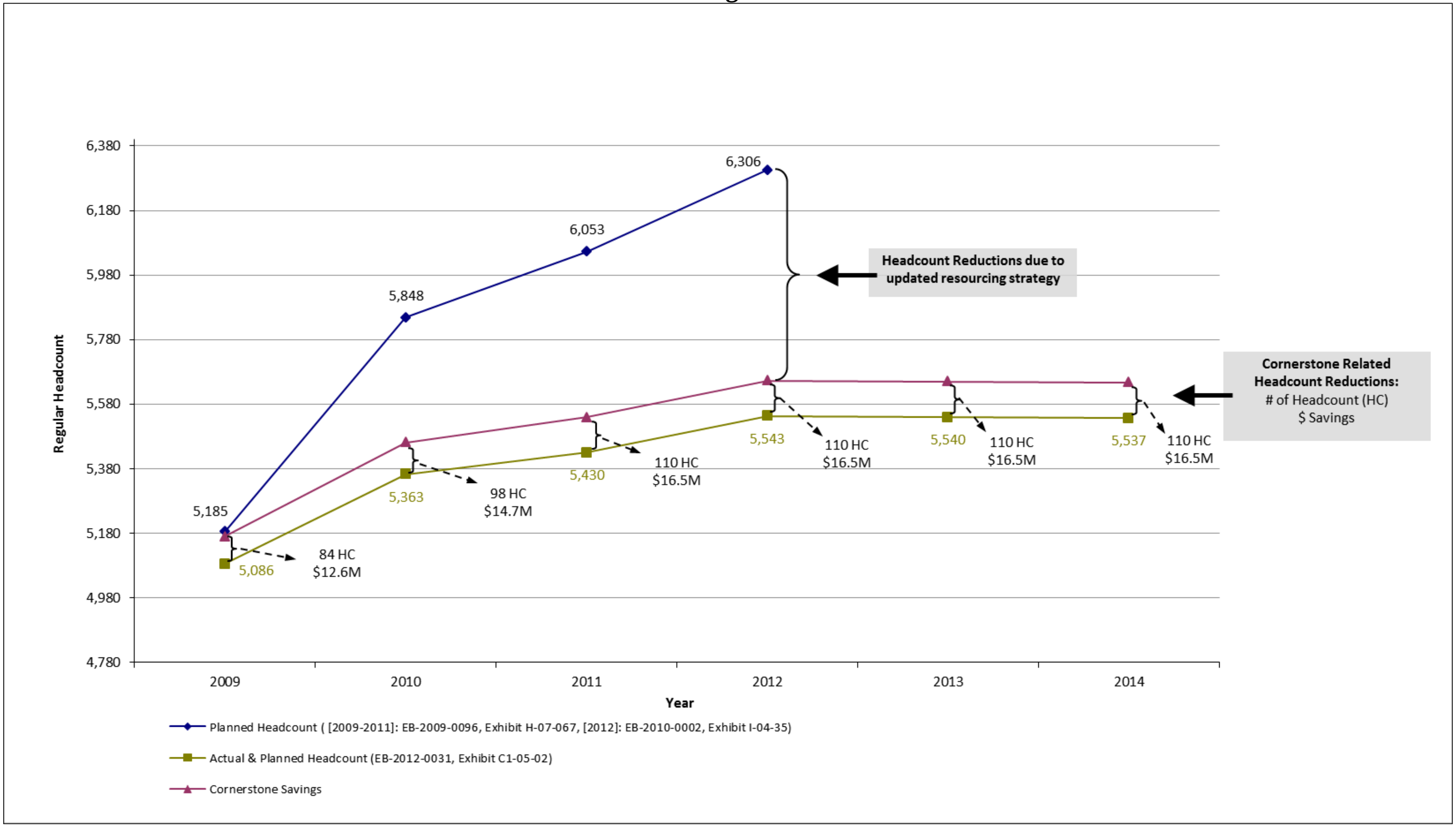
Application Rationalization:

Through the Cornerstone program, IT has been able to drive a rationalization of legacy IT systems including major systems replaced as the core functionality of Phase 1 and 2 as well as many ancillary business and system tools that have been absorbed into the SAP landscape. The net result is a reduction in IT application, database, license and support costs for over 450 (life to date, year end 2011) business software applications and system tools. This reduced IT cost is reflected in the in-year actuals as well as for the test years. Graph 3 represents the value realized from the Application Rationalization value area.

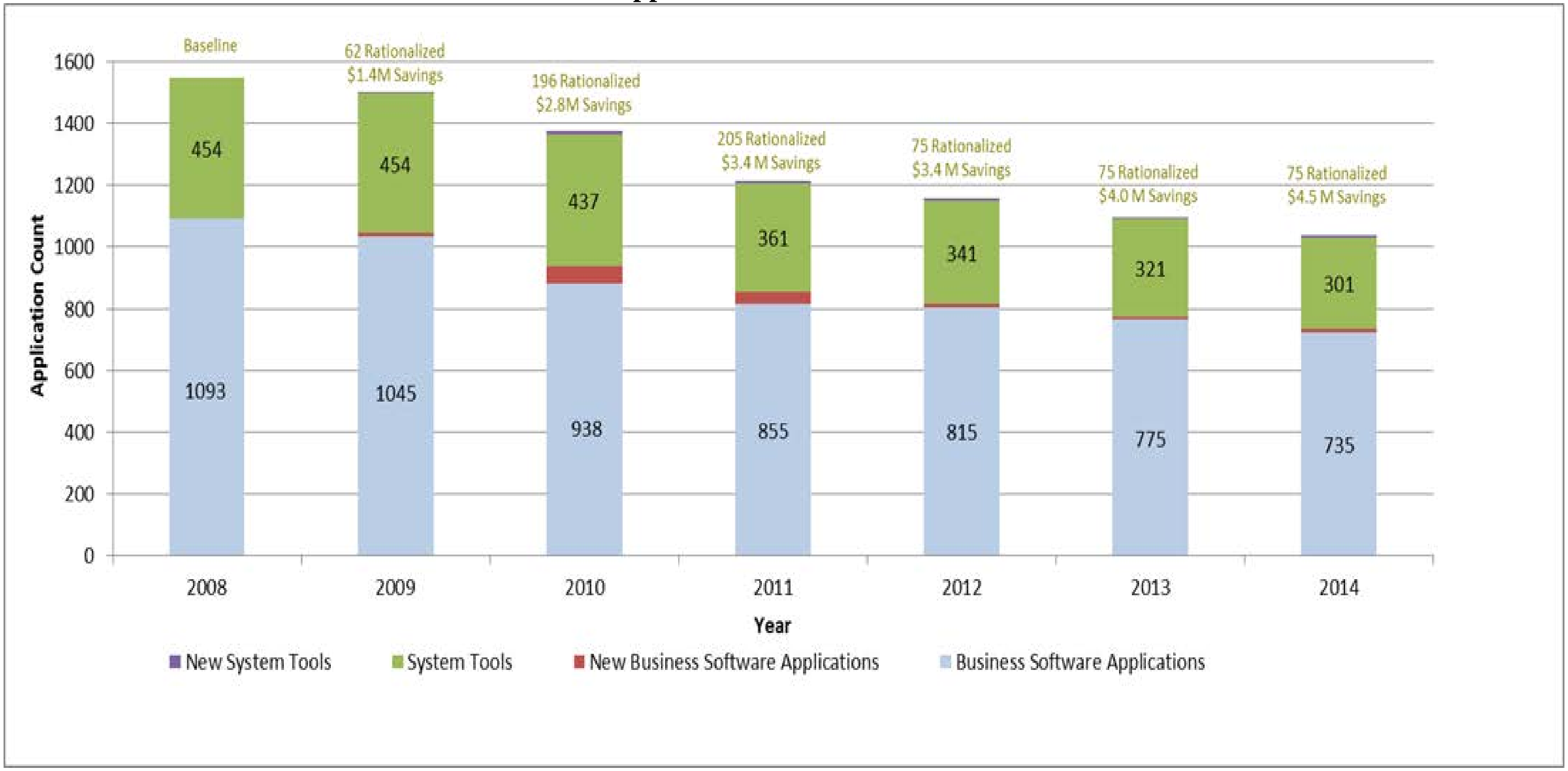
Graph 1
Strategic Sourcing and Discount Capture



Graph 2
Process Efficiencies enabling Headcount Reductions



Graph 3
Application Rationalization



Phase 2 – Enterprise Resource Planning ("ERP") and Business Intelligence ("BI") Functionality (Majority Completed August 2009, minor items completed in 2010)

The ERP & BI initiative replaced the existing PeopleSoft, Cognos and SAS applications with a modern SAP ERP and BI solution in August 2009 integrated into the Phase 1 SAP EAM solution. The result is an integrated enterprise suite that has further enabled more effective information access and productivity within the company. Phase 2 savings (both Transmission and Distribution) total $50 million over a seven year period starting in 2009. Total savings of $15.6 million are expected in the test years 2013 and 2014 as shown in Table 4 and have been incorporated into the current business plan.

Table 4
Total Cornerstone Phase 2 Savings ($M) (Transmission & Distribution)

	2009	**2010**	**2011**	**2012**	**2013**	**2014**
OM&A	1.6	3.8	4.6	4.6	4.6	4.6
Capital	1.2	2.7	3.2	3.2	3.2	3.2
Total	**2.8**	**6.5**	**7.8**	**7.8**	**7.8**	**7.8**

As Phase 1 and Phase 2 have been implemented within an integrated SAP solution of EAM, ERP and BI; savings are tracked based on the integrated solution. Please refer to explanation following Table 3 for details on the realization of Phase 2 benefits.

Phase 3 Enhanced Integrated Planning (In-Service 2010-2014):

Phase 3 will enhance integrated planning, Enterprise Asset Management / Enterprise Resource Planning / Business Intelligence 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 and enhancing SAP functionality for asset analytics, business planning, planning/scheduling/dispatch and supply chain optimization as well as integrating specialized software applications for asset investment planning, geo-spatial analytics and engineering & design automation. The in-service dates for this phase have been extended over the period of 2011-2014 due to the advancement of the Cornerstone Phase 4 initiative. Supply Chain optimization work was completed successfully in June 2011. Asset Analytics, Business Planning & Consolidation, Asset Investment Planning and Engineering Design projects are currently underway. Planning, Scheduling and Dispatch improvements are targeted for 2013/2014.

<u>Supply Chain Optimization Project:</u>

Following the core supply chain implementation in Cornerstone Phase 1, it was recognized that there were additional optimization opportunities to expand the supply chain functionality. The objectives of the optimization project were to further enhance capabilities for strategic sourcing, discount capture, electronic interaction with vendors for procurement and invoicing, and services procurement. The Supply Chain Optimization project completed successfully in June 2011 and the value associated with expanded strategic sourcing and discount capture are tracking to plan.

<u>Asset Analytics:</u>

Enhanced Asset Management (AM) Analytics builds on the success of Cornerstone Phases 1 and 2 by developing a cascading delivery framework of asset management analytics that leverages SAP Business Intelligence to guide/support investment planners to make strategic asset lifecycle investment decisions that optimize cost and operational risks. Analytic tools are being developed to consistently provide a comprehensive and cascading information view of asset risks/priorities based on demographics, condition, performance, criticality, obsolescence, customer, Health Safety & Environment and other operational risks. The Asset Analytics project is currently underway with an in-service date of January 2013 and will achieve value associated with maintenance cost reductions, process efficiencies for asset management staff and improved prioritization of the asset needs to optimize investments.

<u>Business Planning and Consolidation Project:</u>

The SAP BusinessObjects Planning & Consolidation ("BPC") tool provides the framework in which to include the entire business planning, forecasting and reporting process, and will be fully integrated with SAP. The main function of the model is to prepare financial information in support of the business planning process and rate applications to the Ontario Energy Board. The BPC project is currently underway with an in-service date of June 2012 and will achieve value associated with process efficiencies for finance and operating lines of business as well as improved risk mitigation associated with business planning integrity and quality.

<u>Asset Investment Planning ("AIP"):</u>

AIP will deliver business value through revised business processes and tools that will optimize investment decisions aligned with Hydro One strategic objectives, support business planning, investment scenario analysis, estimating, in-year / across-year redirection and improve the collaborative end-to-end investment planning processes as well as support regulatory rate filings. The AIP Project will build upon previous Cornerstone investments and will implement corporate wide investment planning, prioritization and optimization processes through integrated processes and tools in a phased approach. The AIP project is currently underway with a staged approach for a stand-alone implementation in 2012 and a fully integrated solution in 2013 and will achieve value associated with process efficiencies for asset management and operating lines of business as well as improved investment decisions.

Engineering Design Transformation (“EDT”):

The EDT initiative is planned in a staged approach to deliver improvements in engineering design and automation. Stage 1 is currently underway to implement a configured Electrical Design Automation toolset. The full implementation plan will be developed for implementation in 2013. Value is expected to be achieved in the areas of improved engineering design through improved speed to construction, enhanced design accuracy and quality, further standardization and repeatability and loop diagram automation.

Planning, Scheduling and Dispatch:

The Planning, Scheduling and Dispatch project will expand and improve the business processes of work initiation, planning (90+ days), scheduling (5-90 days), dispatch (0-5 days) and work completion and reporting. The solution will leverage SAP, Mobile and GIS investments to improve back office and field worker productivity and drive improved quality and consistency of data captured at source. This initiative is planned to be in-service in 2014 with benefits ramping up starting in 2015.

Phase 3’s implementation schedule has been extended through 2014 due to the advancement of Cornerstone Phase 4. Costs and benefits have been adjusted accordingly. Hydro One expects savings from improved processes, elimination of duplicative data systems and improved transparency across the organization. Total savings of $40.1million are expected in the test years 2013 and 2014 as shown in Table 5.

Table 5
Total Cornerstone Phase 3 Savings ($M) (Transmission & Distribution)

	2009	**2010**	**2011**	**2012**	**2013**	**2014**
OM&A	-	-	0.2	0.2	5.2	7.2
Capital	-	-	2.3	2.3	10.7	17.0
Total	**-**	**-**	**2.5**	**2.5**	**15.9**	**24.2**

Phase 3 benefits are being realized in 2011/2012 for the in-service project (Supply Chain Optimization) and savings are being tracked as a part of the integrated solution. Additional savings will ramp up over the 2013-2015 years to include benefits from Asset Analytics, Business Planning & Consolidation, Asset Investment Planning, Engineering Design Transformation and Planning and Scheduling. The Phase 3 estimated benefit of $160-$200 million will follow the same methodology utilized for Phase 1 & 2 benefits.

Phase 4 (2011-2013) - Replace Customer Information System ("CIS") Functionality (Hydro One Distribution Only)

Phase 4 of the Cornerstone Program will replace end of life Customer Information System ("CIS") including customer/account services, billing, settlements, and open market systems. The CIS project is currently replacing the legacy CIS systems with a unified platform based primarily on SAP's industry leading billing application – Customer Relationship & Billing (CRB).

Hydro One expects Distribution Business savings from the CIS implementation to total $172 million over a 7 year time horizon. Total savings of $28.7 million are expected in the test years 2013 and 2014 as shown in Table 6 and these savings have been incorporated into the current business plan.

Table 6
Total Cornerstone Phase 4 Savings ($M) (Distribution)

	2009	**2010**	**2011**	**2012**	**2013**	**2014**
OM&A	-	-	-	-	10.8 *	16.4 *
Capital	-	-	-	-	0.4 *	1.1 *
Total	**-**	**-**	**-**	**-**	**11.2 ***	**17.5 ***

* Hydro One Distribution only for Cornerstone Phase 4 (CIS)

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 2013 and 2014 Transmission amounts.

Table 1
Total Facilities and Real Estate Capital Expenditures ($ Millions)

Description	Historic			Bridge	Test		TX Allocation	
	2009	2010	2011	2012	2013	2014	2013	2014
Major	16.0	21.7	25.4	39.1	38.0	38.0	21.6	21.6
MFA	1.1	0.8	0.5	6.0	6.0	6.0	3.4	3.4
Total	17.1	22.5	25.9	45.1	44.0	44.0	25.0	25.0

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 including head office space improvements.

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.

2.1 Field Facilities Accommodations Requirements

Table 2
Total Field Facilities Capital Expenditures ($ Millions)

Description	Historic			Bridge	Test		TX Allocation	
	2009	2010	2011	2012	2013	2014	2013	2014
Major	16.0	21.3	24.9	27.0	26.0	26.0	14.7	14.7
MFA	0.8	0.8	0.5	1.5	1.5	1.5	0.9	0.9
Total	16.8	22.1	25.4	28.5	27.5	27.5	15.6	15.6

The capital work program includes improvements to existing facilities, building additions and 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 work programs and changing business requirements.

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 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 $26.0 million in 2013 and 2014 respectively.

2.2 Head Office and GTA Facilities Accommodations Requirements

Table 3
Total Head Office and GTA Facilities Capital Expenditures ($ Millions)

Description	Historic			Bridge	Test		TX Allocation	
	2009	**2010**	**2011**	**2012**	**2013**	**2014**	**2013**	**2014**
Major	0.0	0.4	0.5	12.1	12.1	12.1	6.9	6.9
MFA	0.3	0.0	0.0	4.5	4.5	4.5	2.6	2.6
Total	0.3	0.4	0.5	16.6	16.6	16.6	9.5	9.5

Capital investment of $16.6 million is required for each test year 2013 and 2014. This investment will provide for head office improvements.

In 2010 Hydro One Networks secured an eleven year lease for 483 Bay Street, to serve its ongoing head office requirements. Within the completed lease renewal of 483 Bay, Hydro One Networks was successful in obtaining the commitment of the Landlord to upgrade base building systems/infrastructures and allowances for tenant improvements. The initially planned tenant improvements as outlined in the last transmission rate filling were ultimately deferred during years 2010 and 2011 given consideration to the capital reductions made by the Board in its last transmission decision and the economic situation in the Province of Ontario. The planned improvements are necessary now 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 increasing number of tripping hazards.) Similarly, furniture systems acquired from the previous tenant and refurbished are also now considered to be at end of life.

In 2011 the Company commenced renovations to head office space. The head office tenant improvements are planned to continue during the bridge year and test years.

The head office capital investment consists of both leasehold improvements and replacement furniture systems which will commence in the bridge year 2012 and are expected to continue throughout test years and end in 2014. In each test year the leasehold improvements and the furniture systems funding requirements are estimated to be $12.1 million and $4.5 million. The project costing reflects continuance of the open office environment, completion to standard commercial finishes and commitment to LEED certification.

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 2013 and 2014. This includes replacement of furniture and office equipment 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 2009 to 2014.

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 2013 and 2014 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; and,
- The replacement of core end-of-life Fleet and equipment.

2.0 TRANSPORT AND WORK EQUIPMENT

Transport and Work Equipment capital expenditures, as shown in Table 1, are directly tied to the planned level of activities in the overall work programs, driven by: primarily the core Fleet replacement, additional staffing, changes to the Forestry and Provincial Lines Apprenticeship Programs, as well as supporting the identified levels of the transmission and distribution capital and OM&A sustainment, and development work programs.

Hydro One has approximately 6,700 units with an original capital value ("OCV") of $474 million. Approximately 400 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 185,000 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 2009 – 2014 ($ Millions)

Description	Historic			Bridge	Test		TX Allocation	
	2009	2010	2011	2012	2013	2014	2013	2014
Total Cost	**46.5**	**64.5**	**42.8**	**44.1**	**43.3**	**44.5**	**11.3**	**11.6**

The decrease in actual 2011 and forecast 2012 costs from the previous transmission filing shown in Table 1 above reflects the adjustment of Hydro One Transmission's capital requirements due delays and cancellation of work programs related to the connection of renewable generation since the EB-2010-0002 application. The capital expenditures now primarily address the requirements of our Core Vehicle Replacement Program and are relatively stable through the bridge and test years.

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 vs. 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 2009 to 2014 Period Analysis

As noted in Exhibit C1, Tab 6, Schedule 1 (Costing of Work), the overall size of Hydro One Networks Inc.'s fleet was adjusted to approximately 6,700 vehicles and other equipment in 2012 to match the work program requirements. TWE expenditures are forecasted to be $ 43.3 million in 2013 and $44.5 million in 2014 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 level of capital expenditures proposed for the period of 2012 to 2014 are primarily to address the requirements of the Core Vehicle Replacement Program.

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, with the option of an extension for a 4^{th} and 5^{th} year.

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 a significant amount 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 that all pieces of equipment, ranging from off-roads to helicopters, operate with green standards in mind.

3.0 SERVICE EQUIPMENT

Table 2 identifies the expenditures for Service Equipment for the 2009 to 2014 period.

Table 2
MFA Service Equipment 2009 – 2014 ($ Millions)

Description	Historic			Bridge	Test		TX Allocation	
	2009	2010	2011	2012	2013	2014	2013	2014
Total Cost	**6.6**	**3.8**	**6.7**	**9.9**	**9.3**	**9.8**	**5.4**	**5.6**

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 increased year-over-year. End of life replacement for service equipment is required to ensure safe and efficient operations. Hydro One continues to invest in AED (defibrillator) devices, for example, to enhance basic life support capability at Hydro One workplaces, including offices and vehicles. The fluctuations in historical spend levels reflect the long lead time for purchasing and delivering the equipment. Capital spending remains relatively stable throughout the bridge and test years.

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 2009 to 2014 inventory levels reflect impacts of the increasing work programs with compressed timelines, the increasing transmission asset base and its age, and the external cost pressures, offset by initiatives to manage inventory growth. Various initiatives undertaken by Hydro One Transmission to manage its inventories include the following:

- Integration of planning and procurement processes to maintain the primary strategy of securing materials for transmission capital projects directly from vendors;
- Adjustments in transmission maintenance related inventories to increase flexibility in executing maintenance protocols on the aging asset base
- An increased focus on stocking materials remaining at the end of capital projects to improve the visibility and redeployment of available materials.
- The implementation of stock algorithms to improve inventory performance
- Targeting additional materials to be stocked, where the planning timelines preclude supply directly from the vendors to meet the project requirements

A description of Hydro One Transmission's Supply Chain and initiatives undertaken are described in Exhibit C1, Tab 6, Schedule 1, Section 4.0.

2.0 INVENTORY

As of December 31, 2011, Hydro One Transmission carried a total year-end inventory valued at $16.1 million. Table 1 provides the inventory levels for 2009 to 2014. Included are both the year-end levels and annual average levels for each year.

Table 1
Inventory Levels (Transmission) 2009 – 2014 ($ Million)

	Historic			Bridge	Test	
	2009	**2010**	**2011**	**2012**	**2013**	**2014**
Year End - Materials and Supplies	12.3	12.6	16.1	3.5	3.4	3.5
Annual Average[1]	**11.7**	**12.5**	**14.4**	**9.8**	**3.5**	**3.5**

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

2.1 Planned Levels of Inventories

Much of Hydro One Transmission's materials and supplies are supplied directly from vendors. Inventory is established to provide faster response to planned and unplanned projects and programs from inventoried stock. The basis of forecasting inventory levels reflects planned work program changes.

Materials and Supplies for major transmission projects are often shipped directly to the project sites and are not included in the planned inventory levels, where timelines permit. Inventories are held for the maintenance of existing assets and new development activities. Inventory primarily includes component parts for major equipment and selected materials where lead times and response requirements dictate, as well as materials and equipment that remain at the end of a project.

2.2 Monthly Inventory Levels 2009 to 2011

In response to the Board's directive to the Company, to provide the monthly material and supplies inventory balances as part of rate applications, actual monthly net inventory numbers for the years 2009 through 2011 are shown in Table 2 below.

Table 2
Historical Monthly Inventory Levels 2009 – 2011[1]

$M	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2009	11.6	11.6	11.8	11.8	11.8	11.9	12.0	12.5	12.0	12.0	12.2	12.3
2010	12.3	12.5	12.3	12.0	12.2	12.0	12.0	12.1	12.6	12.6	12.5	12.6
2011	12.6	12.4	12.5	12.7	12.8	12.8	13.5	13.4	13.3	13.2	13.0	16.1

[1] Does not include strategic spare parts inventory.

The inventories of consumable materials are relatively steady due to the nature of transmission work. Failures and maintenance is driven by equipment age, service and available outages. Capital projects are conducted year round, with a slight increase in the summer months and the winter cold months.

HYDRO ONE NETWORKS INC.
TRANSMISSION
Statement of Utility Rate Base
Test Years (2013 and 2014)
Year Ending December 31
($ Millions)

Line No.	Particulars	2013 (a)	2014 (b)
	Electric Utility Plant		
1	Gross plant at cost	$ 14,426.6	$ 15,329.2
2	Less: accumulated depreciation	(4,982.8)	(5,271.0)
3	Net plant in service	$ 9,443.9	$ 10,058.2
4	Construction work in progress	0.0	0.0
5	Net utility plant	$ 9,443.9	$ 10,058.2
	Working Capital		
4	Cash working capital	$ 12.7	$ 11.9
5	Materials and Supplies Inventory	3.5	3.5
6	Total working capital	$ 16.1	$ 15.3
7	Total rate base	$ 9,460.0	$ 10,073.5

COMPARISON OF NET CAPITAL EXPENSE BY MAJOR CATEGORY

	Historic			Bridge	Test	
	2009	2010	2011	2012	2013	2014
Transmission Capital ($ millions)						
Sustaining						
Transmission Stations						
Circuit Breakers	16.6	29.6	29.2	17.6	25.0	25.3
Station Reinvestment	34.6	17.9	36.4	110.2	179.6	190.2
Power Transformers	48.7	106.8	81.1	57.0	87.4	104.8
Other Power Equipment	13.1	13.9	16.2	18.3	22.3	25.6
Ancillary Systems	6.0	13.3	13.5	16.5	19.9	22.0
Stations Environment	3.0	4.0	7.0	6.6	11.6	11.0
Protection, Control, Monitoring, and Telecommunications	82.0	66.8	61.6	107.6	128.5	108.3
Transmission Site Facilities and Infrastructure	20.1	32.3	21.7	21.2	30.0	32.7
Total Transmission Stations Capital	224.1	284.7	266.5	355.1	504.2	519.9
Transmission Lines						
Overhead Lines Refurbishment and Component Replacement	56.8	54.0	52.4	55.5	70.6	68.3
Transmission Lines Reinvestment	15.2	16.2	17.1	10.3	37.9	37.8
Underground Lines Cable Refurbishment & Replacement	4.1	1.4	1.0	5.9	23.9	30.0
Total Transmission Lines Capital	76.0	71.6	70.6	71.6	132.4	136.2
Total Sustaining Capital	300.1	356.3	337.1	426.7	636.5	656.0

		Historic		**Bridge**	**Test**	
	2009	**2010**	**2011**	**2012**	**2013**	**2014**
Development						
Inter Area Network Transfer Capability	343.1	392.8	269.1	142.3	114.8	186.3
Local Area Supply Adequacy	93.7	58.5	57.5	122.2	89.8	46.2
Load Customer Connection	54.4	33.8	51.1	95.7	73.3	30.6
Generator Customer Connection	4.5	3.9	0.1	1.9	3.7	0.8
Performance Enhancement & Risk Mitigation	19.2	19.6	19.0	27.8	27.9	7.5
TS Upgrades to Facilities Distribution Generation	0.2	12.5	10.3	13.7	0.0	28.0
P&C Enablement for Generation Connections	0.9	2.1	3.1	1.4	2.8	13.1
Smart Grid	0.0	0.0	5.8	7.0	2.0	0.0
Total Development	515.9	523.1	415.9	412.1	314.2	312.5
Operations						
Grid Operating and Control Facilities	11.3	3.6	3.7	12.5	15.1	15.5
Operating Infrastructure	8.7	4.0	5.0	35.4	32.4	41.0
Total "Operations"	20.0	7.6	8.8	47.9	47.5	56.5
Shared Services and Other Costs						
Transport, Work & Service Equipment	14.0	17.1	13.1	17.2	16.7	17.2
Information Technology (including Cornerstone)	60.1	24.7	32.9	31.9	30.1	20.9
Facilities & Real Estate	6.3	7.6	3.9	25.6	25.0	25.0
Other (including CDM)	1.4	(0.2)	(1.5)	0.3	0.3	0.3
Total Shared Services & Other Costs	81.8	49.1	48.4	75.0	72.1	63.5
Total Transmission Capital	917.8	936.1	810.2	961.7	1,070.4	1,088.5

LIST OF CAPITAL INVESTMENT PROGRAMS OR PROJECTS REQUIRING IN EXCESS OF $3 MILLION IN TEST YEAR 2013 OR 2014 ($ MILLIONS)

