COST OF SERVICE SUMMARY

1.0 INTRODUCTION

This evidence presents an overview of Hydro One Transmission's Cost of Service. As summarized in Exhibit C2, Tab 1, Schedule 1, the Cost of Service includes the following elements, for which the overall costs for 2013 and 2014 are shown in Table 1 below:

- Operation, Maintenance and Administrative ("OM&A") Expenses,
- Depreciation and Amortization Expense, and
- Payments in Lieu of Corporate Income Taxes.

Table 1
Costs of Service ($ Millions)

Line no.	Description	Test Year	
		2013	**2014**
1	OM&A	453.3	459.7
2	Depreciation and Amortization	346.7	374.7
3	Income Taxes	46.4	55.2
4	**Total Cost of Service**	**846.4**	**889.6**

2.0 KEY ELEMENTS OF THE COST OF SERVICE

Hydro One Transmission's forecast cost of service has been developed consistent with corporate strategic goals to sustain a safe and reliable transmission system that economically meets customer needs and provincial policies, as noted in Exhibit A, Tab 12, Schedules 1 and 2. The Company's planning process is described in detail in Exhibit A, Tab 13, Schedule 1.

2.1 Operation, Maintenance and Administrative Expenses (OM&A)

Total OM&A expenses for the 2013 test year are $453.3 million and for 2014 are $459.7 million.

Hydro One Transmission plans and organizes its OM&A expenses on the basis of the various work programs and functions performed by the Company. These work programs primarily address improvements in infrastructure and improvements in productivity and efficiency. Exhibits in support of OM&A costs have been prepared by function, and appear within the submitted evidence as follows in Table 2:

Table 2

Particulars	2013 Total Cost ($ million)	2014 Total Cost ($ million)	Reference
Summary of OM&A Expenditures	**453.3**	**459.7**	**Exhibit C1, Tab 3, Sch 1**
Breakdown by Function:			
Sustaining	233.5	237.6	Exhibit C1, Tab 3, Sch 2
Development	13.4	14.4	Exhibit C1, Tab 3, Sch 3
Operations	64.3	66.4	Exhibit C1, Tab 3, Sch 4
Customer Care	1.3	1.4	Exhibit C1, Tab 3, Sch 5
Shared Services	69.5	67.6	Exhibit C1, Tab 4, Sch 1
Taxes other than Income Taxes	71.5	72.3	Exhibit C1, Tab 4, Sch 7

2.2 Depreciation and Amortization Expense

The depreciation and amortization expense for Hydro One's submission for 2007 and 2008 Electricity Transmission revenue requirements (EB-2006-0501) was supported by an independent study conducted by Foster Associates Inc. (Foster), completed in June, 2006. In EB-2008-0272, Hydro One submitted a 2008 Technical Update conducted by Foster completed in August 2008 that supported the 2009 and 2010 depreciation and amortization expense. No Depreciation Study or Technical Update was carried out for 2011 or 2012 rates and depreciation rates were not changed from those previously approved. The Board accepted the costs flowing from the previous Depreciation Study and Technical Updates for the purpose of supporting Transmission rates in those years. Foster Associates has completed a new Depreciation Study for Hydro One Transmission in support of its 2013 and 2014 application. The results of this study form the basis of the depreciation submission in this Application.

The Company is proposing to recover $346.7 million in depreciation and amortization expense in 2013 and $374.7 million in 2014. Hydro One Transmission's evidence regarding the depreciation study and its impact on depreciation expense is filed at Exhibit C1, Tab 8, Schedule 1.

2.3 Payments in Lieu of Corporate Income Taxes

As a result of *the Electricity Act, 1998*, Hydro One Transmission has been required to pay proxy taxes since 1999. Evidence outlining the calculation of Payments in Lieu of Income Taxes of $46.4 million for 2013 and $55.2 million for 2014 appears at Exhibit C2, Tab 5, Schedule 1, Attachment 1.

3.0 KEY COMPONENTS IN THE BUILD-UP OF COST OF SERVICE

Key components in the build-up of Cost of Service are:

- resourcing,
- costing of work,
- out-sourced functions, and
- corporate cost allocation.

Each of these components is discussed below.

3.1 Resourcing

Labour costs are charged to OM&A and Capital work programs. The evidence contained at Exhibit C1, Tab 5 presents total staff levels and costs incurred by the Company, as follows:

• Corporate Staffing	Exhibit C1, Tab 5, Schedule 1
• Compensation, Wages, Benefits	Exhibit C1, Tab 5, Schedule 2

3.2 Costing of Work

OM&A and Capital work programs are comprised primarily of costs relating to labour, materials and equipment. Exhibit C1, Tab 6, Schedule 1 provides a schedule that explains how costs flow to work programs. Throughout its operations, Hydro One Transmission has been successful in containing costs and employing productivity measures wherever possible. The Company's achievements in this area are presented in the following exhibits:

• Work Execution Strategy	Exhibit A, Tab 15, Schedule 6
• Cost Efficiencies	Exhibit A, Tab 17, Schedule 1
• Productivity Metrics	Exhibit A, Tab 17, Schedule 2
• Costing of Work	Exhibit C1, Tab 6, Schedule 1

3.3 Outsourcing

As a strategy to reduce costs, improve efficiency and to improve focus on its primary operations, Hydro One has entered into an agreement with Inergi LP to receive a range of services in the following areas:

- information technology,
- customer care,
- settlements,
- supply management,
- payroll and
- finance.

3.4 Corporate Cost Allocation

Hydro One Networks Inc. provides common services to its Transmission and Distribution businesses and to other Hydro One subsidiaries on a centralized basis, as this serves as the most economic approach. The costs of these services and assets are assigned to business units on the basis of cost causation. These costs and assets are directly assigned where it is possible to do so. All other costs and assets are allocated based on cost drivers, direct benefits or other methods as appropriate. Exhibit C1, Tab 7 describes these allocation methods, as well as the derivation of the overhead capitalization rate, which determines the assignment of overhead costs to capital expenditures.

In 2010, the Company commissioned a study by Black and Veatch (B&V) to update the methodology to allocate common costs among the business entities, the results of which were accepted in the Board's EB-2010-0002 Decision with Reasons, dated December 23, 2010. The methodology developed represents the industry's best practices, identifying appropriate cost drivers to reflect cost causality and benefits received.

In 2012, B&V conducted a further review of the common costs allocation methodology that is used in this current filing. The report on this study is provided as Attachment 1 to Exhibit C1, Tab 7, Schedule 1.

SUSTAINING INVESTMENT STRUCTURE

1.0 INTRODUCTION

This exhibit provides an overview of the Sustaining investment structure and the different types of work completed under Sustaining OM&A and Sustaining Capital, as well as outlining the linkages between various transmission assets and their related Capital and OM&A expenditures.

Exhibit C1, Tab 2, Schedule 2 presents portfolio views for key transmission assets including an overview of the strategy used to manage the asset; a combined capital and OM&A perspective of spend; and, two scenario forecasts of fleet demographics in 5 and 10 years based on test-year versus recent historic replacement rates. A strategic-level risk assessment against Hydro One's business values is also provided. The information beyond the test years is not provided for OEB approval purposes, but instead to provide the context for and outline the longer-term impacts of sustaining investment on the in-service fleet of assets.

Information focused on the requested test year Sustaining Capital and OM&A expenditures is provided in Exhibit D1, Tab 3, Schedule 2 and Exhibit C1, Tab 3, Schedule 2 respectively.

2.0 SUSTAINING INVESTMENT STRUCTURE

Sustainment programming for OM&A and Capital involves decision making that determines the appropriate level of investment to meet Hydro One's objectives including OEB requirements. While the specifics of the kinds of work differ amongst the assets involved, it is possible to identify broad categories of work that apply to Sustaining activities.

Sustaining OM&A Work

The following are the categories of Sustaining OM&A work that are typically defined and executed at Hydro One:

Preventive Maintenance: includes preventive maintenance that is time based (cyclical) and condition based. Maintenance activies include:

- Activities conducted to meet Hydro One's obligations defined by the Transmission System Code to "inspect, test and monitor its transmission facilities to ensure continued compliance with all applicable standards and instruments".
- Planned Maintenance for Protection & Control (P&C) is also defined to meet the stringent requirements as specified by the Transmission System Code to conduct "routine verification [that] shall ensure with reasonable certainty that the protection systems respond correctly to fault conditions." Planned Maintenance ensures that Hydro One's assets are functioning properly by completing systematic inspection, detection, and correction of defects before failure or before they develop into major problems that will be more costly to correct later or become safety issues.

Mid-Life Overhaul/Refurbishment: is conducted to upgrade or replace worn subcomponents of specific power system equipment. The primary goal of this type of maintenance is to achieve the design life of the equipment, by mitigating risks (e.g. insulating oil leaks) before they pose a significant risk to asset condition and reliability. Major maintenance of this type must be both technically and economically feasible before being executed. Mid-life overhaul is primarily carried out on station assets such as transformers and breakers.

Corrective Maintenance: includes planned corrective maintenance as well as demand response to emergency situations. This type of maintenance results from unforeseen problems and/or equipment failure. Corrective maintenance is required to address the risk of harm and/or damage to any or all of employee safety, public safety, system reliability or environment.

Sustaining Capital Work

The following are the categories of Sustaining Capital work that are executed:

Planned Replacement: Hydro One mitigates system risk by replacing assets with a likelihood of failure and where the failure of the asset would cause unacceptable negative consequences. Replacement is chosen for assets when there is no technically or economically feasible maintenance option such as increased planned maintenance, refurbishment of the asset, or a system reconfiguration option that may eliminate the need for the asset in question.

Demand Driven Capital Replacement: In certain program areas, Hydro One maintains capital funding in reserve to fund unforeseen equipment failures. Forecasts for the funding are set to historical spending levels unless trending or specific situations would indicate that a change is warranted.

Purchase of Operating Spares: Hydro One maintains a pool of spare equipment to be able to respond to equipment failures. Spares are purchased to support a group of assets giving consideration to the optimal level of spares for specific assets. Coverage is determined through statistical methods based on the historical failure rate of the assets, the procurement time of the asset and the time to install the asset. The final number of spares purchased is adjusted by considering the actual condition of the assets to account for any expected change in the rate of failure.

3.0 SUSTAINING CAPITAL AND OM&A PROGRAM ASSET LINKAGES

Power System assets are divided amongst three asset categories:

- Stations,
- Protection & Control (P&C), Telecom and Metering,
- Lines.

It should be noted that in Exhibit C1, Tab 3, Schedule 2 and Exhibit D1, Tab 3, Schedule 2, P&C telecom and metering are presented as a subset of Stations, as the majority of these facilities are located within transmission stations.

The OM&A and Capital programs are linked by specific assets. The dominant linkages amongst the assets and their related Capital and OM&A programs are shown in the following tables.

Table 1
Stations Capital and OM&A Asset Linkages

Capital Category	OM&A Category	Assets
Station Environment	• Land Assessment and Remediation (LAR) • Environmental Management	• Station Properties as related to LAR • Oil Containment Systems • Transformer Gasket Systems
Circuit Breakers	Power Equipment Maintenance	• Oil Circuit Breakers • SF6 Circuit Breakers • Metalclad Breakers • Vacuum Breakers
Station Re-investment		Integrated station investments, focus on • Air Blast Circuit Breakers • Metalclad Switchgear • Gas Insulated Switchgear • Transformers
Power Transformers		• Transformers
Other Power Equipment		• Disconnect Switches • High Voltage Instrument Transformers • Station Insulators & Bus • Station Cables and Potheads • Capacitor Banks • Station Surge Protection
Ancillary Systems	Ancillary Systems Maintenance	• High Pressure Air Systems • Batteries and Chargers • Station Grounding Systems • AC/DC Service Equipment • Oil and Fuel Handling Systems
Transmission Site Facilities and Infrastructure	Site Infrastructure Maintenance	• Station Properties • Station Buildings • Fences • Drainage and Geotechnical • Fire and Security Systems • Heating, Ventilation and Air Condition

Table 2
P&C, Telecom and Metering Capital and OM&A Asset Linkages

Capital Category	**OM&A Category**	**Asset**
Protection, Control and Metering	Protection, Control, Monitoring and Metering Equipment Maintenance	• Protection & Control and System Monitoring • Revenue Metering
NERC Cyber Security	Cyber Security	All NERC and NPCC regulated Critical Cyber Assets and vulnerabilities
Auxiliary Telecommunication Equipment	Telecommunications	• Power Line System • Microwave Radio Systems • Fibre Optic Cables • Metallic Cable • Site Entrance Protection Systems • Teleprotection Tone Equipment

Table 3
Lines Capital and OM&A Asset Linkages

Capital Category	**OM&A Category**	**Asset**
N/A	Vegetation Management	Rights-of-Way
Overhead Lines Refurbishment and Component Replacement Transmission Lines Re-investment	Overhead Lines Programs	• Phase Conductor • Wood Pole Structures • Line Steel Structures • Shieldwire and Hardware • Line Insulators and Hardware
Underground Lines Cables Refurbishment and Replacement	Underground Cable Programs	• Underground Cables and Potheads • Oil Pressurization Facilities

TRANSMISSION ASSETS AND SUSTAINING INVESTMENT OVERVIEW

1.0 INTRODUCTION

This exhibit provides asset-centric information to support the test-year Sustaining OM&A and Capital expenditures submitted in Exhibit C1, Tab 3, Schedule 2 and Exhibit D1, Tab 3, Schedule 2 respectively. Relationships between the various asset types and programs are summarized in Exhibit C1, Tab 2, Schedule 1 Sustainment Investment Structure.

Information within this exhibit provides a summarized view of the key transmission assets and outlines demographic, performance, and condition information at an asset level. Historic, bridge, and proposed test year expenditures are provided and provide future demographic outlooks. Asset-centric risk commentary is also presented.

Appendix A of this exhibit provides a detailed description of the transmission assets that are managed by Hydro One.

2.0 SUSTAINING OVERVIEW

Sustaining transmission assets is essential to the long term viability and performance of the transmission system. This is reinforced by the Transmission System Code that requires Hydro One to “inspect, test and monitor its transmission facilities to ensure continued compliance with all applicable standards and instruments”. Over the long term, an adequately maintained transmission system that performs to a level of its original design is in the best interest of Hydro One and its customers.

Hydro One Transmission’s assets are reaching the end of their expected service life at a rate that exceeds the historic rate of replacement. In order to maintain the historic level of risk, there will be cost pressures on future capital and maintenance. In addition, the transmission system is in a continuing period of expansion that will present a need for increased maintenance expenditures as the asset base increases. The programs proposed to sustain the assets address current asset needs, and consider the trends we are seeing with demographics, condition and reliability and the associated risk. It must be recognized that any reductions applied to the test years spending will have a compounding effect on system risks and cost pressures now and in the future.

The proposed test year Sustaining investment plan is directionally focused on maintaining equipment reliability and overall system reliability, through increasing Sustaining Capital expenditures, while containing the test year Sustaining OM&A expenditures slightly below the historic average (when adjusted into 2012 dollars).

Sustaining programs strive to continuously innovate through adopting new technologies and approaches. Value will be derived by using innovative analytic tools and technologies. Efficient data collection and manipulation improves the effectiveness and consistency in our investment plans. Value is also achieved through optimizing life cycle investment plans – i.e. use of technologies with attractive maintenance expectations, new technologies for testing and analysis of equipment and the system, and targeting the right balance of capital and OM&A expenditures. In determining the appropriate maintenance strategies consideration is given to various approaches such as condition-based maintenance and time-based maintenance. Benchmarking against other utilities helps ensure that activities are in line with industry standards and practices.

A longer term asset centric view is presented for key transmission assets summarizing the current and future states of demographics, reliability and fleet condition. These three dimensions together provide information to support the increasing test year Sustaining Capital investment plan outlined in Exhibit D1, Tab 3, Schedule 2. Continued growth in the fleet replacement rates for key assets is imperative to manage the long-term reliability and lifecycle cost of the transmission fleet to the benefit of the ratepayer. Reducing Sustaining Capital funding will require increased Sustaining OM&A funding to maintain assets that are at the end of their lives and should be replaced.

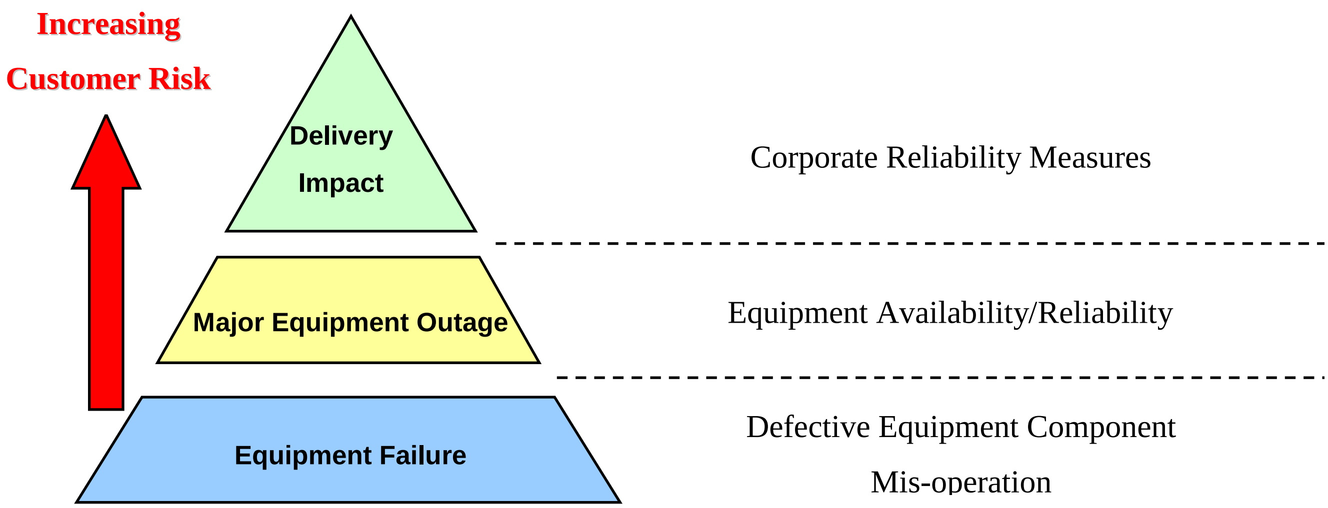
3.0 RELIABILITY OVERVIEW

Throughout the Sustaining exhibits, references are made to asset reliability and to system / delivery reliability. It is important to understand the difference between these two dimensions, as they are related, but need to be analysed separately to have a clear picture of trends and developing risk. They are a lower level of detail than discussed in Exhibit A, Tab 13, Schedule 1.

As a consequence of the redundancy often found in the transmission system, it's not unusual for an equipment defect or failure to have only a momentary impact on the power system, or in some cases no noticeable impact to end-use customers at all. For example, Hydro One typically has redundant transformers at load delivery stations, so that power can continue to be supplied to downstream customers during routine maintenance or in the event of a failure. In the event of a power system fault, depending on fault location and how the protections operate to clear the faulted zone, there may be no delivery interruption at all, or a very short interruption (fractions of a second to a few seconds), or the delivery points could be lost for an extended period of time (minutes to hours). These delivery point interruptions are tracked at the corporate level, benchmarked with peers, and make up the information presented in Exhibit A, Tab 13, Schedule 1.

Hydro One analyses equipment condition and defects as a leading indicator to major equipment performance (i.e. transformers, breakers, protections, circuits). As trends in major equipment performance begin to shift, there will be a lagging effect on broader system reliability. In managing the power system, specifically Sustainment investments, it is imperative to understand the leading-lagging spectrum of equipment condition, to major equipment performance, to system or delivery performance. By the time delivery impact begins to degrade, there would be significant underlying performance issues with major equipment that would take significant time and money to rebound from. Figure 1 represents the increasing impact to Customers as equipment defects evolve to major equipment outages that can impact delivery performance.

Figure 1
System Impact Hierarchy Model

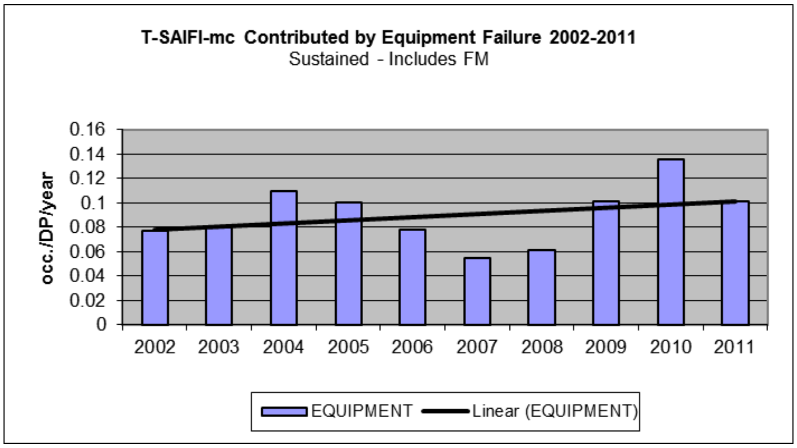


Throughout the Sustaining exhibits, references are made to the impact of a particular asset to system reliability. This is most often expressed in terms of the frequency and duration of power interruptions, T-SAIFI and T-SAIDI respectively. Figures 2 and 3 demonstrate the relative contribution between various assets to the system-wide delivery measures. Note that Lines assets that impact delivery performance typically assessed against the entire system (radial single-point supplies and reinforced multi-circuit supplies), whereas Stations assets are expressed in terms of the multi-circuit delivery performance. Multi-circuit information is suffixed with an "-mc" for clarity (i.e. T-SAIFI-mc).

Figures 2 and 3 show the increasing trend of power interruptions caused by equipment failure for delivery points both single supply and multi-circuit delivery points.

Figure 2
Multi-Circuit Delivery Point Interruptions and Stations Equipment Impact

- Over the past ten years, 69% of interruptions for delivery points fed by multiple-circuits have originated at stations
- There is an increasing trend on delivery point interruptions due to equipment failure



- Sustaining work programs are largely focused on replacing the station assets with the greatest contribution to overal system reliability

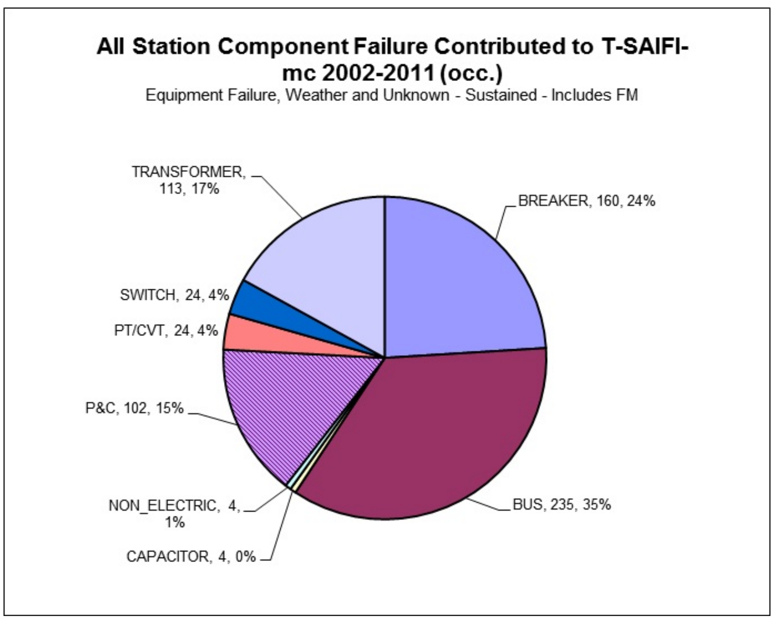
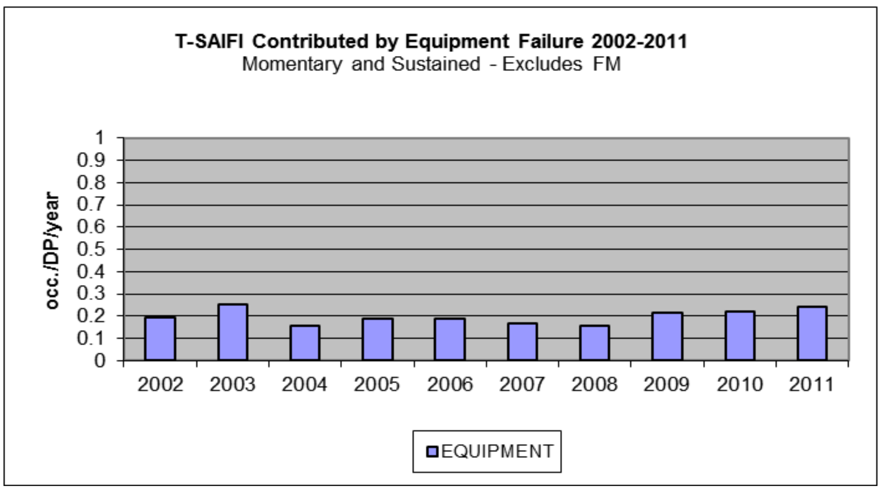
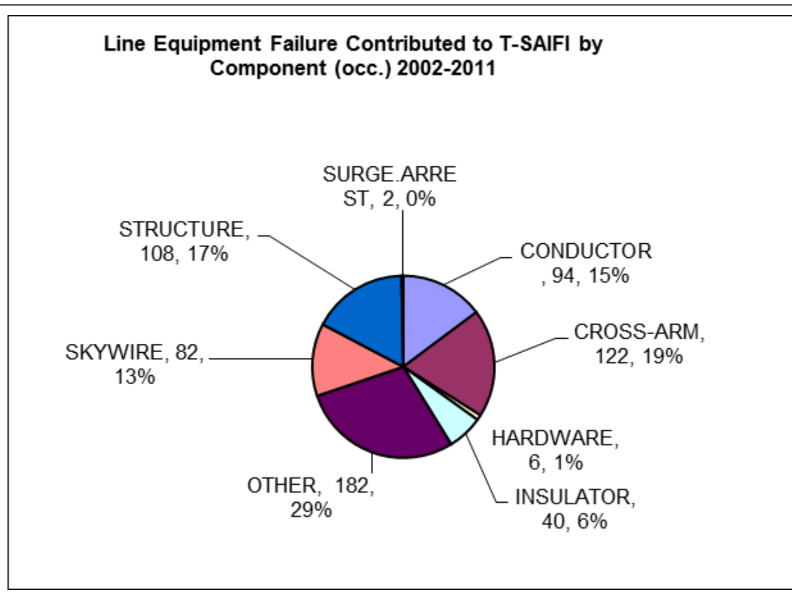


Figure 3

All System Delivery Point Interruptions and Lines Equipment Impact

- Over the past ten years, 73% of interruptions for delivery points fed by single-circuits have originated on the transmission line itself. Following interruptions due to weather, Lines equipment failure is the second leading cause for delivery point interruptions
- There has been a gradual increase over the past 5 years in the trend of Lines equipment failure contributing to system reliability, although the 10-year trend has been stable





- Sustaining work programs are focused on replacing or refurbishing Lines equipment with the greatest impact on system reliability.

4.0 ASSET PORTFOLIO INFORMATION

Key information is presented below within this exhibit for the transmission assets with the most impactive expenditures in the test years. These portfolio views provide a combined capital and OM&A perspective, an overview of the strategy used to manage the asset, and forecasts of fleet demographics in 5 and 10 years based on planned replacement rates.

Please note that expenditures in the portfolio At A Glance view are expressed in current year dollars. For completeness, total Capital and OM&A expenditures have also been included dollars adjusted to 2012, with 2012$ indicated in parenthesis.

4.1 Circuit Breakers

- Over the last 10 years the rate of Sustaining breaker replacements has increased from about 10 breakers per year to as high as 100 breakers per year.
- The increase in replacement rate has been successful in maintaining the reliability of the circuit breaker population. However, circuit breakers continue to be one of the leading causes of delivery point interruptions.
- While the gap between Hydro One's performance and the CEA 5-year average is tightening, Hydro One breaker performance still lags the CEA average.
- Given the demographics of the breaker population, the condition trend and the inability to support some older vintages of breakers, increased capital funding is required to maintain the current level of risk.

Asset Strategy

Continue to increase replacement rates to manage the aging circuit breaker fleet to minimize rate impacts and maintain reliability. Continue to optimize OM&A expenditures conducting regular inspections and diagnostic testing, with an increasing shift towards condition-based maintenance. Largely focus the Capital work programs on replacing air-blast circuit breakers at critical stations with the worst reliability and highest life-cycle maintenance costs, along with obsolete metalclad switchgear with safety concerns, installed in stations feeding urban LDCs.

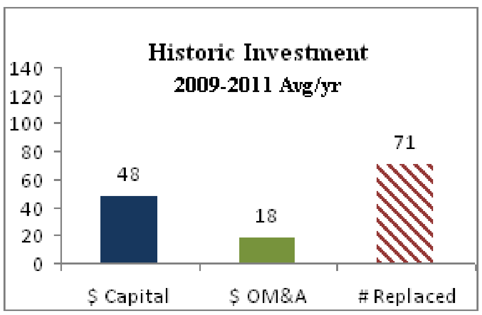
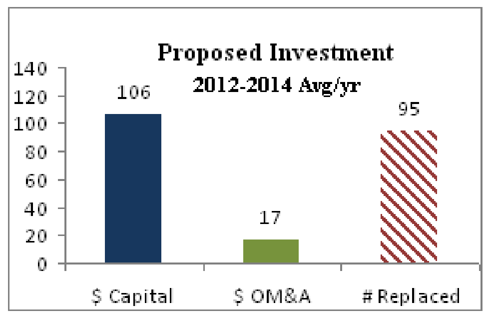
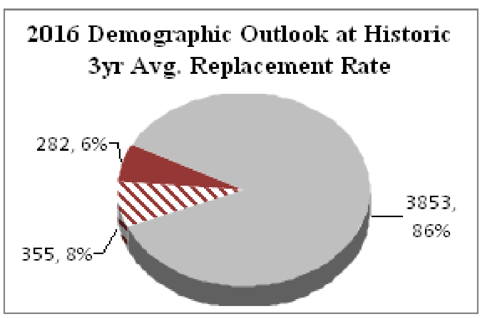
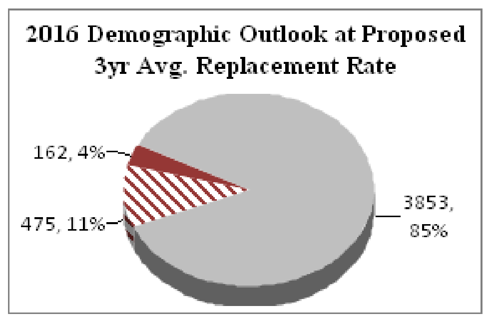
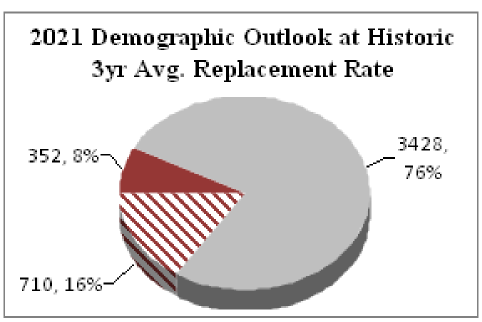
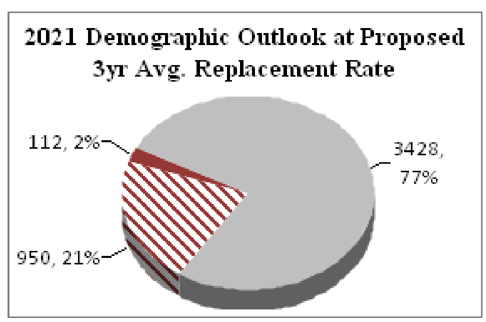
Demographics

- 8% of the breaker fleet is currently beyond expected service life.
- If the replacement rate is not increased, this will change to 6% by 2016 and 8% by 2021 and 4% by 2016 and 2% by 2021 at the proposed test year replacement rate.

Cost Trends and Impacts

- OM&A programs are reducing and the following factors are contributing to this: focus on replacement of the worse performing breakers with high corrective maintenance costs, new technology breakers with lower maintenance costs are starting to be impactive to overall maintenance costs, as are the cost impacts of condition based maintenance.
- Test-year capital expenditure increasing by 120% from recent historic and bridge years
    - Average 3-year historic replacement rate has been roughly 1.6% of the fleet per year.
    - Proposed test-year replacement rate is roughly 2.5% of the fleet per year.
    - Due to cost, reliability trends and obsolescence, a greater number of higher-cost air-blast breakers are being replaced in future years than the historic mix of breaker types

Circuit Breakers At a Glance

	Current State, 3yr Average Historic Investment		Proposed Investment, 3yr Bridge & Test Years Future Investment	
Average CapEx ($M/yr)	48	51 (2102$)	106	103 (2012$)
Average OM&A ($M/yr)	18	20 (2012$)	17	17 (2012$)
Average Replacement (#/yr)	71		95	
Average % Fleet Replaced (%/yr)	1.6%		2.1%	
Investment Levels ($M, # Units)				
Five Year Outlook (# Units)				
Ten Year Outlook (# Units)				
Legend	Beyond Expected Service Life	Replaced	Within Expected Service Life	

Business Value / Objective Commentary

	Impact to Values / Objectives
Safety	Replacement of early vintage metalclad switchgear with modern arc-proof switchgear results in significant safety benefits for staff. Over the past several years, more stringent maintenance of the air-blast circuit breaker (ABCB) population has been effective, but historically there have been explosive failures of the breakers and their associated CTs due to poor condition.
Reliability	Continued replacement of ABCBs with new SF6 breakers will improve reliability of 230kV and 500kV breaker fleet. New SF6 breakers are 5 times more reliable than ABCBs. Increased replacement of worst performing oil and first generation SF6 breakers should see fleet equipment reliability remain stable, despite compounding demographic pressures. Failure to address problematic breakers will see degradation in delivery performance, as breaker defects are a leading cause of delivery point interruptions.
Customer	The Manby event in 2010 is a demonstration of the significant impact that a catastrophic breaker failure can have on Customers, as 1250MW was lost, a significant portion for several hours. Several breaker replacements in the test years are at key generating stations and aim to maintain a reliable generation path. Metalclad replacements in urban areas will maintain delivery reliability to LDCs and their customers.
Innovation	Advancement of diagnostic and analytic tools is helping execute more condition-based maintenance. Installation of medium voltage GIS as part of future investments will improve productivity, result in lower life-cycle costs, and improve reliability
Environment	Replacement of first generation SF6 breakers and problematic GIS duct with known high leak rates, coupled with the timely diagnosis and repair of breakers not planned for replacement helps reduce Hydro One’s GHG emissions.
Cost Effectiveness	Further optimization within the OM&A programs and a continued increase in Sustaining capital replacements helps contain the total cost of managing the aging fleet. Some new technologies have significantly lower operating costs for affected asset types (i.e new SF6 vs. ABCBs). Bundling of maintenance activities allows the work to be executed in the most efficient manner – improved tools and practices are making this possible.

Asset Assessment Details

Demographics

Hydro One uses a normal expected service life of 40 years for most circuit breakers based on manufacturer's life expectancy for circuit breakers and industry standards. The exception is the oil circuit breaker population, where the expected life is 55 years. The average age of the circuit breaker fleet is currently 27 years of age and 8% of the in-service breakers are currently beyond their expected service life. The potential risks to reliability and safety as a result of this long-term demographic pressure needs to be managed through continued Sustaining capital programs.

The following table shows the demographics of the circuit breaker fleet by breaker type.

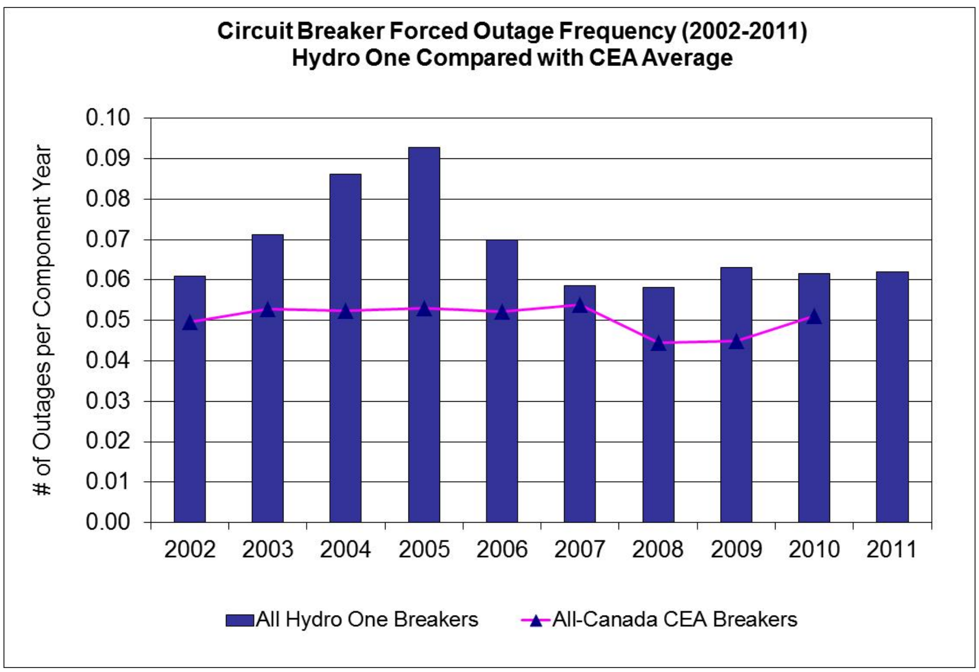
		Breaker Type							
		Air Blast	Oil	SF6	Metalclad	Vacuum	GIS	**Total**	**%**
Age Group (years)	0-10	0	20	614	216	15	22	**887**	**19.8%**
	11-20	0	348	377	156	11	10	**902**	**20.1%**
	21-30	13	93	364	265	10	14	**759**	**16.9%**
	31-40	89	664	15	133	0	53	**954**	**21.2%**
	41-50	88	609	5	76	0	0	**778**	**17.3%**
	> 50	0	189	1	20	0	0	**210**	**4.7%**
	Total	**190**	**1923**	**1376**	**866**	**36**	**99**	**4490**	**100.0%**
	%	**4.2%**	**42.8%**	**30.6%**	**19.3%**	**0.8%**	**2.2%**	**100.0%**	

- Half of the air-blast breakers are beyond the expected life, typically installed at system-critical network stations
- OCBs make up a large portion of the aged inventory and will require increased replacement rates in the future. Near-term expenditures are focused on a surgical replacement of the worst performing units and/or models which are technically obsolete
- A significant portion of the metalclad breakers are operating well beyond their expected life. Legacy designs come with inherent safety risks that require mitigation.

<u>Performance</u>

Increased capital expenditure in recent years has been able to keep Hydro One's equipment reliability generally stable with over the past five years when assessing the total population level of 4,490 circuit breakers. As shown in Figure 4, Hydro One is approximately 20% worse than the CEA average for all circuit breakers at all voltage levels.

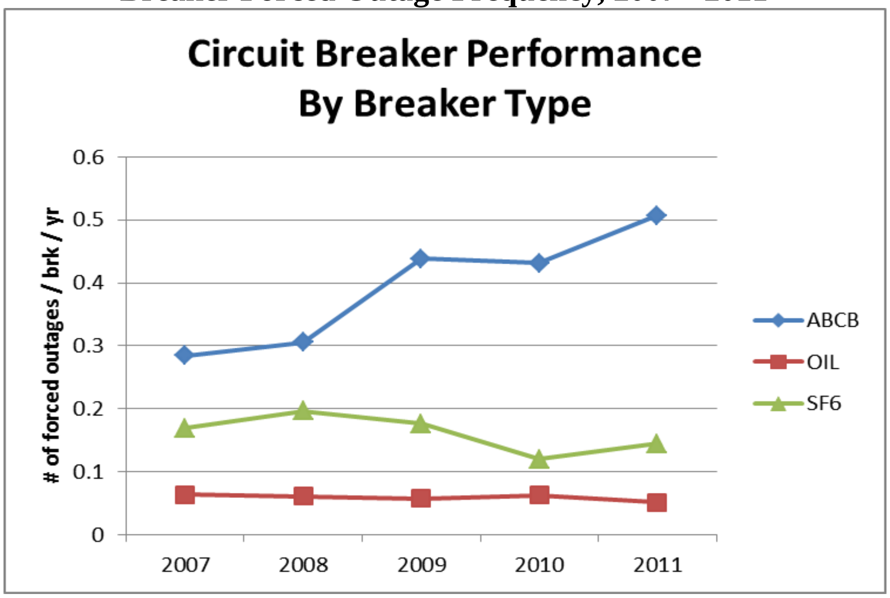
Figure 4
Hydro One Circuit Breaker Performance, All Voltages, vs. CEA Benchmark



When performance is analyzed by voltage level however, Hydro One more substantially underperforms at the 500kV, 230kV, and 115kv system levels at 141%, 154% and 139% of the CEA benchmark respectively in terms of the frequency of forced outages. Performance at sub transmission voltage levels (44kV and below) is significantly better than the CEA forced outage frequency benchmark at 58%. Because of the large number of circuit breakers at or below 44kV, the overall population statistics can be masked by the more numerous, but arguably less important from the bulk power system perspective, lower voltage breakers.

More meaningful to Sustainment planning is consideration to the performance of different interrupting mediums and breaker technologies deployed over the past 50+ years. Breaker reliability by breaker type is presented in Figure 5.

Figure 5
Breaker Forced Outage Frequency, 2007 - 2011



	# forced outages	% of outages	# Installed TODS Breakers	% of installed TODS fleet	Forced outages per breaker per year 5-year average	Trend
AIR BLAST	410	27 %	193	7 %	0.39	**Degrading**
OIL	337	22 %	1102	40 %	0.06	Stable
SF6	634	41 %	899	33 %	0.16	**Improving**
VACUUM	15	1 %	15	0.6%	0.18	Stable
GIS	86	6 %	99	4 %	0.19	Stable
METALCLAD	62	4 %	418	15 %	0.03	Stable

Air blast circuit breakers (ABCBs) are perennially the least reliable breakers across all voltage levels on the transmission system, and the account for a disproportionate number of the forced outages given their relatively small installed base. Their performance trend is degrading significantly despite a focus to improved maintenance and operating practices over the past several years. By 2011, ABCBs on average had a forced outage rate had degraded to approximately 0.5 occurrences per breaker per year. This is analogous to expecting the average air blast breaker to be forced out of service once every 2 years. When ABCBs are replaced, modern high voltage SF6 breakers are used. New high voltage SF6 breakers are achieving forced outage performance of approximately 0.1 occurrences per breaker per year. This is analogous to expecting an SF6 breaker to be forced out once every 10 years. This is a five-fold improvement in the number of forced outage events.

In addition to improved reliability, SF6 breakers are significantly lower cost to operate than ABCBs. Because of the complexity of ABCBs and their dependence on auxiliary systems (high pressure air, additional instrument transformers, etc.), annual historic costs of approximately $30,000 per breaker have been incurred. Comparing with Hydro One's years of experience using newer high voltage SF6 breakers built on today's technology, annual average maintenance costs are approximately $3,000 per breaker. Replacing ABCBs with modern SF6 breakers results in a 90% savings for ongoing maintenance expenditures.

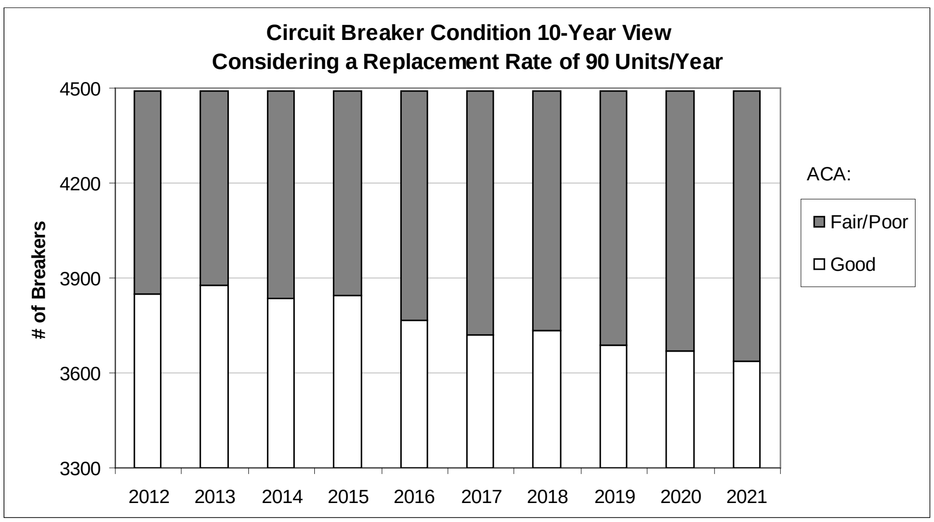
Because of the degrading reliability of ABCBs, their high maintenance costs, and the fact that ABCBs are typically installed at some of the most critical bulk electrical system stations (key network interface stations and transmission switchyards at major generating stations), Hydro One's proposed circuit breaker capital expenditures are greatly focused on replacing ABCBs.

Circuit breaker forced outages are one of the leading causes to customer delivery point interruptions, and represent 26% of the equipment-caused events impacting delivery point interruptions with multiple supplies. In addition to the high voltage ABCB replacements, Sustaining capital investments in the test years are focused on replacing breakers that are at the highest risk of causing delivery point interruptions.

Condition

Without a further increase in replacement rates, the condition of the circuit breaker fleet is expected to degrade over the next 10 years due to the number of breakers exceeding their expected service lives. A 10-year forecast in Figure 6 shows that even with continuing at approximately the proposed replacement rate, the number of breakers in fair/poor condition will double from today. This is a leading indicator for equipment reliability. As such, prioritization of units for replacement will be critical and further increases in the program are expected beyond the test years.

Figure 6
Circuit Breaker Fleet Condition Forecast



Other Influencing Factors

As circuit breaker design has evolved over the past 50+ years, so have safety standards and the requirement for safer work methods to protect utility workers. Early generation metalclad switchgear is most notable for having significant arc flash and electrical burn hazards in the event of equipment failure. These risks become more significant as the equipment ages. Hydro One's metalclad replacements are focused on improving safety by replacing aged metalclad switchgear with improved while at the same time maintaining reliability for the typically urban centers the switchgear supports.

Technical obsolescence is a significant factor for air blast breakers, some first generation SF6 breakers, and certain types of metalclad and oil breakers. Many breakers are no longer supported by vendors and aftermarket parts are not available and/or cost effective.

Breakers that have exceeded their expected service life in terms of number of operations are considered for replacement. Because of their frequent operation, this is most typical of capacitor and reactor breaker positions.

Historic and Future Investment

For many years, the replacement rate was less than 1% of the fleet and as the installed base has aged, the demographic pressures have continued to grow. Replacements in the recent years have moved closer to 2% of fleet. Despite the increased investment, 7% of the breakers are currently beyond their expected service life. Even with continued test-year replacement rates, within 10 years, more than 30% of the breakers will be beyond their expected service life. Exhibit D1, Tab 3, Schedule 2 outlines the proposed test-year Sustaining Capital investments to manage the circuit breaker population.

Circuit Breaker Portfolio	**Historic**					**Bridge**	**Test**	
	2007	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**
# of Sustaining replacements*	31	49	33	81	100	57	104	124
% of Fleet	0.7%	1.1%	0.7%	1.8%	2.2%	1.3%	2.3%	2.8%
Capital ($M)	42.6**	75.1**	48.7**	40.4	55.8	77.2	129.3	111.2
OM&A ($M)	19.5	19.8	19.6	16.4	19.3	16.8	18.1	17.3

* Test-year expenditures are a combination of Circuit Breaker capital and System reinvestment expenditures detailed in Sustaining Capital Exhibit D1, Schedule 3, Tab 2.
** Significant expenditures in 2007, 2008, and 2009 for the Claireville 230kV GIS breaker replacements and reconfiguration ($34 million, $50 million, and $20 million respectively).

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4.2 Transformers

- The rate of transformer replacement over the last 10 years varied, averaging 8/year.
- Currently 21% of the population is beyond their expected service life of 50 years. At the 3-year historic rate of replacement, this will increase to 26% by 2016 and to 30% by 2021
- Condition is a leading indicator for equipment and system reliability. The condition of the transformer fleet, determined through industry standard diagnostic testing (DGA, furans, standard oil tests, etc.) is degrading faster than the replacement rate.
- The forced outage frequency of transformers is relatively stable. However, transformers continue to be one of the leading causes of delivery point interruptions.
- While the gap between Hydro One's performance and the CEA 5-year average is tightening, Hydro One transformers lag the all-Canada CEA average.
- Transformers failures can have a significant impact to local and system reliability, affect LDC and industrial customers, and impact the environment in the event of oil spills. Transformer replacement under failure conditions can take several months to complete, during which Customers are at higher risk for load loss, effectively being on single supply.
- Major failures have been generally stable over the past 5 years, but 2011 saw the highest number in 15 years. Continued replacements are required to contain the future failure rate.
- Regulatory requirements related to oil leaks, noise levels and PCB's in equipment also contribute to the need to replace some of the transformer fleet.
- Given the demographics of the transformer population, the condition trend and the risks associated with transformer failures, increased capital funding is required to maintain an acceptable level of risk.

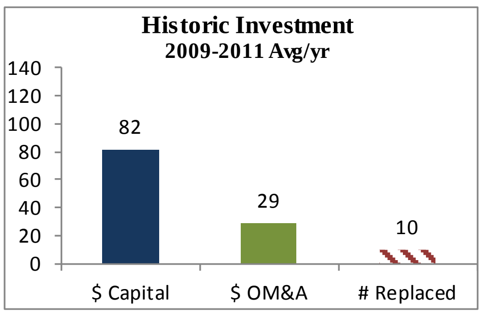
<u>Asset Strategy</u>

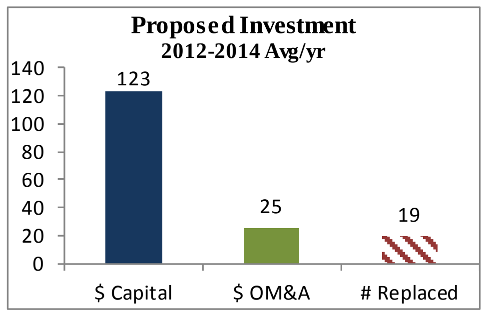
Manage the aging transformer fleet to minimize rate impacts and preserve reliability. Reduce OM&A expenditures, with an increasing shift towards condition-based maintenance and narrowing expenditure for refurbishments in 2012. Increase capital replacement rate to manage pressures of compounding demographics and degrading fleet condition.