1.0 SUSTAINING CAPITAL (EXHIBIT D1, TAB 3, SCHEDULE 2)

1.1 Stations

		2013	2014
S1	Oil Circuit Breaker (OCB) Replacements	9.0	8.6
S2	SF6 Circuit Breaker Replacements	11.0	11.1
S3	GTA Metalclad Switchgear Replacements	12.0	12.0
S4	Albion TS Metalclad Switchgear Replacement	5.1	7.0
S5	Kenilworth TS Metalclad Switchgear Replacement	0.2	6.3
S6	Hanmer TS – 500kV ABCB Replacement	7.5	0.0
S7	Orangeville TS – 230kV ABCB Replacement	8.2	0.0
S8	Pickering A SS – 230kV ABCB Replacement	5.4	1.4
S9	Richview TS – 230kV ABCB Replacement	14.6	15.0
S10	Beck #2 TS – 230 kV ABCB Replacement	3.8	12.4
S11	Bruce A TS- 230kV ABCB Replacement	20.0	14.0
S12	Burlington TS – 230kV ABCB Replacement	5.8	1.9
S13	Abitibi Canyon SS / Pinard TS: Reconfigure and Demerge	24.0	0.0
S14	Beck #1 SS - Build New Switchyard	0.0	2.0
S15	Wallaceburg: TS – Reconfigure to Address Failed Transformers	9.8	0.0
S16	Gage TS EOL Asset Replacement	0.2	16.9
S17	Merivale GIS Bus Replacement	4.9	0.0
S18	NRC TS Rebuild	10.7	10.0
S19	Integrated DESN Investments	58.0	94.1
S20	Replace EOL CGE Transformers	3.5	0.0
S21	Large Power Transformer Replacements	64.8	84.9
S22	Operating Spare Transformer Purchases	12.7	13.1
S23	Disconnect Switch Replacements	7.7	9.3

		2013	2014
S24	Capacitor Bank Replacement Program	3.7	5.1
S25	Instrument Transformer Replacement Program	3.1	3.2
S26	Insulator Replacement Program	4.8	5.0
S27	Station Service Replacements	11.1	12.5
S28	Station Grounding System Replacements	4.9	5.5
S29	Spill Containment Refurbishment & Installation	11.6	11.0
S30	Bruce Special Protection System (BSPS) Replacement	20.7	0.0
S31	ITC - Line Protection Replacements	2.5	2.5
S32	NYPA Tie-Lines - Beck Line Protection Replacement	10.1	1.0
S33	Station P&C Replacements	15.0	30.0
S34	Protection Replacements	19.3	22.1
S35	RTU Replacements	8.4	8.4
S36	DC Signaling (Remote Trip) Replacements	4.8	5.0
S37	DC Signaling Replacements (Toronto North & East)	3.4	0.9
S38	Protection Tone Channel Replacement	5.0	5.0
S39	ITMC Refreshment	2.9	1.1
S40	TDCN Cyber Security	6.7	0.0
S41	NERC CIP V5 Readiness	10.0	9.0
S42	Cyber Security of Load Stations	0.0	6.6
S43	Cyber Systems Life Cycle Management	3.0	3.0
S44	Station Fences and Security Infrastructure	8.9	10.8

1.2 Lines

		2013	2014
S45	Wood Pole Replacement Program	28.0	28.8
S46	Steel Structure Coating Program	10.0	10.9
S47	Shieldwire Replacement Program	5.6	5.7
S48	Transmission Lines Emergency Repairs	7.1	7.9
S49	Insulator Replacement Program	7.3	3.3
S50	S2B Steel Structure Replacements	1.0	0

		2013	2014
S51	Steel Structure Replacement Program	3.6	3.6
S52	C25H Line Refurbishment	0.0	15.0
S53	D1A Line Refurbishment	3.2	0.0
S54	H27H Line Refurbishment	7.5	7.0
S55	V73R/V74R Self Damping Conductor Replacement	7.0	2.0
S56	H24C Line Refurbishment	12.2	13.5
S57	C27P Line Refurbishment	6.2	0.0
S58	Ottawa - Hwy 417 Interchange (Recoverable)	3.2	0.0
S59	Keith TS Hwy 401 Expansion (Recoverable)	11.4	8.9
S60	Toronto-TTC Maintenance Facility (Recoverable)	8.0	0.0
S61	Sudbury-Maley Dr Extension/Widening (Recoverable)	1.2	0.0
S62	H2JK/K6J Underground Cable Replacement	22.5	24.5

Summary – Sustainment	2013	2014
Total Sustaining Projects & Programs Listed Above	**603.8**	**598.8**
Sustaining Projects & Programs Less than $3 M	**72.7**	**74.9**
Total Gross Sustaining Capital (per Exhibit D1-3-3)	**676.5**	**673.7**
Less Capital Contribution	**40.0**	**17.7**
Total Net Sustaining Capital (per Exhibit D1-3-3)	**636.5**	**656.0**

2.0 DEVELOPMENT CAPITAL (EXHIBIT D1, TAB 3, SCHEDULE 3)

2.1 Inter-Area Network Transfer Capability

		2013	2014
D01	New 500 kV Bruce to Milton Double Circuit Transmission Line	16.6	7.3
D02	Installation of Shunt Capacitor Banks at Cherrywood TS Phase 1	6.0	1.0
D03	Installation of Shunt Capacitor Banks at Cherrywood TS Phase 2	3.0	3.0
D04	Clarington TS: Build new 500/230kV Station	70.0	105.0
D05	Installation of Static Var Compensator at Milton SS	30.0	40.0
D06	Reconductor the Lambton TS to Longwood TS 230kV Circuits	17.0	18.0

2.2 Local Area Supply Adequacy

		2013	2014
D07	Toronto Area Station Upgrades for Short Circuit Capability: Leaside TS Equipment Uprate	9.1	2.3
D08	Toronto Area Station Upgrades for Short Circuit Capability: Manby TS Equipment Uprate	12.5	2.0
D09	Toronto Area Station Upgrades for Short Circuit Capability: Re-build Hearn SS	59.4	4.0
D10	Midtown Transmission Reinforcement Plan	26.7	19.2
D11	Preston TS Transformation	0.0	6.0
D12	Guelph Area Transmission Reinforcement	3.0	20.0

2.3 Load Customer Connection

		2013	2014
D13	Tremaine TS: Build New Transformer Station	3.3	0.0
D14	Barwick TS: Build new Transformer Station	7.1	0.0
D15	Nebo TS: Increase Capacity of 230/27.6kV DESN	12.0	0.0
D16	Orleans TS: Build new Transformer Station	7.3	19.0
D17	Bremner TS: Build Line Connection for Toronto Hydro	20.2	37.0
D18	Chalk River CTS: Build 115kV Switching Facilities and connect new Customer Station	4.0	5.0
D19	Nelson TS: Replace T1/T2 DESN with new DESN	12.0	15.5

2.4 Generation Customer Connection

		2013	2014
D20	Samsung South Kent Wind Farm (270 MW) (Formerly Chatham Wind Generation Connection)	4.1	0.0
D21	Lower Mattagami Generation Connections	15.9	2.4
D22	Niagara Region Wind Corporation Generation Connection (230 MW)	25.0	25.0
D23	Armow Wind Generation Connection (180 MW)	1.0	22.0
D24	K2 Wind Generator Connection (270 MW)	20.0	25.0
D25	Adelaide/Bornish/Jericho/ Wind Energy Centres (284 MW)	25.0	20.0

2.5 Protection and Control for Enablement of Distribution Connected Generation (Government Instruction)

		2013	2014
D26	Transfer Trip Signaling Enhancement	5.0	8.0
D27	Transmission Station P&C Upgrades for DG	18.5	20.5

2.6 Protection and Control Modifications for Consequences of Connected Distribution Generation

D28	Transmission Work to Mitigate Distance Limitation	2.8	3.0
D29	UFLS and Load Rejection Modification	0.0	5.0

2.7 Risk Mitigation

		2013	2014
D30	Hawthorne TS: Uprate Short Circuit Capability	5.6	1.0
D31	Allanburg TS: Uprate Short Circuit Capability	4.8	2.0
D32	Basin TS: Add Reactors	4.0	0.0
D33	Main TS: Add Breakers	4.7	0.0

Summary – Development	**2013**	**2014**
Total Development Projects & Programs Listed Above	**455.6**	**438.2**
Development Projects & Programs Less than $3 M	**103.1**	**86.6**
Total Gross Development Capital (per Exhibit D1-3-3)	**558.7**	**524.8**
Less Capital Contribution	**(244.5)**	**(212.3)**
Total Net Development Capital (per Exhibit D1-3-3)	**314.2**	**312.5**

3.0 OPERATIONS CAPITAL (EXHIBIT D1, TAB 3, SCHEDULE 4)

3.1 Grid Operations Control Facilities

	2013	2014
O1 NMS Upgrade	7.3	11.7

3.2 Operating Infrastructure

	2013	2014
O2 Hub Site Management Program	3.2	3.3
O3 Telemetry Expansion Program	2.3	2.3
O4 Wide Area Network Project	10.8	19.3
O5 Frame Relay Replacement Project	5.0	0.0

	2013	2014
O6 Fault Locating Program	1.0	5.0
O7 Station LAN Infrastructure Program	4.0	4.0

Summary – Operations	**2013**	**2014**
Total Operations Projects & Programs Listed Above	**33.6**	**45.6**
Operations Projects & Programs Less than $3 M	**14.0**	**10.9**
Total Operations Capital (per Exhibit D1-3-4)	**47.5**	**56.6**

4.0 SHARED SERVICES AND OTHER CAPITAL (EXHIBIT D1, TAB 4, SCHEDULES 1-5)

4.1 Information Technology

	2013	2014
IT1 Cornerstone Phase 3	26.8	10.0
IT2 GIS Implementation	6.8	1.0
IT3 MFA PC and Printer Hardware	3.3	3.6
IT4 Software Refresh and Maintenance	9.2	11.9
IT5 MFA Servers and Storage	4.0	6.4
IT6 Telecom Infrastructure	3.2	1.8

4.2 Other

	2013	2014
C1 Real Estate Facilities Capital	27.5	27.5
C2 Real estate head office & GTA Facilities	16.6	16.6
C3 TWE1 Transport & Work Equipment	43.3	44.5
C4 SE1 Service Equipment	9.3	9.8

Summary - Shared Services and Other Capital	**2013**	**2014**
Total Shared Services, Other Projects & Programs listed above	**150.0**	**133.1**
Shared Services, Other Projects & Programs less than $3 M	**2.5**	**9.6**
Total Shared Services & Other Capital (per Exhibit D1-4-1)	**152.5**	**142.7**
Transmission allocation of Shared Services & Other Capital (per Exhibit D1-4-1)	**72.2**	**63.4**

INVESTMENT SUMMARY FOR PROGRAMS/PROJECTS IN EXCESS OF $3 MILLION

Sustaining Capital	S1 to S62
Development Capital	D1 to D33
Operations Capital	O1 to O7
Shared Services and Other Capital	IT1 to IT6
	C1 to C4

Hydro One Networks – Investment Summary Document

Investment Category: Sustaining Capital – Stations - Circuit Breakers

Reference #	Investment Name	Gross Cost	Net Cost	In-Service Date
S1	Oil Circuit Breaker (OCB) Replacements	$17.6 M	$17.6	2014 (Program)

Please see Exhibit D1, Tab 3, Schedule 2 for cash flows and other details about the investment.

Need:

This investment is required to address end of life issues of the aging population of oil circuit breakers (OCBs) by proactively replacing those that represent the highest risk to system security and customer connection reliability.

Implications of not proactively managing this population of breakers include overall decline of health of the OCB population and employee safety. Inaction will result in a trend of equipment unavailability, inadequate equipment fault ratings, an increase in probability of failure and equipment outages (both customer and network connected) and an increased risk to Hydro One's strategic objectives. OCBs that reach end of life therefore need to be replaced on an ongoing basis

Summary:

Oil Circuit Breakers account for approximately half of the over 4,400 circuit breakers that Hydro One currently owns and manages. These bulk oil circuit breakers are no longer commercially available and are being replaced with new SF6 Circuit Breaker technology. Criteria, including age, physical condition, parts obsolescence and equipment ratings are used to assess the replacement candidates.

Candidates for replacement are based on assessed conditions and switching duty-cycle requirements, equipment defect records and other localized studies. Prioritization is based on risk as it relates to the HONI strategic objectives.

Results:

This plan will replace OCBs to ensure equipment reliability and maintain customer reliability.

Customer Contribution: $0.0M **Removal Costs:** $1.3M

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Investment Category: Sustaining Capital – Stations - Circuit Breakers

Reference #	Investment Name	Gross Cost	Net Cost	In-Service Date
S2	SF6 Circuit Breaker Replacements	$22.1 M	$22.1M	2014 (Program)

Please see Exhibit D1, Tab 3, Schedule 2 for cash flows and other details about the investment.

Need:

This investment is required to address end-of-life issues of the population of SF6 breakers, by proactively replacing those that represent the highest risk to system security and customer connection reliability.

Implications of not proactively managing this population of breakers include overall decline of health of the SF6 breaker population and employee safety. Inaction will result in a trend of equipment unavailability, inadequate equipment fault ratings, an increase in probability of failure and equipment outages (both customer and network connected) and an increased risk to Hydro One's Safety & Environment business values.

Summary:

Hydro One currently owns and manages over 1,300 SF6 circuit breakers. The breaker types in this investment are at end of life and are being replaced with new SF6 Circuit Breaker technology. These end of life breakers are the original designed low voltage SF6 breakers built in early 1980's and have several major design flaws that require frequent repair and replacement.

A large proportion (about 30%) of the SF6 breaker population is applied for the most onerous, special purpose duties, such as reactor and capacitor bank switching, some involving several hundred operations per year thus accelerating the mechanical and electrical wear-out of the breaker. The complex control and operating mechanisms installed in almost all of these early vintage breakers resulted in increased operating problems and significant maintenance and refurbishment expenditures. Most of these very poor performing breakers have reached or surpassed their mechanical design life.

In summary, candidates for replacement are based on age, assessed condition and switching duty-cycle requirements, performance statistics, equipment defects records and other studies. Prioritization is based on risk as it relates to the Hydro One strategic objectives.

Results:

This plan will replace SF6, circuit breakers to address end-of-life equipment and maintain customer reliability.

Customer Contribution: $0.0M **Removal Costs:** $1.7M

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Investment Category: Sustaining Capital – Stations - Circuit Breakers

Reference #	Investment Name	Gross Cost	Net Cost	In-Service Date
S3	GTA Metalclad Switchgear Replacements	$52.3 M	$34.3M	2015

Please see Exhibit D1, Tab 3, Schedule 2 for cash flows and other details about the investment.

Need:

This investment is required to address the end of life ("EOL") condition of the low-voltage metalclad switchgear in the Greater Toronto Area ("GTA")

The implications of not proactively replacing EOL metalclad equipment are:

- A reliability reduction to Toronto Hydro ("THESL") and its customers resulting in a negative impact on customer satisfaction and corporate reputation
- Increased maintenance expenditures and difficulty in obtaining or fabricating technically obsolete spare parts
- GTA metalclad switchgear equipment are not arc proofed which creates a safety risk

Summary:

Approximately 30% of the metalclad switchgear installations currently operating in the GTA are exceed manufacturer's life expectancy of 40 years. THESL and Hydro One (HONI) have recently identified four locations in the GTA for replacement over the next two years. They are at EOL based on age, parts availability, reliability and safety considerations. The supporting information is obtained from consultations with THESL, asset condition assessment, data registries, routine diagnostics, inspection results, system analysis and outage logs.

This existing switchgear is not built to present day arc proof type C standards which results in safety and reliability concerns. HONI has experienced, on average, two major faults per year with inadequate metalclad arc proofing design. This can result in damages to the adjacent feeders and a potentially hazardous situation for personnel. THESL and HONI are coordinating replacements of end of life metalclad breakers at four transmission stations within the GTA. The replacement program includes the new metalclad circuit breakers along with new protections and the 15 kV cables that supply the switchgear.

Results:

- Maintain customer reliability
- Facilitate recognized practices with the addition of a modern design and safety interlocks
- Implement breakers to current safety standards by the addition of arc proofing

Customer Contribution: $18.0M **Removal Costs:** $2.6M

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Investment Category: Sustaining Capital – System Re-Investment

Reference #	Investment Name	Gross Cost	Net Cost	In-Service Date
S4	Albion TS Metalclad Switchgear Replacement	$12.3 M	$12.3 M	2014

Please see Exhibit D1, Tab 3, Schedule 2 for cash flows and other details about the investment.

Need:

This investment is required to replace metalclad switchgear at Albion TS which is nearing the end of its expected service life.

If this work is not completed, there is significant risk of the decline in the health and reliability of the station switchgear, associated components, and ultimately the reliability of the system and customers in the area.

Summary:

Albion TS contains four (4) LV metalclad buses that are at end of life (EOL). This investment is required to address the EOL condition of the metalclad switchgear including the associated assets (insulators, buses, ancillaries, etc.).

This investment is consistent with Hydro One's transmission station investment plan. At Albion TS, several key risk factors affecting reliability, customer, reputation, safety and environment are influential in prioritizing this station for reinvestment.

A multi-discipline team conducted a site assessment to identify EOL components within the station with the intention of bundling the work into a single efficient work package. The overall investment integrates individual asset needs into an effective plan.

Results:

- Reduce the operational risks, minimize life cycle costs, and improve reliability

Customer Contribution: $0.0M Removal Costs: $0.9M

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Investment Category: Sustaining Capital – System Re-Investment

Reference #	Investment Name	Gross Cost	Net Cost	In-Service Date
S5	Kenilworth TS Metalclad Switchgear Replacement	$13.2 M	$13.2 M	2015

Please see Exhibit D1, Tab 3, Schedule 2 for cash flows and other details about the investment

Need:

This investment is required to replace metalclad switchgear at Kenilworth TS which is nearing the end of its expected service life.

If this work is not completed, there is significant risk of the decline in the health and reliability of the station switchgear, associated components, and ultimately the reliability of the system and customers in the area.

Summary:

Kenilworth TS currently contains four transformers supplying three metalclad switchgear buildings two of which are at end of life. This investment is required to address the EOL condition of the transformers, metalclad switchgear, the associated assets (insulators, buses, ancillaries, etc.).

This investment is consistent with Hydro One's transmission station investment plan which takes into account asset end of life factors such as asset utilization, performance, condition, spare parts, safety, environment, life cycle costs and age. At Kenilworth TS, several key risk factors affecting reliability, customer satisfaction, corporate reputation, safety and environment are influential in prioritizing this station for reinvestment.

A multi-discipline team conducted a site assessment to identify EOL components within the station with the intention of bundling the work into a single efficient work package. The investment will include the installation of new metalclad switchgear , removal of two transformers thereby reducing the station to a single DESN configuration.

Results:

- Reduce the operational risks, minimize life cycle costs, and improve reliability

Customer Contribution: $0.0M **Removal Costs**: $2.0M

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Investment Category: Sustaining Capital - Stations - System Re-Investment

Reference #	Investment Name	Gross Cost	Net Cost	In-Service Date
S6	Hanmer TS – 500kV ABCB Replacement	$ 26.1 M	$ 26.1 M	2013

Please see Exhibit D1, Tab 3, Schedule 2 for cash flows and other details about the investment

Need:

This investment is required to replace Air Blast Circuit Breakers (ABCBs) that are in deteriorated condition and their associated station components.

If this work is not completed, there is significant risk of further equipment deterioration and declining reliability to the system and customers in the area.

Summary:

Hanmer TS is a critical network station just west of Sudbury. It facilitates the transfer of power between Northern and Southern Ontario.

Air blast circuit breakers are the poorest performing breakers in the Hydro One system. They are not produced anymore and there is little-to-no support for parts and technical expertise. These units are also in very poor condition. There are three 500 kV ABCBs at Hanmer TS that were installed in the 1970s.

The identified work within this investment includes replacement of all (3) 500 kV ABCBs with new SF6 breakers, and the replacement of associated equipment.

Results:

- Reduce the operational risks, minimize life cycle costs, and satisfy regulatory requirements.

Customer Contribution: $0.0M **Removal Costs:** $0.5 M

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Investment Category: Sustaining Capital - Stations - System Re-Investment

Reference #	Investment Name	Gross Cost	Net Cost	In-Service Date
S7	Orangeville TS – 230kV ABCB Replacement	$29.6 M	$29.6 M	2013

Please see Exhibit D1, Tab 3, Schedule 2 for cash flows and other details about the investment

Need:

This investment is required to replace Air Blast Circuit Breakers (ABCBs) that are in deteriorated condition and their associated station components.

If this work is not completed, there is significant risk of further equipment deterioration and declining reliability to the system and customers in the area.

Summary:

Orangeville TS facilitates bulk power transfers on the 230 kV network between South-Western and Central Ontario.

Air blast circuit breakers are the poorest performing breakers in the Hydro One system. They are not produced anymore and there is little-to-no support for parts and technical expertise. These units are also in very poor condition. There are six 230kV ABCBs at Orangeville TS that were built in the 1960s and were originally installed at Beck #2 TS.

The identified work within this investment includes replacement of all (6) 230 kV ABCBs with new SF6 breakers and the replacement of associated equipment.

Results:

- Reduce the operational risks, minimize life cycle costs, and satisfy regulatory requirements.

- Improve the bulk system equipment availability indices and the reliability of supply to area customers.

Customer Contribution: $0.0M **Removal Costs:** $1.0 M

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Investment Category: Sustaining Capital - Stations - System Re-Investment

Reference #	Investment Name	Gross Cost	Net Cost	In-Service Date
S8	Pickering A SS – 230kV ABCB Replacement	$11.6 M	$5.8 M	2013

Please see Exhibit D1, Tab 3, Schedule 2 for cash flows and other details about the investment

Need:

This investment is required to replace Air Blast Circuit Breakers (ABCBs) that are in deteriorated condition and their associated station components.

If this work is not completed, there is significant risk of further equipment deterioration and declining reliability to the system and customers in the area.

Summary:

Pickering A SS is a critical station that facilitates bulk power transfer from the OPG nuclear generators to the 230kV network.

Air blast circuit breakers are the poorest performing breakers in the Hydro One system. They are not produced anymore and there is little-to-no support for parts and technical expertise. These units are also in very poor condition. There are six 230kV ABCBs at Pickering A that were built in the 1960s.

The identified work within this investment includes replacement of four (4) 230 kV ABCBs with new SF6 breakers and the replacement of associated equipment. The project also involves the removal of two breakers that are no longer required with Pickering G2 and G3 units not expected to return to service.

Results:

- Reduce the operational risks, minimize life cycle costs, and satisfy regulatory requirements.

Customer Contribution: $5.8M *** Removal Costs:** $0.2 M

*****Discussions are ongoing with OPG regarding cost sharing and appropriate liability exposure as per the Transmission System Code.

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Investment Category: Sustaining Capital - Stations - System Re-Investment

Reference #	Investment Name	Gross Cost	Net Cost	In-Service Date
S9	Richview TS – 230kV ABCB Replacement	$ 61.2	$ 61.2	2017

Please see Exhibit D1, Tab 3, Schedule 2 for cash flows and other details about the investment

Need:

This investment is required to replace Air Blast Circuit Breakers (ABCBs) that are in deteriorated condition and their associated station components.

If this work is not completed, there is significant risk of further equipment deterioration and declining reliability to the system and customers in the area.

Summary:

Richview TS is a critical network station that facilitates bulk transfers on the 230kV network within the GTA.

Air blast circuit breakers are the poorest performing breakers in the Hydro One system. They are not produced anymore and there is little-to-no support for parts and technical expertise. These units are also in very poor condition. There are twenty-four ABCBs at Richview TS that were built in the 1960s.

The identified work within this investment includes replacement of all (24) 230 kV ABCBs with new SF6 breakers and the replacement of associated equipment.

Results:

- Reduce the operational risks, minimize life cycle costs, and satisfy regulatory requirements.

Customer Contribution: $0.0M **Removal Costs:** $5.6 M

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Investment Category: Sustaining Capital – System Re-Investment

Reference #	Investment Name	Gross Cost	Net Cost	In-Service Date
S10	Beck #2 TS – 230kV ABCB Replacement	$34.4 M	$34.4 M	2016

Please see Exhibit D1, Tab 3, Schedule 2 for cash flows and other details about the investment

Need:

This investment is required to replace Air Blast Circuit Breakers (ABCBs) that are in deteriorated condition and their associated station components, and to de-merge Hydro One assets from the Ontario Power Generation (OPG) facilities.

If this work is not completed, there is significant risk of further equipment deterioration and declining reliability to the system and customers in the area.

Summary:

Beck 2 TS is a critical station that connects hydraulic generation from OPG to the 230 kV transmission network.

Air blast circuit breakers are the poorest performing breakers in the Hydro One system. They are not produced anymore and there is little-to-no support for parts and technical expertise. These units are also in very poor condition. There are twenty ABCBs at Beck #2 TS. ABCBs were first installed at Beck #2 TS in the 1960s.

The identified work within this investment includes replacement of all (20) 230 kV ABCBs with new SF6 breakers and the replacement of associated equipment.

Results:

- Reduce the operational risks, minimize life cycle costs, and satisfy regulatory requirements.

Customer Contribution: $0.0M **Removal Costs:** $3.2M

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Investment Category: Sustaining Capital – System Re-Investment

Reference #	Investment Name	Gross Cost	Net Cost	In-Service Date
S11	Bruce A TS – 230kV ABCB Replacement	$35.0M	$35.0 M	2014

Please see Exhibit D1, Tab 3, Schedule 2 for cash flows and other details about the investment

Need:

This investment is required to replace Air Blast Circuit Breakers (ABCBs) that are in deteriorated condition and their associated station components.

If this work is not completed, there is significant risk of further equipment deterioration and declining reliability to the system and customers in the area.

Summary:

Bruce A TS is a critical station that facilitates bulk power transfer from the Bruce Power nuclear generators to the 230kV network.

Air blast circuit breakers are the poorest performing breakers in the Hydro One system. They are not produced anymore and there is little-to-no support for parts and technical expertise. These units are also in very poor condition. In addition to the condition and obsolescence issues, the fault duty (short circuit interrupting capability) of the ABCBs will soon be exceeded. To manage the increased short circuit levels, certain operating measures will be implemented until the breakers are replaced and the switchyard is upgraded. There are sixteen ABCBs at Bruce A TS and they were built in the 1970s.

The identified work within this investment includes the replacement of all (16) 230 kV ABCBs with new SF6 breakers and the replacement of associated equipment.

As the detailed scope and engineering are finalized, discussions with Bruce Power will take place regarding appropriate cost sharing and liability exposure for dual use switchyard assets as per the Transmission System Code.

Results:

- Reduce the operational risks, minimize life cycle costs, and maintain reliability

Customer Contribution: $0.0M **Removal Costs:** $3.0M

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Investment Category: Sustaining Capital – System Re-Investment

Reference #	Investment Name	Gross Cost	Net Cost	In-Service Date
S12	Burlington TS – 230kV ABCB Replacement	$8.1 M	$8.1 M	2014

Please see Exhibit D1, Tab 3, Schedule 2 for cash flows and other details about the investment

Need:

This investment is required to replace Air Blast Circuit Breakers (ABCBs) that are in deteriorated condition and their associated station components.

If this work is not completed, there is significant risk of further equipment deterioration and declining reliability to the system and customers in the area.

Summary:

Burlington TS is a critical station just west of Toronto that facilitates bulk power transfer to the 230kV network.

Air blast circuit breakers are the poorest performing breakers in the Hydro One system. They are not produced anymore and there is little-to-no support for parts and technical expertise. These units are also in very poor condition. There are four ABCBs at Burlington TS and they were built in the 1970s.

The identified work within this investment includes the replacement of all (4) 230 kV ABCBs with new SF6 breakers and the replacement of associated equipment.

Results:

- Reduce the operational risks, minimize life cycle costs, and maintain reliability

Customer Contribution: $0.0M **Removal Costs:** $0.8M

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Investment Category: Sustaining Capital - Stations - System Re-Investment

Reference #	Investment Name	Gross Cost	Net Cost	In-Service Date
S13	Abitibi Canyon SS / Pinard TS: Reconfigure and Demerge	$47.0 M	$46.0 M	2013

Please see Exhibit D1, Tab 3, Schedule 2 for cash flows and other details about the investment

Need:

This investment is required to replace Oil Circuit Breakers (OCBs) that are in deteriorated condition and their associated station components and de-merge Hydro One assets from the Ontario Power Generation (OPG) facilities.

If this work is not completed, there is significant risk of further equipment deterioration and declining reliability to the system and customers in the area.

Summary:

Abitibi Canyon SS facilitates bulk power transfer of OPG hydro-electric generation.

The 115 kV breakers at Abitibi Canyon SS rank amongst the top 30 worst breakers in the Hydro One system. Furthermore, the sole provider of spare parts for these breakers has indicated that they no longer support the breaker type. There are five OCBs at Abitibi Canyon and they were built in the 1940s.

The identified work within this investment includes the replacement and relocation of all (5) 115kV OCBs with new SF6 breakers to Pinard TS. This investment also includes the replacement of associated equipment.

Results:

- Reduce the operational risks, minimize life cycle costs, eliminate safety and environmental issues, and improve the bulk system equipment reliability.
- De-merger of Hydro One assets from the OPG powerhouse and the resulting reduction in business liability.