Transformers At a Glance

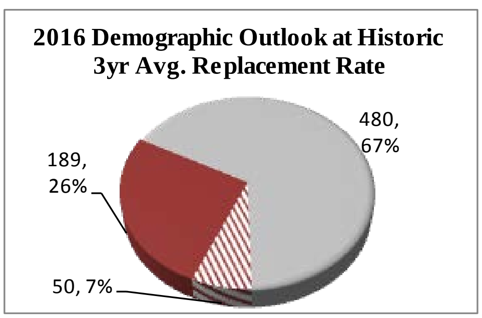
	Current State, 3yr Average Historic Investment		Proposed Investment, 3yr Bridge & Test Years Future Investment	
Average CapEx ($M/yr)	82	83 (2012$)	123	118 (2012$)
Average OM&A ($M/yr)	29	30 (2012$)	25	24 (2012$)
Average Replacement (#/yr)	10		19	
Average % Fleet Replaced (%/yr)	1.4%		2.6%	

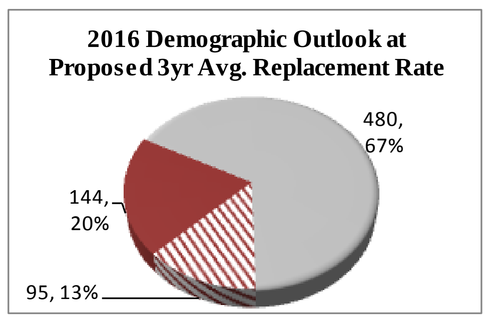
Investment Levels ($M, # Units)



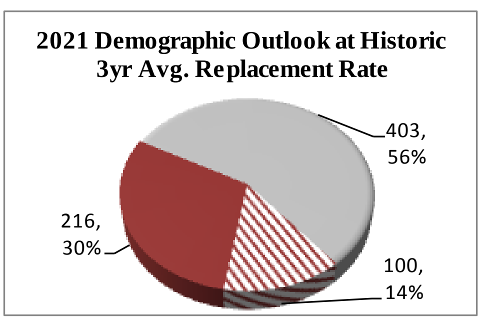


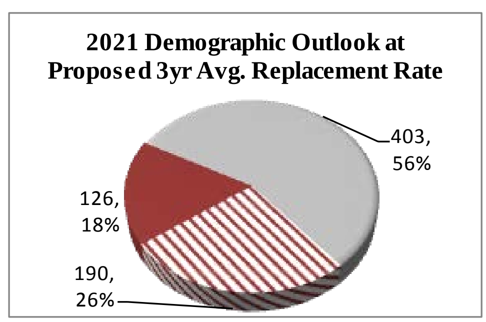
Five Year Outlook (# Units)





Ten Year Outlook (# Units)





Legend: Beyond Expected Service Life | Replaced | Within Expected Service Life

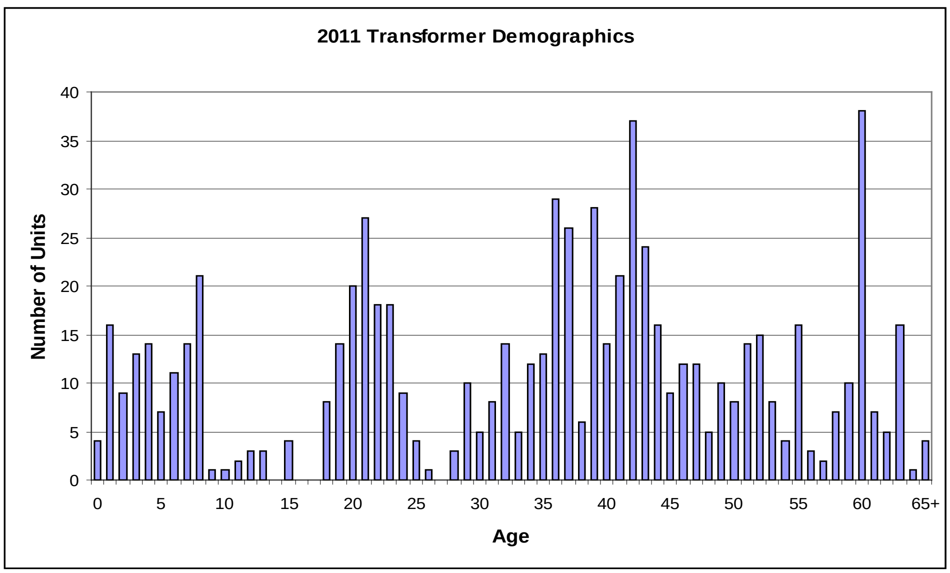
<u>Business Value / Objective Commentary</u>

	Impact to Values / Objectives
Safety	Replacement of transformers in poor condition helps mitigate risks of tank rupture, spills, and fire. Continued renewal of the 500kV three-phase autotransformer fleet reduces safety risk exposure as transformers are specified with tanks specifically designed not to rupture.
Reliability	An increasing replacement rate of aged transformers in poor condition will preserve reliability of the transformer fleet and maintain major failure rates in-line with historic levels. Adoption of improved vacuum ULTCs technology reduces the number of forced outages over technology from previous eras. ULTC maintenance can be significantly extended with vacuum technology. Failure to increase replacement rates will see degradation in equipment and delivery performance, as transformers are a significant cause of delivery point interruptions.
Customer	The Richview transformer failure in 2011 is a demonstration of the significant impact that a catastrophic failure can have on Customers. It resulted in 30MW of load loss for up to two hours, and highway 401 being shut down for over an hour during Toronto rush hour due to smoke from the ensuing transformer fire. Transformer replacements in the test years are planned to reduce the risks associated with these types of events that impact delivery reliability to LDCs and their Customers.
Innovation	Advancement of diagnostic and analytic tools is helping execute more condition-based maintenance and provide improved data for making replacement decisions. Improved work-bundling tools and practices allow maintenance to be packaged more effectively than previously possible.
Environment	Replacement of transformers with known leaks will result in a cost-effective solution that supports Hydro One’s commitment to environmental stewardship. As the regulated end-of-use date of 2025 for oil containing PCBs greater than 50ppm approaches, transformer replacements will be targeted to maintain environmental compliance.
Cost Effectiveness	Reduction in OM&A programs and a continued increase in Sustaining capital replacements helps contain the revenue requirement of managing the aging fleet. Some new technologies have lower operating costs than what they are replacing (i.e modern vacuum ULTCs vs. problematic 1970’s vintage oil-filled tank-mounted ULTCs). Bundling of maintenance activities allows the work to be executed in the most efficient manner – improved tools and practices are making this possible.

Asset Assessment Details

<u>Demographics</u>

Hydro One uses a normal expected service life of 50 years for most transformers. This is based on Hydro One's experience, and is beyond the CEA-average of 40 years. The exception is the 500kV autotransformer population where the expected life is 40 years due to higher electrical stresses and historic failure rates. The average age of the transformer fleet is currently 37 years of age and 21% of the in-service transformers are currently beyond their expected service life. The potential risks to system and customer reliability as a result of this long-term demographic pressure needs to be managed through increasing Sustaining capital programs.



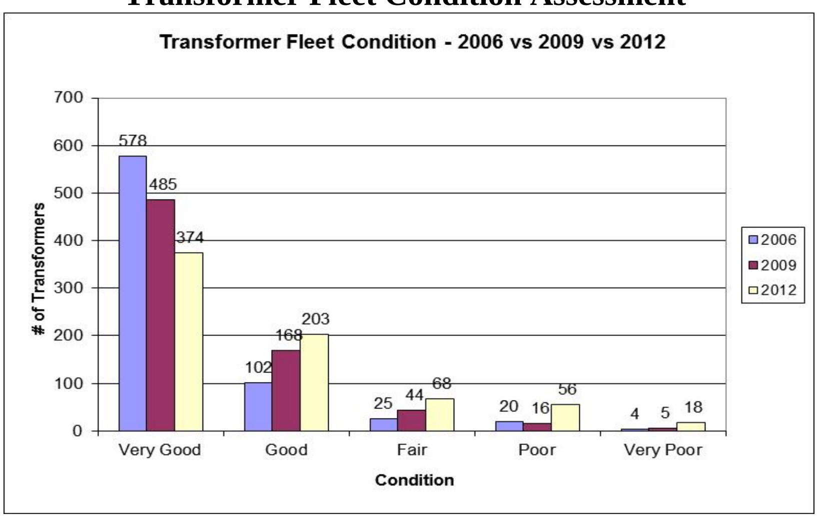
		Voltage Class					
		115 kV	230 kV	345 kV	500 kV	Total	%
Age Group (years)	0-10	47	57	0	7	111	15.4%
	11-20	14	37	0	3	54	7.5%
	21-30	20	63	2	10	95	13.2%
	31-40	35	103	1	16	155	21.6%
	41-50	48	99	1	6	154	21.4%
	> 50	121	29	0	0	150	20.9%
	Total	285	388	4	42	719	100.0%
	%	40 %	54 %	0.6 %	6 %	100 %	

Condition

Transformer condition is an accurate leading indicator of equipment reliability. Condition is primarily based on transformer oil testing (DGA, furan, standard oil testing), power factor testing, and general findings from the preventive and corrective maintenance programs. The internal components degrade as a function of time, heat (from transformer loading), exposure to oxygen, and damaging acids in the insulating oil as a result of insulation aging. Degradation is irreversible and transformer replacement is the only economically viable solution.

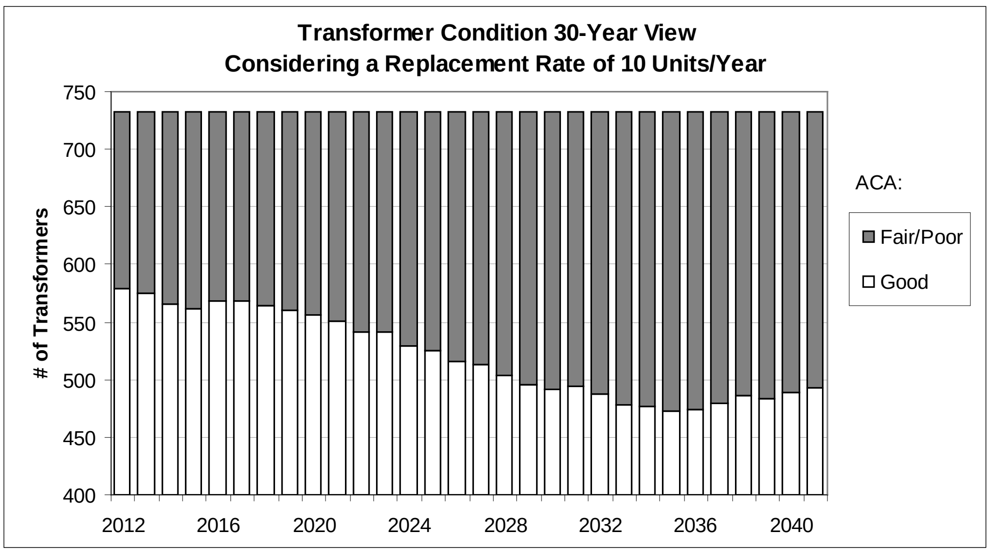
Figure 7 shows updated fleet-wide condition assessment compared with information previously submitted in EB-2008-0272 and a similar assessment done in 2009. The overall fleet condition has degraded over the past several years.

Figure 7
Transformer Fleet Condition Assessment



Over the period of 2007 - 2011, 59 transformers have been replaced including both Sustaining (39) and Development (20) projects/programs. Sustaining replacements have addressed many of the transformers with the highest probability of failure and hence mitigated the most significant risks. In addition, a number of maintenance activities have focused on remedial action for several transformers in the fleet. However to stabilize the rate of change in the condition of the fleet, given the demographics and utilization, a higher rate of replacement is required. A long-term forecast in Figure 8 shows that continuing at the three-year historic replacement rate without further increases, the number of transformers in fair/poor/very poor condition will continue to increase. This is a leading indicator of equipment reliability and eventually system performance. As such, prioritization of units for replacement will be critical and further increases in the program are expected beyond the test years.

Figure 8
Future Transformer Condition Forecast



<u>Performance</u>

Figure 9 shows that the number of major transformer failures varies from one year to the next, with a gradual increasing trend over the past 10 years. The increased number of transformer failures in 2011 is of concern to Hydro One. Risks of transformer failures include customer impact, environmental impacts, and risk to the ability to complete other planned capital and OM&A work programs due to the outages constraints and resources that require redeployment during the response and replacement activities.

Figure 9

Major Transformer Failures

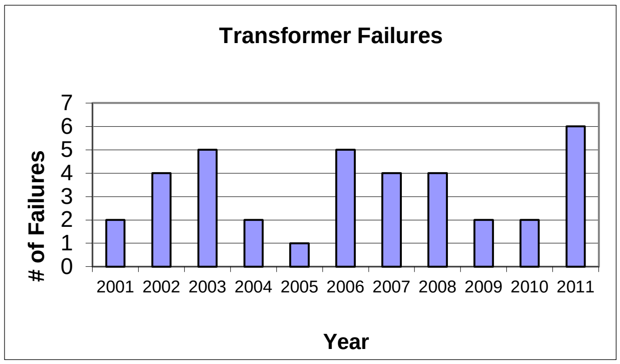
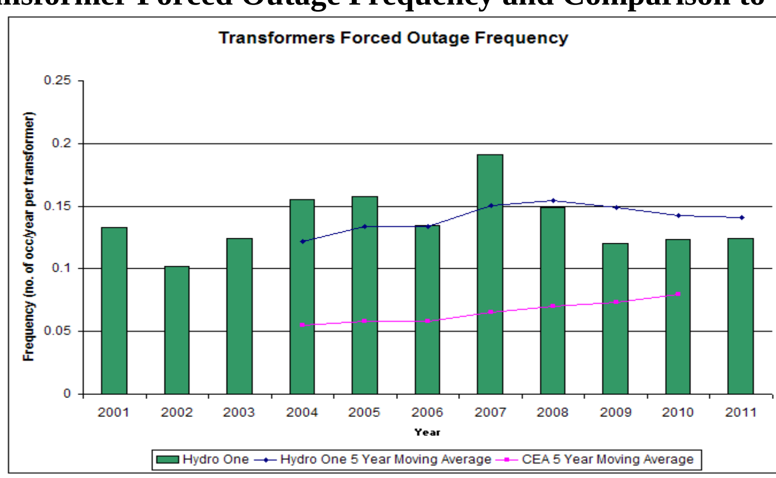


Figure 10 shows that through a combination of capital and OM&A Hydro One has been able to slightly improve the trend of transformer forced outages. There is still a significant gap relative to the CEA all-Canada transmission average. Increased replacements are required to maintain the current level of reliability of the transformer fleet given the demographics and changing condition of the fleet.

Figure 10
Transformer Forced Outage Frequency and Comparison to CEA



Other Influencing Factors

Other factors driving the increase in transformer replacements are summarized below.

- Oil Leaks - Provincial regulations require that oil leaks are mitigated either through temporary measures such as absorbent materials and drip trays, through typically expensive refurbishment to re-gasket transformers, or replacement. Replacement is often the best technical and economical solution for aged transformers.
- Certificate of Approval (CofA) Commitments – often CofA approvals come with a condition of bringing other aspects of the transmission station up to modern standards within a specified period of time, typically 5 years. Transformers are usually the influencing factor in CofA commitments for both spill containment and noise limits.
- PCB – Approximately 25% of bushings older than 1985 are forecast to contain oil with a PCB concentration of greater than 50ppm. Environment Canada has a regulated end-of-use date of 2025 for oil volumes greater than 50ppm. It's anticipated that additional replacements will be required to maintain environmental compliance while still managing reliability risks.

Historic and Future Investment

Transformer Portfolio - Historic & Proposed	2007	2008	2009	2010	2011	2012 Forecast	2013 Test Year	2014 Test Year
# of Sustainment replacements*	9	10	4	10	16	11	20	27
% of Fleet	1.2%	1.3%	0.5%	1.4%	2.2%	1.5%	2.7%	3.7%
Capital ($M, Net)	18.7	40.7	48.7	106.8	81.1	72.4	125.6	170.8
OM&A ($M, Net)	28.5	22.6	29.3	26.4	30.2	24.8	23.8	24.9

**Note that transformer replacements above are conducted under both the categories of Power Transformers and Station Re-Investment as outlined in Exhibit D1, Tab 3, Schedule 2.*

Forecast and test year OM&A expenditures are being constrained significantly below historic levels. When adjusting into 2012$, the 2012 – 2014 average OM&A expenditure is 20% lower than the 2009-2011 historic expenditure. Increasing capital expenditures will result in a 2012-2014 average replacement rate of 2.6% of fleet, which will better position Hydro One to manage risks associated with an aging fleet in degrading condition.

4.3 Protections

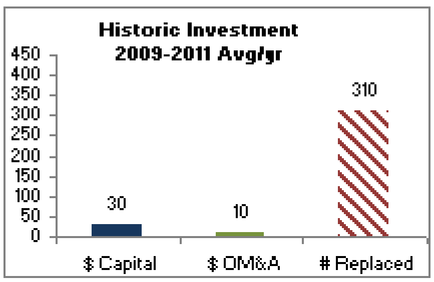
- Protective relays and their associated systems are critical elements of the transmission system. They are connected throughout the transmission network to detect abnormal conditions caused by natural events, physical accidents, or equipment failure. Upon detecting such abnormal conditions protection systems operate immediately operating appropriate disconnecting devices to isolate the affected equipment such as transmission line, transformer, generator, and buswork from sources of energy and the rest of the network. Failure to promptly isolate such conditions can cause a widespread blackout and catastrophic destruction of equipment as well as injury to workers and the public.
- There are over 11,000 protection systems deployed in Hydro One transmission network with up to 100 components making up each system. With the vast number of protections, and complexity of replacement, there is significant risk if a common mode of failure for common manufacturer types/designs is experienced
- Maintaining the historic rate of replacement will result in an increase of protections that operate beyond their service life from the current level of about 31% to 33% of the entire fleet within the next 5 years, thus increasing the risk of failure.
- Protections are in the midst of a major technological change as old electromechanical and solid state relays are no longer available. There are advantages and disadvantages to this technology change. A change in technology adds complexity to replacement activities requiring major layout and configuration rework of existing protection schemes which takes considerable engineering and time. Increasing the risk of a run to failure strategy.
- Advantages of new IEDs include features not previously available including self-monitoring and alarming which allows for less frequent maintenance, optimization life cycle cost by extending preventive maintenance cycles and remote data gathering to increase efficiency and ease of event analysis
- PALC relays, a type of Hydro One solid state protection schemes, have experienced an increase in defects over the last 4 years with the moving average having almost doubled in the last 4 years. An increase in the replacement rate is required to arrest this trend.

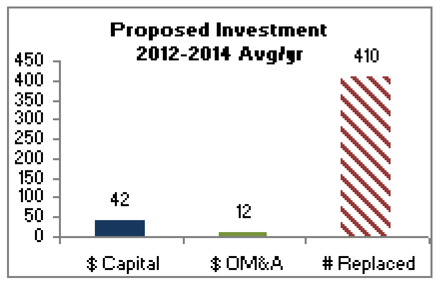
<u>Asset Strategy</u>

Manage the aging protection systems fleet to contain the operational expenditures while maintaining the level of reliability. Proactively replacing before failure is required to fulfill this objective. This will be achieved by greater deployment of modular PCT at load stations with a large number of protections in need of replacement, continuing focused replacements of system critical protections, targeted replacement of failure prone relays (such as PALC), and bundling work opportunities with major refurbishment projects.

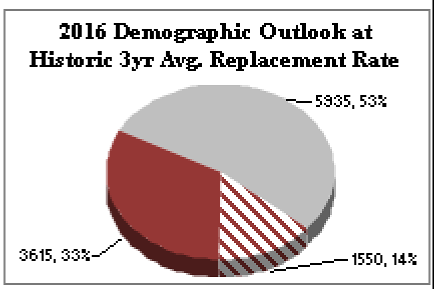
Protections At a Glance		
	Current State, 3yr Average Historic Investment	**Proposed Investment Level, 3yr Bridge & Test Years Future Investment**
Average CapEx ($M/yr)	30 31 (2012$)	42 40 (2012$)
Average OM&A ($M/yr)	10 11 (2012$)	12 11 (2012$)
Average Replacement (#/yr)	310	410
Average % Fleet Replaced (%/yr)	2.8%	3.7%

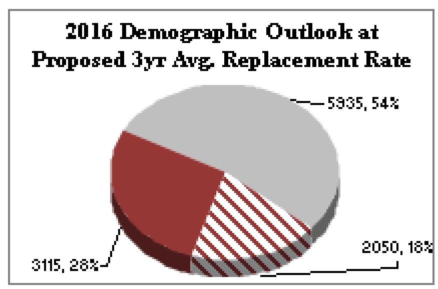
Investment Levels ($M, # Units)



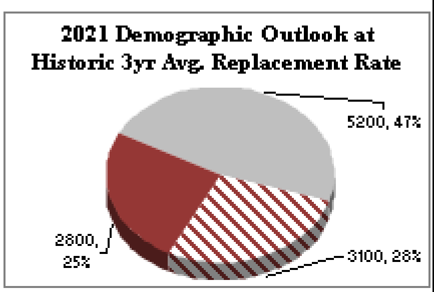


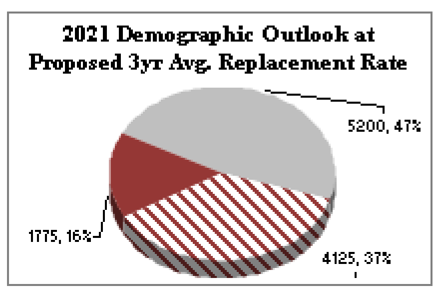
Five Year Outlook ($ Units)





Ten Year Outlook (# Units)





Legend: Beyond Expected Service Life · Replaced · Within Expected Service Life

Business Value / Objective Commentary

	Impact to Values / Objectives
Safety	Proactively addressing protection systems in operation beyond their service life reduces the risk of uncleared faults with potential of exposing workers and public to the harm associated with uncontrolled flow of energy.
Reliability	Proposed rate of replacement maintains the dependability (operating when required) and security (not operating on faults in adjacent protection zones) at present level thus maintaining the overall impact of protections on reliability of the transmission system.
Customer	The frequency of 230kV circuits' outages due to failed protection systems has been increasing over the last 4 years; increased replacement rates with a focus on line protections is expected to arrest this trend. Maintaining and improving overall reliability of protection system (dependable and secure protections) ensures stable or improved service delivery reliability by minimizing the risk of equipment damage and avoiding prolonged outages and sub-optimal operation of provincial power grid. Increased deployment of modern relays will improve our ability to respond to changing customer needs such as connecting new generation.
Innovation	With the increased deployment of modern IED based protection systems the advantage of their monitoring and diagnosing capabilities early detection of station equipment problems is possible, thus equipment damage could be avoided. Also, modern relays can be deployed with pre-tested configuration settings to facilitate more efficient and expeditious system protection due to dynamic power system configuration changes. Increased penetration of IED in the system will yield additional efficiencies in retrieving data from equipment in support of event analysis activities, and will allow new practices (such as distance to fault) to minimize service restoration time. In the last 4 years Hydro One has moved to an innovative way of replacing protections at our load stations. A modular PCT building complete with protections installed, wired, and pre-tested at vendor's facilities is used at selected stations. This leads to cost efficiencies in the initial installation compared to panel by panel replacements.
Environment	Although protection systems do not impact environment directly, when they fail to operate and cause equipment damage, there is a risk of significant environmental impact due to release of harmful agents.
Cost Effectiveness	General stability within the OM&A programs and a continued increase in Sustaining capital replacements helps contain the cost of managing the aging fleet. Reduction of footprint of an individual protection scheme is expected to generate more flexibility to accommodate new requirements within the existing building infrastructure.

Asset Assessment Details

There are three technological vintages of protective relays: electromechanical, solid state and microprocessor based with service life of up to 40 years, up to 25 years, and up to 25 years respectively. The microprocessor based relays, so called intelligent electronic devices (IEDs), are the only deployment alternative today. The other two technologies have been manufacturer discontinued and are no longer available for new installations. The protection systems cannot be out of service for longer than several days without incurring significant penalties in market inefficiency, disrupting planned outages, or impacting provincial or interconnected grid reliability. The time required to engineer and install replacements is in the order of several months to over one year depending on the nature of the system.

Demographics

- 31% of the electromechanical relays are currently beyond expected service life
- 66% of the solid state relays are currently beyond expected service life
- First generation of microprocessor based protective relays is about 6 years away from their service life upper limit

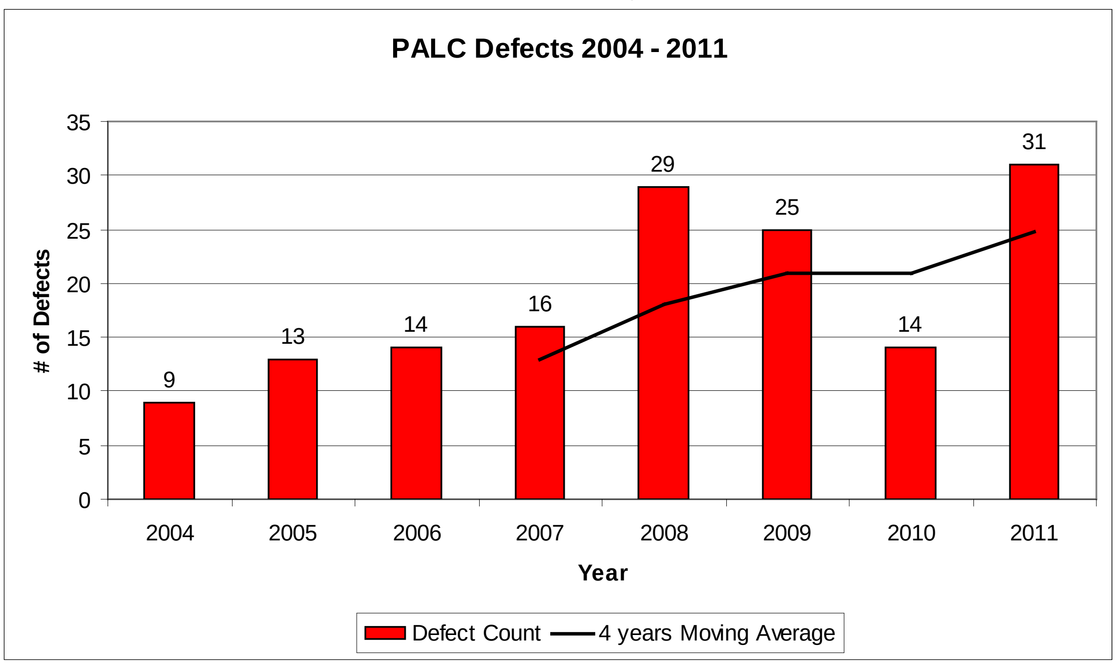
Protection System Relay Type		Total	(%)	% above Service Life
Categories	Electromechanical	3736	34	31
	Solid State	3414	31	66
	Microprocessor	3863	35	0
	Total	11013	100	

<u>Reliability and Performance</u>

- The contribution of protection failures to outages frequency (T-SAIFI-mc, refer to Figure 2 presented earlier) over last 10 years has been about 15%. Contribution to outage duration over the same period has been about 16%.

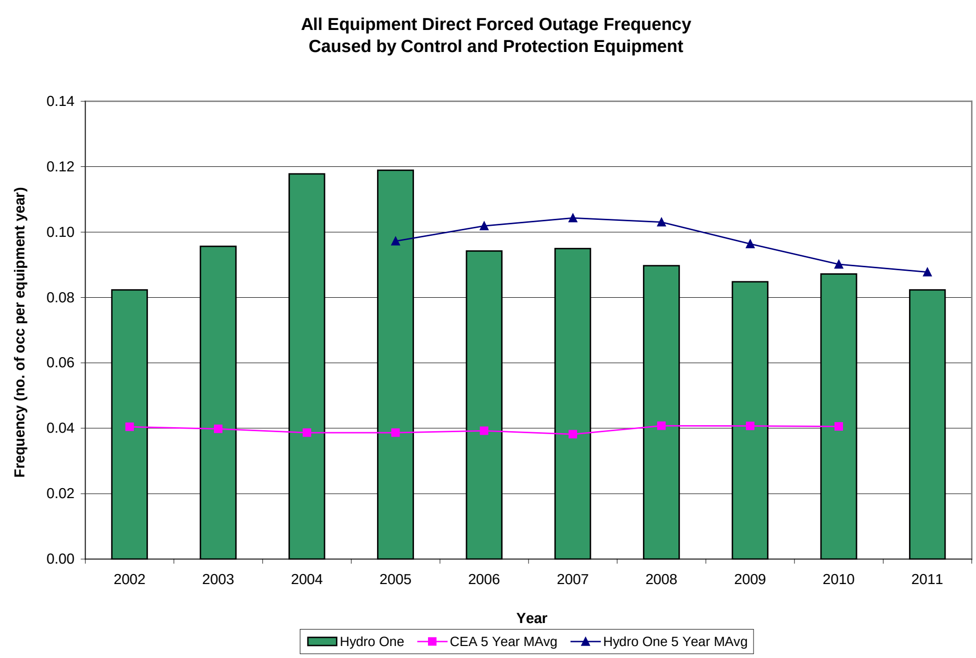
As demonstrated in figure 11 performance data for PALC relays (critical protections for system stability, PALCs are Solid State type of relays) show an increasing trend of recorded defects/troubles. The 4 year moving average has almost doubled over the last 4 years. This is one of the leading indicators described in section 3 of this exhibit.

Figure 11
Recorded historical PALC relays defects 2004-2011.



Replacement programs have been successful in arresting the trend experienced in the 2002-2005 timeframe. Forced outage frequency has been relatively stable over the last few years as demonstrated in Figure 12. However the Forced outage frequency remains significantly above CEA 5yrs moving average. Given the demographics and increase in defects as demonstrated in Figure 11, continuing investments are required to maintain the current trend.