Customer Contribution: $1.0M **Removal Costs:** $2.2 M

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Investment Category: Sustaining Capital - Stations - System Re-Investment

Reference #	Investment Name	Gross Cost	Net Cost	In-Service Date
S14	Beck #1 SS - Build New Switchyard	$83.4 M	$82.4 M	2017

Please see Exhibit D1, Tab 3, Schedule 2 for cash flows and other details about the investment

Need:

This investment is required to replace Air Blast Circuit Breakers (ABCBs) that are in deteriorated condition and their associated station components and to de-merge Hydro One assets from the Ontario Power Generation (OPG) facilities.

If this work is not completed, there is significant risk of further equipment deterioration and declining reliability to the system and customers in the area.

Summary:

Beck #1 SS facilitates bulk power transfer from the OPG hydroelectric generators.

Air blast circuit breakers are the poorest performing breakers in the Hydro One system. They are not produced anymore and there is little-to-no support for parts and technical expertise. These units are also in very poor condition. There are six 115kV ABCBs at Beck #1SS.

The identified work within this investment includes the replacement of all (4) 115kV ABCBs with new SF6 breakers and the replacement of associated equipment.

Results:

- Reduce operational risks, minimize life cycle costs, and improve system reliability.
- De-merger of Hydro One assets from the OPG powerhouse and resulting reduction in business liability.

Customer Contribution: $1.0M **Removal Costs:** $5.3 M

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Investment Category: Sustaining Capital – System Re-Investment

Reference #	Investment Name	Gross Cost	Net Cost	In-Service Date
S15	Wallaceburg TS – Reconfigure to Address Failed Transformers	$26.4 M	$26.4 M	2013

Please see Exhibit D1, Tab 3, Schedule 2 for cash flows and other details about the investment

Need:

This investment is required to replace a failed transformer, and reconfigure the station to facilitate the replacement of other transformers nearing the end of their expected service life.

If this work is not completed, there is significant risk of the decline in the health and reliability of the station transformers, associated components, and ultimately the reliability of the system and customers in the area.

Summary:

Wallaceburg TS is 115kV station located in Western Ontario.

In 2010, the Wallaceburg TS T3 transformer failed and there was a requirement to reconfigure the station and replace the remaining transformers which were in a deteriorated condition.

This investment includes the replacement of the existing four three-phase transformers which were built in the 1940s and 1950s and their associated equipment, and replaces them with two standard size three phase transformers, as well as replacing the entire low voltage switchyard with a modern configuration.

Results:

- Reduce the operational risks, minimize life cycle costs, and improve reliability

Customer Contribution: $0.0M **Removal Costs:** $1.0M

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Investment Category: Sustaining Capital – System Re-Investment

Reference #	Investment Name	Gross Cost	Net Cost	In-Service Date
S16	Gage TS EOL Asset Replacement	$73.6 M	$73.6 M	2016

Please see Exhibit D1, Tab 3, Schedule 2 for cash flows and other details about the investment

Need:

This investment is required to replace most of the equipment at Gage TS which is in a deteriorated condition.

If this work is not completed, there is significant risk of the decline in the health and reliability of the station transformers, associated components, and ultimately the reliability of the system and customers in the area.

Summary:

Gage TS is a complex facility with a unique configuration located in the Hamilton area.

The station is comprised of an original switchyard built in the 1940s, with a further capacity increase in the 1960's. The site is located in the heart of a highly industrial area with close proximity to steel mills and other heavy industry. The transformation load station supplies critical steel industry load.

Operating restrictions are currently in place on the circuit breakers due to their operating ratings and the available fault current concerns that could cause the breaker to fail catastrophically.

Much of the low voltage equipment has insufficient safe working clearance to facilitate routine maintenance. There is a very restricted window during short periods in the year when outages can be arranged in order to facilitate load transfers to neighbouring stations.

Included in the work is refurbishment of deteriorated station components, installation of new transformers, and reconfiguration of the 115 kV supply circuits.

Results:

- Reduce the operational risks, minimize life cycle costs, eliminate safety and environmental issues, and improve reliability

Customer Contribution: $0.0M **Removal Costs:** $6.8M

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Investment Category: Sustaining Capital - Stations - System Re-Investment

Reference #	Investment Name	Gross Cost	Net Cost	In-Service Date
S17	Merivale GIS Bus Replacement	$11.0 M	$11.0 M	2013

Please see Exhibit D1, Tab 3, Schedule 2 for cash flows and other details about the investment

Need:

This investment is required to replace End of Life ("EOL") ITE Bus Duct and associated EOL components at Merivale TS.

If this work is not completed, there is significant risk of the decline in the health and reliability of the station bus duct, associated components, and ultimately the reliability of the system and customers in the area.

Summary:

Merivale TS is a 230kV/115 kV station located in Eastern Ontario. Gas Insulated Switchgear (GIS) was placed in service in 1979.

Merivale GIS equipment are among the poorest performers at Hydro One and contribute a significant portion to the provincial SF6 gas emissions. This is an environmental concern since SF6 is a greenhouse gas. In addition, the original manufacturer is no longer in business, making spare parts and support a significant issue.

This investment will replace the bus duct exits and associated equipment.

Results:

- Reduce operational risks, minimize life cycle costs, and reduce the escape of Greenhouse SF6 gas.

Customer Contribution: $0.0M **Removal Costs:** $1.1 M

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Investment Category: Sustaining Capital - Stations - System Re-Investment

Reference #	Investment Name	Gross Cost	Net Cost	In-Service Date
S18	NRC TS Rebuild	$21.6 M	$21.6 M	2015

Please see Exhibit D1, Tab 3, Schedule 2 for cash flows and other details about the investment

Need:

This investment is required to replace the non-standard 115 kV and 14 kV switchyards portion of National Research Council (N.R.C.) TS and other station components to address several issues associated with EOL equipment that effect the operability and reliability of this station.

If this work is not completed, there is significant risk of further equipment deterioration and declining reliability to the system and customers in the area.

Summary:

N.R.C. TS directly supplies the National Research Council of Canada. This station no longer meets Hydro One's current transmission standards and as such the station operates with restrictions that result in the interruption of power supply to customers and delay Hydro One's response to equipment failures at the station.

The 14 kV switchyard equipment clearances no longer meets today's requirements for working close to live equipment; this imposes safety concerns at the station. Most maintenance work at the station can only be performed during complete station outage on weekends. In addition, a generator (customer owned) is connected to the 14 kV, raising the fault level above the interrupting capability of the oil circuit breakers. These breakers operate with an exclusion zone that limits access to the station.

The transformer oil spill containment does not meet the Hydro One's standard and will be upgraded.

This investment will address operating constraints, reduce safety & environmental risks at the station, and improve reliability of supply to the customer.

Results:

- Remove operating restrictions.
- Eliminate environmental concerns associated with the spill containment.
- Improve the reliability of supply to the customer.

Customer Contribution: $0.0M **Removal Costs:** $2.0 M

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Investment Category: Sustaining Capital - Stations - System Re-Investment

Reference #	Investment Name	Gross Cost	Net Cost	In-Service Date
S19	Integrated DESN Investments	$152.1 M	$152.1 M	2014+

Please see Exhibit D1, Tab 3, Schedule 2 for cash flows and other details about the investment

Need:

This investment is required to address a number of cases where multiple Station assets are approaching end-of-life, and the consolidation of the replacement units into an integrated project has been determined to be the best approach to mitigate risk.

If this work is not completed there is significant risk of the decline in the operability and reliability of the station which will impact reliable delivery of electricity to customers directly supplied from this station.

Summary:

There are a number of cases where DESN (dual element spot network) stations, which facilitate power transformation from the bulk supply stations to load customers, have been identified to require replacement of multiple assets within them. Where these cases exist, there is an opportunity to combine multiple elements into a single work package which allows additional efficiencies to be realized during the design, construction, and commissioning stages of the work.

The underlying force for the investment involves cases where a station requires the replacement of multiple transformers, along with other major station assets such as protections, disconnect switches and surge arresters at the same time and in an integrated manner.

Work is planned at 13 stations within the 2013 and 2014 test years with expenditures of $58.0 million and $94.1 million respectively.

Results:

- Reduce the operational risks and minimize life cycle costs
- Eliminate environmental issues
- Improve the reliability of supply to the customer.

Customer Contribution: $0.0M **Removal Costs:** $10.6M

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Investment Category: Sustaining Capital - Stations – Power Transformers

Reference #	Investment Name	Gross Cost	Net Cost	In-Service Date
S20	**Replace End-of-Life CGE Transformers**	$3.5 M	$3.5M	2013 (Program)

Please see Exhibit D1, Tab 3, Schedule 2 for cash flows and other details about the investment

Need:

This investment is required to replace end-of-life ("EOL") Canadian General Electric ("CGE") transformers.

If this work is not completed, there is significant risk of equipment unavailability, increased operational constraints, and increased risk of customer interruptions.

Summary:

In recent years, CGE designed transformers were identified with design flaws that can cause severe internal overheating of the low voltage leads and result in breakdown of the insulation system. Several of these units have already failed due to this design flaw and the remaining units have been identified as high risk. Oil analysis has corroborated the risk. The CGE transformer units are still in service at stations throughout Southern Ontario, but are presently de-rated to minimize the effects of overheating. The affected sites utilize sister-paired defective units and are heavily loaded.

Temporary measures such as cancellation of non-critical outages, de-rating, load transfers and pre-cooling have already been implemented to help reduce aging rates and to mitigate the risk of failure. Lead time for procurement of replacement transformers is approximately 18 months

This investment will address the replacement transformer units during the 2013/2014 period. The replacement priority for units has been based on oil analysis, loading levels and customer impact.

Results:

- Reduce operational risks and life cycle costs.
- Improve equipment availability and the reliability of supply to area customers.

Customer Contribution: $0.0 M **Removal Costs:** $0.4 M

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Investment Category: Sustaining Capital - Stations – Power Transformers

Reference #	Investment Name	Gross Cost	Net Cost	In-Service Date
S21	Large Power Transformer Replacements	$149.7 M	$149.7 M	2014 (Program)

Please see Exhibit D1, Tab 3, Schedule 2 for cash flows and other details about the investment

Need:

This investment is required to address the condition of end-of-life power tranformers, by way of replacement of those that represent the highest risk to system reliability.

Not proceeding with this investment would allow increased risk to customer supply reliability, increased safety hazards to personnelm an increased risk to shareholder value and risk to the environment. A transformer failure can have serious environmental consequences due to oil spills or safety concerns due to explosions or fire.

Summary:

Power Transformers are the devices used to connect systems of different voltages for the purpose of power flow and voltage regulation. Transformers are the most critical and expensive components of the transmission system. Approximately 719 Hydro One owned power transformers support the Ontario's transmission system. Step-down transformers convert a transmission level voltage (230 kV or 115 kV) to a lower distribution voltage of less than 50 kV for customer supply. Autotransformers connect two high voltage transmission systems such as 500/230 kV and 230/115 kV. Other transformers included in this group are phase shifting transformers, regulating transformers, and shunt reactors.

This investment will result in the replacement of 25 power transformers at or beyond end-of-life.

Results:

- Reduce the operational risks, minimize life cycle costs, eliminate safety and environmental issues, and improve reliability

Customer Contribution: $0.0M **Removal Costs:** $11.3M

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Investment Category: Sustaining Capital - Stations – Power Transformers

Reference #	Investment Name	Gross Cost	Net Cost	In-Service Date
S22	Operating Spare Transformer Purchases	$25.8 M	$25.8M	2014 (Program)

Please see Exhibit D1, Tab 3, Schedule 2 for cash flows and other details about the investment

Need:

To provide adequate spare coverage for timely replacement of 230 KV and 115 KV transformer groups and station service transformers in the event of failure. This investment will bring the inventory of spares in this group to a reasonable level as determined by risk analysis.

Not proceeding with this investment will increase risks to customer supply reliability and system security.

Summary:

This investment addresses the purchase of power transformers for the transmission system for use as operating spares in 2013 and 2014, and will replenish transformers drawn down from system reserves to support demand capital failure replacements.

Transformers purchased under this investment will support a fleet of approximately 719 transformers across multiple sizes and types of transformers.

A probabilistic cost/risk analysis model, consistent with industry standards, has been used to determine the optimum number of spares required for each group. This analysis takes into consideration several factors such as demographics, failure rate and repair/replacement time.

Results:

To provide adequate spare group coverage and shorten the amount of time required for transformer replacement in the event of a transformer failure. This restores equipment and delivery reliability.

Customer Contribution: $0.0M **Removal Costs:** $0.0M

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Investment Category: Sustaining Capital - Stations – Other Power Equipment

Reference #	Investment Name	Gross Cost	Net Cost	In-Service Date
S23	Disconnect Switch Replacements	$17.0 M	$17.0M	2014 (Program)

Please see Exhibit D1, Tab 3, Schedule 2 for cash flows and other details about the investment

Need:

This investment is required to address the condition of high voltage disconnect switches at end-of-life, by way of replacement of those that represent the highest risk to system reliability.

Not proceeding with this investment would allow increased risk to customer supply reliability, increased safety hazards to personnel and an increased inability to complete scheduled work as a result of switch failures during isolation procedures.

Summary:

High voltage disconnect switches perform essential roles in the power system. They facilitate the electrical isolation and connection of system components such as high voltage lines, transformers and breakers. They are both manual and motor driven. There are approximately 5600 high voltage disconnect switches in the system, and an additional 8500 low voltage switches. Normal end of service life for switches is typically 40 years.

There are approximately 1700 switches that are currently over 40 years old. Older switches have no manufacturer's support and do not meet current system design requirements. The older switches also do not have replaceable current carrying parts due to their design.

Hydro One's replacement/refurbishment program has focused on managing switches in the poorest condition. Replacement criteria is based upon age, condition information, performance, reliability, saftey, consequences of failure, spare parts and customer needs.

This investment will result in the replacement of approximately 140 high voltage disconnect switches

Results:

- To improve reliability and system performance.
- To improve ability to effectively maintain equipment

Customer Contribution: $0.0M Removal Costs: $1.3M

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Investment Category: Sustaining Capital - Stations – Other Power Equipment

Reference #	Investment Name	Gross Cost	Net Cost	In-Service Date
S24	Capacitor Bank Replacements	$8.8 M	$8.8M	2014 (Program)

Please see Exhibit D1, Tab 3, Schedule 2 for cash flows and other details about the investment

Need:

This investment is required to address the deteriorating condition of capacitor banks at end of life through replacement of those that present a high risk to system security and reliability.

Failure to proactively manage this population will result in reduced system voltage support, increased transmission losses, customer power quality issues and an increase in the potential for an environmental and /or safety impact in the event of a failure.

Summary:

Capacitor banks are static devices that provide reactive power to the transmission system, which results in an improved power factor and allows for more efficient power transmission.

There are a total of approximately 60 high-voltage capacitor banks in-service at voltages of 115kV and 230kV ranging from 15 MVAR to 410 MVAR, and approximately 300 low-voltage capacitor banks in-service at voltages from 4.16kV to 44kV ranging from 4.6 to 33 MVAR throughout the transmission system.

The need to replace capacitor banks is based on asset condition, reliability data and criticality to the system. Asset condition information used to assist in determining end-of-life includes the deterioration of individual capacitor units or by general deterioration of structure, insulators, fuses and capacitor units.

This investment will result in the replacement of three high-voltage capacitors and seven low-voltage capacitors.

Results:

- Improve reliability of the capacitor bank population by replacing end-of-life capacitor banks.
- Reduce operational constraints and environmental risks associated with capacitor bank failures.

Customer Contribution: $0.0M **Removal Costs:** $0.7M

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Investment Category: Sustaining Capital - Stations – Other Power Equipment

Reference #	Investment Name	Gross Cost	Net Cost	In-Service Date
S25	Instrument Transformer Replacement Program	$6.3 M	$6.3 M	2014 (Program)

Please see Exhibit D1, Tab 3, Schedule 2 for cash flows and other details about the investment

Need:

This investment is required to address the condition of instrument transformers at end-of-life, by way of replacement of those that represent the highest risk to system reliability.

Not proceeding with this investment would allow increased risk to customer supply reliability, increased safety hazards to personnel and an increased inability to complete scheduled work as a result of instrument transformer failures.

Summary:

Instrument transformers perform an essential role in the power system. They allow low power instruments to accurately measure parameters of the power system. Types of instrument transformer include current transformer and voltage transformers. These intrument transformers usually connect to high voltage buses or lines, and send low voltage signals to protection or control equipment. There are over 4800 instrument transformers in the system. Normal end of life for instrument transformers is approximately 40 years, but this can vary based on the exact type of equipment.

Instrument transformers are not run until failure because some models will fail explosively. The chance of having an explosive failure increases after the equipment has passed the end of expected service life. Presently, approximately 15% of instrument transformers are over 40 years old. When instrument transformers fail they can force a bus or line out of service and cause an outage until a replacement is installed.

Hydro One's replacement/refurbishment program has focused on managing instrument transformers in the poorest condition. Replacement criteria is based upon age, performance, reliability, saftey and obsolecence. This investment will result in the replacement of approximately 160 instrument transformers.

Results:

- To improve reliability and system performance.
- To improve safety

Customer Contribution: $0.0M **Removal Costs:** $0.5M

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Investment Category: Sustaining Capital - Stations – Other Power Equipment

Reference #	Investment Name	Gross Cost	Net Cost	In-Service Date
S26	Insulator Replacement Program	$9.8 M	$9.8 M	2014 (Program)

Please see Exhibit D1, Tab 3, Schedule 2 for cash flows and other details about the investment

Need:

This investment is required to address the condition of station insulators at end-of-life, by way of replacement of those that represent the highest risk to system reliability.

Not proceeding with this investment would allow increased risk to customer supply reliability, increased safety hazards to personnel and an increased inability to complete scheduled work as a result of insulator failures.

Summary:

Adequate insulation is one of the basic requirements of any electrical system and its failure is the source of many operating and maintaining problems. The reliability of service depends largely on the frequency of insulator failures. Insulators are used to insulate current carrying parts from one another and from ground, to support live electrical conductors and disconnect switches and to dead end live conductors. There are three basic types of insulators in use at Hydro One stations: pin type (mostly cap & pin), post type and strain type.

Hydro One has experienced increasing failure rates of its insulators and this has led to more widespread invasive testing to detect cracked insulators and a proactive insulator replacement program has been in place since 2000. The replacement program has targeted the more failure prone cap and pin and multi-cone rigid insulators together with the older porcelain strain insulators.

This investment will result in the replacement of approximately 2500 insulators.

Results:

- To improve reliability and system performance.
- To improve safety

Customer Contribution: $0.0M **Removal Costs:** $0.7M

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Investment Category: Sustaining Capital - Stations - Ancillary Systems

Reference #	Investment Name	Gross Cost	Net Cost	In-Service Date
S27	Station Service Replacements	$23.6 M	$23.6M	2014 (Program)

Please see Exhibit D1, Tab 3, Schedule 2 for cash flows and other details about the investment

Need:

This investment is required to address the condition of the aging population of station service transfer schemes through replacement of those that present a high risk to system security and reliability.

Failure to proactively manage this population will result in the inability to operate station equipment as a result of loss of AC or DC power.

Summary:

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 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. If the transfer fails, transmission elements at the station could be forced out of service or de-rated.

There are approximately 100 – 600V AC and approximately 180- 208V AC station service transfer schemes and approximately 60 - 125/250 V DC station service transfer schemes in-service. The average age of the 600 V AC and 125/250 V DC systems are 33 and 34 years respectively with end of life (EOL) typically in the 30 year range. The average age of the 208 V AC system is 23 years with EOL typically at 20 years. The deterioration of the fleet of transfer schemes has been evident for several years. Restoring reliability to these systems through increased maintenance continues to be a challenge due to the lack of spare parts and inability to obtain replacement parts from the manufacturer. Further compounding the reliability issues, the AC transfer schemes are housed within poorly insulated outdoor cubicles and are deteriorating due to corrosion.

The Cherrywood TS, Hanover TS, Richview TS and St. Lawrence TS transfer schemes have exceeded the manufacturers intended life expectancy of 30 years, and have experienced difficulties with the transfer capability both with switchgear and control.

The equipment associated with the transfer schemes (LV fuses, cables, enclosures, and distribution panels) will also be addressed at these locations. Also included will be the replacement of ten 208V transfer schemes at 10 smaller DESN type stations.

Results:

- Improved reliability of the station service transfer schemes by replacing end-of-life station service equipment.

Customer Contribution: $0.0M **Removal Costs:** $1.8M

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Investment Category: Sustaining Capital - Stations – Ancillary Systems

Reference #	Investment Name	Gross Cost	Net Cost	In-Service Date
S28	Station Grounding System Replacements	$10.4 M	$10.4 M	2014 (Program)

Please see Exhibit D1, Tab 3, Schedule 2 for cash flows and other details about the investment

Need:

This investment is required to address the condition of grounding systems at end-of-life, by way of replacement of those that represent the highest risk to system reliability.

Not proceeding with this investment would allow increased risk to customer supply reliability, increased safety hazards to personnel and an increased inability to complete scheduled work as a result of instrument transformer failures.

Summary:

Station grounding systems are installed wherever electrical equipment is found and they are designed to ensure that metal structures and equipment accessible to station personnel or the public have a common potential, and provide a safe electrical environment for people in and around the station. Effective grounding systems limit the damage to equipment caused by fault currents and other system disturbances. They must be capable of carrying the maximum available ground fault current without causing hazardous potentials, interference to power system operation, or equipment damage. Initially, all facilities are designed to meet these criteria. However, over time, the grounding systems can become less than adequate for a number of reasons including impacts of seasonal freeze/thaw cycling, corrosion, changes to standards, and modifications to the station and/or adjacent property. These factors can individually or collectively reduce the ability of the grounding system to perform as originally intended.

This investment will result in the upgrade of the grounding system at approximately 10 stations.

Results:

This investment will address long term public and staff safety issues, limit voltage and current stresses to equipment, maintain a high standard of power quality and ensure the proper operation of system protective devices resulting in a reliable supply to customers.

Customer Contribution: $0.0M **Removal Costs:** $0.8M

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Investment Category: Sustaining Capital – Stations – Stations Environment

Reference #	Investment Name	Gross Cost	Net Cost	In-Service Date
S29	Spill Containment Refurbishment & Installation	$22.6 M	$22.6M	2014 (Program)

Please see Exhibit D1, Tab 3, Schedule 2 for cash flows and other details about the investment

Need:

This investment is required to address the risk of releasing oil off site at various transformer station sites. This risk is present because the transformer oil spill containment system is at end of life and no longer provides adequate protection.

Not proceeding with this investment will not address an unacceptable risk of releasing transformer oil into the environment, leading to negative environmental impact and potential regulatory action by the Ministry of Environment (MOE) under the powers of the Environmental Protection Act R.S.O. 1990, c. E. 19.

Summary:

Transformers contain large volumes (up to 240,000L) of insulating oil (PCBs are within allowable Environment Canada Standards). Periodically, transformers leak and or fail catastrophically releasing large volumes of oil. Spill containment systems are designed to capture the oil contained within one transformer on site. They also are designed to take into account significant accumulations of rain in the event of a severe rain storm. Oil water separators (OWS) are used to prevent spilled oil from leaving the station while allowing rainwater to drain offsite.

The combination of leaking spill containment pits and severe transformer oil leaks present a serious environmental concern. Oil spill containment systems with chronic oil leaks have been identified within this project. The amount of oil that has leaked from the subject transformers is tracked using oil volume top-up records. Problems with traces of oil leaching into the drainage ditch are typically identified. In some locations temporary control measures such as berms are required to prevent oil from migrating off site and potentially into adjacent waterways. These are not long term solutions, and as such containment must be restored as planned with this investment.

This investment covers the installation of a passive oil water separator as well as refurbishment of the existing containment pits. Refurbishing the spill containment system mitigates the risk of releasing oil to the environment and reduces resources required to operate the oil water separation units by eliminating the need to manually pump out the containment units of rain and melt water. Investment plans for the test years include work on approximately 27 spill containment systems.

Results:

- Reduce the risk of off-site pollutant migration and subsequent impacts to the environment.
- Minimize the potential for punitive action by the MOE as a result of oil spills and leaks to the environment.

Customer Contribution: $0.0M **Removal Costs:** $1.7M

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Investment Category: Sustaining Capital – P&C, Telecom and Metering

Reference #	Investment Name	Gross Cost	Net Cost	In-Service Date
S30	BSPS Replacement of End of Life equipment	$35.8M	$35.8 M	2013

Please see Exhibit D1, Tab 3, Schedule 2 for cash flows and other details about the investment

Need:

This investment is required to:

1. Provide Special Protection Scheme coverage for breaker outages at Bruce A, Bruce B, Milton, Claireville, Longwood, Middleport, Nanticoke, Detweiler, Orangeville, Buchanan and Chatham for the grid configuration that will exist following the completion of the new Bruce to Milton line. Without this coverage, outages required to carry out Hydro One's sustainment and development programs will cause curtailment of energy flow out of the Bruce Area at a cost of $4.2M per year. In addition, the scheduling complexity of outages at those stations will increase significantly. The present scheme does not have the functionality to accommodate these breaker outages.
2. Provide expansion capacity for future generation connections in the Bruce Area.
3. Address the pending end of life and obsolescence issue with the existing BSPS.

Not proceeding with this investment will curtail the energy flow out of Bruce Area and greatly complicate outage scheduling of any capital and maintenance work in that part of provincial grid.

Summary:

The existing BSPS went into service in 1991. It is expected to come to physical end of life (EOL) in the 2016 to 2021 period. However, there are already growing obsolescence issues. The existing scheme was designed and built in its entirety by Ontario Hydro. There is no vendor support and the Hydro One personnel with deep knowledge and expertise on the system is within 2 years of retirement. The existing BSPS is being expanded to its capacity limits to provide outputs for existing wind farms in the Bruce area as well as some coverage for the new Bruce system configuration that must be monitored with the new Bruce to Milton circuits in service.

Results:

Reduction in capacity of the Bruce area transmission system during maintenance of breakers in southwestern Ontario station as well as gradual deteriorating capacity of the Bruce area transmission system due to increasing failures with the Bruce Special Protection System will be avoided. Capacity to allow for additional generation in the Bruce Area will be provided.

Customer Contribution: $0.0M **Removal Costs:** $1.8M

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Investment Category: Sustaining Capital – P&C, Telecom and Metering

Reference #	Investment Name	Gross Cost	Net Cost	In-Service Date
S31	ITC - Line Protections Replacement	$7.5M	$7.5 M	2015

Please see Exhibit D1, Tab 3, Schedule 2 for cash flows and other details about the investment

Need:

The line protection and associated communication systems on the interconnection circuits between Michigan and Ontario have been assessed by both ITC in Michigan and Hydro One as at or near their end of life (EOL). The technology employed in these systems has a mean service life expectancy of 35 years and these systems have now been in service for over forty years. Further delay to the replacement of these protections is expected to result in increased outages to these transmission circuits due to protection failures.

Not proceeding with this investment will compromise reliability of interconnection facilities between Ontario and Michigan.

Summary:

The interconnection facility to Michigan in Sarnia/Windsor area consists of four transmission circuits crossing the St Clair River: B3N, J5D, L4D, and L51D. This investment will replace the remaining end of life line protection equipment on the transmission lines which form the interconnection to Michigan. This will be done in accordance to agreements with ITC Holdings Inc., the transmission asset owner of the Michigan terminals of these interconnection facilities.

Replacement of line protections and communication for circuit B3N was initiated by ITC in 2009 and are now complete. This project will replace line protections and associated communication system of the remaining three Michigan lines with modern protection and communication equipment. The interconnection circuits are classified as Bulk Power System facilities subject to the standards established by NPCC and NERC. Hydro One is required under the Market Rules to comply with these standards which are more stringent than those applied to the existing scheme designs.

Results:

Deterioration in the reliability of the Ontario Michigan interconnection facilities will be avoided and the protection systems will be brought up to the standards required by NERC and NPCC.

Customer Contribution: $0.0M **Removal Costs:** $0.4M

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Investment Category: Sustaining Capital – P&C, Telecom and Metering

Reference #	Investment Name	Gross Cost	Net Cost	In-Service Date
S32	NYPA Tie Lines – Beck line protections replacement	$16.3M	$10.8M	2015

Please see Exhibit D1, Tab 3, Schedule 2 for cash flows and other details about the investment

Need:

The line protections and associated communication systems on the New York State interconnections circuits have been assessed by both the New York Power Authority **(**NYPA) and Hydro One as being at or near their end of life (EOL). The technology employed in these systems has a mean service life expectancy of 35 years and these systems have now been in service for over forty years. Further delay to the replacement of these protections is expected to result in.

Not proceeding with this investment will increased outages to these interconnection circuits due to protection failures with subsequent restrictions on energy exports/imports to satisfy operating conditions of respective utilities.