Figure 12
Protection Contribution to Forced Outage Frequency



Condition

Due to the increasing rate of protection systems replacements, the condition of the protection fleet is expected to improve slightly over the next 10 years due to reduction of the number of protections operating beyond their expected service life. The new IED based relays are relatively new technology for which condition metrics and indicators are not yet clear and well established.

Cost Trends and Impacts

- O&M programs are being kept relatively stable relative to historic years
- Modern IED based protection systems allow for extended maintenance intervals thereby lowering the life-cycle maintenance costs.
- Average 3-year historic replacement rate has been below 3% of the fleet per year.
- Accomplishment rate of protection systems replacements are increased to 4% of the fleet to prevent an increase in the number of protections operating beyond their expected service life and to ensure that the "replace before failure" sustainment strategy is successful. As such test-year capital expenditures are increasing from recent historic and bridge years.
- Increased deployment of "PCT in a box" at load stations leads to economies of scale on initial deployment and optimized maintenance during normal station operation.
- Focus on PALC relays which have undergone an increase in defects experienced will reduce corrective costs for these protections.

Historic and Future Investment

For many years, the annual replacement rate of protection systems has been below the rate at which relays age past their expected service life (the average rate of replacement over last 8 years is about 2.6% of the fleet); as such, currently 31% of protections are beyond their expected service life. We are now beginning to see an increase in the defects of some systems. Replacements in the test years will exceed the past years average rate reducing the number of protections in this category, thereby reducing the number of risks associated with the failure of protection systems. The proposed rate of replacement will focus on:

- solid state relays, 66% of which currently are beyond the normal life expectancy and there is an increasing trend in the rate of failure
- stations with a significant portion of protections beyond the life expectancy and in poor condition
- critical installations such as transmission line protections, interconnections and connections to generation facilities

- bundling with other projects that provide efficient protection replacement opportunities

Protection Systems Portfolio	**2009**	**2010**	**2011**	**2012 Forecast**	**2013 Test Year**	**2014 Test Year**
# of replacements	259	283	389	380	400	450
% of Fleet	2.4	2.6	3.5	3.5	3.6	4.0
Capital ($M)	29	32	28.5	36.4	35.6	53.6
OM&A ($M)	10.4	9	11.3	10.5	11.8	12.5

Exhibit D1, Tab 3, Schedule 2 outlines the proposed test-year Sustaining Capital investments to manage the risks of the protection systems population.

4.4 Transmission Underground Cables

- Cables are located in major cities where loading has increased significantly since original installation impacting the aging process as well as the impact of cable failures.
- 19% have reached the 50 year expected service life; at the current rate of replacement this will increase to 28% by 2016 and 36% by 2021.
- Modifications in the last 10 years have successfully improved forced outage frequency. However, the nature of the problems recently experienced is indicative of the need for replacement and has resulted in an increase to the duration of outages and corrective costs. This is expected with aging infrastructure and is an indication of the need to increase capital replacement activities.
- Due to the nature and construction of these assets, failures can result in significant reliability and environmental impacts.

<u>Asset Strategy</u>

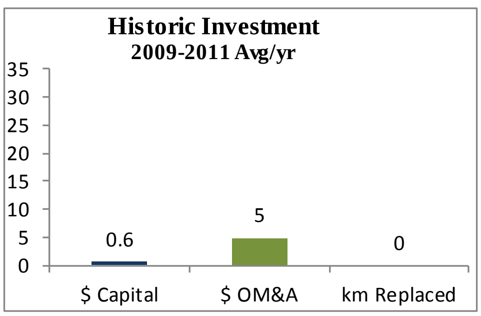
Hydro One’s underground cables supply city Centre’s in Toronto, Ottawa and Hamilton. They are essential for electrical supply and require a high degree of reliability. Experience has shown that underground cable replacements are very costly and can take years to plan and carry out. In the past, Hydro One has employed a rigorous maintenance program which has helped to extend the life of these assets. The current investment strategy is based on the following principles:

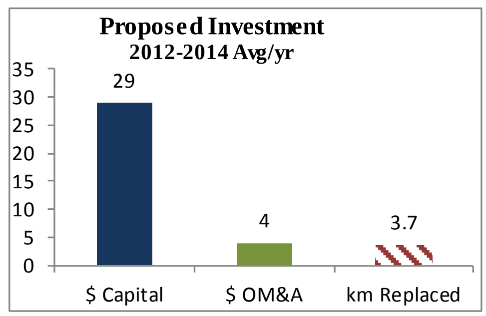
- Maintain O&M expenditures for inspections, analysis, tests, surveys and diagnostics of cables, vaults, jackets and potheads as well as condition, route patrols and corrective activities. Closely monitoring cables that are nearing the end of their expected service life.
- Select cables for replacement based on factors including condition, performance, component obsolescence, age and the assessment of the risk factors associated with leaving a poor cable in service, including system redundancy, environmental receptors and the time to replace.

Underground Cables At a Glance

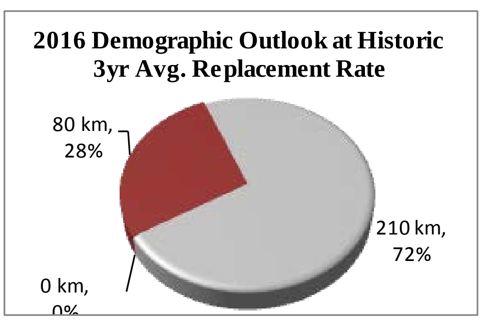
	Current State, 3yr Average Historic Investment	Proposed Investment, 3yr Bridge & Test Years Future Investment
Average CapEx ($M/yr)	0.6 0.6(2012$)	29 28(2012$)
Average OM&A ($M/yr)	5 5(2012$)	4 4(2012$)
Average Replacement (km/yr)	0 km	3.7km
Average % Fleet Replaced (%/yr)	0.0%	1.3%

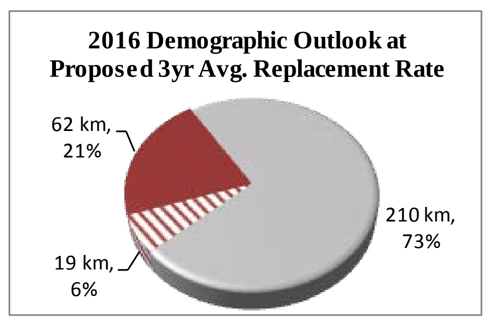
Investment Levels ($M, km)



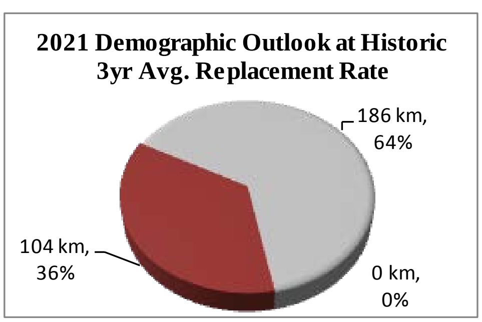


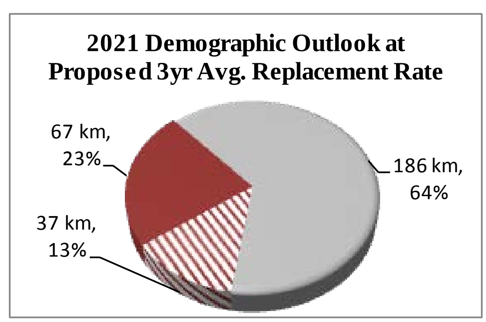
Five Year Outlook (km)





Ten Year Outlook (km)





Legend: Beyond Expected Service Life; Replaced; Within Expected Service Life

Business Value / Objective Commentary

	Impact to Values / Objectives
Safety	Replacement of cable systems in poor condition will reduce the risk of failure and risk of injury to workers who may be working in the vicinity of cables in vaults and/or near the cable terminal ends. It also reduces the risk of safety issues to the public, which could arise from widespread blackout in downtown areas fed from critical circuits.
Reliability	There has been an improvement in forced outage frequency over the past 5 years. However, the duration of outages over the past 5 years is increasing as well as the corrective maintenance costs, which demonstrates that the issues are becoming more serious. Increased replacement activity is required to maintain reliability in the future.
Customer	Failure of underground cables can take months to repair and up to 3 years to replace. This can place considerable strain on the system as it may restrict outages required for maintenance or repair. It also increases the risk of concurrent outages resulting in delivery point interruptions. Overloading other cables and related elements can place the system at risk of failure, loss of supply and blackout to the customer.
Innovation	The majority of the underground transmission cables in the Hydro One network are oil filled. Oil leaks can develop due to breaches in metallic sheath which hermetically seals the insulation. These leaks are time consuming and costly to locate. Hydro One staff in conjunction with an engineering consulting firm have carried out studies and field trials to adapt an existing technology to accurately locate oil leaks on low pressure oil filled cables using a tracer fluid by injecting it into the cable system oil.
Environment	XLPE cables which are extruded polyethylene insulated are now used to replace oil filled cables, which reduces environmental impacts due to oil leaks.
Cost Effectiveness	Increasing sustaining capital programs will stabilize the OM&A corrective costs associated with repairing underground cables in poor condition. XLPE systems being installed are very simple compared to oil filled systems and have lower maintenance costs.

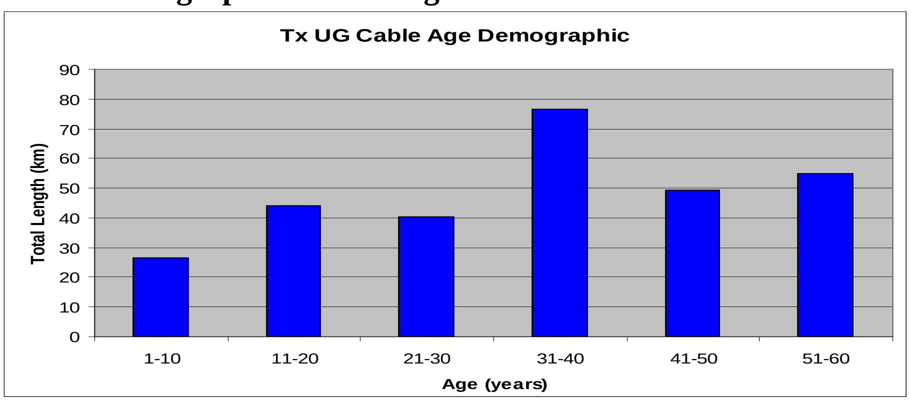
Asset Assessment Details

<u>Demographics</u>

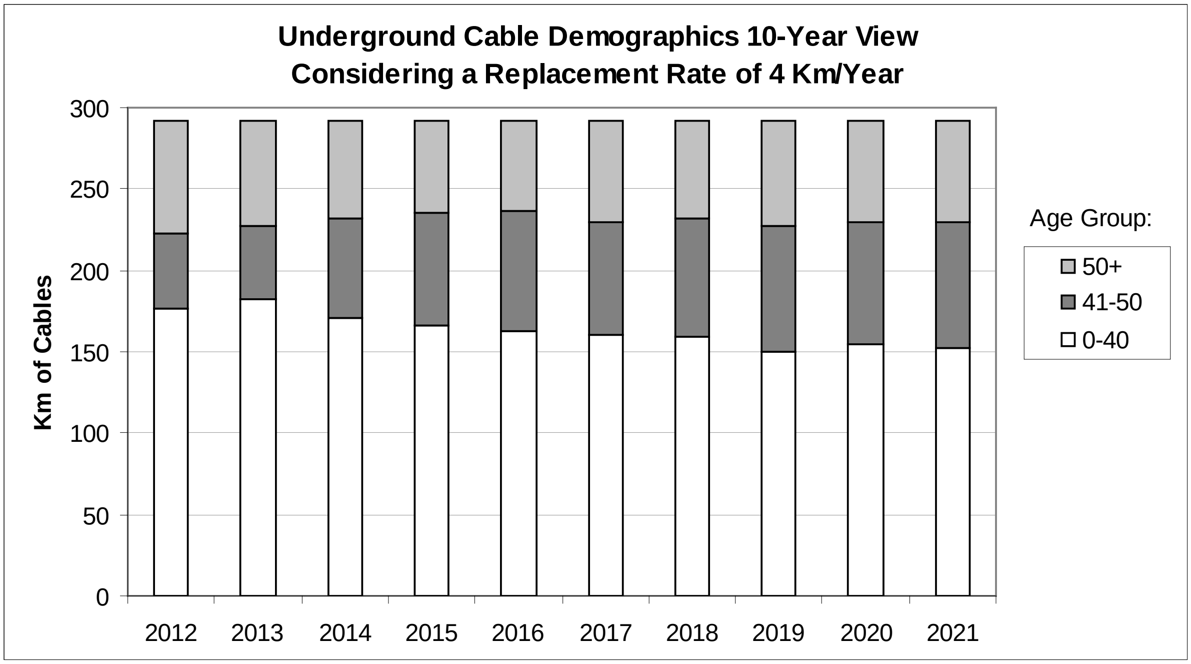
Hydro One uses a normal expected service life of 50 years for underground transmission cables, which is based primarily on the original design expectations. However, in the past Hydro One has employed a very rigorous maintenance program which has helped to extend the life of these assets and a number of cables beyond this age are still in satisfactory operating condition. The average age of the underground cable fleet is currently about 35 years and about 19 % of cables are beyond their expected service life of 50 years. The potential risks to reliability and safety as a result of the aging demographics and deteriorating cable condition needs to be managed through a continued rigorous maintenance program to detect developing defects, as well as through increasing capital programs.

Figure 13 displays the existing demographics; 19% of the cable population has reached the 50 year expected service life. At recent historical replacement rate, this increases to 28% by 2016 and 36% by 2021.

Figure 13
Demographics of Underground Transmission Cables



	Length (km)			
Age	**115 kV**	**230 kV**	**Total**	**%**
1-10	7.17	19.32	26.49	9%
11-20	34.64	9.5	44.14	15%
21-30	10.7	29.6	40.3	14%
31-40	76.6	0	76.6	26%
41-50	49.2	0	49.2	17%
51-60	55	0	55	19%
Total	**233.31**	**58.42**	**291.73**	**100%**



Performance

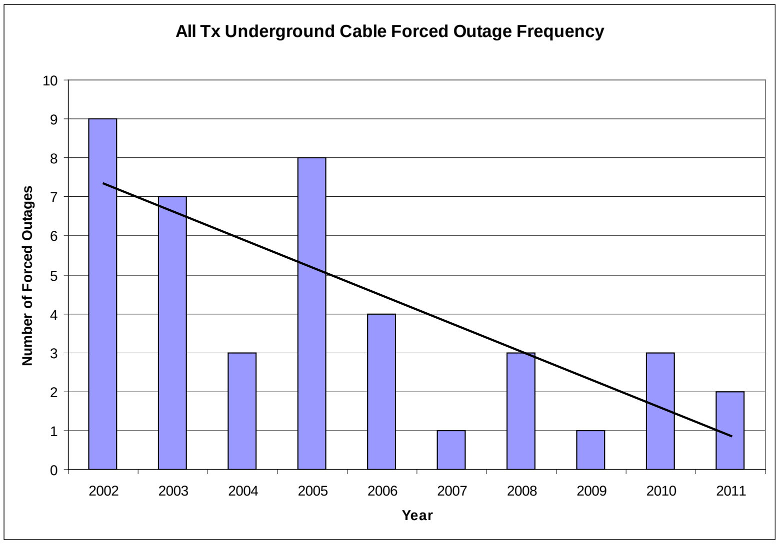
Underground transmission cables were first installed in the Hydro One Network in the early 1950's. They were designed and installed with built in redundancy and capacity so that failures would not immediately result in outages to customers. Many of these cables are still in service but we are now starting to see the effects of aging and the increasing loads placed on them due to the expansion in the downtown areas that they serve. A small percentage of these cables have recently begun to require replacement due to their condition and we expect this trend to continue. There has been minimal impact in customer reliability due to underground cable failures over the last 10 years. However, the examples below highlight the potential risks with the underground system.

- In 2003, a downtown Toronto cable circuit (H3L) failed which resulted in 5500 litres of oil spilling into the Don River. The failure was located and repaired, which took over a month to complete. When the circuit was returned to service, it failed again after only 2 months at another location, indicating the need to replace. Due to system constraints at that time, this circuit was deemed critical and required for service prior to the summer loading, allowing a timeframe of only 8 months within which it had to be replaced. Fortunately, the existing 50 year old steel carrier pipe along the entire route was available to be re-used. Such a project would typically take up to 3 years to execute if excavation was required.

- Another major event occurred in 2010 due to a leaking cable section on circuit H2JK. As the other supply K6J was on planned outage at the time, it caused all of the five (5) delivery points at Strachan TS to go out of service. In the case of H2JK and K6J, the longer term major risk was if the oil leaks increased to a level that was impractical to keep up with, in which case both circuits would have to be removed from service resulting in considerable strain and risk to the system for a prolonged period of time. Hydro One plans to replace these cables over the next 2 years.

Forced outage frequency displayed below represents the number of times an outage is caused due to a failure on part of the underground cable system. There have been a number of major component replacement projects during the past 10 years including joint, termination, oil pressure system and bonding upgrades which have contributed to a reduction in the forced outages. As can be seen in Figures 14 and 15 below, although there has been an improvement in forced outage frequency, the duration of each occurrence over the past 5 years is increasing as are the corrective maintenance costs. This is an representative of problems becoming more serious. Considering the deteriorating condition and demographics of the fleet, an increase in the rate of replacement is required to maintain the current forced outage frequency.

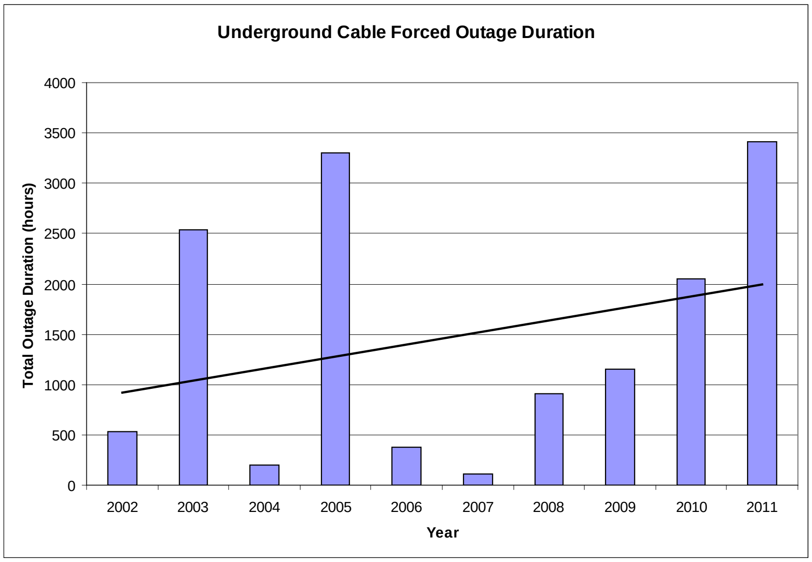
Figure 14
Forced Outage Frequency of Underground Transmission Cables



Average number of forced outage per year = 4.1

Component replacement projects during the past 10 years have contributed to a reduction in the forced outages

Figure 15
Forced Outage Duration of Underground Transmission Cables

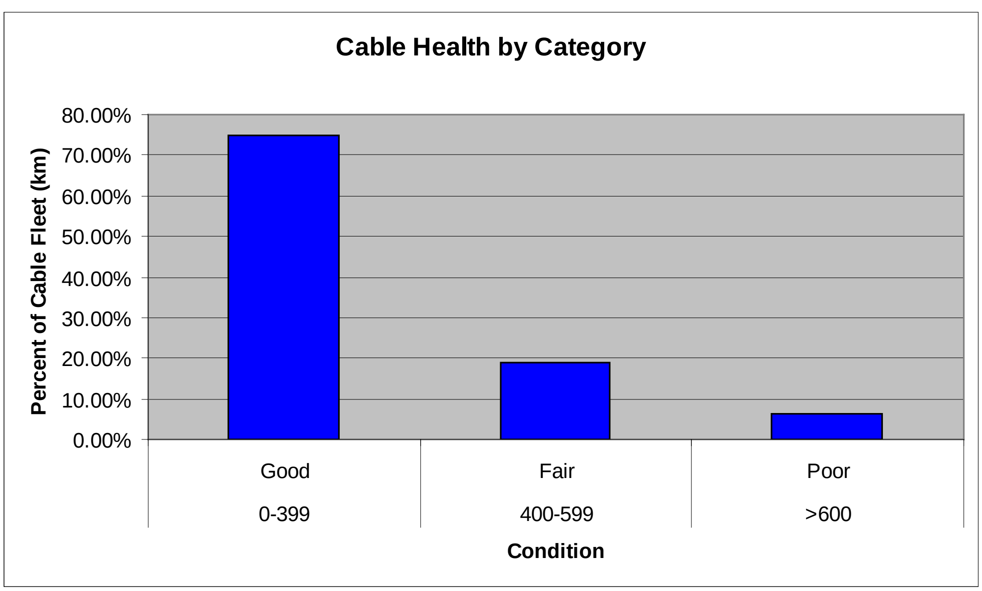


It should be noted that forced outages depicted above were serious enough that they required system operations to force the circuit from service. There were many more cases where other defects and cable leaks were not severe enough to force the circuit from service but instead addressed under a planned outage.

Condition

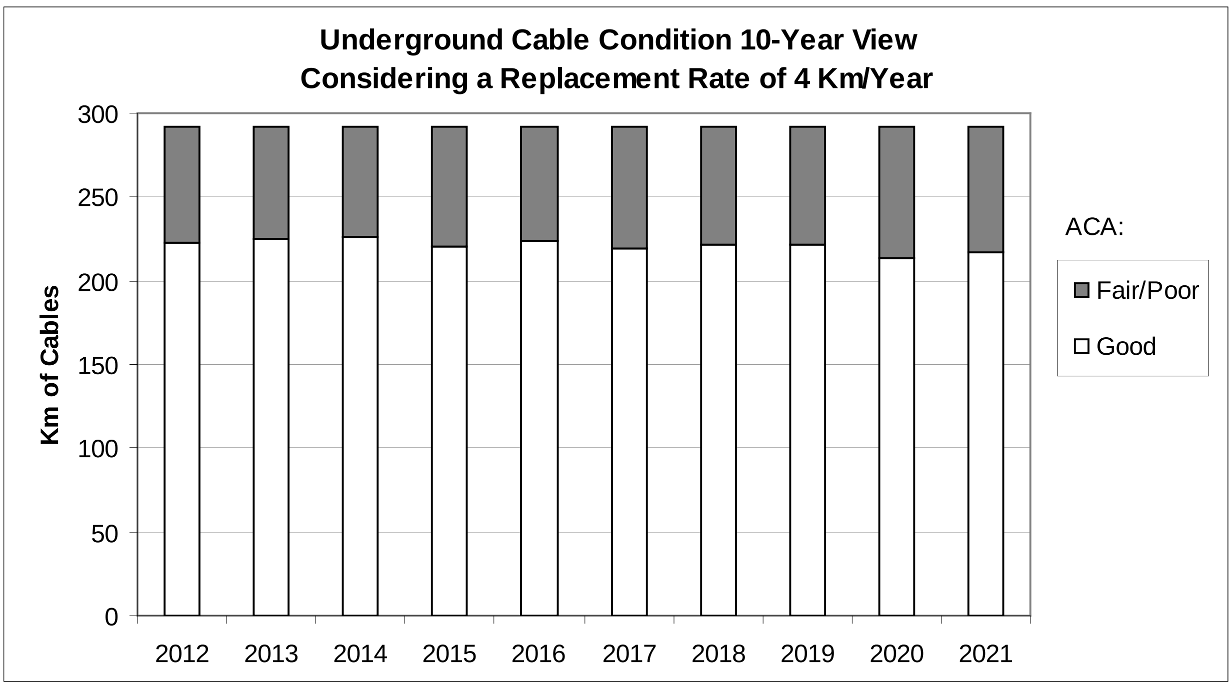
Hydro One Networks maintains a health index of its underground cable inventory based on a variety of condition information and risk factors. This assessment is continuously reviewed and adjusted as new conditions are reported or factors are considered. The current assessment of the underground cable fleet condition is illustrated in Figure 16 below. Not all sections of a buried cable are accessible for maintenance inspections and diagnostics, but the inspections are generally representative of the entire cable system. Cables in the fair/poor categories (currently total about 25% of the population) are considered for replacement within the next 10 years. Circuit criticality, maintenance costs, forced outage frequency and environmental risks are the main factors driving cable replacements.

Figure 16
Cable Health Index



There is one cable replacement project underway during the test years. It is expected that replacement of 4km/year will continue beyond the test years. As can be seen in Figure 17 below, this strategy will maintain the average condition and the portion of cables in fair/poor condition over the next 10 years.

Figure 17
Asset Condition Trend based on Proposed Replacement Rate



Other Influencing Factors

Technical obsolescence is a minor factor for underground cables at this point in time. Capital dollars in 2014 include the planned replacement of a low pressure pumping plant at Riverdale TS as spare parts for this facility are no longer available.

Cost Trends and Impacts

- O&M programs are being kept relatively stable in order to carry out assessment activities that are performed frequently and are critical to provide insight into cable condition.

- Test-year capital expenditure is increasing from recent historic and bridge years due to the need to replace H2JK and K6J from Riverside Jct. to Strachan TS in Toronto. The year over year capital costs vary significantly due to the large cost of individual projects. This can be seen in 2007 due to relocation of a cable to accommodate a rail expansion project. Expenditures in 2011 and 2012 were low, as a plan to replace H2JK and K6J from Riverside Jct. to Strachan TS was deferred due to unexpected difficulties with obtaining land easements.
- Average 3-year historic replacement rate has been roughly 0% of the fleet per year.
- Proposed test-year replacement rate is roughly 1.7 % of the fleet per year
- Considering the overall demographics, cost trend and types of problems experienced on the transmission underground cable systems, the replacement rate is expected to continue to increase.

Historic and Future Investment

There have been a number of major component replacement projects during the past 10 years including joint, termination, oil pressure system and bonding upgrades which have contributed to a reduction in the forced outages. Historically, there was no need to replace in their entirety these first generation assets. However, during the past 10 years, it became necessary to replace 2 cable circuits with 2 more planned for the test years 2013 and 2014. Hydro One is now entering into a period where the cable circuits are approaching their end of expected life and in order to effectively manage the underground cables the replacement rate is expected to continue to increase.

Cable Portfolio – Historical & Proposed	2009	2010	2011	2012	2013	2014
Capital – Replacement (km)	0	0	0	0	5.0	6.2
Capital – Replacement (% of fleet)	0	0	0	0	1.7	2.1
Capital ($M Net)	0.2	1.0	0.6	2.6	30.8	54.5
OM&A ($M Net)	4.4	4.0	6.6	3.6	4.3	4.4

4.5 Wood Pole Structures

- 27% of assets have reached expected service life.
- The historic maintenance and assessment program and rate of replacement (2%) has been successful in maintaining the condition and performance of this asset base.