Summary:

The interconnection facility to NYPA consists of two transmission lines in the Cornwall area crossing the St. Lawrence River and three in the Niagara Falls area crossing the Niagara gorge. This investment will replace the remaining end of life line protection equipment on the transmission lines which form the interconnection to NYPA. This will be done in accordance to agreements with NYPA.

Replacements of line protections for the two lines near Cornwall (L33P and L34P) were initiated jointly with NYPA in 2007 following an event in which the protections on this interface failed to operate correctly resulting in 3000MW load loss in New York State and a major investigation by NERC. This project will replace line protections and associated communication systems of the remaining three NYPA lines at Niagara with modern protection and communication equipment. The interconnection circuits are classified as Bulk Power System facilities subject to the standards established by NPCC and NERC. Hydro One is required under the Market Rules to comply with these standards which are more stringent than those applied to the existing scheme designs.

Results:

Deterioration in the reliability of the Ontario to New York state interconnection facilities will be avoided and the protection systems will be brought up to the standards required by NERC and NPCC.

Customer Contribution: $5.5M (NYPA's share of gross cost) **Removal Costs:** $0.1M

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Investment Category: Sustaining Capital – P&C, Telecom and Metering

Reference #	Investment Name	Gross Cost	Net Cost	In-Service Date
S33	2013-2014 Station P&C Replacement	$45M	$45 M	2015 (Program)

Please see Exhibit D1, Tab 3, Schedule 2 for cash flows and other details about the investment

Need:

Hydro One has identified 9 load supply stations at which most of the protection systems as well as RTU have reached end of life. Replacement of these systems must take place with the next five years in order to avoid growing rates of failures which will result in deteriorating supply reliability from these stations.

Not proceeding with this investment will compromise load supply reliability at 9 stations selected for this program.

Summary:

The optimum approach for addressing the protection replacement need at these 9 stations is to replace the entire relay building. The existing Hydro One developed standardized packaged design solution for replacing the entire relay building at load supply stations will be used. Unlike the protection replacement program (see ISD S-25) and the RTU replacement program (see ISD S-26), in which protection schemes or RTU's are replaced individually, this standardized packaged design solution has all protections and the RTUs installed on racks in a prefabricated building and wired according to Hydro One specification by the vendor in the factory. This approach is more cost effective and also optimizes use of Hydro One's internal expertise. Replacements using standard PCT building design result in savings of about 15% when compared to replacements using piecemeal approach plus they allow for ongoing operational efficiencies. Using modular PCT building is not always possible at the existing stations as many factors have to be considered in the deployment decision (station configuration, space constraints i.e. ability to fit the building within station's real estate footprint, significant stranding of existing protection and control, and telecom assets).

Results:

Deterioration in the reliability of 9 load supply stations due to failing protection systems will be avoided in the most cost effective manner.

Customer Contribution: $0.0M **Removal Costs:** $2.3M

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Investment Category: Sustaining Capital – P&C, Telecom and Metering

Reference #	Investment Name	Gross Cost	Net Cost	In-Service Date
S34	2013-2014 Protection Replacements	$41.4M	$41.4M	2014 (Program)

Please see Exhibit D1, Tab 3, Schedule 2 for cash flows and other details about the investment

Need:

Protection systems are essential to the operation of the power system. The failure of a protection system to operate promptly when required will have serious consequences including one or more of: equipment damage, injury to people, and blackout. Protected element (transformer, bus, line, capacitor bank, etc.) for which the protection systems are known to be non-functional or un-reliable, must be removed from service. It can take several months to replace a protection scheme. Consequently, Hydro One plans replacements of protection schemes before they are likely to fail.

A large population of electromechanical and solid-state relays are operating beyond their expected service life, as the past rate of replacements has not matched the relay aging profile. In response this program will see an increase replacement rates from 40 systems in 2012 to 50 systems in 2013, and 83 systems in 2014 prioritized by the highest risk protections with highest likelihood of failure and largest consequences to the reliability of the grid. The majority of the protection replacements planned in 2013 and 2014 are those schemes that use Programmable Auxiliary Logic Controllers (PALCs). PALCs are based on solid state technology that has a 20-25 year life expectancy. Hydro One has 350 PALCs performing critical functions the bulk of which were installed between 1989 and 1993. The performance of PALCs is deteriorating (average defects for PALCs have almost doubled over the last 4 years compared to the previous 4 year period). PALC programming stations required to maintain these systems use obsolete technology with antiquated 8” floppy discs. Two of the three programming stations owned by Hydro One are still working while the third one is kept to cannibalize parts from in case of failure.

Not proceeding with this investment will jeopardize reliable operation of provincial high voltage transmission grid.

Summary:

The extremely severe consequences of protection systems becoming un-reliable, or failing to operate, requires a preventative sustainment strategy in which protections are replaced before the onset of end of life effects.

This investment is the continuation of the Protection Replacement Program. Three hundred and twenty protection systems are planned to be replaced in 2013 and 2014.

Results:

Deterioration to the reliability and integrity of the critical portions of the grid will be minimized.

Customer Contribution: $0.0M **Removal Costs:** $2.1M
Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Investment Category: Sustaining Capital – P&C, Telecom and Metering

Reference #	Investment Name	Gross Cost	Net Cost	In-Service Date
S35	2013-2014 RTU Replacements	$16.8M	$16.8 M	2014 (Program)

Please see Exhibit D1, Tab 3, Schedule 2 for cash flows and other details about the investment

Need:

Remote Terminal Units (RTUs) 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 Centre (OGCC). The RTUs are also used to provide telemetry to the Independent Electricity System Operator (the IESO) and transmission-connected customers in accordance with the obligations of the Market Rules and the Transmission System Code respectively. The Market Rules provide specific performance levels for data accuracy, update time, and restoration upon failure. Hydro One has a population of about 500 RTUs of various type and vintage.

The program is focused on the RTU's that are assessed to be at end of life. Twenty eight RTUs will be replaced in the years 2013 and 2014 with a further nine RTUs replaced as part of Station P&C Replacement Program described in S24 for a total of thirty seven.

Not proceeding with this investment will impact OGCC ability to effectively manage provincial high voltage grid. Hydro One will be exposed to large numbers of concurrent failures that would overwhelm available expert maintenance resources. The direct result would be serious reduction in the reliability of the assets, negative customer impacts, reduced operability, and numerous breaches of Market Rules. It will also result in higher costs to carry out development and other sustainment programs.

Summary:

A population of 100 RTUs has reached a Poor or Very Poor condition rating and is at end-of-life. Under that methodology RTUs are scheduled for replacement either when the reliability has failed to meet the Hydro One and Market Rule requirements and/or there is no vendor support or supply of spare parts for these RTU's and/or the RTUs are also at or near the point of functional obsolescence (meaning the RTU cannot be expanded to accommodate planned station expansion or perform required additional control function). Failure of an RTU results in complete loss of monitoring and control of a station. The consequences of this include delayed or no response to equipment alarms, delayed restoration of customer outages, delayed switching for planned work, and bottling of generation.

Results:

Maintain the required functionality and reliability of monitoring and control of the grid.

Customer Contribution: $0.0M **Removal Costs:** $0.8M

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Investment Category: Sustaining Capital – P&C, Telecom and Metering

Reference #	Investment Name	Gross Cost	Net Cost	In-Service Date
S36	DC Signaling (Remote Trip) Replacements	$9.8M	$9.8M	2014 (Program)

Please see Exhibit D1, Tab 3, Schedule 2 for cash flows and other details about the investment

Need:

Direct Current (DC) signaling is still used in the protection systems of many of Hydro One transmission circuits which have tapped load supply stations. The reliability of DC signaling is essential to the reliability of load supply at all such tapped stations. DC signaling relies on transmission of DC voltages over dedicated, continuous metallic telephone wires between stations, and uses DC based relaying to transmit/receive and monitor the DC communications channels. If the DC signaling for a transmission circuit is degraded or unavailable, the redundant supply capability of the tapped stations is lost and the load is vulnerable to single contingency events or, in some cases, transformers will be removed from service exposing load to curtailment for the resulting capacity restriction. These required actions compromise load supply reliability and increase cost.

This and future releases will replace all remaining DC signalling from use within Hydro One system including customer owned stations.

Not proceeding with this investment will further jeopardize load supply reliability at stations where DC signaling provides protection path.

Summary:

DC signaling facilities are at end of life. Both HONI owned and Telco owned metallic cables are typically as old as the stations (over 40 years old) and at the end of life due to increasing breaks in the old cable insulation sheaths that require repairs as well as constant operation and frequent failures of compressor equipment required for the operation of these cables. Over 10-years ago Telcos have provided letters stating that new DC signaling is no longer offered and maintenance of existing DC circuits will be reduced to best effort basis. DC relaying equipment in the stations is also at end of life. The manufacture of this equipment was discontinued in the mid 1980's, spares and repairs are limited by the ability to re-claim spare components from old relays, and they have failure rates below the threshold for replacement of relay devices in Hydro One (less than 25 device-years/failure).

Results:

Deterioration in load supply reliability due to increasing rates and durations of DC signaling outages will be arrested and corrected.

Customer Contribution: $0.0M **Removal Costs:** $0.5M

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Investment Category: Sustaining Capital – P&C, Telecom and Metering

Reference #	Investment Name	Gross Cost	Net Cost	In-Service Date
S37	DC Signaling Replacements (Toronto North & East)	$4.3M	$4.3M	2014 (Program)

Please see Exhibit D1, Tab 3, Schedule 2 for cash flows and other details about the investment

Need:

Direct Current (DC) signaling is still used in the protection systems of many of Hydro One transmission circuits which have tapped load supply stations. As such, the reliability of DC signaling is essential to the reliability of load supply at all such tapped stations. This project will eliminate DC signalling teleprotections on 13 transmission lines and 14 transformer stations supplying the North-Eastern part of the Greater Toronto Area (GTA). Specifically, the following stations are affected by this project: Richview TS, Finch TS, Bathurst TS, Fairchild TS, Leslie TS, Agincourt TS, Malvern TS, Cherrywood TS, Sheppard TS, Ellesmere TS, Scarborough TS, Bermondsay TS, Warden TS, and Leaside TS.

Not proceeding with this investment will further jeopardize load supply reliability of the lines and stations above where DC signaling provides protection path.

Summary:

DC signaling relies on transmission of DC voltages over dedicated and continuous metallic telephone wires between stations, and uses DC based relaying to transmit/receive and monitor the DC communications channels. If the DC signaling for a transmission circuit is degraded or unavailable, the redundant supply capability of the tapped stations is lost and the load is vulnerable to single contingency events or, in some cases, transformers will be removed from service exposing load to curtailment for the resulting capacity restriction. These required actions compromise load supply reliability and increase cost.

DC signaling facilities are at end of life. Both HONI owned and Telco owned metallic cables are typically as old as the stations (over 40 years old) and at the end of life due to increasing breaks in the old cable insulation sheaths that require repairs as well as constant operation and frequent failures of compressor equipment required for the operation of these cables. Over 10-years ago Telcos have provided letters stating that new DC signaling is no longer offered and maintenance of existing DC circuits will be reduced to best effort basis. DC relaying equipment in the stations is also at end of life. The manufacture of this equipment was discontinued in the mid 1980's, spares and repairs are limited by the ability to re-claim spare components from old relays, and they have failure rates below the threshold for replacement of relay devices in Hydro One (less than 25 device-years/failure).

Results:

Deterioration of supply reliability in the North-Eastern GTA will be arrested and corrected.

Customer Contribution: $0.0M **Removal Costs:** $0.2M

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Investment Category: Sustaining Capital – P&C, Telecom and Metering

Reference #	Investment Name	Gross Cost	Net Cost	In-Service Date
S38	Protection Tone Channel Replacements	$10.0M	$10.0M	2014 (Program)

Please see Exhibit D1, Tab 3, Schedule 2 for cash flows and other details about the investment

Need:

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 signalled by means of a change in the pitch of a tone. These are referred to a 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. Due to intricate interconnectivity between communication devices and protective relays it is most efficient to replace tone equipment at the same time as protection replacement. Consequently, the program to replace tone equipment has always been coordinated with that for protection replacement. This investment will continue to coordinate with the protection replacement program and should conclude the replacement of all remaining end of life tone channel end devices from the protection systems of all lines designated as part of the Bulk Power System. Hydro One has assigned highest priority to sustaining the reliability of protections that are subject to NPCC and NERC Reliability Standards. Consequences of failures of these protections can be most severe from system stability and operating efficiency stand point.

Not proceeding with this investment will lead to deterioration of reliability of provincial HV transmission grid with potential to violate NPCC/NERC reliability standards.

Summary:

This investment is replacing remaining end of life tone channel equipment from protection systems on high voltage transmission lines with higher priority assigned to circuits governed by NERC and NPCC reliability standards.

Results:

Major risk to the reliability of the grid will be cost effectively eliminated.

Customer Contribution: $0.0M **Removal Costs:** $0.5M

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Investment Category: Sustaining Capital – P&C, Telecom and Metering

Reference #	Investment Name	Gross Cost	Net Cost	In-Service Date
S39	ITMC Refreshment	$4.4M	$4.4M	2014

Please see Exhibit D1, Tab 3, Schedule 2 for cash flows and other details about the investment

Need:

The telecom management centre that support protection and control of the provincial grid has been in operation for nearly 15 years and is in need of rehabilitation. Hardware and control room layout, together with auxiliary systems that support logistics of the ITMC control room are to be replaced/upgraded to continue to provide required functionality and adequate level of performance. Monitoring of telecom facilities and systems that support protection and control of the provincial grid are critical to ensure its reliable operation and to ensure that maintenance activities are carried out in a secure and optimized manner.

Not proceeding with this investment will jeopardize integrity and effectiveness of telecom facilities monitoring function thus affecting reliability of transmission network.

Summary:

Monitoring of Hydro One's telecom systems that support HV transmission network is carried out from Hydro One Telecom NOC (Network Operating Centre). NOC has been in operations in its current configuration for almost 15 years without undergoing major refurbishment. Hardware platforms that support control room operations and back office activities have aged to the point of technical obsolescence. Hardware platforms, although still being supported, are not performing at the level expected to support state-of-the-art control room environment and service level expectations. This is further compounded by the ever expanding reach of telecom systems to the Hydro One's distribution network related to implementation of ADS initiative. Number of managed elements continues to grow (smart meter related telecom infrastructure, ADS related telecom devices, WAN initiative related telecom gear) and this taxes the existing support systems to their limit.

Results:

- Reduce operational risk, reduce life cycle cost, and restore reliability of telecom systems monitoring function

Customer Contribution: $0.0M **Removal Costs:** $0.0M

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Investment Category: Sustaining Capital

Reference #	Investment Name	Gross Cost	Net Cost	In-Service Date
S40	Telecom Device Control Network Cyber Security	$10.4M	$10.4 M	2013

Please see Exhibit D1, Tab 3, Schedule 2 for cash flows and other details about the investment

Need:

This investment is required to ensure an appropriate level of security on critical telecommunication facilities as required to meet the requirements of NPCC Directory 4, Appendix A, Section 3. This Directory came into force Dec 1, 2009

Summary:

The Telecom Device Control Network (TDCN) Cyber Security Project will address certain security issues associated with the telecom network that is used for the protection and control of the grid

Results:

• Security risks affecting the operation of the grid will be addressed.
• Comply with NPCC/NERC regulatory cyber security requirements.

Customer Contribution: $0.0M **Removal Costs:** $0.0M

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Investment Category: Sustaining Capital

Reference #	Investment Name	Gross Cost	Net Cost	In-Service Date
S41	NERC CIP V5 Readiness	$19.0M	$19.0M	2014

Please see Exhibit D1, Tab 3, Schedule 2 for cash flows and other details about the investment

Need:

NERC has developed a major new revision to the Cyber Security Standards that is expected to come into effect in 2015. This standard expands the scope of cyber assets that are required to be under security management. Hydro One must make investments to ensure compliance with the requirements of this new standard.

Summary:

Under NERC CIP V5 about 90 additional Hydro One stations will require physical security boundaries and cyber asset management systems such as access control management and logging, firmware patch control, firewalls and intrusion detection. Hydro One will need to have these upgrades completed by late 2014 in order to be ready for an audit in 2015.

Results:

Hydro One will be maintain compliance with evolving NERC Cyber Security requirements.

Customer Contribution: $0.0M **Removal Costs:** $0.0M

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Investment Category: Sustaining Capital

Reference #	Investment Name	Gross Cost	Net Cost	In-Service Date
S42	Cyber Security of Major Load Supply Stations	$11.7M	$11.7M	2015

Please see Exhibit D1, Tab 3, Schedule 2 for cash flows and other details about the investment

Need:

Transmission stations supplying major urban or industrial load is should be protected against a Cyber attack.

Summary:

Once design standards, security management systems and processes are in place and fully mature for meeting the evolving NERC standards, it is prudent to apply these to expand beyond the existing station standards to protect stations supplying major cities and industrial load centres. Hydro One plans a project to do this in starting in 2014.

Results:

8 stations supplying major cities and industrial load centres will be upgraded to cyber security standards.

Customer Contribution: $0.0M **Removal Costs:** $0.0M

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Investment Category: Sustaining Capital

Reference #	Investment Name	Gross Cost	Net Cost	In-Service Date
S43	Cyber Systems Life Cycle Management	$6.0M	$6.0M	2014

Please see Exhibit D1, Tab 3, Schedule 2 for cash flows and other details about the investment

Need:

Systems installed for establishing electronic security perimeters and for the management and monitoring of Critical Cyber Assets will require an upgrading and refresh starting in 2013. These systems can requires shorter upgrading cycles due to the "cat and mouse" aspect of the security function and the need for evolving counter-measures to new forms and avenues of attacks.

Summary:

Hydro One has deployed about 120 systems that perform intrusion detection, firewalling, security incident detection and logging, password management and access control and malware and anti-virus detection. These began to be deployed in large numbers in 2008 and some much earlier. This program will update hardware and software to meet the capacity and obsolescence issues.

Results:

Hydro One's Critical Cyber Asset management and monitoring systems will be maintained to required reliability, effectiveness and vendor support.

Customer Contribution: $0.0M **Removal Costs:** $0.0M

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Investment Category: Sustaining Capital - Stations – Security Infrastructure

Reference #	Investment Name	Gross Cost	Net Cost	In-Service Date
S44	Station Fences & Security Infrastructure	$19.7 M	$19.7M	2014

Please see Exhibit D1, Tab 3, Schedule 2 for cash flows and other details about the investment

Need:

- Significant risks occur when station perimeters are breached including the potential for severe injury or fatality to the intruders.
- Copper thieves steal fence grounds, underground grid, live grounds off transformer neutrals as well as station equipment.
- There are heightened safety concerns for employees and first responders where tampering with electrically live equipment has occurred.
- The reliability and integrity of the power system is undermined, which could affect the operation of other equipment or those of customers.
- The most recent example of an impactive security breach was at Scott TS on January 21, 2012 where a member of the public tripped several elements in the Scott TS switchyard after having gained unauthorized access to the station. The result was a loss of 160MW of load to the local LDC and transmission-connected industrial customers in the Sarnia area. The impact to the process-based industrial customers and the economies they contribute to are significant upon loss of supply. Hydro One recognizes the need to provide secure perimeters to the station facilities to reduce the likelihood of these types of events.

Summary:

- Security Infrastructure is designed to effectively deter, delay, detect and respond to security threats that target Transmission stations.
- These threats can include copper theft, criminal activity, domestic extremism and terrorism.
- Investments are required in order to maintain system reliability, and promote greater safety within the station environment.
- The program follows a risk based approach using Threat & Risk Assessments (TRA) to determine station criticality, exposure threats and the impacts on reliability and safety.
- An additional and enhanced suite of security equipment and systems has been developed to provide a range of protection options at stations. This suite includes items like reinforced fencing (both razor mesh and anti-tamper), intrusion and tamper detection, security cameras, horns, strobe lights and other sensors. The appropriate level of deployment is based on the Threat & Risk Assessments conducted for sites.
- Not implementing the appropriate level of security means the risk to stations will continue to occur with likelihood of severe injury or fatality from the intrusions, risk of outages and emergency maintenance.

Results:

- The program's security objectives are to deter, delay, detect and respond to intruders breaching the station perimeter.
- By investing in Security Infrastructure, Hydro One seeks to protect its TS assets as well as enhance reliability and public & employee safety.

Customer Contribution: $0.0M **Removal Costs:** $1.4M

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Investment Category: Sustaining Capital – Lines – Overhead Lines Component Refurbishment and Replacement

Reference #	Investment Name	Gross Cost	Net Cost	In-Service Date
S45	Wood Pole Replacement Program	$56.8M	$56.8M	2014 (Program)

Please see Exhibit D1, Tab 3, Schedule 2 for cash flows and other details about the investment

Need:

This investment is required to address wood pole structures that have reached the end of their service life in order to maintain their reliability and safety in a cost-effective manner.

Not proceeding with this investment will increase the risk of structure failures during adverse weather conditions with associated risks to public safety and transmission system reliability. Since the majority of wood pole lines are single supply, component failures on these lines usually cause supply interruptions to customers.

Summary:

Hydro One's transmission system consists of approximately 21,000 route kilometers (or 29,000 circuit km) of overhead transmission lines. The transmission line system includes approximately 92,000 steel and wood structures. The wood structure lines consist of about 7,000 route km which includes 42,000 wood pole structures. The majority of the wood pole structure population is located in Northern Ontario, typically in remote locations with difficult access.

Wood structures deteriorate over time; the rate of deterioration depends on age, location, weather, type of wood, treatment, insects and wildlife. As a result, uniform deterioration does not occur and the condition of wood structures varies, even in the same location. Wood components are replaced when their condition has deteriorated to a point where there is a significant risk of failure under adverse weather conditions. Replacement candidates are based on on-going condition assessment programs. Asset condition assessment work includes detailed helicopter inspection (DHI) and ground line inspection. DHI assesses the upper area of wood structures and ground line inspection assesses the lower part of wood structures. A total of 1,700 wood pole structures that have reached the end of their service life according to their condition assessment will be replaced in 2013 and 2014 (850 wood poles per year).

Results:

- Maintain transmission system security and customer delivery reliability
- Reduce safety hazards to employees and the public from potential structure failures
- Replace 1,700 sub-standard wood pole structures that have reached the end of their service life

Customer Contribution: $0.0M **Removal Costs:** $7.7M
Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Investment Category: Sustaining Capital – Lines – O/H Lines Component Refurbishment and Replacement

Reference #	Investment Name	Gross Cost	Net Cost	In-Service Date
S46	Steel Structure Coating Program	$20.9M	$20.9M	2014 (Program)

Please see Exhibit D1, Tab 3, Schedule 2 for cash flows and other details about the investment

Need:

This investment is required to restore the galvanized coating that protects the steel structures from corrosion and to extend their service lives. Structure coating is used to cost effectively manage the life cycle of these structures.

Not proceeding with this investment will result in further deterioration of the steel structures and eventually lead to advancing the replacement of structures at a substantially greater cost.

Summary:

Hydro One's transmission system consists of about 21,000 route kilometers (about 29,000 circuit kilometers) of overhead transmission lines. The system is almost exclusively made up of overhead lines and a large part of the system is supported by approximately 50,000 steel structures.

Hydro One's steel structures are manufactured with a zinc-based galvanized coating which protects the underlying steel against corrosion. The coating will generally last from 30 to 60 years, with the more corrosive environments depleting the coating at a quicker rate. Once the coating has depleted, bare metal is exposed to the atmosphere and the steel will corrode at a rate up to 25 times faster than the galvanized coating. The accelerated corrosion of the base metal increases the risk of structural damage to structure members, which will eventually need to be replaced if left uncoated.

Asset condition assessment is carried out on an annual basis with a focus on line sections with in-service dates greater than 40 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 members, or in the case where the coating is depleted, the amount of metal loss that has occurred. Structure asset condition assessment is an ongoing program that requires field inspections with follow-up analysis to determine if any structural damage has taken place. Current detailed condition information and further analysis suggests that within the next 10 years, about 3,500 structures will need to have their corrosion protection re-instated in order to stem the deterioration of Hydro One's steel structures. As such, structure coating is an ongoing annual program which will coat approximately 350 structures per year.

Results:

- Apply the protective galvanized coating on 700 steel structures to extend their life
- Maintain reliability and optimize the life-cycle costs of these 700 steel structures

Customer Contribution: $0.0M **Removal Costs:** $0.0M
Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Investment Category: Sustaining Capital - Shieldwire Replacement Program

Reference #	Investment Name	Gross Cost	Net Cost	In-Service Date
S47	Shieldwire Replacement Program	$11.3M	$11.3M	2014 (Program)

Please see Exhibit D1, Tab 3, Schedule 2 for cash flows and other details about the investment

Need:

This investment is required to replace shieldwire that has reached end-of-life.

Not proceeding with this investment will jeopardize system reliability, cause an increased number of customer interruptions, and will increase public and employee safety risks.

Summary:

Hydro One's transmission system consists of about 35,000 kilometres of overhead shieldwire (or 21,000 route km). Almost all overhead transmission lines have shieldwire strung above the conductor to protect against lightning strikes and provide grounding continuity. The majority of shieldwire in Hydro One's system is made of galvanized steel wire, whose protective zinc coating deteriorates over time. When the galvanizing corrosion protection has depleted, the underlying steel begins to corrode resulting in loss of metal, reduction in strength, and eventual failure of the shieldwire. When failure does occur, the broken shieldwire usually makes contact with the conductors before falling to the ground.

To mitigate the risk of shieldwire failure, Hydro One has implemented an annual shieldwire-testing program which selects samples from line sections throughout the network. Shieldwire samples are removed and sent to a laboratory for ductility and tensile strength testing to gather additional data on its condition. If the test data for a particular shieldwire fails to meet end-of-life criteria, then that shieldwire is replaced.

Shieldwire test results from previous years indicate that there are currently about 220 km of galvanized shieldwire that have reached end-of-life. Additionally, there are approximately 330 km of galvanized shieldwire currently in poor condition that will also require replacement in the near future. Therefore, it is estimated that future shieldwire replacement will need to average about 150 km per year in the next two years.

Results:

- Eliminate 300 km of the identified shieldwire that require replacement.
- Reduce worker and public safety risks associated with shieldwire failures.

Customer Contribution: $0.0M **Removal Costs:** $0.8M

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Investment Category: Sustaining Capital – Transmission Line Emergency Repairs

Reference #	Investment Name	Gross Cost	Net Cost	In-Service Date
S48	Transmission Lines Emergency Repairs	$15.0M	$15.0M	2014 (Program)

Please see Exhibit D1, Tab 3, Schedule 2 for cash flows and other details about the investment

Need:

This investment is required to make emergency repairs to the overhead transmission system as they occur.

Not proceeding with this investment is not an option. Transmission line emergencies usually result in the presence of a public/employee safety hazard, a circuit outage and/or customers out of power.

Summary:

Hydro One's transmission system consists of approximately 21,000 route kilometers (or 29,000 circuit km) of overhead transmission lines, which have been built in the province over the past century or more. The transmission line system includes approximately 50,000 steel and 42,000 wood structures ranging in age from new to 100+ years old.

An emergency is defined as:
A structure or component that has failed or is at risk of imminent failure. Failure could result in a serious public/employee safety hazard, circuit outage and/or property damage.

When structures and/or components fail under emergency circumstances it is not usually due to age or condition and, in most cases, the failure could not have been prevented. The reasons for failure include but are not limited to; normal weather conditions (eg. lightning), severe weather events (eg. tornado), motor vehicle accidents, design defects, acts of vandalism, etc.

In addition to structures and/or components that have already failed, Hydro One service providers must respond several times each year to structures and/or components that are **"at risk of imminent failure".** An example would be a wooden arm or structure that has been damaged by lightning. It may not have failed but is very close to failing. Such repairs are also considered an emergency.

Results: Minimize public/employee safety risk

Minimize circuit/customer outage time

Customer Contribution: $0.0M **Removal Costs:** $2.0M

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Investment Category: Sustaining Capital – Insulator Replacement Program

Reference #	Investment Name	Gross Cost	Net Cost	In-Service Date
S49	Insulator Replacement Program	$10.6M	$10.6 M	2014 (Program)

Please see Exhibit D1, Tab 3, Schedule 2 for cash flows and other details about the investment

Need:

This investment is required to replace insulators that have reached end-of-life.

Not proceeding with this investment may negatively impact system reliability, cause an increased number of customer interruptions, and will increase public and employee safety risks.

Summary:

Hydro One's transmission system consists of about 410,000 insulator strings. This program replaces transmission lines insulators that have reached or are approaching end-of life. Insulator failures result in outages and at times allow energized conductor to fall to the ground creating a safety hazards.

Transmission line insulators normally have a life expectancy similar to that of conductors. However, some insulators require replacement before the circuit reaches end-of-life. This program addresses end of life insulators and also deals with unforeseen insulator issues such as known insulator design or manufacturing issues for different insulator types.