Asset Strategy

Hydro One's Transmission system contains about 42,000 wood pole structures. Hydro One's historical experience and industry standards indicate that the expected life of wood poles is 40-50 years. Replacement criteria are based on the results of wood pole inspections and tests done in accordance with CSA guidelines.

Historic replacements have averaged about 850 structures per year and projections based on condition data and reliability performance data indicate that it is necessary to continue at this rate of replacement 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; these 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 were about 5,800 structures of this type in the system and approximately 2,000 structures remain today.

Cost Trends and Impacts

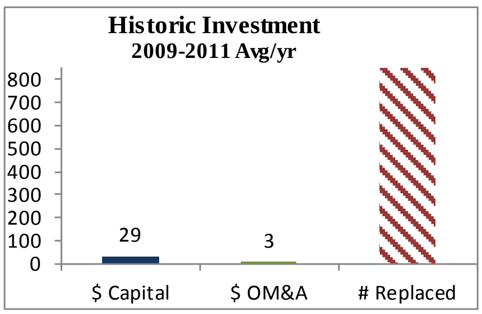
This is a mature program and the number of poles at the end of their expected service life identified each year through condition assessments is in line with the replacement rate. Therefore the majority of poles can be scheduled for replacement in a planned manner prior to failure.

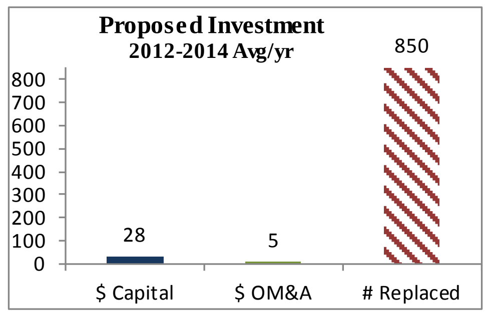
- O&M and Capital programs are being kept relatively stable.
- Average 3-year historic replacement rate has been roughly 2% of the fleet per year.
- Proposed test-year replacement rate is roughly 2% of the fleet per year.
- Once the defective Gulfport structures are eliminated from the network (in approximately 5 years), the replacement levels are expected to decrease.

Tx Wood Poles At a Glance

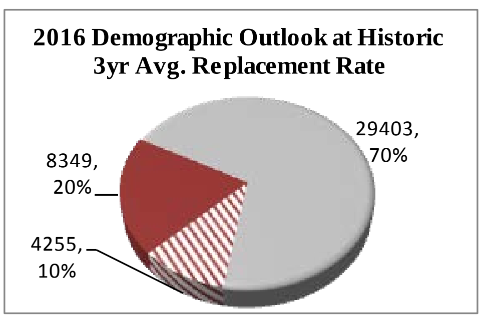
	Current State, 3yr Average Historic Investment		Proposed Investment, 3yr Bridge & Test Years Future Investment	
Average CapEx ($M/yr)	29	31(2012$)	28	27(2012$)
Average OM&A ($M/yr)	3	4(2012$)	5	4(2012$)
Average Replacement (#/yr)	851		850	
Average % Fleet Replaced (%/yr)	2.0%		2.0%	

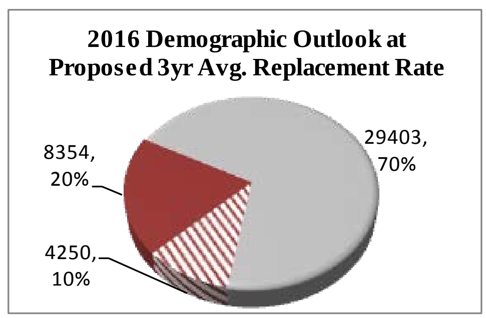
Investment Levels ($M, # Units)



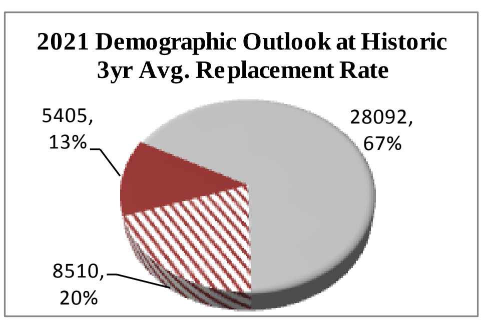


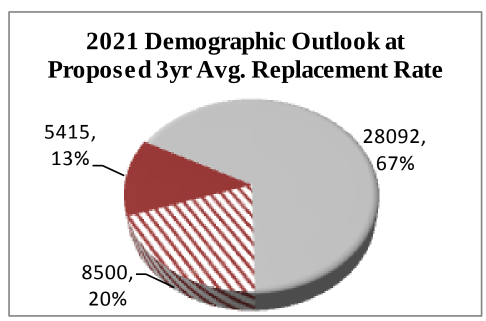
Five Year Outlook (# Units)





Ten Year Outlook (# Units)





Legend: Beyond Expected Service Life | Replaced | Within Expected Service Life

Business Value / Objective Commentary

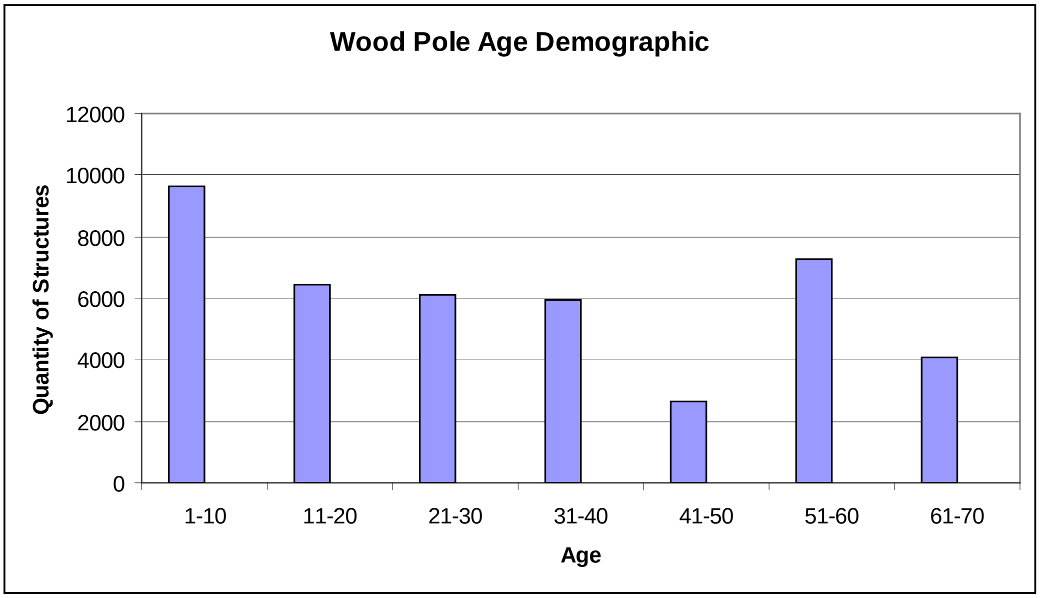
	Impact to Values / Objectives
Safety	The transmission system is located in the public domain and a number of the maintenance activities have been designed to identify possible failures before they occur. This plan will minimize the risk of wood pole failures bringing energized conductor to the ground creating a hazardous situation for the public.
Reliability	The historic rate of replacement has resulted in a slight decrease in wood pole structure failures over the last 10 years and the reliability is expected to remain consistent at about 15 failures per year over the next 10 years which is comparable to the CEA average.
Customer	The majority of transmission wood pole structures are located in Northern Ontario and many of these structures support radial circuits. As a result a wood pole or cross-arm failure can often result in a direct customer outage. Many of these northern wood pole circuits feed major industrial customers and without an adequate supply of power these customers are often forced to shut down until power is restored. The current plan will minimize the customer interruptions.
Innovation	Hydro One Networks plans to install composite poles, which are an emerging technology, on a trial basis to assess their maintainability, effectiveness and overall life cycle costs. Networks also developed a unique work procedure to drill test wood pole structure Gulfport arms from a helicopter. This provides an efficient and cost effective means to prioritize the replacement of these defective units.
Environment	The current strategy minimizes emergency response activities, which typically place a higher risk of negative impact on environmentally sensitive areas over planned proactive replacement.
Cost Effectiveness	Wherever possible, condition assessment activities are scheduled in a complementary fashion such that cyclical and non-cyclical needs are addressed as efficiently as possible. Planned proactive replacement of wood pole structures is typically more cost effective than emergency response due to overtime premiums for after-hours response. Gulfport structures are larger and more costly to replace than 115kV wood pole structures. Once this program is completed, average cost per structure will decrease.

Asset Assessment Details

The wood pole 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 pole structures are comprised of either a single or multiple wood pole/s that support a wood cross-arm which is bolted to the wood pole and is used to support the insulator strings and conductors. Due to the nature of the design, the wood cross-arm tends to be the weak link and is typically the primary cause of failure. Based on Hydro One's experience, the normal expected service life is between 40 to 50 years for wood pole structures. The average age of the wood pole fleet is currently 31 years.

Wood pole assessments include detailed helicopter inspections of the condition of cross-arms and pole tops, and individual pole testing to evaluate the soundness of the wood near the ground line. The number of poles reaching the end of their service life identified each year through condition assessments is in line with the historical replacement rate. As such, the majority of poles can be scheduled for replacement in a planned manner prior to failure. Scheduling and urgency for replacements considers public exposure, history of failures and customer risks/system configuration.

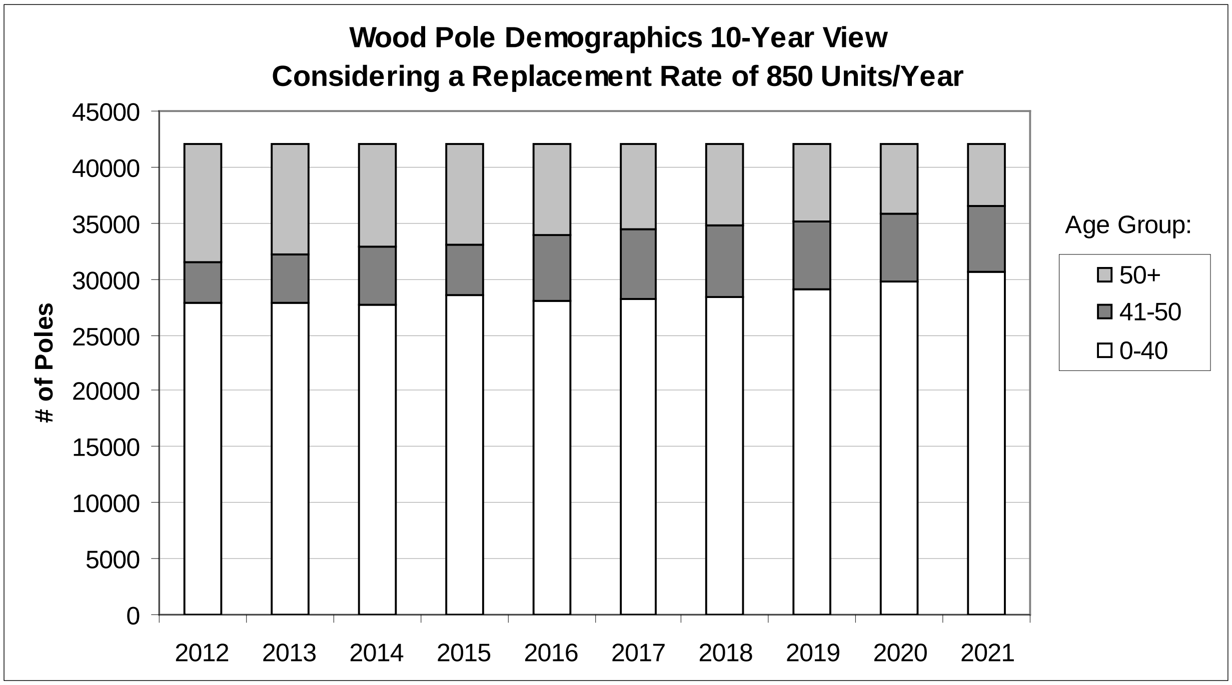
Figure 18
Demographics of the Wood Pole Population



Age (yr)	Quantity	Percentage
1-10	9,617	23%
11-20	6,444	15%
21-30	6,083	14%
31-40	5,948	14%
41-50	2,622	6%
51-60	7,240	17%
61-70	4,053	10%
Total	**42,007**	**100%**

As can be seen in figure 19, with the current investment plans the number of wood poles beyond 50 years old will improve from the present 27% to 13% by 2021 and the average age of the fleet will decrease from 31 years to 29 years.

Figure 19
Demographic Trend of Wood Poles based on the Proposed Rate Of Replacement



Performance

The majority of transmission wood pole structures are located in Northern Ontario and many of these structures support radial circuits. As a result a wood pole or cross-arm can often result in a direct customer outage. Many of these northern wood pole circuits feed major industrial customers and without an adequate supply of power, these customers are often forced to shut down until power is restored. The timeframe to repair a broken cross-arm or structure is on average 2 days and can be longer given difficult access conditions.

<u>Failure Rate:</u>

	115 kV			230 kV			Total (115 & 230 kV)
Year	**Crossarm**	**Structure**	**Total**	**Crossarm**	**Structure**	**Total**	
2002	8	2	10	3		3	13
2003	14	3	17	5	1	6	23
2004	5	6	11	2		2	13
2005	7	1	8	3		3	11
2006	7	2	9	6		6	15
2007	8	7	15	9		9	24
2008	8	4	12	4	1	5	17
2009	5		5	2		2	7
2010	6	5	11	6	1	7	18
2011	6	1	7	3		3	10
Total	74	31	105	43	3	46	151

Average number of failures = 15.1 / year over the past 10 years.

Figure 20
Forced Outage Frequency of Wood Poles

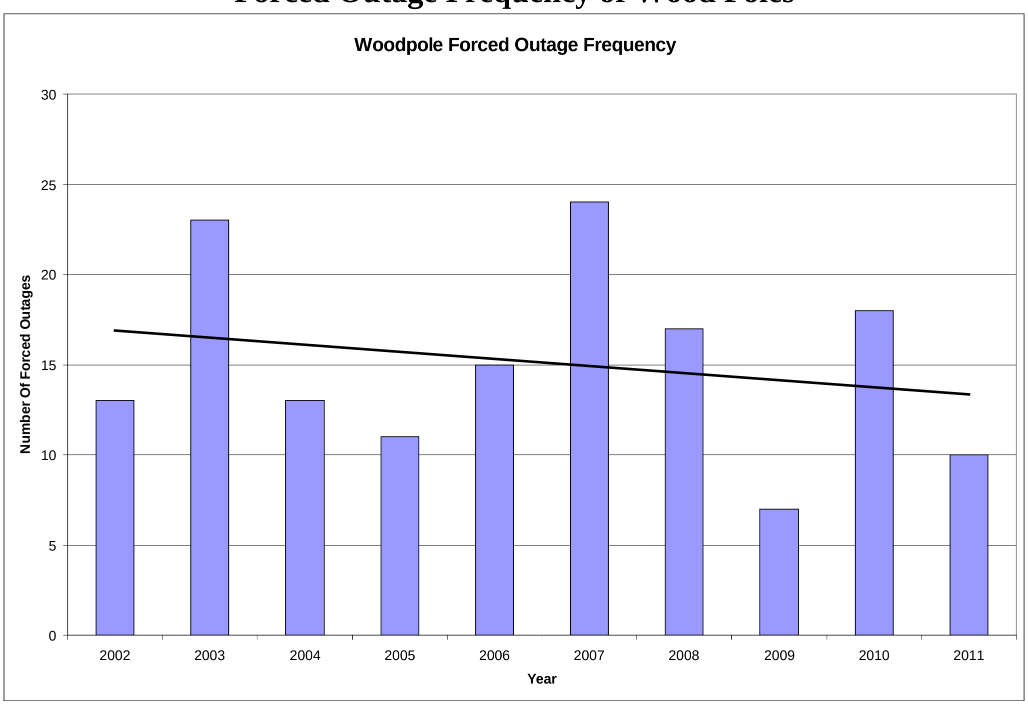
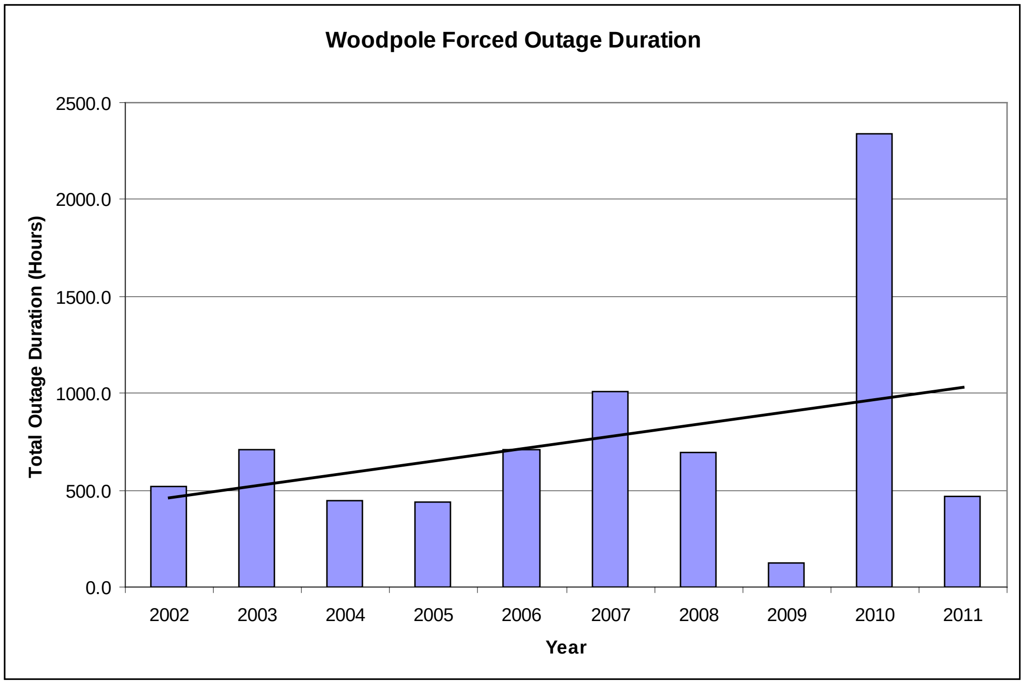


Figure 21
Forced Outage Duration of Wood Poles

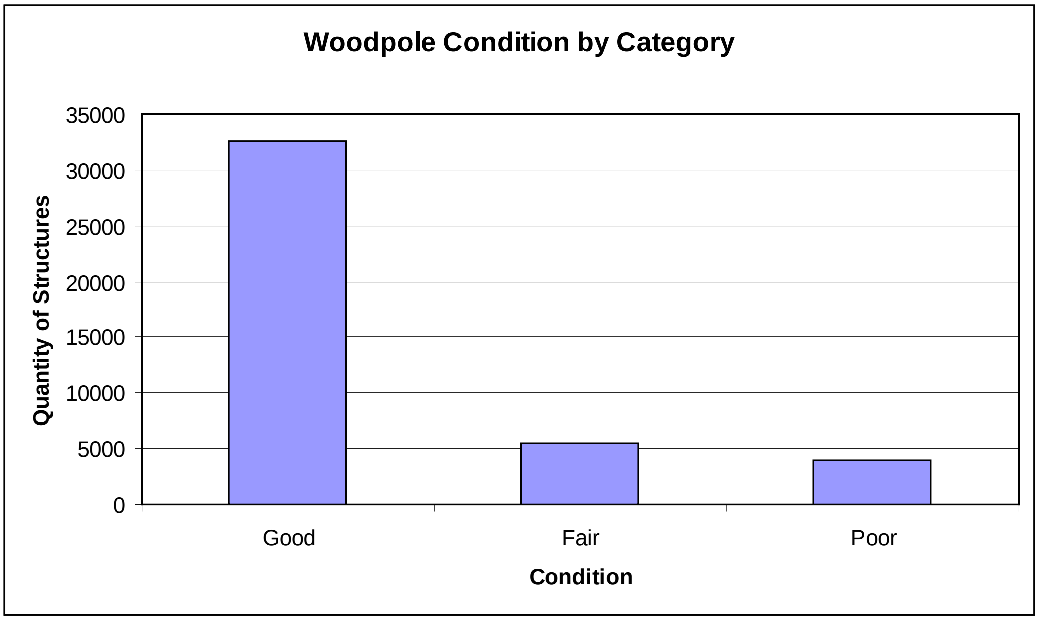


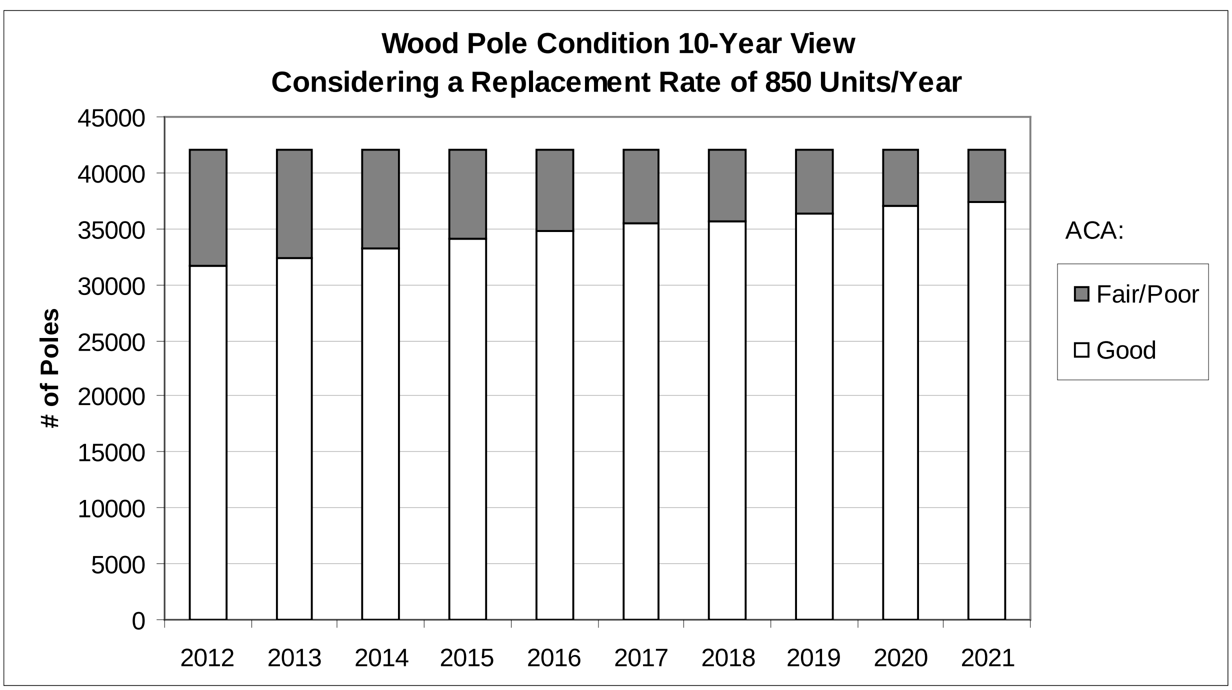
As can be seen in Figure 20, the wood pole forced outage frequency has improved over the last 10 years as the defective Gulfport structures are eliminated from the system. Figure 21 demonstrates the outage duration which has a deteriorating trend; with an extreme spike in 2010. This type of year is not unexpected given many of these circuits are radial supplies and in remote locations.

Condition

The current assessment of the wood pole is summarized in the graph below. The assessment is continuously reviewed and adjusted as new conditions are reported or factors are considered. Wood poles in the fair/poor categories (currently totals about 22% of the population) are considered for replacement within the next 10 years.

Figure 22
Condition of Wood Pole Population





As can be seen in Figure 22, at the current rate of replacement the number of wood poles in poor/fair condition is expected to remain stable with the current replacement strategy. Based on the projected age and condition, the wood pole failure rates are expected to be in line with historical trends. As a result, reliability and safety risks will be in line with past performance.

Other Influencing Factors

Hydro One plans to begin using composite poles to replace a small portion of its wood pole population that have reached their expected service life. This will allow for evaluation of this emerging technology product to determine if life cycle costs of these assets can be reduced. Any benefits realized would be on the longer term horizon.

Historic and Future Investment

Historically, the replacement rate has been about 2% and has been very effective at keeping pace with the number of structures that reach their expected service life. Once the remaining defective Gulfport structures are eliminated from the network in about 5 years, the number of replacements is expected to be reduced.

Wood Pole Portfolio – Historic & Proposed	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**
Capital - # of replacements	817	774	811	880	862	850	850	850
Capital - % of fleet replaced	1.9	1.8	1.9	2.1	2.1	2.0	2.0	2.0
Capital ($M Net)	**24.8**	**21.8**	**28.0**	**29.6**	**30.1**	**27.2**	**28.0**	**28.8**
OM&A ($M Net)	**2.5**	**3.6**	**3.5**	**3.5**	**2.9**	**4.5**	**4.6**	**4.8**

4.6 Transmission Steel Structures

- Tower coating programs have been used for a number of years, however, interruptions to these programs, current demographics and condition data indicates that an increase in the funding is required to avoid deterioration to a the point where coating is no longer a viable and cost effective option.
- Results of recent assessments have identified rapid deterioration of steel structures in corrosive areas which is an indicator of the immediate need to ramp up this program.
- Based on current data, about 11% of our fleet requires replacement or refurbishment/ coating within the next 10 years.
- By adopting a structure replacement strategy the risks associated with structure failure are increased as are the difficulty in obtaining the required lengthy circuit outages. Additionally the life cycle costs of regular coating programs are estimated to be less than half of a replacement strategy.

<u>Asset Strategy</u>

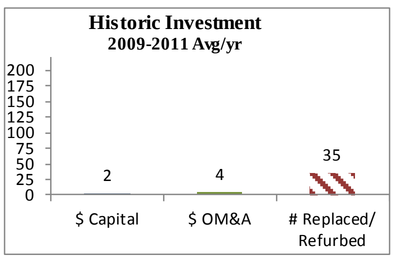
There are approximately 50,000 steel structures on the transmission system. Steel structures are manufactured with a hot dipped galvanized zinc coating to protect the steel from corrosion. Based on Hydro One Networks and industry experience, the expected life of zinc coating can be anywhere from 30 to 60 years. Towers themselves can be maintained indefinitely if properly treated. The actual life can vary significantly based on the tower environment; generally, the expected life is 80-100 years if they are not re-coated/painted, at which point they would require complete tower replacement.

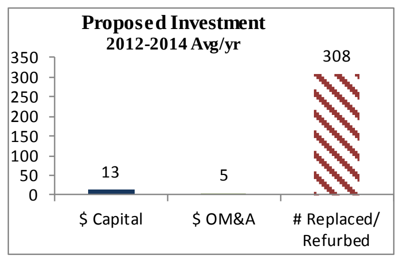
The existing strategy to manage the aging fleet of steel towers is a combination of planned replacements, member refurbishment and tower coating which optimizes the life cycles costs for these assets.