There are several known manufacturing issues on porcelain insulators installed in 1960s, 1970s and 1980s. Polymer insulators installed in 1980s and 1990s at higher voltage levels have design deficiencies with respect to the effects from corona and have a much shorter life than glass or porcelain depending on their installed orientation on the line.

Past insulator test results indicate that there are currently about 400 strings of insulators on the 115/230Kv network that have been identified as reaching the end of their expected life on the 115 & 230 kV network. More recently an additional 1800 strings on the 500 kV network have also been identified as defective through testing that were installed in the 1970's and suffer from a manufacturing defect know as cement growth. The cement is integral to the mechanical strength of the insulator string, and failure typically results in conductor drop and circuit outage. Due to the criticality of the 500 kV network, it is planned to replace these defective units during the test years.

Results:

- Replace 2200 strings of the identified insulators that require replacement.
- Reduce employee and public safety risks associated with insulator failures.
- Minimize the risk of unplanned circuit outage

Customer Contribution: $0.0M **Removal Costs:** $0.8M
Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Investment Category: Sustaining Capital – Lines – O/H Lines Component Refurbishment and Replacement

Reference #	Investment Name	Gross Cost	Net Cost	In-Service Date
S50	S2B Steel Structure Replacements	$7.2M	$7.2 M	2013

Please see Exhibit D1, Tab 3, Schedule 2 for cash flows and other details about the investment

Need:

This investment is required to to address corrosion issues on 16 structures reaching the end of their service life on circuit S2B from Copper Cliff JCT x Martindale TS. The current state of these structures poses a risk to system and customer reliability as well as employee and public safety.

Not proceeding with this investment will increase the risks to system and customer reliability and employee and public safety in the area.

Summary:

Hydro One's transmission system consists of about 21,000 route kilometers (about 29,000 circuit kilometers) of overhead transmission lines including approximately 50,000 steel structures. This project is for complete replacement of 16 of these structures as the metal loss of the steel is significant and poses a reliability and safety risk.

The steel structures from Copper Cliff JCT to Martindale TS are double circuit structures that hold circuits S2B and S1R. The section of S2B being replaced is close to one of the Vale mine sites and serves as a critical supply of power to the area.

Based on an engineering analysis, several structures on the S2B section from Copper Cliff JCT to Martindale TS require repairs both at the footing and at above ground level. Refurbishment of the structures (member replacements) is not an economical option as the majority of the structure members are pitted and thus almost every member would require replacement. The proposed work includes complete replacement of structures 26 to 41.

Results:

- Reduce the risk of a major interruption of supply to customers
- Reduce safety hazards to employees and to the public from potential structure failure

Customer Contribution: $0.0M **Removal Costs:** $0.8M

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Investment Category: Sustaining Capital – Lines – Overhead Lines Component Refurbishment and Replacement

Reference #	Investment Name	Gross Cost	Net Cost	In-Service Date
S51	Steel Structure Replacement Program	$7.2M	$7.2 M	2014 (Program)

Please see Exhibit D1, Tab 3, Schedule 2 for cash flows and other details about the investment

Need:

This investment is required to replace structures that have reached the end of their service life due to excessive metal loss from corrosion where the mechanical strength of the structure no longer meets Hydro One design standards. Complete structure replacement is required when too many structure members need to be replaced, making refurbishment an uneconomical option.

Not proceeding with this investment will increase the risks to system and customer reliability as well as employee and public safety.

Summary:

Hydro One's transmission system consists of about 21,000 route kilometers (about 29,000 circuit kilometers) of overhead transmission lines including approximately 50,000 steel structures. Transmission lattice towers can be subdivided into the following components: legs, diagonals, struts, arms, and redundant members. Each member serves a specific purpose in supporting the tower and has a unique set of forces and stresses associated with it.

The steel used in transmission towers is manufactured with a zinc-based galvanized coating and is used to protect steel towers from corrosion. Over time the zinc corrodes eventually exposing the bare steel underneath. Once the galvanized coating has been depleted, the bare steel becomes exposed to the environment and begins to corrode at a much faster rate. In many cases, the steel has been found to corrode up to 25 times faster then while protected by the zinc. If the tower is not painted with a galvanized coating and corrosion is allowed to continue, steel member will begin to lose strength and eventually fall below Hydro One design standards. Once a structure is identified as being in poor condition through visual inspection and sample zinc coating measurement, a detailed corrosion assessment is conducted to determine whether it is possible to replace a portion of the steel members and coat the remaining structure to protect it from corrosion or whether it is economical to replace the entire structure. A total of 8 steel structures that have reached the end of their service life according to their condition assessment will be replaced in 2013 and 2014.

Results:

- Maintain transmission system security and customer delivery reliability
- Reduce safety hazards to employee and the public from potential structure failures
- Replace 8 sub-standard steel structures that have reached the end of their service life

Customer Contribution: $0.0M **Removal Costs:** $0.8M

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Investment Category: Sustaining Capital – Line Refurbishment Projects

Reference #	Investment Name	Gross Cost	Net Cost	In-Service Date
S52	C25H Line Refurbishment	$52.5 M	$52.5 M	2017

Please see Exhibit D1, Tab 3, Schedule 2 for cash flows and other details about the investment

Need:

This investment is required to address the condition of the conductors on the 230 kV circuit C25H from Chats Falls SS to Havelock TS (170 km). The conductor has deteriorated to the point where the strength and ductility characteristics are below established criteria determining end of life.

Not proceeding with this investment will increase the probability of future line failures that will adversely impact the supply reliability to a number of industrial and residential customers in the Region. Conductor failures will also create a risk to public safety.

Summary:

Conductors are a critical element of a transmission line. Conductors with loss of ductility in the steel strands are susceptible to failure from movements caused by wind, ice and changes in conductor tension. The conductor on C25H from Chats Falls SS to Havelock TS is 84 years old. Conductor tests reveal that the tensile strength and ductility has deteriorated to an extent that the conductor is at end of life. Furthermore, the insulators, hardware and shieldwire on this line are also approaching end-of-life and require replacement.

This investment will consist of replacing the existing 795 kcmil ACSR conductor with a new (similar size) conductor on the 170 km km section of line between Chats Falls SS and Havelock TS. Proposed refurbishment work will return this section of line to a near-new condition and will also meet future load growth demands.

Results:

- Reduce safety hazards to the public from potential component failures of the transmission line.
- Maintain customer delivery reliability and voltage performance.

Customer Contribution: $0.0M **Removal Costs:** $2.8M

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Investment Category: Sustaining Capital – Line Refurbishment Projects

Reference #	Investment Name	Gross Cost	Net Cost	In-Service Date
S53	D1A Line Refurbishment	$3.2M	$3.2 M	2013

Please see Exhibit D1, Tab 3, Schedule 2 for cash flows and other details about the investment

Need:

This investment is required to address the condition of the conductors on the 115kV circuits D1A/D3A from Decew Falls SS to St. Johns Valley Jct (4.2 km). The conductor has deteriorated to the point where the strength and ductility characteristics are below established criteria determining end of life.

Not proceeding with this investment will increase the probability of future line failures that will adversely impact the supply reliability to a number of industrial and residential customers in the Region. Conductor failures will also create a risk to public safety.

Summary:

Conductors are a critical element of a transmission line. Conductors with loss of ductility in the steel strands are susceptible to failure from movements caused by wind, ice and changes in conductor tension. The conductor on D1A/D3A from Decew Falls SS to St. Johns Valley Jct is 69 years old. Conductor tests reveal that the tensile strength and ductility has deteriorated to an extent that the conductor is at end of life. Furthermore, the insulators, hardware and shieldwire on this line are also are approaching end-of-life and require replacement.

This investment will consist of replacing the existing 605 kcmil ACSR conductor with a new (similar size) conductor on the 4.2 km section of line between Decew Falls SS and St. Johns Valley Jct. Proposed refurbishment work will return this section of line to a near-new condition and will also meet future load growth demands.

Results:

- Reduce safety hazards to the public from potential component failures of the transmission line.
- Maintain customer delivery reliability and voltage performance.

Customer Contribution: $0.0M **Removal Costs:** $0.2M

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Investment Category: Sustaining Capital – Line Refurbishment Projects

Reference #	Investment Name	Gross Cost	Net Cost	In-Service Date
S54	H27H Line Refurbishment	$14.5 M	$14.5 M	2014

Please see Exhibit D1, Tab 3, Schedule 2 for cash flows and other details about the investment

Need:

This investment is required to address the condition of the conductors on the 230 kV circuits H27H from Bannockburn Jct to Havelock TS (29 km). The conductor has deteriorated to the point where the strength and ductility characteristics are below established criteria determining end of life.

Not proceeding with this investment will increase the probability of future line failures that will adversely impact the supply reliability to a number of industrial and residential customers in the Region. Conductor failures will also create a risk to public safety.

Summary:

Conductors are a critical element of a transmission line. Conductors with loss of ductility in the steel strands are susceptible to failure from movements caused by wind, ice and changes in conductor tension. The conductor on H27H from Bannockburn Jct to Havelock TS is 83 years old. Conductor tests reveal that the tensile strength and ductility has deteriorated to an extent that the conductor is at end of life. Furthermore, the insulators, hardware and shieldwire on this line are also approaching end-of-life and require replacement.

This investment will consist of replacing the existing 795 kcmil ACSR conductor with a new (similar size) conductor on the 29 km section of line between Bannockburn Jct and Havelock TS. Proposed refurbishment work will return this section of line to a near-new condition and will also meet future load growth demands.

Results:

- Reduce safety hazards to the public from potential component failures of the transmission line.
- Maintain customer delivery reliability and voltage performance.

Customer Contribution: $0.0M **Removal Costs:** $0.8M

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Investment Category: Sustaining Capital – Line Refurbishment Projects

Reference #	Investment Name	Gross Cost	Net Cost	In-Service Date
S55	V73R/V74R Self Damping Conductor Replacement	$9.0 M	$9.0 M	2014

Please see Exhibit D1, Tab 3, Schedule 2 for cash flows and other details about the investment

Need:

This investment is required to address the condition of the conductors on the 230 kV circuits V73R/V74R from Claireville TS to Richview TS (9.6 km). These circuits contain a problematic self-damping conductor which has proven unable to adequately control aeolian vibration. An inadequate vibration control system would lead conductors to fatigue and ultimately to fail prematurely.

Not proceeding with this investment will increase the probability of line failures that will adversely impact the supply reliability to a number of industrial and residential customers in the Region. Conductor failures also pose a risk to public safety.

Summary:

Conductors are a critical element of a transmission line. Conductors with known vibration design problems are susceptible to failure from movements caused by wind. Hydro One experienced near conductor failures at multiple locations on other circuits containing self-damping conductors in 2010. Effected circuits were removed from service and conductors were replaced under emergency programs. V73R/V74R circuits also have been strung with this inferior self-damping conductor. It is almost impossible to detect conductor fatigue due to vibration at its early stages through routine inspection methods as crack initiation/propagation typically starts within inner layers. Usually when there are broken strands at most outer layer, conductor is at its final failure stage. Therefore, routine inspection methods cannot effectively prevent potential conductor failures due to vibration and this conductor requires replacement.

This investment will consist of replacing the existing 912 kcmil self-damping conductor with a new (similar size) standard ACSR conductor on the 9.6 km section of line between Claireville TS and Richview TS.

Results:

- Reduce safety hazards to the public from potential component failures of the transmission line.
- Maintain customer delivery reliability and voltage performance.

Customer Contribution: $0.0M **Removal Costs:** $1.0M

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Investment Category: Sustaining Capital – Line Refurbishment Projects

Reference #	Investment Name	Gross Cost	Net Cost	In-Service Date
S56	H24C Line Refurbishment	$25.7M	$25.7 M	2014

Please see Exhibit D1, Tab 3, Schedule 2 for cash flows and other details about the investment

Need:

This investment is required to address the condition of the conductors on the 230kV circuit H24C from Marine JCT to Oshawa North JCT (54 km). The conductor has deteriorated to the point where the strength and ductility characteristics are below established criteria determining end of life.

Not proceeding with this investment will increase the probability of future line failures that will adversely impact the supply reliability to a number of industrial and residential customers in the Region. Conductor failures will also create a risk to public safety.

Summary:

Conductors are a critical element of a transmission line. Conductors with loss of ductility in the steel strands are susceptible to failure from movements caused by wind, ice and changes in conductor tension. The conductor on H24C from Marine JCT to Oshawa North JCT is 83 years old. Conductor tests reveal that the tensile strength and ductility has deteriorated to an extent that the conductor is at end of life. Furthermore, the insulators, hardware and shieldwire on this line are also approaching end-of-life and require replacement.

This investment will consist of replacing the existing 795 kcmil ACSR conductor with a new (similar size) conductor on the 54 km section of line between Marine JCT and Oshawa North JCT. Proposed refurbishment work will return this section of line to a near-new condition and will also meet future load growth demands.

Results:

- Reduce safety hazards to the public from potential component failures of the transmission line.
- Maintain customer delivery reliability and voltage performance.

Customer Contribution: $0.0M **Removal Costs:** $1.3M

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Investment Category: Sustaining Capital – Line Refurbishment Projects

Reference #	Investment Name	Gross Cost	Net Cost	In-Service Date
S57	C27P Line Refurbishment	$6.2 M	$6.2 M	2013

Please see Exhibit D1, Tab 3, Schedule 2 for cash flows and other details about the investment

Need:

This investment is required to address the condition of the conductors on the 230 kV circuit C27P from Chats Falls SS to Galetta JCT (6.5 km). The conductor has deteriorated to the point where the strength and ductility characteristics are below established criteria determining end of life.

Not proceeding with this investment will increase the probability of future line failures that will adversely impact the supply reliability to a number of industrial and residential customers in the Region. Conductor failures will also create a risk to public safety.

Summary:

Conductors are a critical element of a transmission line. Conductors with loss of ductility in the steel strands are susceptible to failure from movements caused by wind, ice and changes in conductor tension. The conductor on C27P from Chats Falls SS to Galetta JCT is 80 years old. Conductor tests reveal that the tensile strength and ductility has deteriorated to an extent that the conductor is at end of life. Furthermore, the insulators, hardware and shieldwire on this line are also approaching end-of-life and require replacement.

This investment will consist of replacing the existing 795 kcmil ACSR conductor with a new (similar size) conductor on the 6.5 km section of line between Chats Falls SS and Galetta JCT. Proposed refurbishment work will return this section of line to a near-new condition and will also meet future load growth demands.

Results:

- Reduce safety hazards to the public from potential component failures of the transmission line.
- Maintain customer delivery reliability and voltage performance.

Customer Contribution: $0.0M **Removal Costs:** $0.3M

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Investment Category: Sustaining Capital – Secondary Land Use and Recoverable Projects

Reference #	Investment Name	Gross Cost	Net Cost	In-Service Date
S58-S61	Transmission Lines Re-investment Program – Recoverable Projects	$58.4 M	$0.0 M	

Please see Exhibit D1, Tab 3, Schedule 2 for cash flows and other details about the investment

Need:

This investment is required to relocate, remove or reinforce transmission assets in order to facilitate third-party projects such as roadwork, transit systems, and other major infrastructure or development work that may encroach upon or impact Hydro One assets and Right of Ways.

Not proceeding with this investment will impede third-party projects and may lead to legal action against Hydro One, as well as customer dissatisfaction and poor public perception for Hydro One.

Summary:

Hydro One's transmission network consists of approximately 29,000 circuit km of overhead transmission lines. These transmission lines are used to transmit electric power, via network and radial circuits, to either direct transmission customers, or to transformation points for distribution to retail customers. The Transmission Lines Re-investment Program – Recoverable Projects has been designed to meet reliability expectations, regulatory and legal requirements, and to minimize safety impacts associated with transmission line sections that may be impacted by third-party proponent-driven projects. This program enables the relocation, removal and reinforcement of transmission assets in order to facilitate third-party development projects, the costs for which are fully or partially recoverable.

Results:

This investment will allow Hydro One to relocate, remove or reinforce transmission assets, thereby enabling third-party proponents to proceed with their projects without impacting Hydro One transmission assets. Also, this investment mitigates legal and reputation risks for Hydro One.

Customer Contribution: $58.4M **Removal Costs:** $0.0M

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Investment Category: Sustaining Capital – Lines – UG Cables Component Refurbishment and Replacement

Reference #	Investment Name	Gross Cost	Net Cost	In-Service Date
S62	H2JK/K6J Underground Cable Replacement (Riverside Jct x Strachan TS)	$53.1M	$53.1 M	2014

Please see Exhibit D1, Tab 3, Schedule 2 for cash flows and other details about the investment

Need:

This investment is required to replace two 115 kV underground transmission circuits that have reached the end of their service life totaling 11.2 circuit kilometers that run from Strachan TS to Riverside Jct. along Toronto's waterfront.

Not proceeding with this investment will lead to reliability and supply issues to the downtown Toronto area.

Summary:

These buried cables were installed in 1957 and are constructed of a copper conductor surrounded with paper insulation and pressurized with oil from pre-pressurized tanks at the terminal ends of the circuit. They are contained within a lead sheath to hermetically seal the cable insulation which is covered with a protective jacket to insulate and help provide corrosion protection to the sheath. The low pressure oil system plays an essential part of the insulation system by saturating and maintaining the dielectric strength of the lapped paper insulating tapes over the core of the cable. The cable route length is 5.6 km and the majority of the circuit length runs parallel to Lakeshore Boulevard West along the Toronto waterfront.

These circuits have been electrically reliable throughout their life, but have been plagued with multiple oil leaks during the last 7 years which have become progressively worse. System alarms monitor the cable circuits for oil loss and each leak that was detected in the past, was located, and assessed, repaired and the contaminated soil was recovered and remediated. In all cases, the defect in the lead sheath demonstrated a reasonable cause for the leak (i.e. workmanship or isolated flaw). However in 2009, two large leaks that occurred were uncovered and subsequent failure analysis discovered widespread corrosion of the lead sheath on both the K6J cables and H2JK cables which signals the end of the service life of a cable system.

Locating oil leaks, repairing the cables and remediating the contaminated surrounding soil is very time consuming and expensive. Each event typically costs between $250 k and $500 k. These circuits are critical to maintain adequate supply to downtown Toronto. If oil leak rates increase to a level that is unsustainable, a decision would have to be made to shut off the oil supply and remove the circuits from service which would reduce redundancy of supply to downtown Toronto. The time period required to carry out the replacement of these underground cables is typically 2 to 3 years.

Results:

- Maintain system and customer reliability
- Prevent public safety incidents by maintaining a reliable supply to the downtown core
- To address environmental risks by replacing leaking cables

Customer Contribution: $0.0M **Removal Costs:** $5.9M

Project Classification per OEB Filing Guidelines:

Project Class:	Sustaining
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Investment Type: Inter-Area Network Transfer Capability

Reference #	Investment Name	Gross Cost	In-Service Date
D1	New 500kV Bruce to Milton Double Circuit Transmission Line	$715M	Q2 2012

Please see Exhibit D1, Tab 3, Schedule 3, Appendix A, Table 2 for cash flow and other details about this project.

Need:
To construct a new double-circuit 500kV line between Bruce and Milton in accordance with the Ontario Power Authority recommendation; to address the inadequate transmission capacity to transmit renewable and base load generation in the Bruce Area to the load in southern Ontario.

Summary:
The existing transmission in southern Ontario was not capable of accommodating the generation expected to come into service in the Bruce Area; hence additional transmission capability was required. The Ontario Power Authority determined that the preferred solution to increase the transfer capability of the 500kV system was to build a new 500kV double circuit transmission line between the Bruce Complex and Milton SS to securely incorporate the generation from all eight units from Bruce NGS and the committed renewable generation in the Bruce Area.

The new 500kV double circuit line will span a distance of 176km adjacent to the existing 500kV double circuit line utilizing an expanded transmission corridor. One of the 500kV circuits will connect at Bruce A TS, and the other at Bruce B SS. Both circuits will terminate at Milton SS. Addition of new equipment at the existing switchyards is also being undertaken to accommodate the connection of the new circuits.

The Ontario Energy Board granted Hydro One 'Leave to Construct' approval under Section 92 of the OEB Act in its Decision and Order dated September 15, 2008 in Proceeding EB-2007-0050 and an Order-In-Council granting Environmental Assessment approval was received in December 2009. The Niagara Escarpment Commission granted approval under the provision of the Niagara Escarpment Planning and Development Act in its Notice of Decision dated May 10, 2011.

The project construction is underway and the circuits are projected to be energized by Summer 2012. Ongoing project work to address removal of temporary access roads, right-of-way environmental mitigation, and biodiversity work will continue into 2013. As well, expenditures will be incurred in 2013 and 2014 for real estate costs associated with the expropriation of lands that were approved by the OEB under Section 99 of the OEB Act in its Decision Order dated March 15, 2011 under Proceeding EB-2010-0023.

The current cost projection for this project is $715M and is less then the $753M outlined in Proceeding EB-2010-0002 Exhibit A, Tab 11, Schedule 5.

Results:
Provide sufficient transmission capacity to reliably transmit the output of the Bruce NGS and 1700 MW of renewable generation in the Bruce Area and surrounding counties.

Project Classification per OEB Filing Guidelines:

Project Class:	Development
Project Need:	Non-Discretionary: The project is required to satisfy the recommendations outlined by the Ontario Power Authority to accommodate new generation.

Hydro One Networks – Investment Summary Document

Investment Type: Inter-Area Network Transfer Capability

Reference #	Investment Name	Gross Cost	In-Service Date
D2	Installation of Shunt Capacitor Banks at Cherrywood TS-Phase 1	$7.3M	Q4 2014
D3	Installation of Shunt Capacitor Banks at Cherrywood TS-Phase 2	$7.3M	Q2 2015
D4	Clarington TS: Build new 500/230kV Station	$270.0M	Q2 2015

Please see Exhibit D1, Tab 3, Schedule 3, Appendix A, Table 2 for cash flow and other details about this project.

Need:

To build new 500/230kV auto-transformation facilities, provide reactive support and reinforce the 230kV supply capability in the east GTA following the retirement of Pickering Nuclear Generating Station (NGS). Not proceeding with this investment would result in inadequate capacity to supply the east GTA loads.

Summary:

The Ontario Power Authority (OPA) has advised Hydro One that the Pickering NGS current license allows it to operate only until March 2015. While Ontario Power Generation is exploring the possibility of maintaining the operation of the station to 2019, there are technical, economic and regulatory issues to be resolved before any extension beyond 2015 can be confirmed as the station is approaching the end of its useful life. Therefore, a credible scenario is that Pickering NGS would be shut down by spring 2015.

The shutdown of Pickering NGS will result in overloading on the Cherrywood TS 500/230kV autotransformers and a significant reduction in reactive support. Pickering NGS currently provides 3000 MW of active power and over 1200 MVar of reactive power to supply and support the east GTA loads. The OPA, in letters dated October 3, 2011 and January 11, 2012 (refer to Exhibit D1, Schedule 3, Tab 3 Appendix B), has asked Hydro One to initiate work to provide additional 500/230kV auto-transformation capacity in the east GTA by spring 2015.

The proposed plan for the new station contains two 750MVA, 500/230kV auto-transformers, 500kV and 230kV switching facilities and two 300 MVar capacitor banks. The proposal has these facilities located at Clarington Junction site; where Hydro One has available land space. The OPA has also identified that additional reactive support at Cherrywood TS is required and is recommending the installation of two 300 MVar capacitor banks also by spring 2015. Hydro One is targeting one of the Cherrywood capacitor banks to be completed by the end of 2014 for more effective work scheduling and resource deployment.

Hydro One has initiated preliminary engineering, environmental assessment and project development work for providing these projects.

Results:

Provide adequate supply to east GTA and maintain system reliability following the retirement of Pickering NGS.

Project Classification per OEB Filing Guidelines:

Project Class:	Development
Project Need:	Non-Discretionary: The projects are needed to satisfy the recommendations by the OPA to address the east GTA supply needs following the retirement of Pickering NGS.

Hydro One Networks – Investment Summary Document

Investment Type: Inter-Area Network Transfer Capability

Reference #	Investment Name	Gross Cost	In-Service Date
D5	Installation of Static Var Compensator at Milton SS	$100M	Q2 2015

Please see Exhibit D1, Tab 3, Schedule 3, Appendix A, Table 2 for cash flow and other details about these projects.

Need:
To provide an additional 250 MW of transmission capacity out of the Bruce Area to support additional renewable generation following the decommissioning of the Nanticoke coal-fired plant. It will also provide local voltage support and regulation to the West GTA area, especially when local generation is not available. Not proceeding with this investment would result in the inability to connect additional renewable generation in the Bruce area.

Summary:
The existing transmission out of the Bruce complex comprises of four 500kV circuits and six 230kV circuits to transmit power from the six Bruce nuclear units and the existing wind generation in the Bruce area to the load in Southern Ontario. The new Bruce to Milton 500kV double circuit line is to be in-service in 2012 to provide additional transmission capacity to support the return of two Bruce nuclear generating units and the addition of renewable generation contracted in the Bruce Area.

Ontario's Long-Term Energy Plan identified the requirement for additional reactive capability to support additional renewable generation in the Bruce Area and support the large transfers out of the Bruce area with the reduction in generation at Nanticoke following its decommissioning by 2014. The OEB amended Hydro One's transmission license on March 1, 2011 to provide for additional reactive facilities in southwestern Ontario subject to the OPA's recommendation on scope and timing.

The Ontario Power Authority, in a letter dated October 3, 2011, has asked Hydro One to proceed with the addition of a 350 MVar static Var compensator (SVC) connected at the 500kV level at the Milton Station by spring 2015. The Ontario Power Authority has provided support for the preferred solution as outlined in Appendix C of Exhibit D1, Schedule 3, Tab 3.

Results:
Improve reactive support and increase transfer capability out of the Bruce area by an additional 250MW to support additional renewable generation in the area.

Project Classification per OEB Filing Guidelines:

Project Class:	Development
Project Need:	Non-Discretionary: The project is needed to satisfy Hydro One's transmission license requirement to provide reactive facilities in southwestern Ontario to increase the transfer capability from the Bruce area.

Hydro One Networks – Investment Summary Document

Investment Type: Inter-Area Network Transfer Capability

Reference #	Investment Name	Gross Cost	In-Service Date
D6	Reconductor the Lambton TS to Longwood TS 230kV Circuits	$40M	Q4 2014

Please see Exhibit D1, Tab 3, Schedule 3, Appendix A, Table 2 for cash flow and other details about these projects.

Need:

To increase the transfer capability of the 230kV circuits west of London to accommodate up to 500 MW of renewable/gas-fired generation. Not proceeding with this investment would result in the inability to connect additional generation in the west of London area.

Summary:

The existing bulk transmission system in the west of London area consists of three double circuit 230 kV transmission lines connecting Sarnia, Lambton and Chatham respectively with the Longwood and Buchanan transformer stations near London. Following the incorporation of the new Bruce to Milton 500 kV line in 2012, these 230kV transmission lines will limit the transfer capability from the west into the London area. To incorporate additional generation west of London, increased transfer capability of these 230kV lines is required.

The Ontario Long-Term Energy Plan identified the requirement for increased transfer capability of the transmission system west of London. The OEB amended Hydro One's transmission license on March 1, 2011 to upgrade one or more transmission lines west of London subject to the OPA's recommendation on scope and timing.

The OPA, in its letter dated June 30, 2011 (refer to Exhibit D1, Schedule 3, Tab 3, Appendix D) has recommended upgrading the ampacity of the Lambton to Longwood 230kV circuits to 1700-1900 amps between Lambton TS#2 and Macksville Junction.

This upgrade will allow for the connection of up to 500 MW of generation west of London. This project will involve reconductoring approximately 70km of the existing conductor with new ACSR conductor.

This project will require approval by the OEB under Section 92 of the OEB Act and Environmental Assessment Approval by the Ministry of Environment. Hydro One has initiated preliminary engineering and project development work for this project. Hydro One applied for 'Leave to Construct' approval from the OEB on March 28, 2012.

Results:

Increase the transmission capacity to reliably connect up to 500 MW of additional renewable/gas-fired generation in the west of London area.

Project Classification per OEB Filing Guidelines:

Project Class:	Development
Project Need:	Non-Discretionary: The project is required to satisfy Hydro One's transmission license requirement to upgrade transmission circuits west of London.

Hydro One Networks – Investment Summary Document

Investment Type: Local Area Supply Adequacy

Reference #	Investment Name	Gross Cost	In-Service Date
D7	Toronto Area Station Upgrades for Short Circuit Capability: Leaside TS Equipment Uprate	$26.6M	Q4 2013
D8	Toronto Area Station Upgrades for Short Circuit Capability: Manby TS Equipment Uprate	$17.5M	Q4 2013

Please see Exhibit D1, Tab 3, Schedule 3, Appendix A, Table 3 for cash flow and other details about the projects.

Need:

To replace aging 115kV breakers and associated 115kV switchyard facilities at Leaside TS and Manby TS, and to improve short circuit ratings at these stations to comply with the Transmission System Code. Not proceeding with this investment would result in risk of poor reliability to customers and an inability to connect new generation in the Toronto 115kV area.

Summary:

Both Leaside TS and Manby TS are 230/115kV autotransformer stations supplying the City of Toronto; Leaside TS supplies the eastern section of the central area of the City and Manby TS supplies the western section of the central area of the City.

Both stations 115kV switchyards are equipped with 115kV oil breakers with an asymmetrical current rating of 45.5A. It is planned to uprate the station fault current withstand capability to 50kA as per the Transmission System Code. This will permit incorporation of up to 300MVA of new generation in the Leaside TS 115kV area and up to 300MVA of new generation in the Manby 115kV area. It should be noted that these capabilities are generally not additive.

At Leaside TS, the uprating work requires that 28 existing oil breakers in the 115kV switchyard be replaced and sections of the station strain bus uprated. The average age of these oil breakers is 48 years and the breakers are approaching end of life. Similarly at Manby TS, the uprating work requires that 16 existing oil breakers in the 115kV switchyard be replaced and sections of the station strain bus uprated. The average age of these oil breakers is 51 years and the breakers are approaching end of life. Three oil breakers associated with decommissioned circuits K7B and K8B are to be removed.

A number of additional components such as 115kV instrument transformers and insulators have also been identified as end of life and due for replacement. The project includes the replacement of all end-of-life components in the Leaside TS and Manby TS 115kV switchyard to take advantage of 115kV outages. Initially protection replacements were also considered a requirement; however following detailed engineering design review it was determined that significant protection replacements were not required at this time.

The Ontario Energy Board agreed with the need for the project in its Decision and Order dated, December 23, 2010 under Proceeding EB-2010-0002.The construction for both projects is underway. The current cost is about $26M lower than outlined in Proceeding EB-2010-0002 as a result of the detailed engineering design review identifying reduction in scope. The delayed in-service date for Leaside TS is due to the difficulties in obtaining outages to stage the station upgrade work.

Results:

Replace aging equipment and allow incorporation of new generation in the City of Toronto.

Project Classification per OEB Filing Guidelines:

Project Class:	Development
Project Need:	Non-Discretionary: The project is required to address end-of-life equipment at Leaside TS and Manby TS and to meet compliance and reliability requirements.

Hydro One Networks – Investment Summary Document

Investment Type: Local Area Supply Adequacy

Reference #	Investment Name	Gross Cost	In-Service Date
D9	Toronto Area Station Upgrades for Short Circuit Capability: Rebuild Hearn SS	$103.9M	Q4 2013

Please see Exhibit D1, Tab 3, Schedule 3, Appendix A, Table 3 for cash flow and other details about the project.

Need:
To replace aging facilities at Hearn SS, and improve short circuit ratings at this station to comply with the Transmission System Code. Not proceeding with this investment would result in risk of poor reliability to customers and an inability to connect new generation in the Toronto 115kV area.

Summary:
The Hearn SS facility consists of an 115kV switchyard with lines connecting to Leaside TS, Esplanade TS, John TS and the new Portlands Generating Station. The station is a critical element of the supply to the City of Toronto.

The station was built in the early 1950's to connect the old Hearn Generating Station. The need for rebuilding the station has been identified as most components: breakers, buses and insulators are at the end of useful life. In addition, the 115kV breakers at the station are rated at 37.5kA and do not meet the Transmission System Code requirement and need to be replaced to allow new distributed generation to be connected in the City of Toronto.

The project covers rebuilding the Hearn 115kV switchyard using gas insulated switchgear. The new GIS switchyard will be built adjacent to the existing Hearn switchyard on lands acquired from Ontario Power Generation.

The Ontario Energy Board agreed with the need for the project in its Decision and Order dated, December 23, 2010 under Proceeding EB-2010-0002. The construction of the project is now underway. The current cost is about $19M higher than outlined in Proceeding EB-2010-0002 due to increased costs for the turn key GIS station identified following the tendering process and for P&C upgrades identified following the detailed engineering review. The delayed in-service date is due to a delay in acquiring property for the new switchyard and the increased scope of work.

Results:
Replace aging equipment, improve system reliability and enable connection of new generation in the City of Toronto.

Project Classification per OEB Filing Guidelines:

Project Class:	Development
Project Need:	Non-Discretionary: The project is required to address end-of-life equipment at Hearn SS and to meet compliance and reliability requirements.

Hydro One Networks – Investment Summary Document

Investment Type: Local Area Supply Adequacy

Reference #	Investment Name	Gross Cost	In-Service Date
D10	Midtown Transmission Reinforcement Plan	$114.8M	Q3 2014

Please see Exhibit D1, Tab 3, Schedule 3, Appendix A, Table 3 for cash flow and other details about the project.

Need:
To replace aging facilities and provide adequate supply capacity to meet future load growth. Not proceeding with this investment would result in increased risk of customer interruptions affecting supply reliability for customers.

Summary:
The existing transmission facilities in the Midtown area consists of three 115 kV transmission lines that run between Leaside TS and Wiltshire TS. These lines provide the supply to Toronto Hydro customers served via Bridgman TS and Dufferin TS as well as provide load transfer capability between the Leaside TS and Manby TS 230/115kV autotransformer stations.

There is a need to refurbish a section of one of the existing 115kV circuits underground cables section between Birch Junction and Bayview Junction. This section of cable is at the end of its useful life and has been identified as requiring replacement. There is also a need to provide additional transmission capacity to relieve the overloading under first contingency and address load growth at Bridgman TS and Dufferin TS.

This project provides for the reinforcement of the midtown transmission corridor by installing a new circuit between Leaside TS to Bridgman TS at the same time as the replacement of the Birch Junction to Bayview Junction cable section to minimize costs and avoid unnecessary disruption to the community.

The Ontario Energy Board granted Hydro One “Leave to Construct” approval under Section 92 of the OEB Act in its Decision and Order dated June 17, 2010 under Proceeding EB-2009-0425. This project is subject to the Environmental Assessment Act in accordance with the Class EA for Minor Transmission Facilities. On June 30, 2010 Hydro One filed the final Environmental Study Report with the Ministry of the Environment. The project construction is now underway.

The current cost is about $8M higher than outlined in Proceeding EB-2009-0425 primarily due to higher construction costs for the work and costs associated with delays in obtaining project approvals. The in-service date was delayed due to additional time required for local consultations and to secure the approvals for the underground portion of the work.

The project cost that is allocated to the development component of the project (i.e. after subtracting cost allocated to replacement of the cable) will be recoverable through incremental revenue from the appropriate rate pool and capital contributions from the customers, as indicated in Table 3 of Exhibit D1, Tab 3, Schedule 3. The capital contribution amounts indicated therein are considered preliminary as they are only finalized when the Capital Cost Recovery Agreement is signed and when the project is placed in-service. The capital contributions are determined as per Hydro One’s Transmission Customer Contribution Policy in accordance with the Transmission System Code.

Results:
Improve load meeting capability and transmission reliability for customers in the City of Toronto mid-town area.

Project Classification per OEB Filing Guidelines:

Project Class:	Development
Project Need:	Non-Discretionary: The project is required to increase transmission supply capacity and address end-of-life facilities to reliably serve customers in the City of Toronto.

Hydro One Networks – Investment Summary Document

Investment Type: Local Area Supply Adequacy

Reference #	Investment Name	Gross Cost	In-Service Date
D11	Preston TS Transformation	$20.0M	Q2 2016
D12	Guelph Area Transmission Reinforcement	$65.0M	Q2 2016

Please see Exhibit D1, Tab 3, Schedule 3, Appendix A, Table 3 for cash flow and other details about the project.

Need:
To reinforce the electricity supply to the South-Central Guelph area and to the Kitchener/Cambridge area, and provide adequate capacity to accommodate future 115 kV load growth in the South-Central Guelph area. Not proceeding with this investment would impair the ability to provide a reliable supply and support future load growth.

Summary:
The south central area of the City of Guelph is supplied at 115kV by 230/115kV transformation located at Burlington and Cambridge via two 115kV double circuit lines. This area has experienced significant growth in electricity demand and the existing facilities are reaching their supply capability limit. The load is forecast to continue to grow over the next 20 years, with continuing development of the Hanlon Industrial Park being one of the key contributors to this growth.

It is proposed to reinforce the area supply by adding 230/115kV transformation locally in the Guelph area by building a new 230/115kV autotransformer station, complete with 115kV switching in order to provide termination of all the existing 115kV circuits into the new station. The new auto transformer station would be located at the existing Guelph Cedar station and be connected to the existing 230kV system via a 5 km overhead line tap from the existing 230kV double circuit line in the area.

It is also proposed to add a second 230/115kV autotransformer and associated switching at the existing Preston TS to reinforce the 230kV circuits that supply Cambridge and the 115kV circuits that supply the Kitchener area to improve reliability of supply for the area customers.

The overall investment will require Ontario Energy Board "Leave to Construct" approval under Section 92 and Environmental Assessment Approval by the Ministry of Environment. The approval applications will include assessment of the project’s alternatives.

The OPA, in its letter dated March 8, 2012 (refer to Exhibit D1, Schedule 3, Tab 3, Appendix E) has recommended proceeding with the project development work at both the Guelph area and Preston TS including the completion of necessary environmental and regulatory approval processes.

Result:
Improve the reliability of supply to the South-Central Guelph area and to the Kitchener/Cambridge area.

Project Classification per OEB Filing Guidelines:

Project Class:	Development
Project Need:	Non-Discretionary: The project is required to increase reliable transmission capacity in the Guelph, Kitchener and Cambridge areas to supply new load customers.

Hydro One Networks – Investment Summary Document

Investment Type: Load Customer Connection

Reference #	Investment Name	Gross Cost	In-Service Date
D13	Tremaine TS: Build new Transformer Station	$30.5M	Q1 2013

Please see Exhibit D1, Tab 3, Schedule 3, Appendix A, Table 4 for cash flow and other details about the project.

Need:
To add new transformation capacity to alleviate overloading and address future load growth in the South Halton area. The Local Distribution Companies (Milton Hydro, Burlington Hydro) have requested that Hydro One build a new 230/27.6 kV transformer station. Hydro One is obligated under the Transmission System Code to meet customer supply needs when requested by the area customers.

Summary:
Palermo TS is an existing 230/27.6 kV DESN station, located in the Town of Oakville that supplies Burlington Hydro, Milton Hydro and Oakville Hydro. The station load has exceeded its capacity by about 130%. Additionally, the loading on other stations supplying these Local Distribution Companies is approaching capacity and load is forecast to continue to grow in this part of Halton Region by 2-3% per year over the next five to ten years. The Local Distribution Companies, Milton Hydro and Burlington Hydro, have requested that Hydro One build a new transformer station to alleviate overloading and to supply new loads in the Palermo TS supply area.

The location of the new transformer station is near Tremaine Road between the two 230 kV transmission corridors. The project will include two new 230/27.6 kV, 75/125MVA transformers and a low-voltage switchyard with 8 feeder positions.

The Ontario Energy Board approved the Tremaine TS project as a Category 2 project in its Decision and Order dated, December 23, 2010 under Proceeding EB-2010-0002. This project is subject to the Ontario Environmental Assessment Act in accordance with the Class EA for Minor Transmission Facilities. On June 9, 2011 Hydro One filed the final Environmental Study Report with the Ministry of the Environment. The project is currently under construction.

The current cost is about $2M higher than outlined in Proceeding EB-2010-0002 due to increased scope of work including four additional feeders and additional revenue metering instrument transformers. The in-service date has also been delayed by request of the participating LDCs.

The project cost will be recoverable through incremental revenue for the appropriate rate pool and capital contributions from the customers, as indicated in Table 4 of Exhibit D1, Tab 3, Schedule 3. The capital contribution amounts are considered preliminary as they are only finalized when the Capital Cost Recovery Agreement is signed and when the project is placed in-service. The capital contributions are determined as per Hydro One's Transmission Customer Contribution Policy in accordance with the Transmission System Code.

Results:
Add transformation capacity to alleviate overloading and meet the future load requirements in the South Halton area.

Project Classification per OEB Filing Guidelines:

Project Class:	Connection
Project Need:	Customer Driven: This project is required to supply customers' future load growth.

Hydro One Networks – Investment Summary Document

Investment Type: Load Customer Connection

Reference #	Investment Name	Gross Cost	In-Service Date
D14	Barwick TS: Build new Transformer Station	$23.8M	Q3 2013

Please see Exhibit D1, Tab 3, Schedule 3, Appendix A, Table 4 for cash flow and other details about the project.

Need:

- To replace end-of-life (EOL) equipment at Fort Frances TS and ensure reliable supply to customers.
- To address power quality and delivery point performance issues related to a 98km long 44 kV feeder and non-standard supply arrangement.
- To address problems in supplying new loads in the Rainy River area

Not proceeding with this investment would increase the risk of power interruptions and a further decline in supply reliability. Furthermore, Hydro One is obligated under the Transmission System Code to meet customer supply needs and provide adequate reliability.

Summary:

The primary supply for Fort Frances - Rainy River area load is from the tertiary winding of an auto transformer located at Fort Frances TS via a 98 km long, poor performing 44 kV feeder. The auto transformer and its associated 44 kV equipment, are more than 52 years old and based on its condition, performance and availability of spare parts is at the end of its useful life. The risk associated with the failure of these assets is unacceptable as it would result in an inability to supply the Fort Francis - Rainy River area load.

To address the supply reliability issue Hydro One recommended building a new transformer station Barwick TS closer to the load, near the town of Chapple, Ontario. It will be equipped with two standard 115/44 kV, 25/42 MVA transformers and a low-voltage switchyard with 2 feeder positions and one capacitor bank.

The Ontario Energy Board approved the Barwick TS project as a Category 2 project in its Decision and Order dated, December 23, 2010 under Proceeding EB-2010-0002. This project is subject to the Ontario Environmental Assessment Act in accordance with the Class EA for Minor Transmission Facilities. On November 17, 2010 Hydro One filed the final Environmental Study Report with the Ministry of the Environment. The project is currently under construction.

The current cost is about $8M higher than outlined in Proceeding EB-2010-0002 due to increased scope of site specific work identified following detailed engineering such as: higher noise mitigation costs, access road and landscaping costs and higher material costs. The in-service date has been delayed due to more extensive stakeholder discussions with a local community.

As this project is required to address end-of-life facilities, no capital contribution is required from the customer (Hydro One Distribution) as per Hydro One's Transmission Customer Contribution Policy in accordance with the Transmission System Code.

Results:

Improve the supply reliability and reduce maintenance and safety concerns associated with aging and non-standard supply equipment at Fort Frances TS.

Project Classification per OEB Filing Guidelines:

Project Class:	Connection
Project Need:	Customer Driven: The project is required to replace end-of-life equipment, provide adequate supply reliability and provide for future load growth.

Hydro One Networks – Investment Summary Document

Investment Type: Load Customer Connection

Reference #	Investment Name	Gross Cost	In-Service Date
D15	Nebo TS: Increase Capacity of 230/27.6kV DESN	$19.2M	Q4 2013

Please see Exhibit D1, Tab 3, Schedule 3, Appendix A, Table 4 for cash flow and other details about the project.

Need:
To add new transformation capacity to alleviate overloading and address future load growth in the Nebo TS area. The Local Distribution Companies: Horizon Utilities and Hydro One Distribution have requested that Hydro One provide increased capacity at the existing Nebo TS. Hydro One is obligated under the Transmission System Code to meet customer supply needs when requested by the area customers.

Summary:
Nebo TS is an existing 230/27.6 kV DESN station, located in the City of Hamilton, that supplies both Horizon Utilities and Hydro One Distribution. The load forecasts provided by Horizon Utilities and Hydro One Distribution show the need for additional 230/27.6 kV capacity in the Nebo TS supply area. This need is driven by the existing load exceeding the capacity by about 2MW and an average load growth of 4% per year over the next 10 years. Both Horizon Utilities and Hydro One Distribution have requested additional capacity at Nebo TS to alleviate overloading and to supply new loads.

The additional capacity will be provided by replacing the existing 230/27.6kV 50/83MVA transformers with new 230/27.6kV 75/125MVA transformers and adding 6 new feeder positions. This will provide a capacity increase of about 65 MVA which will meet Customers' need for about 10 years. The increased capacity and project costs will be shared between Horizon Utilities and Hydro One Distribution. Project development work is currently under way.

The project cost will be recoverable through incremental revenue for the appropriate rate pool and capital contributions from the customers, as indicated in Table 4 of Exhibit D1, Tab 3, Schedule 3. The capital contribution amounts are considered preliminary as they are only finalized when the Capital Cost Recovery Agreement is signed and when the project is placed in-service. The capital contributions are determined as per Hydro One's Transmission Customer Contribution Policy in accordance with the Transmission System Code.

Results:
Increase transformation capacity to alleviate overloading and meet the future load requirements in the Nebo TS area.

Project Classification per OEB Filing Guidelines:

Project Class:	Connection
Project Need:	Customer Driven: This project is required to supply customers' future load growth.

Hydro One Networks – Investment Summary Document

Investment Type: Load Customer Connection

Reference #	Investment Name	Gross Cost	In-Service Date
D16	Orleans TS: Build new Transformer Station (formerly East Ottawa TS)	$33.4M	Q3 2014

Please see Exhibit D1, Tab 3, Schedule 3, Appendix A, Table 4 for cash flow and other details about the project.

Need:
To add transformation capacity in the Orleans area (in east Ottawa) to meet future load growth and to improve supply reliability. Hydro One Distribution has requested that Hydro One build a new transformer station. Hydro One is obligated under the Transmission System Code to meet customer supply needs when requested by the area customers.

Summary:
The City of Orleans and the surrounding area are served by Hydro One Distribution from the three existing stations: Wilhaven DS, Navan DS and Bilberry Creek TS. The loading at Bilberry Creek has been at its capacity limit since around the year 2000 and new load growth has been supplied from Wilhaven DS and/or Navan DS. Both Wilhaven DS and Navan DS are supplied from a single 115kV circuit and have experienced several outages over the past few years. Hydro One Distribution has therefore requested building a new dual supply station to serve customer load in the area to improve load supply reliability as well as to provide additional capacity.

It is proposed to build the new station in the Orleans Area east of Ottawa which will be connected to the transmission system via a 230kV circuit and an 115kV circuit. The project will include two new 50/83 MVA transformers and a low voltage switchyard with four feeder positions. The new transformer station will provide improved reliability for Hydro One Distribution customers.

Project development, property acquisition and environmental assessment work are currently under way.

The project cost will be recoverable through incremental revenue from the appropriate rate pool and capital contributions from the customers, as indicated in Table 4 of Exhibit D1, Tab 3, Schedule 3. The capital contribution amounts are considered preliminary as they are only finalized when the Capital Cost Recovery Agreement is signed and when the project is placed in-service. The capital contributions are determined as per Hydro One's Transmission Customer Contribution Policy in accordance with the Transmission System Code.

Results:
Increase transformation capacity to meet the future load requirements and improve reliability in the east Ottawa area.

Project Classification per OEB Filing Guidelines / IPSP Status:

Project Class:	Connection
Project Need:	Customer Driven: This project is required to supply customers' future load growth.

Hydro One Networks – Investment Summary Document

Investment Type: Load Customer Connection

Reference #	Investment Name	Gross Cost	In-Service Date
D17	Bremner TS: Build Line Connection for Toronto Hydro	$60.0M	Q4 2014

Please see Exhibit D1, Tab 3, Schedule 3, Appendix A, Table 4 for cash flow and other details about the project.

Need:
To provide connection to Toronto Hydro's proposed Municipal Transformer Station, Bremner MTS. Hydro One is obligated under the Transmission System Code to meet customer supply needs when requested by the area customers.

Summary:
Toronto Hydro is proposing to build a new municipal transformer station on the west side of the Roundhouse at Bremner Blvd and Rees Street in downtown Toronto. It is proposed to connect the new station to the 115kV cable circuits that span between John TS to Esplanade TS.

The connection will require extending and looping the existing 115kV circuits through Bremner MTS and building a high voltage switching facility at the station to connect Toronto Hydro's step down transformers. The 115kV circuit extensions will be installed in a tunnel to be built by Toronto Hydro. Toronto Hydro has requested that high voltage gas insulated switching (GIS) facilities be provided for the connection of the 115kV cables and the stepdown transformers. The high voltage switching facilities will be installed inside the Toronto Hydro Bremner MTS building. Both the cable extensions and the high voltage switching facilities will be owned and operated by Hydro One.

The project is in the preliminary planning stage. A new facility such as the one proposed will require Environmental Assessment approval from the Ministry of Environment in accordance with the provincial Environmental Assessment Act (Class EA for minor Transmission Facilities) which will be undertaken by Toronto Hydro.

The project cost will be fully recoverable through capital contribution from the customer Toronto Hydro, as indicated in Table 4 of Exhibit D1, Tab 3, Schedule 3. The project costs and capital contribution amounts are considered preliminary as they are only finalized when the Capital Cost Recovery Agreement is signed and when the project is placed in-service. The capital contributions are determined as per Hydro One's Transmission Customer Contribution Policy in accordance with the Transmission System Code.

Results:
To provide connection to the new Toronto Hydro Bremner MTS in downtown Toronto.

Project Classification per OEB Filing Guidelines:

Project Class:	Connection
Project Need:	Customer Driven: This project is required to satisfy customers' supply requirements.

Hydro One Networks – Investment Summary Document

Investment Type: Load Customer Connection

Reference #	Investment Name	Gross Cost	In-Service Date
D18	Chalk River CTS: Build 115kV Switching Facilities and connect new Customer Station	$10.0M	Q2 2014

Please see Exhibit D1, Tab 3, Schedule 3, Appendix A, Table 4 for cash flow and other details about the project.

Need:
To provide connection to Atomic Energy of Canada Limited's (AECL) new customer transformer station, Chalk River CTS. Hydro One is obligated under the Transmission System Code to meet customer supply needs when requested by the area customers.

Summary:
AECL owns Chalk River CTS which is supplied radially from Des Joachims TS via 115kV circuit D6. AECL proposed to build a new station about a kilometer up the right of way from the existing station. The new station will replace the existing station and all station facilities and the idled section of line will be removed.

The connection will require building a new 115kV switching station on circuit D6 to connect the new AECL Chalk River transformers. The 115kV switching station will be built on the right of way and will be owned and operated by Hydro One. Land for the new facilities will be provided by AECL.

The project cost will be fully recoverable through capital contribution from the customer AECL, as indicated in Table 4 of Exhibit D1, Tab3, Schedule 3. The project cost and capital contribution amounts are considered preliminary as they are only finalized when the Capital Cost Recovery Agreement is signed and when the project is placed in-service. The capital contributions are determined as per Hydro One's Transmission Customer Contribution Policy in accordance with the Transmission System Code

Results:
To provide connection for the new AECL owned transformer station.

Project Classification per OEB Filing Guidelines:

Project Class:	Connection
Project Need:	Customer Driven: This project is required to satisfy customers' supply requirements.

Hydro One Networks – Investment Summary Document

Investment Type: Load Customer Connection

Reference #	Investment Name	Gross Cost	In-Service Date
D19	Nelson TS: Replace T1/T2 DESN with new DESN	$29.8M	Q4 2014

Please see Exhibit D1, Tab 3, Schedule 3, Appendix A, Table 4 for cash flow and other details about the project.

Need:
To add transformation capacity in London Area to improve supply reliability to meet future load growth. Hydro One is obligated under the Transmission System Code to meet customer supply needs when requested by the area customers.

Summary:
Nelson TS is an existing station with two 115/13.8 kV DESNs, located in the city of London, that supplies London Hydro. The T1and T2 DESN consists of two 115/13.8 kV, 18/33 MVA transformers that supplies about 20 MW of 13.8 kV load. The T3 and T4 DESN has two 115/13.8 kV, 60/100 MVA transformers that supplies about 50 MW of 13.8 kV load.

London Hydro has requested that the existing T1 and T2 DESN at Nelson TS be decommissioned and replaced with a new 115/27.6 kV, 50/83 MVA station. The new Nelson TS will supply the 20MW of load currently supplied by the existing T1 and T2 DESN as well as provide capacity for additional load growth in the London area. To enable the decommissioning of the existing T1 and T2 DESN and building of the new DESN, the 20MW of existing load at the station will be transferred to Talbot TS during the construction phase.

The project cost will be recoverable through incremental revenue for the appropriate rate pool and a capital contribution from the customer, as indicated in Table 4 of Exhibit D1, Tab 3, Schedule 3. The capital contribution amounts are considered preliminary as they are only finalized when the Capital Cost Recovery Agreement is signed and when the project is placed in-service. The capital contributions are determined as per Hydro One's Transmission Customer Contribution Policy in accordance with the Transmission System Code.

Results:
Increase transformation capacity to meet the future load requirements and maintain supply reliability to customers in the London area.

Project Classification per OEB Filing Guidelines:

Project Class:	Connection
Project Need:	Customer Driven: This project is required to supply customers' future load growth.

Hydro One Networks – Investment Summary Document

Investment Type: Generation Customer Connection

Reference #	Investment Name	Gross Cost	In-Service Date
D20	South Kent Wind Farm (270 MW) (Formerly Chatham Wind Generation Connection)	$10.7M	Q2 2013

Please see Exhibit D1, Tab 3, Schedule 3, Appendix A, Table 5 for cash flow and other details about the project.

Need:
To connect 270 MW of renewable generation to the transmission network. The generation project was awarded a contract by the OPA as part of the Green Energy Investment Agreement between the Ontario Government and the Korean Consortium. Failure to proceed with this investment will not meet Hydro One's obligation to connect generator customers under the Transmission System code.

Summary:
The Korean Consortium (KC) was awarded a contract to connect a 270 MW wind farm in Southwestern Ontario. The proposed South Kent Wind Farm will be located on approximately 1000 acres spanning the townships of Raleigh, Harwich and Howard; located in Chatham-Kent. The South Kent Wind Farm will be connected to the transmission system by a single 230kV circuit from customer owned collector stations (Sattern CGS, Railbed CGS) to Chatham SS. The generator proponent will be building the two collector stations and approximately 34km of 230kV line to connect the wind farm to Chatham SS. The Hydro One connection work consists of installing a new 230kV diameter with two breakers at Chatham SS to incorporate the customer connection.

The project cost will be fully recoverable through capital contributions from the customers, as indicated in Table 5 of Exhibit D1, Tab 3, Schedule 3. The capital contribution amounts are considered preliminary as they are only finalized when the Capital Cost Recovery Agreement is signed and when the project is placed in-service. The capital contributions are determined as per Hydro One's Transmission Customer Contribution Policy in accordance with the Transmission System Code.

Results:
Provide connection of the 270 MW wind farm to the transmission network at Chatham SS.

Project Classification per OEB Filing Guidelines:

Project Class:	Connection
Project Need:	Customer Driven: The project is required to incorporate new renewable generation that was contracted by the OPA under direction from the Ontario Government.

Hydro One Networks – Investment Summary Document

Investment Type: Generation Customer Connection

Reference #	Investment Name	Gross Cost	In-Service Date
D21	Lower Mattagami Generation Connections (450 MW)	$30.9M	Late 2013

Please see Exhibit D1, Tab 3, Schedule 3, Appendix A, Table 5 for cash flow and other details about the project.

Need:
To connect new renewable generation in the Lower Mattagami River to the transmission network. The Minster of Energy directed Ontario Power Authority to assume the responsibility of the Crown and negotiate a financial energy supply agreement with OPGI. Failure to proceed with this investment will not meet Hydro One's obligation to connect generator customers under the Transmission System code.

Summary:
Ontario Power Generation Inc. (OPGI) is proposing to upgrade their generating stations in the Lower Mattagami River, namely Little Long GS, Smoky Falls GS, Harmon GS and Kipling GS, to increase generation output by approximately 450MW. The proposed redevelopment of the existing generating plants on the Lower Mattagami River involves installing a third generating unit at Little Long GS, Harmon GS and Kipling GS and replacing the existing four-unit Smoky Falls generating station with a new three-unit facility.

The project scope has changed since Proceeding EB-2010-0002, resulting in the addition of Protection, Control and Telecom facilities at Little Long SS. The cost of the scope change is entirely recoverable from the customer. The following investments are required to accommodate the additional output from the generating facilities on the Lower Mattagami River:

- Addition of a second 230kV circuit on the L20D corridor from Harmon GS to Kipling GS.
- Connection of a second tap point for each of the existing generating stations to the 230kV network.
- Addition of Protection, Control and Telecom facilities at Little Long SS.
- Uprating of the section of the 115kV circuits H6T and H7T between La Forest Junction and Timmins TS.

The project cost directly attributable to the generator will be recoverable through capital contributions from the generator, as indicated in Table 5 of Exhibit D1, Tab 3, Schedule 3. The capital contribution amounts are considered preliminary as they are only finalized when the Capital Cost Recovery Agreement is signed and when the project is placed in-service. The capital contributions are determined as per Hydro One's Transmission Customer Contribution Policy in accordance with the Transmission System Code.