Steel Structures At a Glance

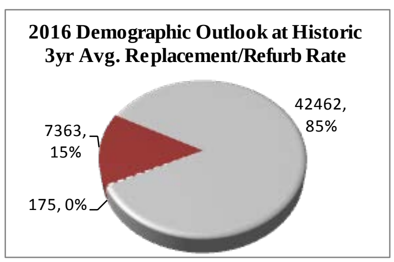
	Current State, 3yr Average Historic Investment	Proposed Investment, 3yr Bridge & Test Years Future Investment
Average CapEx ($M/yr)	2 2(2012$)	13 12(2012$)
Average OM&A ($M/yr)	4 5(2012$)	5 5(2012$)
Average Replacement (#/yr)	0	8
Average % Fleet Replaced (%/yr)	0.0%	0.01%
Average Coating/Refurb (#/yr)	35	300
Average % Coating/Refurb (%/yr)	0.1%	0.6%

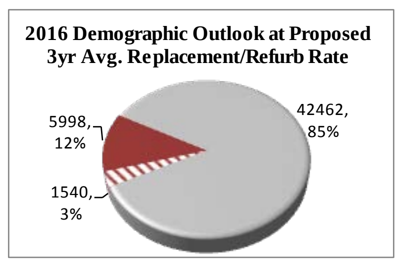
Investment Levels ($M, $ Units)



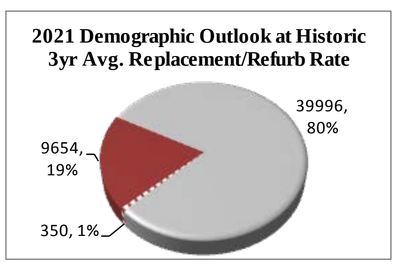


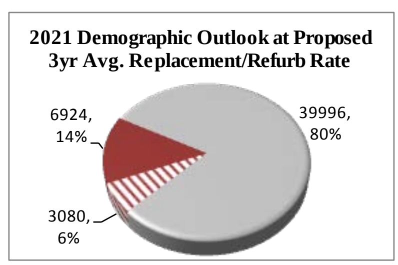
Five Year Outlook (# units)





Ten Year Outlook (# units)





Legend: Beyond Expected Service Life | Replaced | Within Expected Service Life

Business Value / Objective Commentary

	Impact to Values / Objectives
Safety	Refurbishment of steel structures will reduce the risk of failure and risk of injury to Hydro One employees and the public in the event of structure failure.
Reliability	There has been an increase in forced outage frequency over the past 5 years. Increased capital investment is required to improve this trend. The rate of deterioration of steel structure surface condition indicates that a significant percentage of our fleet of steel structures will be in a condition where the protective zinc coating will be depleted and metal loss will then begin to occur if this program is not increased. This could result in structures becoming structurally unsafe causing an increase in forced outages.
Customer	Failure of critical steel structures that may carry multiple circuits can take significant time to replace. This can place considerable strain on the system as it may result in loss of supply to large customers including utilities and generation connections.
Innovation	Hydro One Networks continue to explore new steel tower coatings that require less steel preparation work to apply in order to be effective, as well as coatings that are longer lasting than those that are currently commercially available.
Environment	The optimum time to coat a steel structure is when a very small thickness of zinc coating exists on the steel members. This requires very little surface prep and minimizes the risk of environmental contamination. Hydro One's strategy is to achieve optimal timing which minimizes environmental risks.
Cost Effectiveness	Optimum timed tower coating has a life cycle cost of about half of that of tower replacement and does not require extensive outages, which are very difficult to obtain.

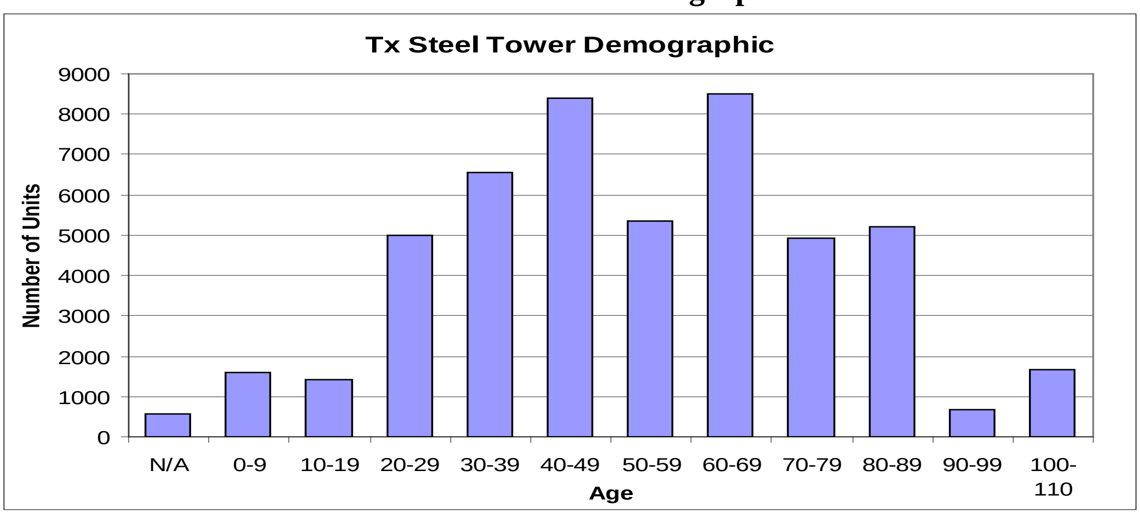
Asset Assessment Details

<u>Demographics</u>

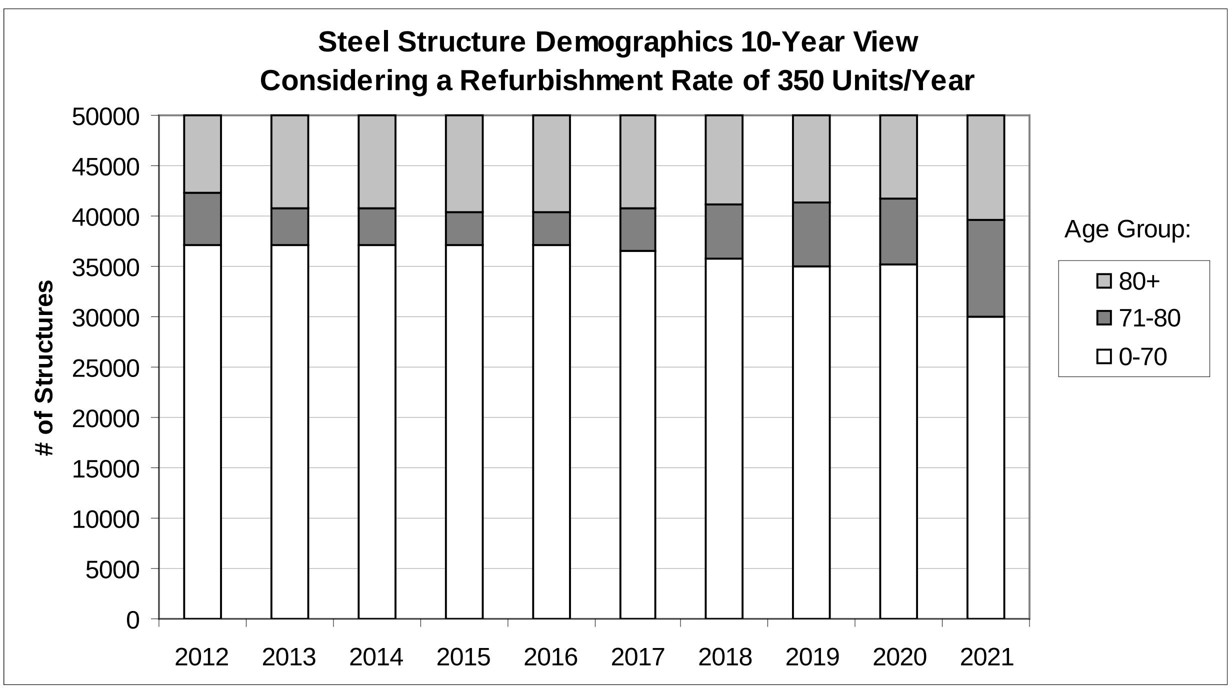
Hydro One’s Transmission system includes about 50,000 steel towers. The expected life of steel structures is 80-100 years if they are not re-coated/painted. Currently 3% of steel transmission towers are beyond 100 years of age and 11% are between 80-100 years of age.

The expected life of zinc coating can be anywhere from 30 to 60 years. Historically, the former Ontario Hydro and Hydro One networks instituted tower coating programs which have extended the life of some of these assets, however, interruptions to these programs, current demographics and recent condition data indicates a need to increase this program. Effective tower coating can maintain a steel tower structure indefinitely.

Figure 23
Steel Tower Demographics



	Quantity of Structures					
Age	**115kV**	**230kV**	**500kV**	**N/A**	**Total**	**% of Total**
N/A	345	100	6	121	572	**1%**
0-9	739	823	9	10	1581	**3%**
10-19	260	453	713	6	1432	**3%**
20-29	231	1614	3120	36	5001	**10%**
30-39	111	3408	3010	41	6570	**13%**
40-49	170	5509	2628	77	8384	**17%**
50-59	1819	3416	1	130	5366	**11%**
60-69	2822	5439	0	254	8515	**17%**
70-79	1975	2017	1	938	4931	**10%**
80-89	1533	2809	0	860	5202	**10%**
90-99	280	0	1	405	686	**1%**
100-110	1460	8	0	182	1650	**3%**
Total	**11745**	**25596**	**9489**	**911**	**49890**	**100%**



As can be seen in Figure 23, under the current sustainment plans for steel structures the average age of the fleet will increase from 52 years in 2012 to 60 years in 2021. The percentage of steel towers greater than 80 years old will remain at 14% by 2021.

<u>Performance</u>

Although single circuit tower outages typically do not result in delivery point interruptions, a multi circuit tower failure can result in customer outages, which would take a significant amount of time to restore due to the required time to replace/repair the damaged steel tower.

Figure 24:
Steel Tower Failures

	Voltage (kV)			
Year	**115**	**230**	**500**	**Total**
2002	2	3	0	**5**
2003	1	0	0	**1**
2004	0	1	0	**1**
2005	0	1	0	**1**
2006	1	0	1	**2**
2007	0	0	0	**0**
2008	0	1	1	**2**
2009	0	3	0	**3**
2010	0	0	0	**0**
2011	1	4	0	**5**
Total	**5**	**13**	**2**	**20**

Average number of failures = 2 per year over the past 10 years.

Forced outage frequency, demonstrated in Figure 25, represents the number of times an outage is caused due to a steel structure failure. It excludes forced outages caused by external interferences (animal contact, weather, etc.). Typical failures resulting in forced outages include a failed, broken or bent tower member. There has been a slight increase in forced outage frequency over the past 10 years. With the current condition of the steel structures and the demographics of the fleet, it is expected that an increase in the capital program will be required to prevent increases in forced outages due to steel structures.

Figure 25
Forced Outage Frequency of Steel Towers

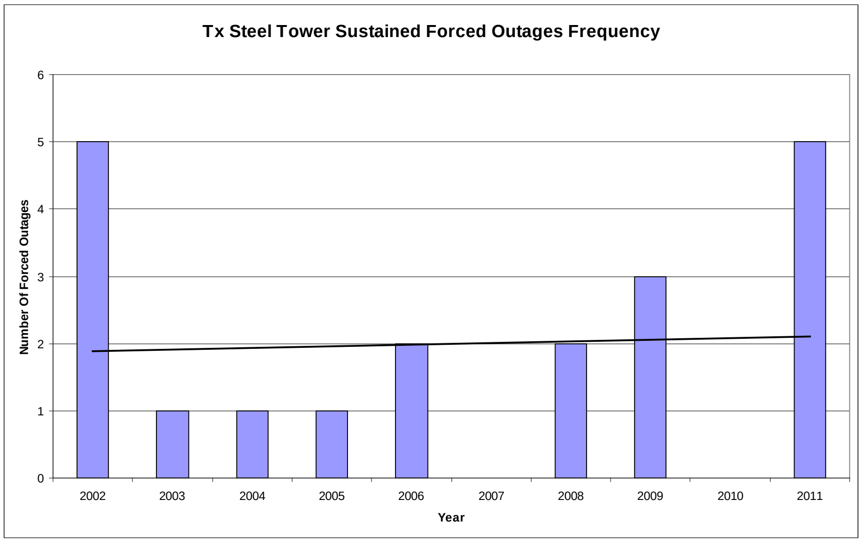
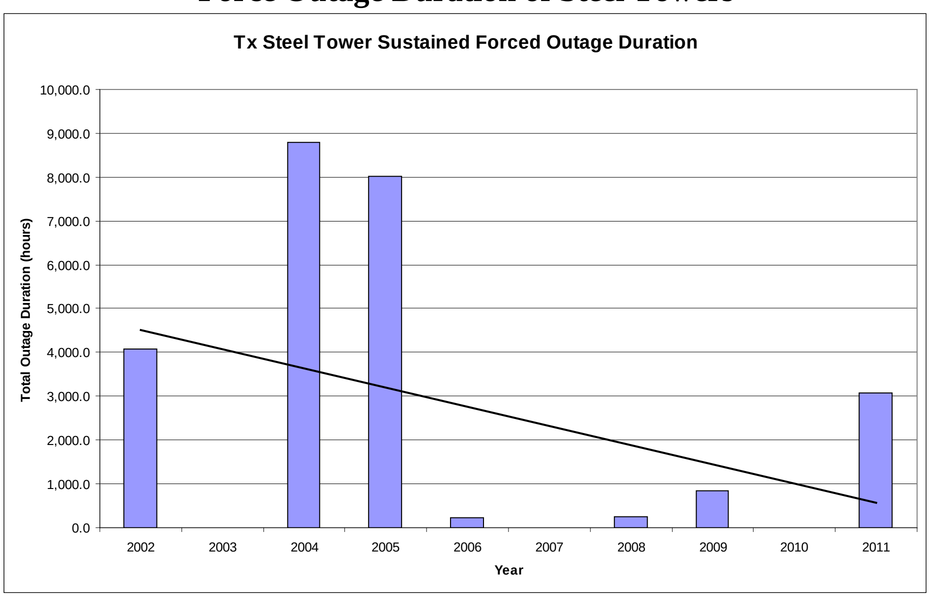


Figure 26
Force Outage Duration of Steel Towers



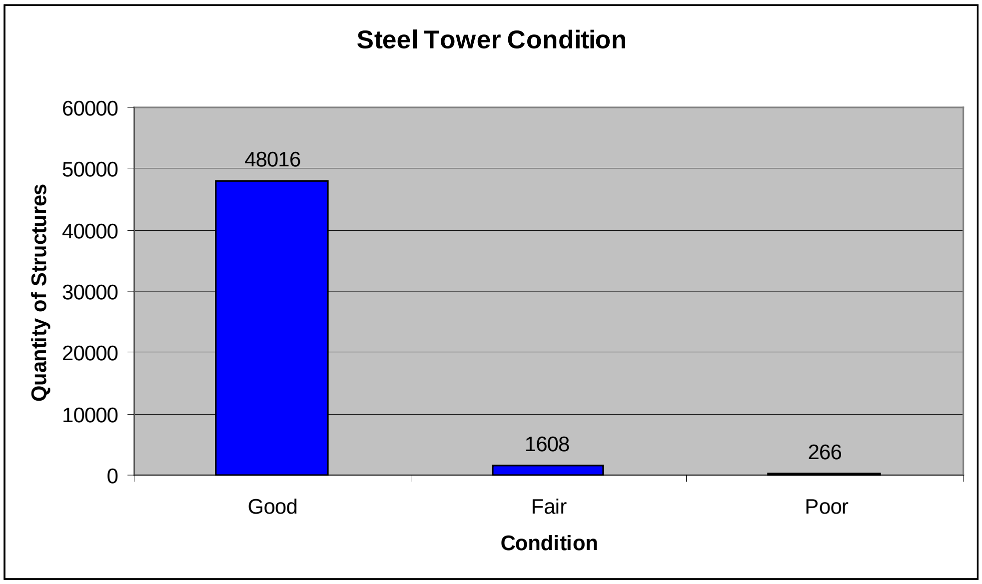
The Forced outage duration of steel towers shows a decreasing trend. In 2004 and 2005 there were a number of outages that occurred in very remote locations with difficult access affecting this trend.

Condition

Condition of towers is determined through inspections, patrols and detailed corrosion assessment. Towers are visually rated based on field guides that have been developed in accordance with NACE (Nation Association of Corrosion Engineers) guidelines on the degree of corrosion. Detailed corrosion assessment includes climbing towers and measuring the remaining thickness of protective coating (generally zinc), loss of metal if any and assessment of bolts and fittings. Reinstating the protective coating by painting presents the lowest life cycle cost and technically could be carried out on an ongoing basis to extend the life of these assets in perpetuity. Reliability is not a major consideration in determining the end of life of the coating, but if not reinstated and tower steel left to corrode, it would result in complete tower replacement at significantly higher costs.

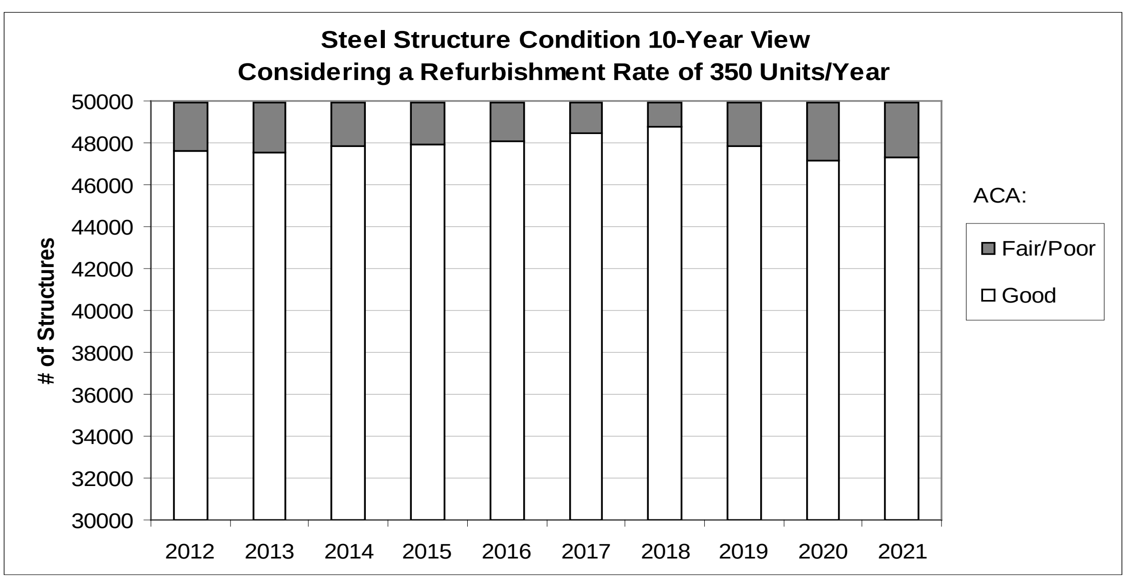
The current assessment of the steel tower fleet condition is illustrated in the Figure 27 below. This assessment is continuously reviewed and adjusted as new conditions are reported or factors are considered. Towers in the fair/poor categories (currently total about 4% of the population) meet the current refurbishment/coating criteria. An additional 7% will require refurbishment/coating in the next 10 years.

Figure 27
Steel Tower Condition



Towers in fair condition require coating within the next 5 years. Towers in poor condition require coating/refurbishment or if they have exceeded the optimum time to coat they will eventually require replacement.

Figure 28
Condition Trend at Planned Rate of Refurbishment



As demonstrated in Figure 28, the planned coating/refurbishment rate will maintain the number of towers of fair / poor condition over the next 10 years following which a further increase in the program will be required to maintain this risk profile.

Other Influencing Factors

Current approved coatings typically require extensive steel preparation in order for the coating to adhere once the zinc coating becomes depleted beyond an acceptable level which can be very costly. Hydro One Networks are investigating using alternative products in order to reduce the amount of steel surface preparation and the cost to carry out this work.

Cost Trends and Impacts

- O&M programs are being kept relatively stable with assessment activities performed frequently to assess zinc coating thickness and member condition.
- Test-year capital expenditure is increasing from recent historic and bridge years as there is a need to ramp up tower coating activities.
  - Average 3-year historic coating / refurbishment has been roughly 0.07% of the fleet per year,
  - Proposed average 3- year coating / refurbishment rate is roughly 0.6% of the fleet per year.
  - Average 3-year historic replacement rate has been 0% of the fleet per year.
  - Proposed average 3-year replacement rate is roughly 0.02% of the fleet per year.

Historic and Future Investment

The existing strategy to manage the aging fleet of steel towers is a combination of planned replacements, member refurbishment and tower coating. The goal of the program is to coat towers prior to reaching the member refurbishment or replacement stage. The number of towers that have been repaired, coated or replaced over the past 10 years has been very low. Results of recent asset condition inspections has pointed to rapid deterioration of steel structures in highly corrosive areas, which demonstrates a need to ramp up this program. Therefore, Hydro One

Networks plans to undertake an aggressive tower coating program to sustain these assets and minimize their life cycle costs, as they are very costly and disruptive to replace. Tower coating has been identified as the preferred alternative as it has a life cycle cost of roughly half that of tower replacement and is less impactive to the system as circuit outages required for coating are minimal.

Tower Portfolio - Historic Trend	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**
Capital – Coating/Refurb (quantity)	73	176	71	33	0	200	350	350
Capital – Coating/Refurb (% of Fleet)	0.1	0.4	0.1	0.1	0	0.4	0.7	0.7
Capital – Replacements (quantity)	0	0	0	0	0	16	4	4
Capital – Replacements (% of Fleet)	0	0	0	0	0	0.03	0.01	0.01
Capital ($M)	1.6	1.8	2.5	2.9	0.6	8.7	14.6	14.5
OM&A ($M)	3.3	5.0	5.1	3.6	4.7	4.8	4. 8	5.0

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4.7 Transmission Conductors

- Historic programs have been minimal but able to maintain the performance of conductors.
- Currently 16% of conductors are beyond their expected service life of 70 years. This number will double over the next 10 years.
- Current demographics and condition indicate that conductor sampling, testing and replacements will have to increase to maintain current levels of performance and risk.

Asset Strategy

Hydro One's transmission network consists of approximately 29,000 circuit km of overhead transmission lines. The average age of transmission conductors is about 49 years old. The life expectancy of conductors is estimated to be 70 years based on an Ontario Hydro study. The actual life varies with environmental conditions being the primary factor. Hydro One considers asset condition assessment results, performance data and asset demographics when making investment decisions related to conductors. To gather condition data, once they reach 50 years of age conductors are assessed by removing samples from different line sections and testing conductor strength, corrosion and serviceability characteristics (e.g. ductility and damage due to metal fatigue). When a conductor is deemed to have reached its end of service life all major components within that line section including the structures, shieldwire, ubolts and insulators are assessed and the line is refurbished to meet present and future system requirements.

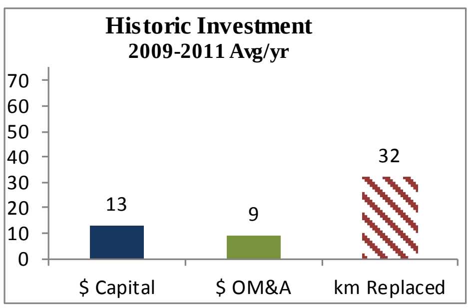
Cost Trends and Impacts

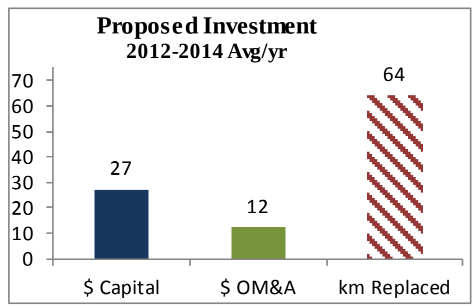
- O&M programs increase due to an increase in the conductor sample and testing program from 2% to 5%. This increase is required due to the current demographic trend and need for more detailed condition data to optimize replacement programs.
- Capital replacement program will increase from historic and bridge years. The increase from 0.1% to 0.2% is due to the current demographics and Hydro One's experience with conductor test results that are in the 70 year old range.