The cost of the work for the construction of the line connection, approximately 4km of 230kV double circuit line from Smoky Falls GS to the existing H22D and L20D circuits, is included in the total cost of this project but may be contracted to a third party by OPGI.

Results:
- Provide adequate transmission facilities to allow the connection of OPGI Lower Mattagami plant expansions.
- Enable Ontario Power Authority to successfully procure approximately 450MW of renewable generation north of Sudbury.

Project Classification per OEB Filing Guidelines:

Project Class:	Connection
Project Need:	Customer Driven: The projects are required to incorporate new renewable generation in northern Ontario to satisfy government directive(s).

Hydro One Networks – Investment Summary Document

Investment Type: Generation Customer Connection

Reference #	Investment Name	Gross Cost	In-Service Date
D22	Niagara Region Wind Corporation Generation Connection (230 MW)	$51.0M	Q2 2014

Please see Exhibit D1, Tab 3, Schedule 3, Appendix A, Table 5 for cash flow and other details about the project.

Need:
To connect a 230 MW wind farm to the transmission network. The generation project was awarded a contract by the OPA in February 2011 as part of the Feed In-Tariff (FIT) program. Failure to proceed with this investment will not meet Hydro One's obligation to connect generator customers under the Transmission System code.

Summary:
Niagara Region Wind Corporation (NRWC) was awarded a contract to connect a 230 MW wind-farm located in Southern Ontario. The proposed Niagara Region Wind Farm will be located in the Townships of West Lincoln, Wainfleet and Pelham and the Towns of Grimsby and Lincoln in the Niagara peninsula. The NRWC wishes to utilize an idle 115kV 25Hz transmission line as a connection point onto the transmission system. Since the termination point for this idle 115kV 25Hz transmission line is at Hamilton Beach Junction, a new 100 m transmission connection is required between Hamilton Beach Junction to Hamilton Beach TS. Also reconductoring of the idle 115kV 25Hz transmission line and reinforcement of the steel structures will be required in order to transmit the 230 MW of renewable generation. A new switching position will be developed at Hamilton Beach TS with one 115 kV breaker to terminate the customer connection.

The project is in the preliminary planning stage. The Hydro One connection work consists of installing the 115kV termination and breaker at Beach TS and refurbishing and upgrading the 115kV idle line.

The project cost will be fully recoverable through capital contributions from the customers, as indicated in Table 5 of Exhibit D1, Tab 3, Schedule 3. The capital contribution amounts are considered preliminary as they are only finalized when the Capital Cost Recovery Agreement is signed and when the project is placed in-service. The capital contributions are determined as per Hydro One's Transmission Customer Contribution Policy in accordance with the Transmission System Code.

Results:
Provide connection of a 230 MW wind farm to the transmission network at Hamilton Beach TS.

Project Classification per OEB Filing Guidelines:

Project Class:	Connection
Project Need:	Customer Driven: The project is required to incorporate new renewable generation that was awarded a FIT contract by the OPA.

Hydro One Networks – Investment Summary Document

Investment Type: Generation Customer Connection

Reference #	Investment Name	Gross Cost	In-Service Date
D23	Armow Wind Generation Connection (180 MW)	$25.0M	Q2 2014

Please see Exhibit D1, Tab 3, Schedule 3, Appendix A, Table 5 for cash flow and other details about these projects.

Need:

To connect 180 MW of renewable generation to the transmission network. The generation project was awarded a contract by the OPA as part of the Green Energy Investment Agreement between the Korean Consortium and the Ontario Government. Failure to proceed with this investment will not meet Hydro One's obligation to connect generator customers under the Transmission System code.

Summary:

The Korean Consortium was awarded a contract to connect a 180MW wind farm in the Bruce Area. The proposed Armow Wind Farm will be located south of Kincardine, Ontario adjacent to an existing 230kV double circuit line. The project will be connected to the 230kV transmission system approximately 12.5km from Bruce A TS via a short line tap to one of the existing 230kV circuits. In-line breakers will be required to sectionalize and tap the existing 230kV circuit. These breakers are required to address system protection issues associated with the connection. A new three-breaker sectionalizing station will be required to be installed at the point of interconnection.

The project is in the preliminary planning stage.

The cost of the sectionalizing station will be pool funded consistent with Proceeding EB-2010-0002 for in-line circuit breaker projects as it is system driven and provides system benefits. The portion of the project costs associated with the generator connection will be fully recoverable through capital contributions from the customer, as indicated in Table 5 of Exhibit D1, Tab 3, Schedule 3. The capital contribution amounts are considered preliminary as they are only finalized when the Capital Cost Recovery Agreement is signed and when the project is placed in-service. The capital contributions are determined as per Hydro One's Transmission Customer Contribution Policy in accordance with the Transmission System Code.

Results:

Provide connection of a 180 MW wind farm to the transmission network near Bruce A TS.

Project Classification per OEB Filing Guidelines:

Project Class:	Connection
Project Need:	Customer Driven: The project is required to incorporate new renewable generation that was contracted by OPA under direction from the Ontario Government.

Hydro One Networks – Investment Summary Document

Investment Type: Generation Customer Connection

Reference #	Investment Name	Gross Cost	In-Service Date
D24	K2 Wind Generator Connection (270 MW)	$55.0M	Q4 2014

Please see Exhibit D1, Tab 3, Schedule 3, Appendix A, Table 5 for cash flow and other details about the project.

Need:
To connect 270 MW of renewable generation to the transmission network. The generation project was awarded a contract by the OPA as part of the Green Energy Investment Agreement between the Korean Consortium and the Ontario Government. Failure to proceed with this investment will not meet Hydro One's obligation to connect generator customers under the Transmission System code.

Summary:
K2 Wind Ontario L.P., a limited partnership of Capital Power, Samsung Renewable Energy Inc. and Pattern Renewable Holdings Canada ULC was awarded a contract to connect a 270 MW wind farm in the Bruce Area. The proposed wind farm will be located in the municipalities of Ashfield-Colborne and Wawanosh, Ontario. K2 Wind will be connected to one of the 500 kV Bruce-Longwood transmission circuits via a new 500 kV Ashfield SS that will sectionalize this 500kV circuit about 61.5 km from Bruce B SS into a four-circuit breaker ring arrangement including voltage transformation to 138 kV at the K2 Wind CGS.

The project cost will be fully recoverable through capital contributions from the customers, as indicated in Table 5 of Exhibit D1, Tab 3, Schedule 3. The capital contribution amounts are considered preliminary as they are only finalized when the Capital Cost Recovery Agreement is signed and when the project is placed in-service. The capital contributions are determined as per Hydro One's Transmission Customer Contribution Policy in accordance with the Transmission System Code.

Results:
Provide Connection of a 270 MW wind farm to the transmission network on the Bruce-Longwood circuits.

Project Classification per OEB Filing Guidelines:

Project Class:	Connection
Project Need:	Customer Driven: The project is required to incorporate new generation that was contracted by the OPA under direction from the Ontario Government.

Hydro One Networks – Investment Summary Document

Investment Type: Generation Customer Connection

Reference #	Investment Name	Gross Cost	In-Service Date
D25	Adelaide/Bornish/Jericho Wind Energy Centres (284 MW)	$55.0M	Late 2014

Please see Exhibit D1, Tab 3, Schedule 3, Appendix A, Table 5 for cash flow and other details about the project.

Need:
To connect four wind farms totaling 384 MW to the transmission network. The renewable generation projects were awarded contracts by the OPA as part of the Feed-In Tariff (FIT) program. Failure to proceed with this investment will not meet Hydro One's obligation to connect generator customers under the Transmission System code.

Summary:
NextEra Energy Canada was awarded a contract to connect three renewable energy projects with a total generating capacity of 283.5 MW in Southwestern Ontario: (i) Adelaide Wind Energy Centre (60MW) located in Middlesex County; (ii) Bornish Wind Energy Centre (73.5 MW) located in Middlesex County; and (iii) Jericho Wind Energy Centre (150 MW) located in Lambton County and Middlesex County. These three wind farms will be connected to one of the existing 500 kV Bruce-Longwood transmission circuits via a new 500 kV Evergreen SS that will sectionalize this 500kV circuit about 36.5 km from Longwood TS into a three-circuit breaker ring arrangement. The voltage transformation to 121 kV will be located adjacent to the Evergreen SS at a customer-owned station, Parkhill CTS, for use by the customer.

Suncor Energy Products Inc. was also awarded a contract to develop a 100 MW Cedar Point II Wind Power Project in Lambton County in Southwestern Ontario. This wind farm will be connected to the same 500kV Bruce-Longwood transmission circuit via the new Evergreen SS.

The Hydro One connection work will consist of constructing the 500kV switching facilities and making the 500kV connections to the wind farms' transmission facilities.

The project cost will be fully recoverable through capital contributions from the customers, as indicated in Table 5 of Exhibit D1, Tab 3, Schedule 3. The capital contribution amounts are considered preliminary as they are only finalized when the Capital Cost Recovery Agreement is signed and when the project is placed in-service. The capital contributions are determined as per Hydro One's Transmission Customer Contribution Policy in accordance with the Transmission System Code.

Results:
Provide connection of four wind farms (384 MW) to the transmission network on the Bruce-Longwood circuits.

Project Classification per OEB Filing Guidelines:

Project Class:	Connection
Project Need:	Customer Driven: The project is required to incorporate new renewable generation that was awarded FIT contracts by the OPA.

Hydro One Networks – Investment Summary Document

Investment Type: Protection and Control for Enablement of Distribution Connected Generation

Reference #	Investment Name	2013 Gross Cost	2014 Gross Cost	In-Service Date
D26	Transfer Trip Signaling Enhancement	$5.0M	$8.0M	Annual

Please see Exhibit D1, Tab 3, Schedule 3, Appendix A, Table 6 for cash flow and other details about the project.

Need:
This investment is required to address the concerns of generators have with being required to shutdown or curtail their operation for outages that are not covered by the basic transfer trip implementation. For many generators the lost revenue costs will far outweigh their share of the cost to implement enhanced transfer trip signaling.

Not proceeding with this investment will result in connected generators being unnecessarily forced out of service during planned or un-planned transmission outages. The optimum arrangement in terms of minimizing total costs to the generators will not be realized.

Summary:
The Connection Impact Assessment that for generators connecting to the distribution system is done strictly for normal operating conditions. It does not take into account outage scenarios on the transmission system. Consequently, the transfer trip facilities are scoped only for the effect of contingencies under normal conditions. When elements at the connecting transmission station or the upstream transmission stations are out of service for planned or forced maintenance, the transfer trip signaling is inadequate.

These enhanced transfer trip signaling facilities will cover:

1. outages to the feeder breaker for the feeder to which the generator is connected with the feeder connected through the companion "back-to-back" breaker at the TS
2. outages to one of the transformers at the TS
3. outages to one of the buses at the TS
4. outages to the tie breaker at the TS
5. outages to one of the transmission lines supplying the TS
6. some outage conditions in the terminal station for the transmission lines supplying the TS

The cost for the implementation of the first item should be shared among all generators requiring transfer trip that are connected to the same feeder. The cost for the implementation of items 2 to 4 should be shared among all generators requiring transfer trip that are connected to the same station. The cost for the implementation of items 5 and 6 should be shared among all generators requiring transfer trip that are connected to the same transmission line. Thus, there are three different grouping of cost sharing to be managed. The cost of these investments is recovered from the generators.

Results:
Allow the renewable generation to continue operations un-affected by transmission planned and forced outages.

Project Classification per OEB Filing Guidelines:

Project Class:	Development:
Project Need:	Discretionary: The project is being requested by an increasing number of generators

Hydro One Networks – Investment Summary Document

Investment Type: Protection and Control for Enablement of Distribution Connected Generation

Reference #	Investment Name	2013 Gross Cost	2014 Gross Cost	In-Service Date
D27	TS P&C Upgrades for Distribution Connected Generation	$18.5M	$20.4M	Annual

Please see Exhibit D1, Tab 3, Schedule 3, Appendix A, Table 6 for cash flow and other details about the project.

Need:
This investment is required to preserve the loading and protection capability of the feeders, to maintain proper protection for Transmission assets, to maintain reliability of supply to the distribution systems and to provide a safe interconnection for generators.

Not proceeding with this investment will result in the inability of many generators to connect to the distribution systems.

Summary:
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 may include:

- Feeder Protection Replacement to preserve the loading capability of the feeders and provide directioning to prevent false tripping
- Bus Protection Modification to prevent false tripping
- Line Back-up Protections to protect transmission assets from energy backfed from generation on the distribution systems
- Basic Transfer Trip Signaling to prevent DG islanding and coordinate with reclosing
- Station Telecom Facilities for Transfer Trip
- Station telemetry expansion for feeder telemetry and additional equipment alarms

The cost of these investments is recovered from the generators.

Results:
Allow the connection of renewable generation to the distribution system throughout Ontario without deterioration in Transmission supply reliability while maintaining protection of Transmission assets and load carrying capacity of the feeders.

Project Classification per OEB Filing Guidelines:

Project Class:	Development:
Project Need:	Non-Discretionary: The project is required to incorporate new renewable generation to satisfy government directives.

Hydro One Networks – Investment Summary Document

Investment Type: Protection and Control Modifications for Consequences of Connected Distribution Generation

Reference #	Investment Name	2013 Gross Cost	2014 Gross Cost	In-Service Date
D28	Transmission Work to Mitigate Distance Limitation	$2.8M	$3.0M	Annual

Please see Exhibit D1, Tab 3, Schedule 3, Appendix A, Table 7 for cash flow and other details about the project.

Need:
Resolve power quality issues associated with generators located in violation of the power-distance limitation.

Not proceeding with this investment will limit the options to address power distance violations leaving distribution load customers with serious power quality problems and generators suffering frequent tripping.

Summary:
This funding is for the protection and control modifications required on transmission assets which are needed for the mitigation projects required to address the power-distance limitation problems observed at connected projects. This work was approved in EB-2010-0229 (Hydro One's exemption application). The Board approved $44M for power-distance limitation work for specific distribution connected projects connected by Hydro One prior to Hydro One identifying the power-distance problem. Some of the power-distance fixes will involve protection and control changes on transmission assets. These will be required mainly for cases where the selected solution to the power-distance rule violation is to move a DG to a different feeder. Costs will be incurred to modify the feeder protections on the new feeder. In the test years, it is expected that $5.8M of the $44M required for power-distance rule mitigation will be for P&C modifications at TS's.

Results:
Allow the operation of renewable generation on the distribution system without deteriorating power quality.

Project Classification per OEB Filing Guidelines:

Project Class:	Development:
Project Need:	Non-Discretionary: The project is required to operate renewable generation to satisfy government objectives.

Hydro One Networks – Investment Summary Document

Investment Type: Protection and Control Modifications for Consequences of Connected Distribution Generation

Reference #	Investment Name	2013 Gross Cost	2014 Gross Cost	In-Service Date
D29	UFLS and Load Rejection Modification	0	$5.0M	Annual

Please see Exhibit D1, Tab 3, Schedule 3, Appendix A, Table 7 for cash flow and other details about the project.

Need:

This investment is required to maintain the capability of protections schemes which are required for the reliability of the bulk electricity system.

Not proceeding with this investment will result in contravention of Hydro One's reliability compliance obligations, as they pertain to the IESO and NPCC's requirements for under frequency load shedding, and the reliability of Special Protections Schemes.

Summary:

Section 10.4 of Chapter 5 of the Market Rules requires the Transmitter to have 25% of load available for manual shedding when the frequency declines below 59.0Hz. A further 30% of load must be available for automatic shedding by under-frequency relays. There is also a requirement to shed further load manually when the frequency drops below 58.5Hz. The load selected for manual shedding must not include load selected for automatic shedding.

As currently designed, Under-Frequency Load Shedding (UFLS) and manual shedding systems operate by tripping pre-defined feeder breakers at Transmission Stations. With generation connected to the feeders, the number of feeder breakers that only trip load is being reduced. It is expected that by 2014 there will be insufficient load-only feeders to meet the combined requirements for UFLS and manual load shedding. Costs will be incurred to implement alternate arrangements to comply with market rules and shed load independently of generation.

Special Protection Schemes initiate tripping of generation, load or both in response to contingencies on the transmission system. The tripping of load is accomplished by tripping of the feeder breakers. With generation connected to the feeders, the amount of load available for rejection is reduced. The load rejection capability of these schemes needs to be preserved. The alternate load rejection costs are incurred once the aggregate amount of generation reduces the load available for rejection below the required amount at that station. For larger schemes the costs are incurred once the total generation in the zone reduces the amount of load required for rejection in the zone.

Results:

Preserve the function of Transmission System protection schemes while allowing the connection of renewable generation to the distribution system throughout Ontario.

Project Classification per OEB Filing Guidelines:

Project Class:	Development:
Project Need:	Non-Discretionary: The project is required to preserve the functionality of mandated or essential system protection schemes.

Hydro One Networks – Investment Summary Document

Investment Type: Risk Mitigation

Reference #	Investment Name	Gross Cost	In-Service Date
D30	Hawthorne TS: Uprate Short Circuit Capability	$11.8M	Q4 2013

Please see Exhibit D1, Tab 3, Schedule 3, Appendix A, Table 10 for cash flow and other details about the project.

Need:

To restore the reliability levels of the 115kV system supplying the Ottawa area. Currently, high short circuits levels at Hawthorne TS restrict the capability of the 115kV stations under normal operating conditions. Not proceeding with this investment would result in continued reduced reliability to customers in the Ottawa 115kV area.

Summary:

Hawthorne TS is a 500/230/115kV autotransformer station supplying the City of Ottawa and surrounding areas. The 115kV switchyard is equipped with 115kV oil breakers with an asymmetrical current rating of 45.5A. As a result of new generators and various transmission project upgrades and modifications in recent years, the Hawthorne TS 115kV switchyard short circuit level has crept and now exceeds breaker capabilities. The increase is not attributable to a single customer or system modification as this was identified following a short circuit system model update and review in spring 2011. Model updates from interconnected neighbours have also resulted in increased short circuit levels. Operating restrictions and interim measures (i.e. opening of the Merivale 115kV bus) are required to manage this issue which reduces the reliability and operating flexibility of the 115kV system.

The upgrade work at Hawthorne requires 12 existing breakers to be replaced with new standard size 50kA SF6 breakers and sections of the strain bus to be uprated. Nine of these 12 breakers have an average age of 44 years. With typical life expectancy of breakers ranging between 30-55 years, these breakers are approaching end-of-life. Providing 50kA breakers at Hawthorne is consistent with the short circuit capabilities established in the Transmission System Code for 115kV facilities. The remaining three breakers are 25 years old and they will be returned to inventory for reuse. End of life insulators and aging control cabling will also be replaced at the same time to take advantage of 115kV switchyard outages.

There is significant renewable generation interest in the Ottawa and surrounding areas; however the existing short circuit limitations prevent additional generation from connecting. The upgrade work will allow up to 300MW of additional generation to connect in these areas.

This project was not initially included in EB-2010-0002 as it was identified after the submission of prefiled evidence. The project scope and rationale was discussed in response to OEB Staff Interrogatory I-01-111. In Interrogatory I-01-111, it was identified that the upgrades were required to address breakers nearing end-of-life and to connect a significant level of FIT generation. However, subsequent reviews have established the breaker short circuit capabilities had been exceeded prior to the FIT projects.

Results:

Restore the reliability of the 115kV stations supplying the Ottawa 115kV area to historical levels, address equipment nearing end-of-life and facilitate the connection of renewable generation in Ottawa and surrounding areas.

Project Classification per OEB Filing Guidelines:

Project Class:	Development:
Project Need:	Non-Discretionary: The project is required to restore reliability levels of the 115kV system supplying the Ottawa area.

Hydro One Networks – Investment Summary Document

Investment Type: Risk Mitigation

Reference #	Investment Name	Gross Cost	In-Service Date
D31	Allanburg TS: Uprate Short Circuit Capability	$19.0M	Q4 2013

Please see Exhibit D1, Tab 3, Schedule 3, Appendix A, Table 10 for cash flow and other details about the project.

Need:
To restore the reliability levels in the 115kV system supplying the Niagara area. Currently, high short circuits levels at Allanburg TS restrict the capability of the 115kV station under normal operating conditions. Not proceeding with this investment would result in continued reduced reliability to customers in the Niagara area.

Summary:
Allanburg TS is a 230/115kV autotransformer station supplying the Niagara area. The station's 115kV switchyard is equipped with 115kV oil breakers with an asymmetrical current rating of 45.4kA. As a result of a number of generation connections and transmission project upgrades and modifications in the Niagara area and other parts of southern Ontario over the past few years, the Allanburg TS 115kV switchyard short circuit level has increased and now exceeds breaker capabilities. The increase is not attributable to a single customer or system modification as this was identified following a short circuit system model update and review in summer 2010. Model updates from interconnected neighbours have also resulted in increased short circuit levels. Operational restrictions and interim measures (i.e. splitting the Allanburg 115kV bus) are required to manage this issue which reduces the reliability and operating flexibility of the 115kV system.

The upgrading work requires 15 existing breakers (average age 47 years) in the 115kV switchyard be replaced with new 50kA SF6 breakers and sections of the strain bus be uprated. With the typical life expectancy of breakers ranging between 30-55 years, these breakers are approaching end-of-life. Providing 50kA breakers at Allanburg is consistent with the short circuit capabilities established in the Transmission System Code for 115kV facilities.

There is significant renewable generation interest in the Niagara area; however, the existing short circuit limitations prevent additional generation from connecting. The upgrade work will allow up to 150MW of additional generation to connect in these areas.

This project was not initially included in EB-2010-0002 as it was identified after the submission of prefiled evidence. However, the project scope and need was identified in response to OEB Staff Interrogatory I-01-111.

Results:
Restore the reliability of the Allanburg 115kV station supplying the Niagara area to historical levels, address equipment nearing end-of-life and facilitate the connection of renewable generation in the Niagara area.

Project Classification per OEB Filing Guidelines:

Project Class:	Development:
Project Need:	Non-Discretionary: The project is required to restore reliability levels for the Allanburg 115kV station supplying the Niagara area.

Hydro One Networks – Investment Summary Document

Investment Type: Risk Mitigation

Reference #	Investment Name	Gross Cost	In-Service Date
D32	Basin TS: Add Reactors	$6.0M	Q4 2013

Please see Exhibit D1, Tab 3, Schedule 3, Appendix A, Table 10 for cash flow and other details about the project.

Need:
To mitigate the risk of damage to equipment caused by temporary overvoltages on the downtown 115kV system. Not proceeding with this investment would result in significant risk of damage to cables and equipment at Basin TS, Gerrard TS, and Carlaw TS.

Summary:
The 115kV circuits H1L and H3L connect Hearn SS and Leaside TS, and supply load in downtown Toronto. The circuits also supply Gerrard TS, Carlaw TS and Basin TS. Because these circuits have long underground cable sections, the high cable charging capacitance can lead to temporary overvoltages during disturbances. Temporary overvoltages can damage major equipment including transformers.

In the past, rod gaps have been relied on to protect against such overvoltages. A review in late 2010 of the temporary overvoltage protection requirements identified that the existing rod gaps at Basin TS, Gerrard TS and Carlaw TS are inadequate to protect the equipment connected to these circuits on a long term basis.

Installing 12 MVar 115kV shunt reactors on circuits H1L and H3L at Basin TS, where there is sufficient space, will mitigate this excessive overvoltage risk.

The reactors will be installed at the same time as the new Hearn 115kV switchyard project for work bundling efficiencies and to minimize outages that may impact the supply to the Toronto city core.

Results:
Provide adequate long term protection of major power equipment connected to circuits H1L and H3L from excessive temporary overvoltages.

Project Classification per OEB Filing Guidelines:

Project Class:	Development:
Project Need:	Non-Discretionary: The project is required to reduce the risk of equipment damage and maintain reliability.

Hydro One Networks – Investment Summary Document

Investment Type: Risk Mitigation

Reference #	Investment Name	Gross Cost	In-Service Date
D33	Main TS: Add Breakers	$6.7M	Q4 2013

Please see Exhibit D1, Tab 3, Schedule 3, Appendix A, Table 10 for cash flow and other details about the project.

Need:
To mitigate the risk of damage to equipment caused by temporary overvoltages on the downtown 115kV system. Not proceeding with this investment would result in significant risk of damage to cables and equipment at Main TS.

Summary:
The 115kV circuits H7L and H11L connect Hearn SS and Leaside TS, and supply load in downtown Toronto and load at Main TS. Because these circuits have long underground cable sections, the high charging capacitance can lead to temporary overvoltages during disturbances. Temporary overvoltages can damage major equipment including transformers.

In the past, rod gaps have been relied on to protect against such overvoltages. A review in late 2010 of the temporary overvoltage protection requirements for the new Hearn GIS switchyard identified that the existing rod gaps at Main TS are inadequate to protect the Main transformers on a long term basis.

Installing 115kV shunt reactors is the best way to solve the high temporary overvoltage problem; however, there was insufficient space at the sites of Hearn SS, Leaside TS and Main TS for installing 115kV shunt reactors on circuits H7L and H11L. As a result, high voltage breakers will be installed to disconnect the Main TS transformers and arresters will be installed at Main TS to maintain reliable supply and prevent exposure to unacceptable temporary overvoltages. Main TS had sufficient space to install the high voltage breakers.

The breakers will be installed at the same time as the new Hearn 115kV switchyard project for work bundling efficiencies and to minimize outages that may impact the supply to the city core.

Results:
Provide adequate long term protection of major power equipment connected to circuits H7L and H11L from excessive temporary overvoltages.

Project Classification per OEB Filing Guidelines:

Project Class:	Development:
Project Need:	Non-Discretionary: The project is required to reduce risk of equipment damage and maintain reliability.

Hydro One Networks – Investment Summary Document

Investment Category: Operating Capital: Grid Operations Control Facility

Reference #	Investment Name	Gross Cost	In-Service Date
O1	Network Management System Upgrade	$28M	Mid 2015

Please see Exhibit D1, Tab 3, Schedule 4, Table 2 for cash flow and other details about each project.

Need:

The Network Management System (NMS) must be upgraded due to the impending end of life of the software, hardware components and operating system. As of late 2014, the current application software, Alstom (formerly Areva) Energy Management System (EMS) 2.5, will be two releases out of date and will not support future business requirements. The server hardware has been in continuous operation since 2008, and is therefore reaching end of life between 2013 and 2015. The existing operating system becomes end of life in 2014

The upgrade must be completed by 2015 to allow Hydro One to remain within the supportability window stipulated by the vendors. This ensures Hydro One will receive an appropriate level of hardware replacement support and vendor supplied software patches to maintain NERC Cyber Security compliance and to mitigate the business risks associated with operating the Transmission system using a control system that is at end-of-life.

Summary:

The NMS is the mission critical operating tool used for monitoring and control of the Hydro One Transmission System. The reliable operation of the Ontario Power System is dependent on the continued availability and high performance of the NMS.
This investment upgrades the NMS operating system, software and associated server hardware currently in service at the Ontario Grid Control Centre and the Richview Backup Centre.

Results:

Completion of this investment will result in the following accomplishments: (i) All NMS application installations upgraded to Alstom EMS version 2.7; (ii) Hydro One's NMS will continue to be compliant with NERC Cyber Security regulations; (iii) hardware upgrades for continued sustainability; (iv) better performance and reliability (v) additional capacity for transmission growth and incorporation of distributed generation connections.

Project Classification per OEB Filing Guidelines:

Project Class:	Operations
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Investment Category: Operating Capital – Operating Infrastructure

Reference #	Investment Name	Gross Cost	In-Service Date
O2	Hub Site Management Program	$6.5M	Late 2014

Please see Exhibit D1, Tab 3, Schedule 4 for cash flows.

Need:

This investment is required to:

- provide capacity expansion for the monitoring and control of new or expanded transmission stations and new transmission connected generators,
- maintain the performance and reliability of monitoring and control of critical grid stations and facilities
- refresh end-of-life gateway systems

Summary:

A Hub Site is a location which comprises a number of gateway systems that connect the transmission stations in their geographic vicinity to the OGCC and back-up centre. There are 37 Hub Sites.

As new assets or transmission connected generators are added to the grid, the gateways become fully loaded and more gateways need to be added. As the number of gateways at a hub site increases, the risk of loss of that single site exceeds thresholds for grid control reliability and the hub site needs to be split into two or more locations. Presently, there are 6 sites that exceed these thresholds.

Gateway systems are computer systems which are subject to software technology obsolescence after a period of about 6 years. This program also refreshes these systems in order to keep the fleet within range of vendor supported versions.

Additional gateways will be installed to provide capacity for the monitoring and control of new grid assets and transmission connecting generators. Some new hub sites will be added and large hub sites split. Gateway obsolescence will be optimally managed.

Results:

Grid development projects and generation connections can proceed without impediment or delay and grid loss-of-control risks associated with loss of a hub site are contained to acceptable levels. The 2013 and 2014 program will focus on upgrading and off-loading of the three most critical hubsites.