Tx Conductors At a Glance

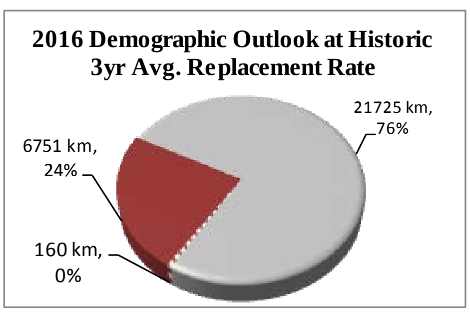
	Current State, 3yr Average Historic Investment	Proposed Investment, 3yr Bridge & Test Years Future Investment
Average CapEx ($M/yr)	13 14(2012$)	27 26(2012$)
Average OM&A ($M/yr)	9 9(2012$)	12 12(2012$)
Average Replacement (km/yr)	32 km	64 km
Average % Fleet Replaced (%/yr)	0.1%	0.2%

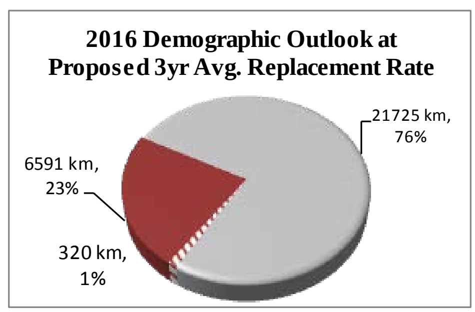
Investment Levels ($M, km)



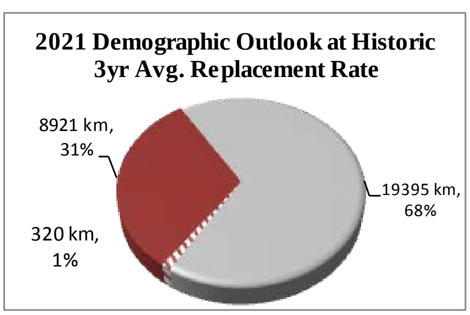


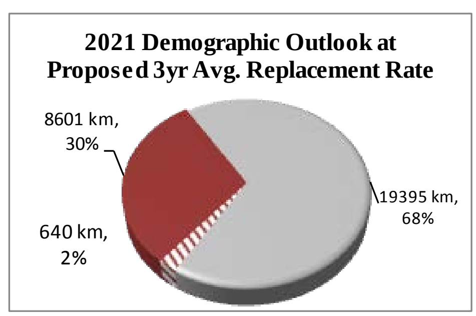
Five Year Outlook (km)





Ten Year Outlook (km)





Legend: Beyond Expected Service Life | Replaced | Within Expected Service Life

Business Value / Objective Commentary

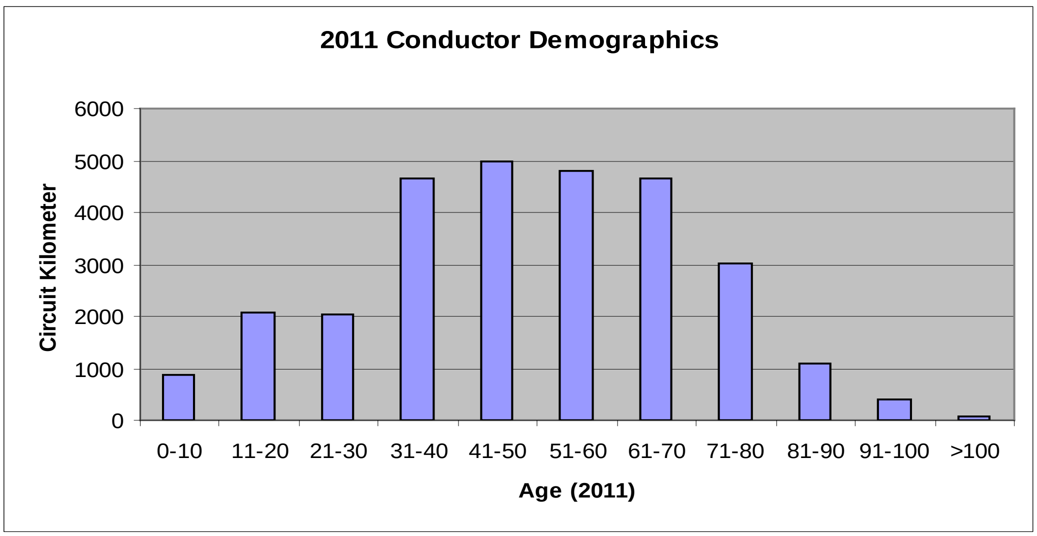
	Impact to Values / Objectives
Safety	Transmission lines are located in the public domain. Refurbishment of transmission conductors will reduce the risk of failure and risk of injury to public in the event of conductor failure.
Reliability	There has not been a considerable change in contribution of conductors to the overall number of outages over the last 10 years. However, duration of outages associated with conductor related issues during the past 10 years has increased indicating that the issues are becoming more severe. Condition trends also indicate that the number of outages related to conductors will increase unless the refurbishment rate is increased.
Customer	Failure of conductors, especially those that may feed large customers on single supply, can have significant consequences to supply continuity.
Innovation	Hydro One Networks continue to utilize high temperature low sag conductors that carry increased load while still respecting the mechanical loading constraints of the existing structure. Networks are also investigating the use of a remote controlled conductor assessment device that can be used on energized lines and crawls along the conductor to non-destructively assess conductor condition.
Environment	Failure response to downed/failed conductor will impose a higher risk of damage to environmentally sensitive areas than that of planned conductor replacement.
Cost Effectiveness	Work bundling of planned conductor replacement with refurbishment of other transmission line components at the same time is a cost effective approach that is taken in replacing all conductors.

Asset Assessment Details

<u>Demographics</u>

The majority of Hydro One circuits were built between 1940 and 1980. As such, a bow wave of conductors will be reaching the 70 year expected service life in the next 20 years. Currently about 16% of the conductors are over 70 years of age. This will double in the next 10 years and by 2021 approximately 32% of transmission conductors will have reached or exceed the average expected service life.

Figure 29
Conductor Demographics



Transmission Conductors Demographics			
		Circuit km	%
Age Group	0-10 years	861	3
	11-20 years	2 064	7.2
	21-30 years	2 027	7.1
	31-40 years	4 658	16.3
	41-50 years	4 979	17.4
	51-60 years	4 806	16.8
	61-70 years	4 660	16.3
	>70 years	4 581	15.9
	Total	28 636	100

Performance

Figure 30
Conductor Forced Outage Frequency

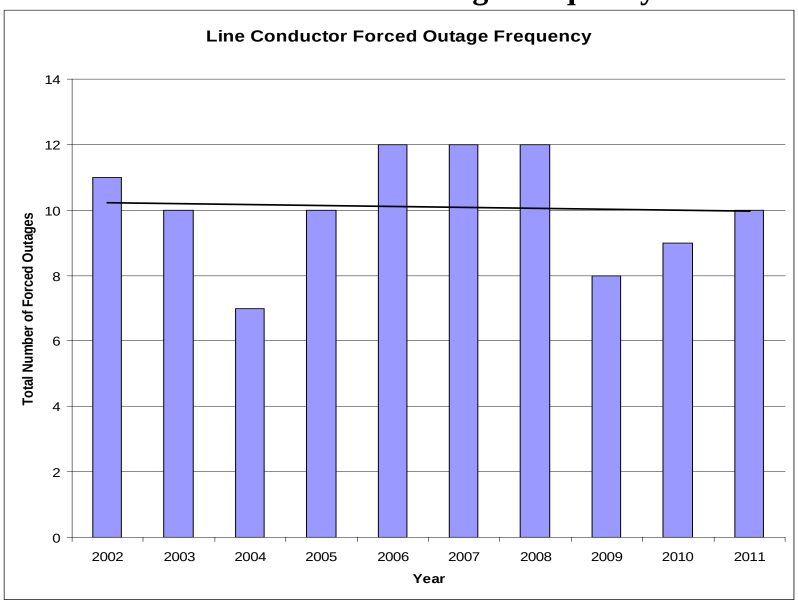
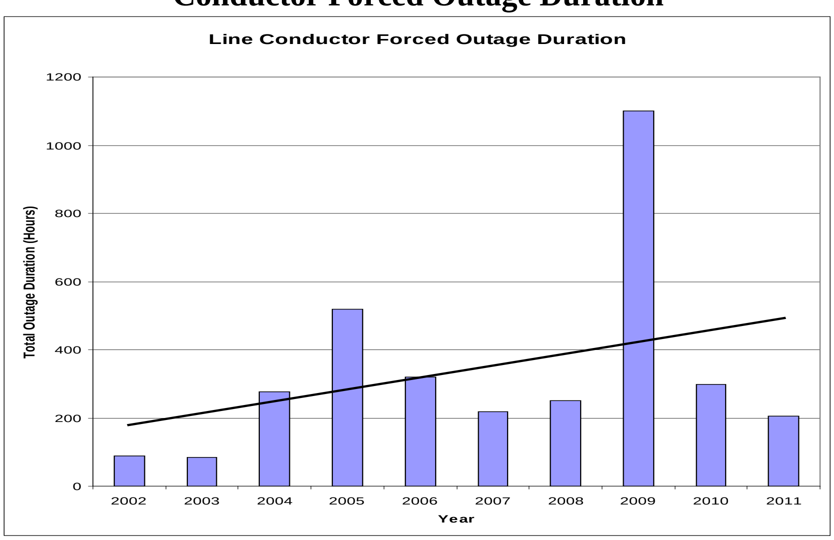


Figure 30 illustrates the number of sustained outages due to conductor failures in past 10 years, which has been stable.

Figure 31
Conductor Forced Outage Duration

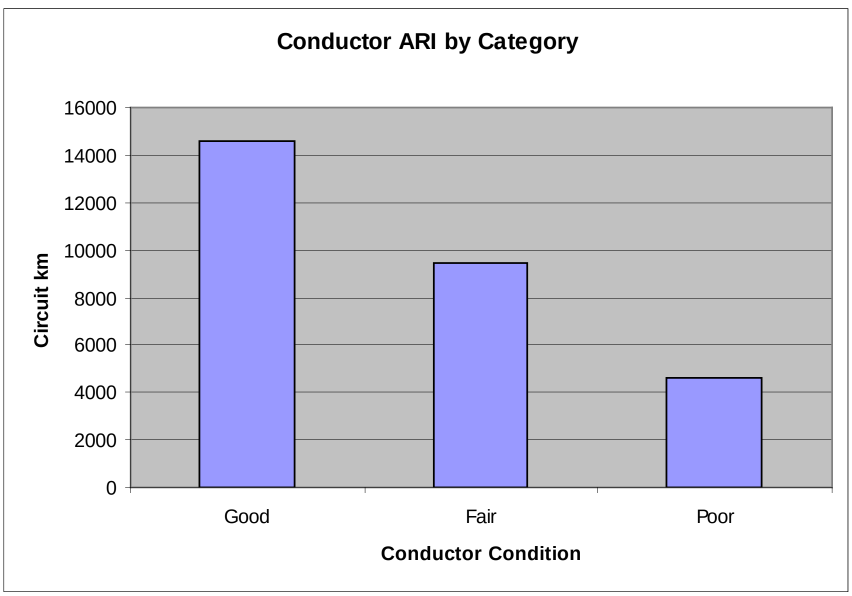


Forced outage duration displayed in figure 31 demonstrates that conductor outage duration has increased over the last 10 years. This is a measure of the severity of the defects that caused the circuit to be forced from service. This trend is expected to continue given the demographics and condition of the fleet.

Condition

The current overview of the conductor condition is illustrated in graph below. The corrosivity of the surrounding environment will have a significant impact on the condition of the conductor. Hydro One has implemented a condition assessment program to assess condition of conductors after they reach 50 years of age. There are about 885 line sections that are 50 years of age and older, and about 27% of these have been tested through routine laboratory tests. The results from these tests and previous studies carried out on life expectancy of conductors indicate that the general health of the conductor population is in accordance with Figure 32 below.

Figure 32
Conductor Condition Ratings



Other Influencing Factors

There are other factors such as Aeolian Vibration that can considerably affect the life expectancy of a conductor. Geographical location, line orientation and more importantly conductor tension contribute to level of vibration each circuit experiences, which directly influences the useful lifespan of a conductor. For example, the following premature conductor failures were due to combination of conductor condition and conductor fatigue due to vibration.

- Two conductor failures on N21W/N22W circuits in 2004 and 2005 when conductors were only 44/45 years old.
- Multiple near conductor failures on B10/B20H circuits in 2009 when conductors were only 39 years old.

Historic and Future Investment

Over the last 3 years about 30 circuit km of transmission conductor per year were replaced as part of the conductor replacement program (about 0.1% of transmission conductor fleet per year). The proposed level will include average annual replacement of about 85 circuit km of conductors (0.29% of the fleet) during the test years. The circuits being addressed in the bridge and test years have all been identified as in poor condition through the testing and assessment process. The proposed OM&A funding level has increased slightly due to the need for more condition assessments as the fleet ages.

Conductor Portfolio – Historical & Proposed	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**
Capital – circuit km	30	30	37	22	75	95
Capital - % of fleet	0.1	0.1	0.13	0.08	0.26	0.33
Capital ($M Net)	**14.4**	**14.7**	**10.2**	**8.6**	**36**	**37.5**
OM&A ($M Net)	8.4	7.3	10.6	10.6	12.8	13.6

Appendix A

Hydro One Transmission Asset Descriptions

Hydro One Transmission Assets

1.0 Introduction

This report provides descriptions, demographic data and performance data for major transmission assets that are affected by Hydro One Sustaining investments. This report is intended to provide context for the investment programs described in Exhibit C1, Tab 3, Schedule 2 - Sustaining Operating, Maintenance and Administration (OM&A) and in Exhibit D1, Tab 3, Schedule 2 - Sustaining Capital.

This report describes assets that are in the following categories:

- 2.0 Station – Power System Equipment
- 3.0 Stations – Protection and Control
- 4.0 Lines

2.0 Station – Power System Equipment Descriptions

This section provides descriptions of major power system assets that are found at Hydro One Stations excluding Protection and Control assets.

2.1 Circuit Breakers - General

A circuit breaker is a mechanical switching device that is capable of making, carrying and interrupting electrical current under normal and abnormal circuit conditions. Abnormal conditions occur during a short circuit such as a lightning strike or conductor contact to ground. During these conditions, very high electrical currents are generated that greatly exceed the normal operating levels. A circuit breaker is used to break the electrical circuit and interrupt the current to minimize the effect of the high currents on the rest of the system.

Transmission system buses are typically configured to provide either a breaker and a half or a breaker and one third arrangement, providing a degree of redundancy. Medium voltage breakers are typically configured in a radial feeder arrangement but a degree of redundancy is provided by the feeder tie switch normally used at DESN stations. Breakers may be constituted either as a 3-pole unit, with the operating mechanisms of all three phases contained in a single tank; or 3 single-pole units, with each pole contained in its own tank, and linked together to operate simultaneously. General Purpose circuit breakers are intended to operate infrequently. Definite purpose circuit breakers are designed to operate frequently, for applications such as capacitor and reactor switching.

Hydro One currently manages approximately 4490 in-service circuit breakers. These breakers are separated into different classes based on specifications, voltage and manufacturer. The insulating medium determines the type of circuit breaker e.g. oil, air, vacuum or sulphur hexafluoride (SF_6) gas. Circuit breaker technology has evolved over time with the use of these insulating media i.e. oil was developed first, then high pressure air blast circuit breakers (ABCBs), and now vacuum and SF_6 Air blast technology replaced oil to cope with the higher power system voltages (the physical space and oil volume requirements at these higher voltages are enormous), but it also eliminated the environmental and fire hazards associated with oil. SF_6 was later introduced to replace air because it is a very stable, chemically inert gas whose insulating properties are 2-3 times greater than air making it ideal for use at high system voltages.

Circuit breakers are intended to operate infrequently; however, on the occurrence of an electrical fault, the breaker must operate reliably and very quickly to interrupt the fault without damage to itself and with a minimum disturbance to the remainder of the circuit and the electrical system. Typically, they are capable of interrupting currents in as short a time as 32 milliseconds.

Hydro One currently employs a variety of breaker technologies and ratings at non-GIS substations. The majority of the oil and air blast, (obsolete technology) circuit breakers are over 40 years of age with some approaching 60 years since their original manufacture.

While SF6 and Air Blast designs are applied across the complete medium and high voltage rating spectrum, oil circuit breakers are not applied beyond the 230kV level. Magnetic Air and Vacuum technologies are restricted to the medium voltage categories below 50kV and together with their medium voltage SF6 counterparts are applied, in outdoor air insulated stations (AIS) and in indoor metalclad switchgear arrangements. The majority of SF_6 breakers and essentially all oil breakers within the Hydro One system are of the dead tank type. Typically the dead tank design is the most cost effective since it can incorporate all necessary current transformers, thereby reducing space and installation requirements. Due to physical similarities, many oil circuit breakers that have reached the end of their service lives are being replaced with dead tank SF_6 breakers.

In dead tank design, the interrupter chamber is accommodated in a grounded metal housing. SF_6 gas serves as an insulator between the live contact assembly and the surrounding metal housing. High voltage terminals are connected to the interrupter chamber through outdoor bushings. Bushings normally incorporate bushing CTs thus avoiding the need for free standing HV current transformers. Dead tank circuit breakers employing both the old double-pressure technology and the newer, and simpler, single pressure technology have been applied on the Hydro One system. The dead tank design has been widely used at the medium voltage levels and at the lower transmission voltage applications (115 and 230 kV, but has also been developed for application at the highest voltage levels). Several have been successfully applied on the Hydro One 500 kV system.

In the live tank design, the interrupter chamber, which may be of the porcelain or composite material, is supported and insulated from ground, by vertical insulating support columns. Thus the chamber or tank is operated at system voltage. Voltage level determines the dimensions of the support and the tank insulators.

A very small portion of Hydro One HV SF_6 breakers and all HV air blast breakers are of the live tank type and are normally associated with separate, free standing, current transformers.

2.1.1 Oil Circuit Breakers

Oil Circuit Breakers (OCBs) are installed on the power system to interrupt load and fault currents and to de-energize power carrying assets to facilitate maintenance. An OCB consists of either one or three steel tanks filled with insulating oil in which pairs of operating contacts are immersed. These contacts are enclosed in an arc control "pot" which enables rapid extinction of the arc during an interruption.

A typical high voltage OCB used by Hydro One is shown in Figure 1.

Figure 1 - Three Tank Oil Circuit Breaker

Method of Arc Extinction

The method of arc extinction employed in OCBs is high-resistance interruption. The arc is controlled in such a way that its resistance is caused to increase rapidly, thus reducing the current until it falls to a value that is insufficient to maintain the gas ionization process.

Main Components

The main components of bulk OCBs are listed below, along with a short description of their use and purpose:

Control Cabinet and Operating Mechanism

The cabinet contains control relays, wiring, heaters, current transformer terminals, and the breaker-operating mechanism.

Tank

The tank contains the oil, the interrupter units, support mechanisms and operating rods and linkages to ensure simultaneous operation of each interrupting unit. Current transformers for protective relaying and metering purposes are also installed inside the tank where the incoming high voltage connections are located.

Exterior of the Tank

Oil-filled bushings are mounted on the tank for electrical clearance and the connection of the breaker into the power system.

2.1.2 SF6 Circuit Breakers

The first SF_6 circuit breaker was developed in the late 1960s and was a double-pressure design (low pressure tank and high pressure reservoir), based on the air blast technology. The double pressure design is very complex both electrically and mechanically and was quickly rendered obsolete by the single pressure design developed in the mid 1970s. The simpler, single pressure SF_6 insulated circuit breaker, despite some early design reliability issues, has now become the technology of choice for transmission class circuit breakers. No compressor or other complex auxiliary equipment is required, since the gas for arc interruption is compressed in a puffer action by a piston during the opening operation. Recent improvements in the single pressure design, by the use of self blast or other related techniques to assist the interrupting process, has resulted in still simpler and more reliable breakers using spring charged or hydraulic-spring operating mechanisms.

A typical HV SF_6 circuit breaker used by Hydro One is shown in Figure 2.

Figure 2: Dead Tank SF_6 Circuit Breaker

Hydro One introduced SF_6 equipment to the system at a very early stage in its evolution during the 1970s. As a result of this, they did suffer from significantly raised failure rate due to prototype problems. In addition, the degradation in performance was accelerated by the more onerous operating and special purpose switching conditions encountered on the Hydro One system.

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 of 2000 switching operations.

Heaters are required on many of these breakers to prevent liquefaction of the SF6 gas at the low temperatures prevailing in Ontario. Heaters and control equipment, contactors, thermostats, and wiring degrade at an accelerated rate under these extreme conditions.

Gas seals leak at an increased level at low temperature putting increased pressure associated apparatus. Generally, earlier models have more problems than later ones, since modern equipment has improved seal and valve designs.

2.1.3 Air Blast Circuit Breakers (ABCBs)

High voltage (115kV, 230kV and 500kV) ABCBs are typically applied in "breaker and a half" and "breaker and a third" schemes which provide improved reliability by redundancy. Low voltage (less than 50kV) ABCBs are connected radically to supply load to individual feeders. A typical HV ABCB used by Hydro One is shown in Figure 3 below.

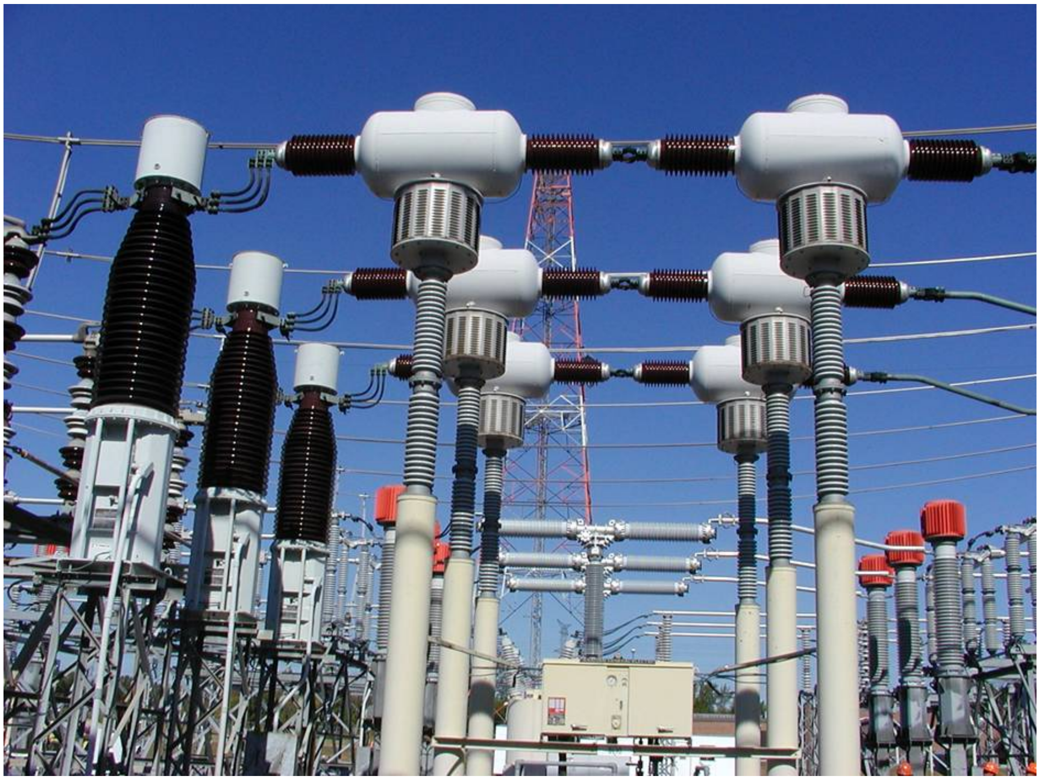


Figure 3: 230 kV Air Blast Circuit Breaker

ABCBs are complicated in design and incorporate a large number of moving parts, valves and seals. They also require a high-pressure compressed air (HPA) supply. Centralized HPA systems are installed at all locations that have a population of ABCBs. The HPA systems are usually comprised of multi-stage compressors, chemical or heated dryers, numerous air storage receivers, extensive piping and valving arrangements, and controls. The design, condition and successful operation of the central air systems have a direct bearing on the capability of the ABCB to properly perform its designed function. Excessive moisture in the air could lead to explosive failure of circuit breakers. Conversely if ABCBs experience excessive leakage it will result in excessive run times for compressors and dryers and increased maintenance and refurbishment costs related to the air system

The utility industry has identified degradation of gaskets, seals, and valves as the critical long-term issues related to EOL of ABCBs. Experience has shown that gasket and seal deterioration is time-related with major performance problems being experienced when gaskets and seals are 20-25 years old. To deal with these in the past Hydro One has undertaken a major rebuild of each ABCB after approximately 20-25 years of service. The last rebuild program was completed in 1995. OEM facilities and resources associated with the rebuild program are no longer available and major rebuilds are no longer feasible.

2.1.4 Gas Insulated Switchgear (GIS)

Gas insulated switchgear (GIS) is an assembly of switchgear in which all of the major components, except for the entrance bushings, are housed within a grounded metal enclosure containing pressurized sulphur hexafluoride (SF_6) gas. The GIS is compartmentalized in such a manner as to readily facilitate maintenance of individual components with minimum disruption to adjacent components and also to minimize gas losses in the event of an uncontrolled rupture of an enclosure. Many compartments are fitted with pressure relief devices which are designed to relieve excess pressure in the event of an internal fault and so prevent enclosure rupture. GIS is very compact compared to AIS and is applied at all the voltage levels, LV, HV and EHV on the Hydro One system. Gas insulated switchgear is an attractive alternative to an outdoor air insulated substation (AIS), particularly where space constraints and protection from harsh environmental conditions are a consideration.

All are indoor installations. Some are in heated buildings, while others are in unheated buildings. Several stations have extensive outdoor runs of bus between the GIS and associated overhead line terminations and transformers. As shown in Figure 4 and 5, the GIS incorporate some or all of the following components:

- Circuit breakers
- Switches - disconnect and ground switches
- Bus

Other equipment including: SF_6/air entrance bushings; SF_6/cable terminations, instrument transformers, current and voltage transformers, surge arresters and protection, control, and monitoring equipment

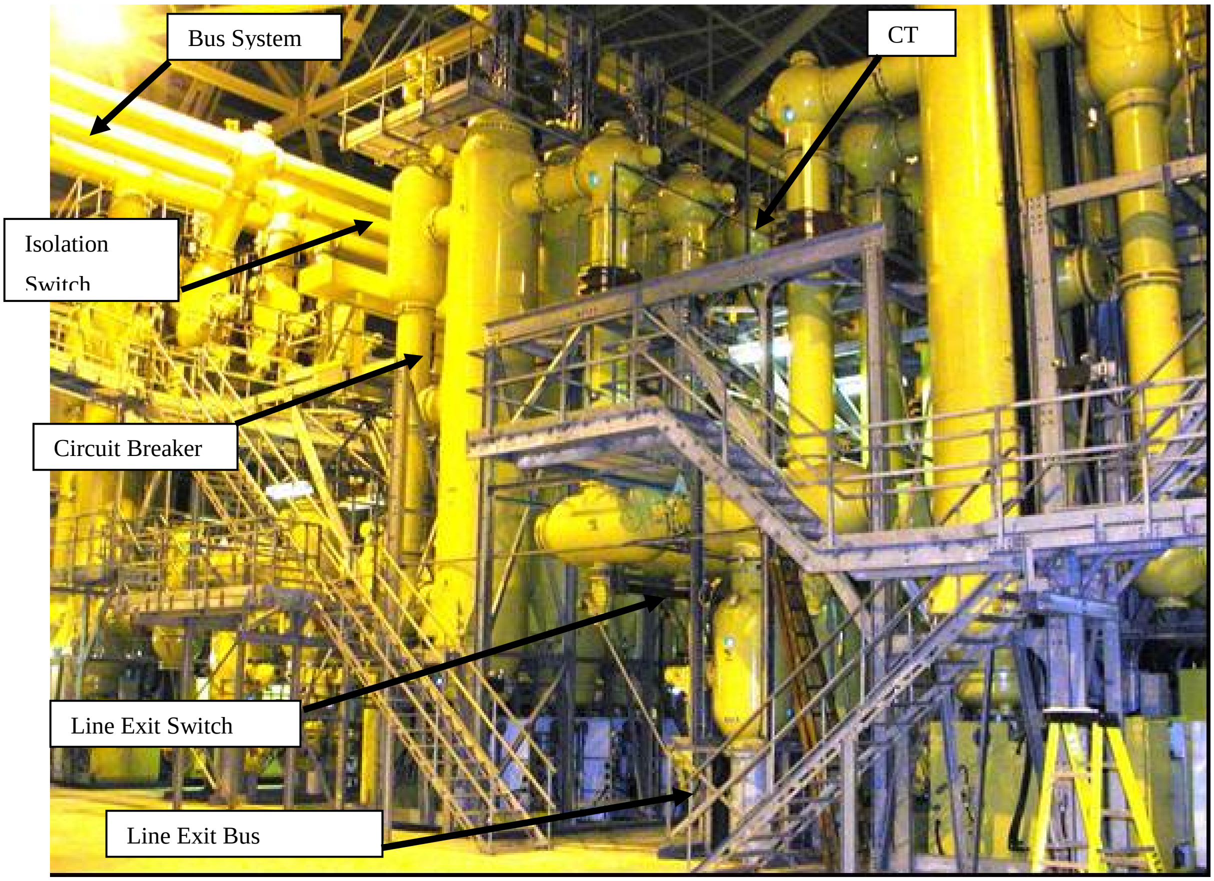


Figure 4: 500 kV GIS Indoor Equipment

Figure 5: 500 kV GIS Outdoor Exit Bus Equipment

Metal enclosed, concentric, SF_6 insulated buses are used to interconnect other live GIS components such as circuit breakers, disconnect switches and interfaces with overhead lines, cables and transformers. Within the bus, aluminum conductors are supported on epoxy resin insulators. About 30% of the failures which have occurred since the late 1970s have been on these epoxy resin insulators. The current failure rate is considerably lower and Hydro One has developed diagnostics and monitoring procedures to detect potential failures.