Project Classification per OEB Filing Guidelines:

Project Class:	Operating
Project Need:	Non Discretionary

Hydro One Networks – Investment Summary Document

Investment Category: Operating Capital – Telemetry Expansion Program

Reference #	Investment Name	Gross Cost	In-Service Date
O3	Telemetry Expansion Program	$4.6M	Late 2014

Please see Exhibit D1, Tab 3, Schedule 4 for cash flows.

Need:

Telemetry expansion is needed to eliminate unnecessary equipment outages and wasteful use of the time of field staff, to allow optimum utilization of assets and to better manage aging assets.

Summary:

The function of Ontario Grid Control Centre (OGCC) depends on voltages, power flow, statuses of switching devices, and alarms transmitted in real time from the transmission stations throughout the province. This information is called telemetry.

A legacy problem that exists in many Hydro One stations is the “bundling” of alarms. When older stations were built, limitations in equipment and telecommunication capacity required multiple alarm signals at a station to be wired together and transmitted back to the operator as a single alarm. About 2,000 of these require service personnel to be urgently dispatched to the station to determine the real cause. In the meantime, action must be taken based on the worst case interpretation of the bundled alarm and this sometimes requires removing equipment from service resulting in reduced reliability of supply, market congestion or, in some instances, immediate interruption of load. In most instances these actions prove unnecessary when alarm details become known. Each year about 280 such emergency callouts are made. These 2000 alarms and are high priority to have unbundled. The program prioritizes stations that have longer travel time and larger numbers of bundled alarms.

Modern protection and control equipment provides additional information from stations that will allow assets such as transformers to be utilized more effectively. Improved equipment limits facilitate allowing an outage to proceed.

Results:

Telemetry sets from 8 stations will be expanded to present-day standards.

Project Classification per OEB Filing Guidelines:

Project Class:	Operating
Project Need:	Discretionary

Hydro One Networks – Investment Summary Document

Investment Category: Operating Capital – Wide Are Network Project

Reference #	Investment Name	Gross Cost	In-Service Date
O4	Wide Area Network Project	$55.5M	Late 2015

Please see Exhibit D1, Tab 3, Schedule 4 for cash flows.

Need:

Hydro One requires expanded telecommunication capacity into many of its transmission stations to support: protection and control for transmission development, advanced distribution system, video surveillance for security and operating, cyber security and enterprise systems such as conferencing and mobile workforce enablement. The telecom capacity required to support these applications has grown from 500Mbps in 2009 to 1300Mbps by the end of 2010. Presently, 50% of the rings on the existing Synchronous Optical Network (SONET) system are between 90-100% of full capacity. An independent study of Hydro One's Transmission, Distribution and enterprise application roadmap concluded that Hydro One’s bandwidth needs will increase to over 7000Mbps by the end of 2015. If the capacity on Hydro One’s fibre network is not expanded, existing and future telecom services will be displaced off onto leased telecom services.

Summary:

Most of Hydro One’s transmission stations are in remote locations that are not served by high bandwidth telecommunication providers. Hydro One has been using the fibre optic cables built onto transmission lines for the protection and control of the grid to service some of these telecommunication requirements. However, the existing terminal equipment does not make optimum use of the fibre capacity and there are some locations where capacity is already fully allocated. The needs for protection and control take precedence.

This project will implement new network technology to make more efficient use of the existing fibre optic cables on transmission circuits. This technology, which is readily scalable, will provide the capacity to meet all telecom needs expected over the next five years and beyond and avoid large leased telecom services costs.

Results:

Hydro One will have scalable wide-area telecom capacity to meet expanding telecommunication needs. OM&A costs for existing telecom leased services and those required for committed projects will be reduced by 47%. Management of multiple networks will be consolidated achieving improvements in provisioning, network operation and management of security.

Project Classification per OEB Filing Guidelines:

Project Class:	Operating
Project Need:	Discretionary

Hydro One Networks – Investment Summary Document

Investment Category: Operating Capital – Frame Relay Replacement Project

Reference #	Investment Name	Gross Cost	In-Service Date
O5	Frame Relay Replacement Project	$10.4M	Late 2013

Please see Exhibit D1, Tab 3, Schedule 4 for cash flows.

Need:

Hydro One currently has 153 Frame Relay (FR) telecom circuits that provide communications between the OGCC and 121 Transformer Stations (TS) for control of the power grid. Frame Relay is an old technology that is being discontinued by the telecom service providers. In May of 2010, Hydro One received notification from Bell Canada that Frame-Relay (FR) services will cease on December, 2013. Hydro One must transfer all of its services running on the FR circuits over to new circuits using the modern Multiprotocol Label Switching (MPLS) technology. Not transferring all circuits by end of 2013 has the potential to significantly impact the reliability of the grid, as OGCC risks losing redundant communication links, and in some cases, even complete communication to major hub-sites and a large number of major and minor stations.

Summary:

This investment will replace the Frame-Relay services offered by Bell Canada with a new service that is enabled over the Bell Canada Multiprotocol Label Switching Network (MPLS).

Results:

The new service will provide Hydro One with the required communications circuits needed to sustain control of the Ontario Power Grid. Conversion to MPLS will align with the WAN Project to expand the Hydro One network for additional uses including: Corporate Data Exchange, Connected Workforce and Voice over IP at stations identified for migration to these services.

Project Classification per OEB Filing Guidelines:

Project Class:	Operating
Project Need:	Non-Discretionary

Hydro One Networks – Investment Summary Document

Investment Category: Operating Capital – Fault Locating Program

Reference #	Investment Name	Gross Cost	In-Service Date
O6	Fault Locating Program	$6M	Dec 2014

Please see Exhibit D1, Tab 3, Schedule 4 for cash flows.

Need:

The Fault Locating program is needed to reduce costs associated with locating faults on transmission lines, to reduce the outage duration associated with each fault event and reduce health and safety risk to staff and carbon footprint associated with time presently spent in vehicles and helicopters searching for the fault location.

Summary:

In the late nineties and early years of the first decade, Hydro One funded research programs to develop reliable, accurate and automated analytical methods to calculate the location of a fault on transmission lines from information captured by the protective relays and digital fault recorders at all of the terminal stations of the line. As end-of-life replacement of electromechanical relays with digital relays progresses, the ability of these modern devices to be internetworked and remotely interrogated makes it possible for Fault Locating to be operationalized at the Ontario Grid Control Centre (OGCC). In 2004 Hydro One began a program to install data extraction networking infrastructure in the Transmission Stations to enable this. Progress on this was paused during the implementation of the Cyber Security systems mandated by NERC standards. Those systems were completed by 2010 and revised standards for the data extraction infrastructure have been deployed. The first group of 13 stations with Fault Locating capability connected to the OGCC became operational in 2010 and 2011 with good success reducing helicopter time, staff travel time and shortening restoration on 7 occasions in one year.

This program will deploy Fault Locating to an additional 17 stations in 2013 and 2014.

Results:

Benefit calculations indicate annual savings in the range of $0.5M, outage time reductions of about 580 hours, staff driving reduction of 27,000km and reduction in helicopter time of about 230 hours.

Project Classification per OEB Filing Guidelines:

Project Class:	Operating
Project Need:	Discretionary

Hydro One Networks – Investment Summary Document

Investment Category: Operating Capital – Station LAN Infrastructure Program

Reference #	Investment Name	Gross Cost	In-Service Date
O7	Station LAN Infrastructure Program	$8.0M	Late 2014

Please see Exhibit D1, Tab 3, Schedule 4 for cash flows.

Need:

Modern digital protection, control and monitoring devices located in Transmission Station have the ability to be networked together. The internetworking of these devices provides many benefits in the form of reduced cabling costs, reduced cost for primary measuring devices or transducers, reduced design costs, and the ability to achieve business efficiencies by remote interrogation of the devices for fault locating, event analysis and asset utilization information.

As end-of-life replacement programs have been installing these modern devices, past practice has been to install Local Area Network (LAN) cabling and equipment among the specific devices being replaced. Then, when further end-of-life replacements, or generation connection or station expansion programs, install more digital equipment, the LAN system is extended to accommodate. This results in different design standards and different vintages of equipment and can cause delays to the affected projects. It has been determined that a more efficient approach is to identify stations that will be needing installation of digital equipment for planned sustainment, development or connection work, and install a standardized and secure station LAN infrastructure sized to meet all forecast LAN capacity needs for that station. This eliminates any impediments to the projects, reduces design and installation costs, and ensures a LAN infrastructure that is more secure and more easily monitored and maintained.

Summary:

This program installs a standardized LAN infrastructure, appropriate to the class of station, which incorporates Cyber Security, remote monitoring and has the capacity, or expandability, to meet all forecast needs.

Results:

For the 2013 and 2014 program 6 stations will be equipped with LAN Infrastructure to ready them for planned Sustainment, Development of connection projects.

Project Classification per OEB Filing Guidelines:

Project Class:	Operating
Project Need:	Discretionary

Hydro One Networks – Investment Summary Document
Cornerstone Phase 3 – Enhance Integrated Planning

Reference #	Investment Name	In-Service:
IT1	Cornerstone Phase 3 – Enhance Integrated Planning	**2011-2014**

Need:

Phase 3 will enhance integrated planning 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 investment is required to support the achievement of business objectives and to release significant business value. Not proceeding with this investment would eliminate the integrated tools and systems that are needed to further optimize asset lifecycle decisions and improve operational efficiency and productivity. It would also necessitate a continued reliance on existing end-user disparate systems/databases for this decision support.

Investment Summary:

In 2006, Hydro One developed an information technology (IT) strategy that called for replacement of core business systems (and associated bolt-ons) which had reached or were approaching end-of-life, with one or two off the shelf Enterprise Resource Planning (ERP) systems. In 2007, Hydro One embarked on this strategy by initiating Cornerstone Phase 1, an SAP Enterprise Asset Management (EAM) solution. This project was successfully completed in June 2008. Cornerstone Phase 2 was completed in Q3 of 2009 to replace PeopleSoft Finance/Human Resources/Payroll Functionality that is integrated with the EAM solution.

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 asset and other business data to be captured once and used consistently throughout Hydro One 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 using mobile technology.

Phase 3 will enhance integrated planning, Enterprise Asset Management / Enterprise Resource Planning / Business Intelligence 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 and enhancing SAP functionality for asset analytics, business planning, planning/scheduling/dispatch and supply chain optimization as well as integrating specialized software applications for asset investment planning, geo-spatial analytics and engineering & design. The in-service dates for this phase have been extended over the period of 2011-2014 due to the advancement of the Cornerstone Phase 4 initiative. Supply Chain optimization work was completed successfully in June 2011. Asset Analytics, Business Planning & Consolidation, Asset Investment Planning and Engineering Design projects are currently underway. Planning, Scheduling and Dispatch improvements are targeted for 2013/2014. Cornerstone Phase 3 is planned to conclude in 2014.

Results:

Cornerstone Phase 3 will deliver the following business benefits

- Implement improved processes and tools for Asset Analytics, Supply Chain, Asset Investment Planning, Business Planning and Consolidation, Engineering Design Automation and improve planning, scheduling and dispatch capabilities.
- Consolidate and eliminate duplicative end-user databases/applications
- Streamline processes and improve information transparency

Costs:	**2013** ($M)	**2014 ($M)**	**Total** ($M)
Capital* and Minor Fixed Assets	26.8	10.0	36.8

Hydro One Networks – Investment Summary Document
GIS Implementation

Reference #	**Investment Name**	**In-Service:**
IT2	GIS Implementation	**2014**

Need:

This is a foundational investment required to support initiatives across the entire Hydro One organization. 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 metering and smart grid initiatives.

If this investment is not undertaken, there are a number of risks across Line of Businesses (LOBs). First and foremost, up-to-date geospatial information resources assist safety practices as crews have easier access to accurate and timely views of the network. There is also a risk of sub-optimal crew routing for work, and for outage restoration, for sub-optimal planning, and for litigation due to improperly managed real estate.

Investment Summary:

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 and condition facilitates planning and outage management, supports mobile workforce management through more effective crew routing and automated vehicle location (AVL), manages real estate records and Hydro One property, and provides the intelligent 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). At the present time, there is no single system of record; spatial data is managed in siloed databases and business processes across Hydro One; consumers of spatial data are required to maintain their own spatial repositories, which do not necessarily reflect the current state of the network. In addition, not all data is available in a GIS format, complicating interoperability. There is no publically consumable data portal, and no integration to other critical business systems such as SAP.

This investment will create a consolidated system of record for spatial data, and publish it to users for planning, outage management or via a published web portal. This will entail completing the conversion of data, reconciling the data and business processes, publishing a spatial data web portal, and completing integration with SAP and other enterprise applications. This investment provides for updates to GIS infrastructure, particularly software applications.

Results:

- *Improved Decision Quality:* Provide immediate access to more comprehensive and integrated spatial asset and connectivity data in corporate systems, contributing to consistency and timeliness in asset planning, maintenance and outage decisions.
- *Improved Safety:* Provide timely access to reliable, accurate and up-to-date data regarding the state of the network, which empowers work crews to work more safely.
- *Reduced Litigation:* Provide access to a single, seamless and up-to-date repository of records from which organization can avoid and defend against litigation for land usage.
- *Prevent Rework:* Provide a single, seamless repository of spatial records that eliminates the need for maintaining separate spatial data.
- *Support Next Generation Applications:* Provide access to network properties and connectivity information to support next generation applications such as FLISR and VVO. (described above).

Costs:	**2013 ($M)**	**2014 ($M)**	**Total ($M)**
Capital and Minor Fixed Assets	6.8	1.0	7.8

Hydro One Networks – Investment Justification
MFA PC and Printer Hardware

Reference #	Investment Name	In-Service:
IT3	MFA PC and Printer Hardware	**2013 - 2014**

Need:

This investment driver funds the lifecycle refresh of PC and printer hardware. This equipment includes desktops, laptops, tablets, printers, and plotters. This equipment is used by Hydro One staff to perform their daily work such as accessing email, desktop applications (i.e. Microsoft Office), and enterprise applications.

This investment is required to fund the replacement of existing PC and printer equipment that has reached the end of useful life, and upgrade existing equipment to meet business needs.

Not proceeding with this investment could negatively impact the delivery of all IT services to the business by using equipment that does not meet business needs or is past the end of its useful life increasing the risk of breakdown and lost productivity.

Investment Summary:

This funding is required to replace/upgrade existing equipment to ensure it delivers the required level of reliability and service to the business. Old equipment that is past the end of its useful life becomes unreliable and negatively impacts the ability of the business to perform their day to day work, the increasing costs to Hydro One and its ratepayers. In addition, existing equipment may need to be upgraded to meet the changing needs of the business.

Results:

The PC and printer hardware assets will reliably support business needs and the performance of day-to-day work unimpeded by end-of-life computer reliability problems. .

Costs	**2013 ($M)**	**2014 ($M)**	**Total ($M)**
Minor Fixed Assets	3.3	3.6	6.9

Hydro One Networks – Investment Justification
Software Refresh and Maintenance

Reference #	Investment Name	In-Service:
IT4	Software Refresh and Maintenance	**2013 - 2014**

Need:

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. Applications are replaced or upgraded 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.

Investment Summary:
In 2013 and 2014, planned costs include the continuation of the Windows 7 and MS Office 2010 upgrade, and commencing Windows Server 8 upgrades to keep data center infrastructure vendor supported. Costs also include a migration from 32-bit processing to a 64-bit computing environment on both client and server platforms to accommodate the evolution of enterprise applications to 64-bit operating system platforms.

Results:
Enterprise Applications will remain compatible and current.

Costs	2013 ($M)	2014 ($M)	Total ($M)
Software Refresh and Maintenance	9.2	11.9	21.1

Hydro One Networks – Investment Justification
MFA Servers and Storage

Reference #	Investment Name	In-Service:
IT5	MFA Servers and Storage	**2013 - 2014**

Need:
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.

Investment Summary:
The replacement cycle of refresh of Wintel and Unix servers to maintain vendor supported levels will included ancillary hardware upgrades, and capacity upgrades for core access control and middleware environments in anticipation of increased data processing with SAP-driven processing..

Results:
The Windows & Unix Server assets will provide timely and reliable services to the Hydro One business.

Costs	2013 ($M)	2014 ($M)	Total ($M)
Minor Fixed Assets	4.0	6.4	10.4

Hydro One Networks – Investment Justification
MFA Telecom Infrastructure

Reference #	Investment Name	In-Service:
IT6	Telecom Infrastructure	**2013 - 2014**

Need:
This investment is required to replace end-of-life assets and to maintain service reliability and security, by refreshing network switches and routers, upgrading telephone Private Branch Exchange (PBX) switches, replacing un-interruptible power source system, and upgrading the security solutions for external network interfaces.

Telecom infrastructure is the underlying hardware to support the business telecom network which is used to transmit data required to run business applications. Voice or data network improvements or replacements are undertaken to improve network efficiency and to ensure equipment is current and supported by third party vendors.

Investment Summary:
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.

Results:
The Telecom Infrastructure refresh will provide a secure and reliable network to support core business applications and communications.

Costs	2013 ($M)	2014 ($M)	Total ($M)
Minor Fixed Assets	3.2	1.8	5.0

Hydro One Networks – Investment Summary Document

Reference #	Investment Name	Gross Cost	In-Service Date
C1	Real Estate Field Facilities Capital for 2013	$27.5	Late 2013
C1	Real Estate Field Facilities Capital for 2014	$27.5	Late 2014

Need:

Facilities Capital Work Program addresses facilities portfolio accommodation needs in terms of facility improvements, building additions and new facilities in line with Company operational requirements. This program also focuses on ensuring critical facility structural and other building integrity improvements are made to administrative and service centres to ensure appropriate maintenance and operation of the asset in the longer term.

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 work programs and changing business requirements.

The aging facilities asset base in conjunction with operational needs of the business units requires capital investment in order to continue to provide adequate accommodation space. Approximately 40% of administrative and service centre facilities infrastructure is estimated to be more than 40 years old. The program focuses on undertaking the critical component replacement work on a priority basis including provision of new buildings, buildings additions and facility renovations.

Summary:

Key program work activities include:
- Addressing Company accommodation requirements in terms of new buildings, building 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 mould.

Capital investment of $27.5M is required for 2013 and similarly $27.5M is required for 2014 to provide for new accommodation solutions, address need for new buildings, buildings additions and provide for facilities improvements in order to continue to provide adequate accommodation space to support work programs.

Results:

- Secured necessary accommodation space in the field in line with work programs requirements.
- Improved Administrative and Service Centre facilities through replacement of roof structures, windows, HVAC systems and other structural elements.

Hydro One Networks – Investment Summary Document

Reference #	Investment Name	Gross Cost	In-Service Date
C2	Real Estate Head Office and GTA Facilities Capital for 2013	$16.6M	Late 2013
C2	Real Estate Head Office and GTA Facilities Capital for 2014	$16.6M	Late 2014

Need:
The Facilities Capital Work Program is responsible to ensure program delivery in terms of capital improvements and providing for Company accommodation needs. The funding requirements in 2013 and 2014 mainly reflects on the expanded facilities work program that primarily responds to current and future anticipated Company work space accommodation needs.

Capital investment of $16.6 million and $16.6 million is required in 2013 and 2014 respectively. This investment will provide for head office accommodation improvements work that began in late 2011 and is expected to continue in the bride year 2012 and in 2013 and 2014.

Effective February 1, 2010 Hydro One Networks secured an eleven year lease for 483 Bay Street, to serve its ongoing head office requirements. Within the completed lease renewal of 483 Bay, Hydro One was successful in obtaining the commitment of the Landlord to upgrade base building systems/infrastructures, allowances for tenant improvements. The initially planned tenant improvements as outlined in the last transmission rate filling were ultimately deferred during years 2010 and 2011 given consideration to regulatory decision and the economic situation in the Province of Ontario.

In 2013 the gross leasehold improvements and the furniture systems funding requirements are estimated to be $12.1 million and $4.5 million respectively and similar requirements in the following test year 2014 the gross leasehold improvements are similarly estimated to be $12.1 million and the furniture systems funding requirements are estimated to be $4.5 million

The leasehold improvements are necessary as major head office building infrastructure elements are now at end of life and require replacement. Similarly, furniture systems were acquired from the previous tenant, refurbished and are also now considered to be at end of life. The planned tenant improvements are part of the negotiated lease agreement.

Summary
Capital investment of $16.6 million and $16.6 million is required in both years 2013 and 2014 respectively to provide for head office accommodation improvements

Results:

Completed necessary improvements to head office space.

Hydro One Networks – Investment Summary Document
Shared Services Capital – Transport & Work Equipment

Reference #	Investment Name	In-Service:
C3	Shared Services Capital – Transport & Work Equipment	**2013 - 2014**

Need:

Transport and Work Equipment expenditures for 2013 and 2014 are required to: primarily replace end of life core Fleet and equipment, support the growing levels of transmission and distribution capital and OM&A sustainment, development, and operations work programs, and support staffing expansions resulting from Provincial Lines and Forestry Apprenticeship Programs.

Not proceeding, or delaying this investment would: lead to lower than required fleet and equipment levels, have an unfavorable impact on the appropriate mix of vehicles and equipment required, and may cause a shift to use of more expensive rental units. Extending the life of the vehicles past their optimum level of economic and reliable operations will also result in increased equipment and user operating costs, reduced reliability and unsafe operating conditions.

Investment Summary:

Hydro One controls and manages approximately 6,700 fleet units and other equipment which support the various lines of business (LOBs) including Provincial Lines, Stations, Forestry and Construction Services. Fleet vehicles must be maintained at an optimum level to comply with various regulations (Highway Traffic Act, CVOR regulations, etc.) and to maintain LOB productivity by minimizing downtime and travel time and taking advantage of opportunities resulting from improvements in technology.

Present replacement criteria are based on manufacturers' recommendations and repair history. Light vehicles are replaced after 6 years or 185,000 km, service trucks are replaced after 6 years or 200,000 km, and work equipment is replaced after 8 – 10 years or 330,000 km. This is used as a guideline and ultimately it is used in combination with break-even analysis, including replacement cost, depreciation, operating cost and potential life expectancy.

The key contributors to the 2013 and 2014 capital program include:

- Primarily the replacement of core fleet and equipment;
- Additional vehicle and equipment requirements to support the Forestry Apprenticeship Program and additional staff;
- Additional vehicle and equipment requirements to support the Provincial Lines Apprenticeship Program and additional staff;
- Additional vehicle, light and heavy equipment required to support the growing levels of the transmission and distribution capital and OM&A sustainment, development, and operations work programs.

Results:

- This investment will result in reduced operating costs, increased efficiency, and reliability.

Costs:

	2013 ($M)	**2014**($M)
Capital* and Minor Fixed Assets (Networks Only)	43.3	44.5

*Includes overhead and Allowance for Funds Used During Construction at current rates

Hydro One Networks – Investment Summary Document
Shared Services Capital – Service Equipment

Reference #	Investment Name	In-Service:
C4	Shared Services Capital – Service Equipment	**2013 - 2014**

Need:

Minor fixed asset expenditures for service equipment in 2013 and 2014 are required: to support the growing levels of transmission and distribution capital and OM&A sustainment, development, and operations work programs which includes the initiatives of the GEGEA, to replace end of life and obsolete equipment, and staffing expansions.

Service equipment is used by field staff to carry out day-to-day work activities including specialized transportation equipment to and from the work site. This equipment must be maintained at appropriate levels such that work can be executed in a safe and cost effective manner. Inadequate investment will result in equipment breakdowns or increased labour time. Overall this would adversely impact job costs, outage duration, and work program accomplishments.

Investment Summary:

Minor fixed asset (MFA) spending for service equipment represents items > $2000 each exclusive of general computer MFA requirements, real estate MFA requirements and fleet MFA requirements, addressed elsewhere, which are necessary to replace end of life equipment used by field staff to execute the work program in a cost effective manner.
Purchases in this category include:

- Minor specialized transportation equipment such as snowmobiles, all terrain vehicles, boats, barges, and related accessories to transport crews to off-road work sites,
- Measuring and testing equipment to carry out a variety of work activities including trouble shooting, performance testing of equipment, wood pole density testing, battery testing, relay test systems, moisture analyzers, circuit breaker testers, resistance testers, etc.,
- Tools and a wide range of other miscellaneous equipment such as PCB waste bins, portable generators, cabling trailers and equipment, satellite equipment for mobile emergency preparedness, insulator power washing equipment, Automated External Defibrillators devices, conventional line tensioning puller ropes, Maintenance shop equipments to describe a few.
- Relatively large tanker units utilized in the service of transformers including SF6 gas carts, degassifiers used to remove impurities from insulating oil, heated oil tankers, oil filters, oil farm upgrades and dry air machines.

MFA service equipment requirements will vary year to year depending on a number of factors including the overall asset condition, the number of large cost “one-time” items that occur from year to year, the size of the work program and associated staffing levels projected in the business plan, random equipment failures, unanticipated system impacts, weather severity and trends which affect the intensity and use of certain types of equipment particularly related to storm and trouble call programs.

Spending in both 2013 and 2014 is focused on the level of equipment required to accomplished the growth in the overall transmission and distribution work programs, and end of life replacement of specific large equipment such as oil tankers, degassifiers, gantry crane, transformer drying systems and air supply equipment used to overhaul and maintain large power transformers and manage the related oil requirements. Such purchases are a part of long term replacement plans to replace end of life equipment that are expected to extend to 2012 and beyond.

Results:

- Maintain equipment and tool fleets at the required levels to accomplish the growing levels of capital and OM&A sustainment, development, and operations work programs in 2013 and 2014;
- This investment will result in reduced operating costs, increased efficiency, and reliability.

Costs:

	2013 ($M)	**2014** ($M)
Capital* and Minor Fixed Assets (Networks Only)	9.3	9.8

*Includes overhead and Allowance for Funds Used During Construction at current rates

HYDRO ONE NETWORKS INC.
TRANSMISSION
Continuity of Property, Plant and Equipment
Historical (2009, 2010, 2011), Bridge (2012) & Test (2013, 2014) Years
Year Ending December 31
Total - Gross Balances
($ Millions)

Line No.	Year	Opening Balance	Additions	Retirements	Sales	Transfers In/Out	Closing Balance	Average
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
Historic								
1	2009	10,481.4	661.3	(34.3)		(27.1)	11,081.3	10,781.3
2	2010	11,081.3	843.2	(19.5)	(3.0)	26.1	11,928.1	11,504.7
3	2011	11,928.1	791.8	(27.6)	(3.6)	(1.9)	12,686.9	12,307.5
Bridge								
4	2012	12,686.9	1322.1	(34.5)		0.0	13,974.5	13,330.7
Test								
5	2013	13,974.5	945.5	(41.3)		0.0	14,878.7	14,426.6
6	2014	14,878.7	937.4	(36.5)		0.0	15,779.7	15,329.2

HYDRO ONE NETWORKS INC.
TRANSMISSION
Continuity of Property, Plant and Equipment - Accumulated Depreciation
Historical (2009, 2010, 2011), Bridge (2012) & Test (2013, 2014) Years
Year Ending December 31
($ Millions)

Line No.	Year	Opening Balance	Provision	Retirements	Sales	Transfers In/Out	Closing Balance	Average
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
Historic								
1	2009	3,861.4	246.6	(34.3)	0.0	(1.8)	4,071.9	3,966.7
2	2010	4,071.9	265.4	(19.5)	(2.6)	(4.6)	4,310.6	4,191.3
3	2011	4,310.6	282.3	(27.6)	(3.2)	0.3	4,562.4	4,436.5
Bridge								
4	2012	4,562.4	317.1	(34.5)		0.0	4,845.0	4,703.7
Test								
5	2013	4,845.0	316.9	(41.3)		0.0	5,120.5	4,982.8
6	2014	5,120.5	337.4	(36.5)		0.0	5,421.5	5,271.0

HYDRO ONE NETWORKS INC.
TRANSMISSION

Continuity of Property, Plant and Equipment - Construction Work in Progress
Historical (2009, 2010, 2011), Bridge (2012) & Test (2013, 2014) Years
Year Ending December 31
($ Millions)

Line No.	Year	Opening Balance	Capital Expenditures	Transfers To Plant	Closing Balance
		(a)	(b)	(c)	(d)
Historic					
1	2009	763.0	917.8	(664.4)	1016.4
2	2010	1016.4	936.1	(837.7)	1114.7
3	2011	1114.7	810.2	(796.9)	1128.0
Bridge					
4	2012	1128.0	961.7	(1322.1)	767.6
Test					
5	2013	767.6	1070.4	(945.5)	892.5
6	2014	892.5	1088.5	(937.4)	1043.6

HYDRO ONE NETWORKS INC.
TRANSMISSION
Statement of Working Capital
Annual Average
Test Years (2013 and 2014)
($ Millions)

Line No.	Particulars	2013 (a)	2014 (b)
1	Cash Working Capital	$ 12.7	$ 11.9
2	Materials and Supplies	3.5	3.5
3	Total	$ 16.1	$ 15.3