2.1.5 Metalclad Switchgear

Metalclad switchgear is an assembly of switchgear in which all of the major components are housed within a grounded metal enclosure. Construction for this type of equipment utilizes insulated bus and compartmentalization. The switchgear is compartmentalized in such a manner that all major power components are completely segregated from each other by a grounded metallic enclosure. Metalclad switchgear is an attractive alternative to an outdoor air insulated substation (AIS), particularly where space constraints and protection from harsh environmental conditions are a consideration.

All Hydro One metalclads are indoor installations. Some are in heated buildings, while others are in unheated buildings. The switchgear incorporates some or all of the following components:

- Circuit breakers
- Switches
- Bus
- Other equipment including: entrance bushings; cable terminations, instrument transformers, current and voltage transformers, surge arresters and protection, control, and monitoring equipment

The majority of Hydro One's voltage metalclad switchgear installations consist typically of an indoor line-up of 10 to 14 cells as illustrated in Figure 6.

Figure 6: Typical Hydro One Metalclad Switchgear

Figure 7 shows a typical circuit breaker withdrawn from the Metalclad Switchgear.

Figure 7: Circuit Breaker Withdrawn from Breaker Compartment

Figure 8 shows a typical control cabinet that is located within the Metalclad Switchgear.

Figure 8: Control Compartment

There are a variety of circumstances that result in internal arcs in metalclad switchgear. Often times this failure occurs when the breaker fails during routine switching or when clearing a through fault. A dangerous situation also exists when a breaker fails to properly open prior to racking-in or racking-out. Other causes of internal failure are due to partial discharge activity that weakens the insulation over time. Overvoltage surges on equipment with weakened insulation can result in internal failure. Operational mishaps can occur to cause internal faults such as mis-operation, or tools, grounds or other equipment being left in a cubicle during maintenance checks.

Although the probability of an arcing fault inside MV metal-clad switchgear is low, the cost in terms of personnel safety and equipment damage is high when an arcing fault occurs. Since the early 1980's some Canadian utilities including Hydro One have purchased arc resistant medium voltage switchgear. Hydro One still retains a significant population of older switchgear on the system which was retrofitted with minimum arc resistance provision but does not meet current standards for arc resistance. The majority of the circuit breakers in these switchgears are either obsolete air magnetic or SF6 designs. All modern switchgear incorporates vacuum circuit breakers for economic reasons and because of environmental concerns with SF6.

Arc resistant switchgear is characterized by some special design features necessary to achieve the required ratings. The switchgear enclosure construction must be designed to contain the internal arc pressure and direct it to the pressure relief flaps or exhaust chambers designed to safely vent the arc products. Movable vent flaps are designed to open due to the arc fault pressure, increasing the volume containing the arc products. Any ventilation designs with flaps that are open under normal operating conditions must close when an arc fault occurs

Racking and operation of all equipment such as circuit breakers, switches and instrument transformers must be through closed doors.

The integrity of the low voltage control and protective device circuitry is critical. Instrument compartments, which contain the protective relays, meters, devices, and wiring, should be separate reinforced modules. The interior surfaces of the instrument compartment are considered as part of the arc resistant enclosure boundary and must satisfy the same criteria as the switchgear enclosure during type testing. This protects personnel who may be working in or near the compartment as well as the P&C devices themselves, and control wiring which may otherwise be destroyed as a result of the arc fault. This is extremely important as the protective scheme is being relied on to limit the duration of the arc fault.

Sufficient clearance must be provided above the switchgear to allow the arc products to be dispersed properly and not to be reflected back into the area that could be occupied by personnel. Additionally sufficient clearance from the pressure relief flaps should be provided for any control cable trays, medium voltage insulated cables, buses or other electrical equipment located above the switchgear. Where appropriate clearances are not possible due to the design of the enclosure/building, an exhaust plenum can be provided to safely vent the gases externally to an area that is not accessible to personnel. The plenum design must be tested to verify satisfactory performance under internal arc fault conditions.

Studies in the past indicate that certain existing indoor metalclads of simple design (i.e. few compartments per cell) can be retrofitted with limited arc resistant functionality. This has been implemented in all of the pre-1985 metalclads which comprise about 50% of the Hydro One metalclad population. However this limited arc resistance functionality does not generally comply with Hydro One current Safety and Arc Flash requirements. In addition at least 10 of these installations require the cell door to be opened and the circuit breaker to be manually levered into place, which represents a high risk for personnel safety.

2.2 Transmission - Power Transformers

Transformers are static devices whose primary purpose is to either step-up or step-down voltage. Transformers change AC electric energy at one-voltage level to AC electric energy at another level via induction of a magnetic field. A transformer consists of two or more coils of wire wrapped around a common ferromagnetic core. One of the transformer windings is connected to the source of the AC electric power called the primary or input winding, and the second winding connected to the load is called the secondary or output winding. The main connection between the windings is the common magnetic flux present within the transformer's core.

2.2.1 Power Transformers

The purpose of a power transformer is to convert large amounts of electrical power from one voltage level to another. These devices vary in size from that of a small car to the size of a small house. There are two general classifications of power transformers: transmission transformers and distribution transformers. Transmission transformers connect transmission lines of various voltages to one another. Transmission power transformers are almost always fitted with the under load tap changer (ULTC) mechanism. A picture of a typical Hydro One's transmission station power transformer is shown in Figure 9.

Figure 9: Typical Transmission Station Power Transformer

Transformers are made up of the following primary components. Some components are optional, as indicated below, depending on the transformer application:

- Primary and secondary windings each installed on a laminated iron core
- Some also have tertiary windings
- Internal insulating mediums
- Main tank
- Bushings
- Cooling system, including radiators, fans and pumps (Optional)
- Off circuit tap changer De-energized tap changer (Optional)
- ULTC LTC (Optional)
- Current and potential transformers
- Mechanism cabinets.

Primary and Secondary Windings

The primary and secondary windings of a transformer are each installed on a laminated iron core and serve as the coils that react with the magnetic flux of the transformer core. When the magnetic circuit takes the form of single ring encircled by two or more groups of primary and secondary windings distributed around the periphery of ring, the transformer is termed a core type transformer. Core type transformers represent close to 100% of the power transformers built today and are widely applied because the design is technically reliable and it is cost effective. Figure 10 shows the construction of a single-phase core type transformer.

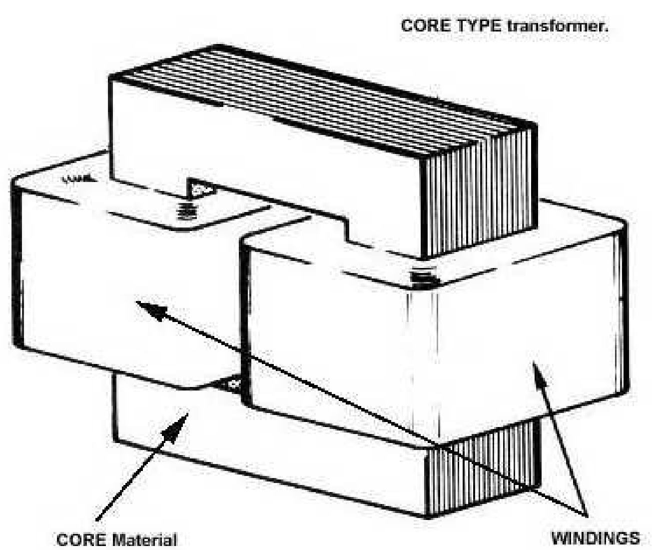


Figure 10: Core Type Transformer

When the primary and secondary windings take the form of a common ring that is encircled by two or more rings of magnetic material distributed around its periphery, the transformer is termed a shell type transformer. Figure 11 shows the construction of a shell type transformer.

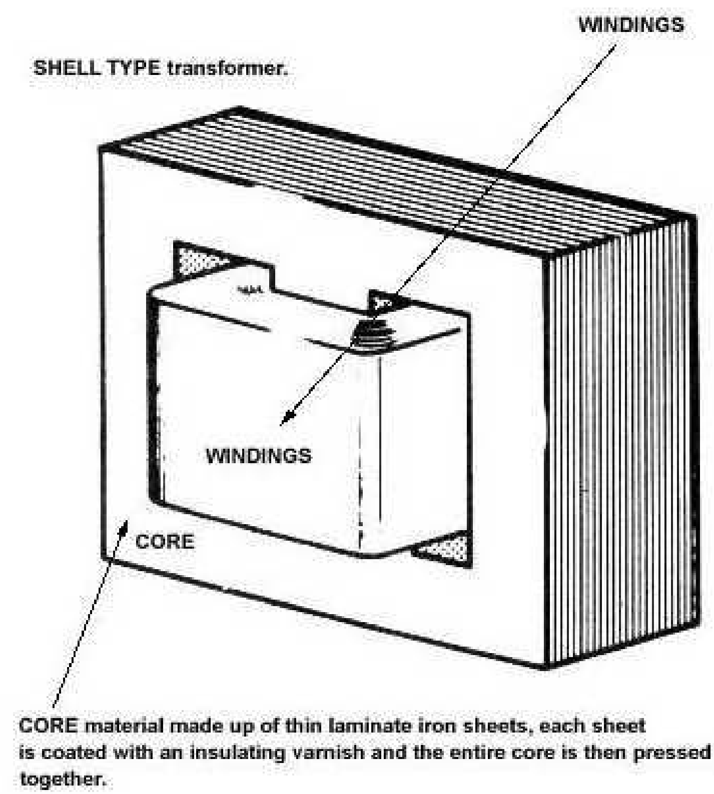


Figure 11: Shell Type Transformer

Shell type transformers are an older, more complex, transformer design that are more costly to build, but normally exhibit a superior short circuit withstand capability. Westinghouse transformers built prior to 1965 are of this design. The winding materials are made of both copper and aluminum, available in sheet (foil) and rectangular conductor configurations. For transposed cable applications only copper is used.

Internal Insulating Mediums

The internal insulating mediums serve as the necessary electric insulation and in the case of mineral oil as a coolant. Low cost, high dielectric strength, excellent heat-transfer characteristics, and ability to recover after dielectric overstress make mineral oil the most widely used transformer insulating material. The oil is reinforced with solid insulation in various ways. The major insulation usually includes barriers of wood-based paperboard (pressboard), the barriers usually alternating with oil spaces. Because the dielectric strength of oil is approximately half that of the pressboard, the dielectric stress in the oil is higher than that in the pressboard, and the design structure is usually limited by the stress in the oil. The insulation on the conductors of the winding may be enamel or wrapped insulating paper tape which is either cellulose or nylon based. The use of insulation directly on the conductor actually inhibits the formation of potentially harmful electrical breakdown streamers in the oil, thereby increasing the strength of the structure. Heavy paper wrapping is also usually used on the leads which connect the windings to the external terminals of the transformer.

Main Tank

The main tank is used to hold the active components of the transformer in an oil volume that maintains a sealed environment through the normal variations of temperature and pressure. Typically the main tank is designed to withstand a full vacuum for initial and subsequent oil fillings and is able to sustain a positive pressure. The main tank also supports the internal and external components of the transformer. Main tank designs can be classified into 2 types those being conservator and sealed types.

Hydro One typically uses conservator types which have an externally mounted tank that is designed to hold up to 12% of the main tank's volume. As the transformer oil expands and contracts due to system loading and ambient temperature changes, the corresponding oil volume change must be accommodated. This tank is used to provide a holding mechanism for the expansion and contraction of the main tank's oil over these temperature variations. This design reduces oxygen and moisture contamination since normally only a small portion of oil is exchanged between the main tank and the conservator and a minimum volume of the oil is exposed to the air. However, eventually oil in the conservator is exchanged with oil in the main tank and oxygen and other contaminates gain access to the insulation.

Bushings

Bushings are used to facilitate the ingress of the electric power circuits in an insulated, sealed (oil-tight and weather-tight) manner. A bushing is typically composed of an outer porcelain body mounted on metallic flange. The phase leads are either independent paper insulated, or are an integral part of the bushing. At the higher voltage levels, additional insulation is incorporated in the form of mineral oil and wound paper stress cone installed within the porcelain body.

Power transformers bushings can be roughly divided into "bulk" and "condenser" types and are used on the primary and secondary winding connections including the neutral points.

Cooling System (Radiators, Fans, and Pumps)

Cooling systems provide a means for the removal of internal heat generated through the transformer losses. The system is necessary to prevent the build up of excessive internal temperatures that would shorten the life of the insulation systems. Transformer cooling system ratings are typically expressed as:

- Self-cooled (radiators) with designation as ONAN (oil natural, air natural).
- Forced cooling first stage (fans) with designation as ONAF (oil natural, air forced).
- Forced cooling second stage (fans and pumps) with designation as OFAF (oil forced, air forced).
- Forced cooling first or second stage (fans and pumps) with designation as ODAF (oil directed, air forced).

The utilization of a number of cooling stages allows for an increase in load carrying capability. Loss of any stage or cooling element may result in a forced de-rating of the transformer.

Off Circuit Tap Changer (OCTC)

An OCTC is a device by which the power transformer turns ratio can be altered over small range to effect changes in output voltage as required. The change in ratio is typically accomplished in the high voltage winding by dividing the physical winding into two halves in combination with the use of several selectable winding taps. An OCTC application typically allows for an adjustment of 5% above nominal and 5% below nominal voltage in 2½ % steps. An OCTC must only be operated with the transformer off potential.

Underload Tap Changer (ULTC)

ULTCs allow for automatic voltage changes while adjusting to varying load conditions on line. An ULTC is of particular importance to those situations where frequent voltage regulation is required because of the characteristic of the load. ULTCs are complex in their design. As a control mechanism, they consist of moving mechanical parts, a drive motor, linkages and voltage regulation sensing equipment. The ULTC incorporates tapped connections to the main windings that can be selected automatically, through a series of main and arcing contacts, to adjust the secondary voltage of the transformer without interrupting the load.

Current Transformers

Current transformers (CTs) sample the current in a line and reduce it to a safe and measurable level. CTs consist of a secondary winding wrapped around a ferromagnetic ring (transformer bushing's primarily lead), with the single primary line running through the centre of the ring. The ferromagnetic ring holds and concentrates a small sample of the flux from the primarily line. That flux then induces a proportional voltage and current in the secondary winding.

Mechanism Cabinets

The mechanism cabinet is an externally mounted box that supports voltage and current control relay, secondary control circuits, and in some cases the tap changer motor and position indicators.

2.2.2 Autotransformers

An autotransformer is a special case of power transformers, which are used primarily to transform voltages and currents between transmission system voltage levels (between 500 kV and 230 kV and between 230 kV and 115 kV in Hydro One's system). In the case of an autotransformer, there is no electrical isolation between the primary and secondary windings, as part of the winding is common and shared by the primary and secondary. This is a cost-effective solution in applications where the primary to secondary voltage ratios are less than about 2:1 and where the common connection is acceptable. Autotransformers can be fitted with the ULTC mechanism as well.

Because there is no electrical isolation between the primary and secondary windings in an autotransformer, no phase shift occurs between primary and secondary voltages. Most conventional two winding three phase transformers are built with a 30-degree phase shift inherent in the design. Therefore the application of autotransformers has to be carefully planned to ensure that the appropriate phase relationship exists in the system. In the Hydro One system autotransformers are used with primary voltages at 500 kV, 230 kV and 115 kV. However, those with a primary voltage of 115 kV are rarely needed and are only used where special phasing is required.

2.2.3 Phase Shifting Transformers

In an alternating current system, the voltage varies from maximum to minimum 60 times per second, or 60 Hertz. In two systems, both operating at 60 Hertz, there can be a shift between when the reference phase of one system peaks and the other system peaks. This would cause an electrical disturbance if both systems were interconnected. Real power flow in transmission systems is controlled through control of phase differences, therefore phase shifting transformers are employed in selected locations to optimize power flows in the system. Phase shifting transformers are very complex to design and manufacturer and often require a two-tank design.

2.2.4 Shunt Reactors

While strictly speaking, shunt reactors are not transformers, they are similar in construction and considered by Hydro One in the same asset class. A shunt reactor is basically a single winding wound on an iron core and its construction, maintenance and testing is similar to a power transformer.

A transmission line has two main electrical properties characteristic of its design, resistance and reactance. Reactance can be either inductive or capacitive, one cancelling out the effect of the other. Both resistance and reactance contribute to transmission line losses, while resistance is fixed and cannot be changed, the inductive reactance can be cancelled by capacitive reactance or increased by adding additional inductive reactance.

The primary purpose of shunt reactors is to introduce reactance into a circuit. Shunt reactors are normally used to absorb reactive power for voltage control. Series reactors are devices normally used to increase the effective reactance on a circuit to limit fault current.

2.2.5 Regulator Transformers

Regulator transformers are transformers whose sole purpose is to provide voltage regulation through use of an internal tap changer. The nominal incoming and outgoing voltages are the same but the outgoing voltage can be varied slightly in 2.5% increment to satisfy the voltage requirements of connected customers.

2.2.6 Grounding Transformers

Grounding transformers are used to provide a neutral point for grounding an electrical system.

Electrical distribution systems can be configured as a grounded or ungrounded system. A grounded system has an electrical connection between source and the earth, whereas an ungrounded system has no intentional connection. Sometimes it is necessary to create a ground on an ungrounded system for safety or to aid in protective relaying applications. Smaller transformers similar in construction to power transformers are used in this application.

2.2.7 Station Service Transformers

The operation of the transmission station requires power for various services such as lighting, operation of fans, relay room heating and ventilation, power for battery chargers, etc. The most reliable source of such power is directly from the transmission or distribution lines. Small power transformers are used to provide this power supply.

2.3 HV/LV Switches

Disconnect switches are used to visually and electrically isolate equipment or line sections of the transmission system for purposes of maintenance, safety, and other operating requirements. Disconnect switches generally have no assigned or tested current interruption capabilities. However it is common practice within Hydro One as in other North American utilities to use them to interrupt small bus currents of a few amperes and transformer magnetizing currents of limited magnitude. Also included in this asset class are load interrupter switches which have limited load and fault interrupting capability. The interrupter mechanism normally contains a gas/vacuum, as the insulating medium and these switches also must be capable of providing visual confirmation of the open/close position. The switches currently in use on the Hydro One transmission system have been purchased from more than 10 different manufacturers over the past 60 years.

In general switches consist of a mechanically movable copper or aluminums conductor /blade, supported on insulators and mounted on a metal base. Rotation of one or more of the insulator stacks causes the current path to make or break the circuit, as required as shown in Figure 12. The operating or control mechanism may be a simple hook stick, manually gang operated, or motor operated. The latter is primarily used on transformer and line circuits, where protective relays may be used to operate the switch automatically as shown in Figure 13. Disconnect switches are relatively simple in design compared to circuit breakers because they are not required to interrupt large currents in most applications.

Kearney (type DHB) 138kV 1200A Disconnect Switch

Figure 12: Center Rotating Disconnect Switch

ABB (type TTR-6) Motor Operated Disconnect

Figure 13: Motor Operating Mechanism for a Switch

Disconnect switches may be mounted vertically, horizontally or inverted and various switch designs may be deployed depending on the station arrangement of facilities. These are described according to their operation or blade motion as shown in Table 1.

Vertical Break	Blade contact rises out of the jaw contact-three insulator stacks are usually used
Side Break	Blade contact parts to the side
Double Break, Centre Rotating	Contacts at each end of the blade part to opposite sides due to the rotation of the centre of the centre of three insulator stacks
Centre Break, Both Ends Rotating	Both jaw and tongue contacts move to the one side by rotation of both insulator stacks.

Table 1: Switch Operation Description

A load interrupter switch typically comprises of a motor operated, three phase, load carrying and interrupting device having a limited fault interrupting capability, mounted on support insulators and metal support structure. The interrupter may be either air or vacuum, or SF6 which is the dominant technology on the Hydro One system. It may, or may not, incorporate disconnect blades for isolating purposes. Typical load carrying and breaking capabilities are in the 600A to 2000A range and interrupter switches have been applied in the MV, HV and EHV rating categories. Interrupters on the older designs were typically sealed for life and replaced rather than repaired upon failure. In some cases the OEM is no longer supplying or supporting the older design, thus driving the EOL decision process for certain applications. The more recent designs are very similar in design and operation to live tank SF6 circuit breakers. There are almost 300 load interrupter switches on the Hydro One system. Depending on the operating requirements, some switches are manually operated and others motor operated.

2.4 High Voltage Instrument Transformers (HVITs)

HVITs consist of voltage and current transformers that are independent, freestanding devices that are used in Hydro One' transmission stations at voltages of 115 kV and above.

The application of control, protection (relaying) and metering functions to HV systems requires the use of sensitive measuring devices, which are typically incapable of withstanding the high currents and high voltages present on the Hydro One' primary system. For this reason, the primary voltages and currents in typical HV systems must be accurately transformed to low values that are acceptable to the measuring devices. In HV systems special transformers called instrument transformers carry out this function.

There are two basic types of instrument transformers: voltage transformers (VTs) and current transformers (CTs).

VTs are devices for measurement of bus and line voltages that, on the primary side, are connected between the phase and neutral conductors of the HV system. The ratio of the primary to the secondary winding is typically chosen to provide a secondary voltage of 120 volts when the primary system voltage is at its nominal value. This secondary voltage is used for control, protection and metering devices and varies directly in proportion to the primary system voltage.

CTs are devices for measurement of line currents that are connected on the primary side in series with the phase conductors of the HV system. The ratio of the primary to the secondary winding is typically chosen to provide a secondary current of 5 Amps when the primary system current is at its nominal value. This secondary current is used for control, protection and metering devices and varies directly in proportion to the current in the primary system.

VTs and CTs in HV systems are usually oil insulated and enclosed in a high strength sealed porcelain insulator to withstand the applied voltage stresses. Presently, other types of current transformers are being supplied that use SF_6 as the insulating medium instead of oil.

There are two different types of voltage transformers: inductive and capacitive as described below.

An inductive VT is wound in the similarly to a conventional power transformer: it uses inductive coupling to reduce the primary (high) voltage to a lower analogue voltage. Inductive VTs can be used at any voltage level, but they are only cost effective at lower voltages, typically below 115 kV. In the Hydro One' system, inductive VTs are used primarily up to 44 kV.

The cost of inductive VTs increases significantly with increasing voltage, such that at voltages ≥115 kV, almost all VTs are of the capacitive type. This is mainly due to problems associated with winding inductive VTs at higher voltages and the increased difficulty in maintaining the insulation between the windings.

Capacitive voltage transformers use a capacitive voltage divider (connected phase to ground - one per phase) to obtain a lower voltage supply across the last capacitor in the stack. This voltage level typically ranges between 5 and 24 kV. A small, and accurate, induction transformer is used in the base of each single phase CVT to obtain an analogue voltage, typically 120 V, for use in measuring circuit voltage.

CVTs use wrapped paper to form small capacitors, which are then stacked to form the capacitive voltage divider. Insulation of the CVT (around the capacitors and the inductive transformer) is maintained by oil immersion.

Figure 14 shows a typical capacitive voltage transformer.

Figure 14: Capacitive Voltage Transformer

Together with the primary measuring function CVTs can also be used to moderate transient recovery voltages as may occur in the interruption of short line faults by circuit breakers.

Current transformers are wound inductive type transformers that are used to obtain an accurate low current analogue of HV currents. Rated CT secondary currents are either 5 A or 1 A. In North America the 5 A secondary rating is typically used. Current ratings are defined by Standards; in Canada the applicable Standard is CSA C13. CTs typically use oil as the insulating medium. However, Hydro One has a small number of SF_6 insulated CTs.

Instrument transformers must produce current and voltage waveforms reliably for use in control, relaying and metering circuits. The acceptable limits of accuracy are outlined in CSA C13. The following outlines the acceptable accuracy for current and voltage transformer applications.

For relay systems, the VTs must be accurate to 1% or 3%, depending on the accuracy class required (1P or 3P), over their applicable rated output range. There are 5 standard output ranges or burdens that are commonly specified, namely: W – 12.5 VA, X – 25 VA, Y – 75 VA, Z – 200 VA and ZZ – 400 VA. For metering systems, the VTs must be accurate to 0.3% over their applicable rated output. Similar standard output ranges or burdens as for relay applications apply. For some applications where harmonic waveform capture is required, special VT accuracy limits are required. Such special limits are separately covered in the Standards.

For relay systems, the CTs providing input current to relays must be capable of a nominal accuracy under rated conditions; but must be capable of producing 20 times rated output current, at an acceptable accuracy, under fault conditions. In North America, CTs used for relay systems typically must have a 10% accuracy at an output of 20 times nominal CT current, or 100 A for a

5 A rated CT. The CT must also be capable of a stated voltage output at the 20 times nominal secondary current.

For metering systems CTs must be capable of much higher accuracy than for protection applications; but they do not need to be capable of accurate output at the extreme currents encountered during a fault. For revenue accuracy circuits in Canada, the accuracy of a CT output must be 0.3% at rated current and the CTs must be certified by Measurement Canada. The second portion of the specification of a metering accuracy CT is the rated burden into which the CT must supply its rated current. Standard burdens in North America range between 1 and 3 ohms.

2.5 Station Insulators

Insulators are used in transmission stations for termination of conductors at structures and to support busses 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. The electrical stresses are caused by the high voltage between live parts during normal and abnormal conditions. Abnormal conditions may include lightning strikes and operation in contaminated conditions. Sub-optimal insulator design or deteriorated conditions may result in loss of electrical withstand capability of the insulation leading to flashovers. Mechanical stresses include compression, torsion, tension and cantilever forces.

Corrosion of metal fittings, damage due to vandalism, and cement growth are some of the factors that adversely affect the mechanical integrity of the insulator. Extreme environmental conditions, such as harsh winter weather and industrial pollution, also reduce the mechanical and electrical strength of insulators. Insulator units with resistive glazed (RG) porcelain posts or having a silicone coating are often used to improve the withstand capabilities under these specific conditions.

The most common materials used in insulators are porcelain, glass and polymeric. The vast majority (over 99% -) of the station insulators in the Hydro One system are porcelain type insulators. Glass is used mostly for insulator strain and idler discs or polymeric type insulators are used mostly at lower voltages.

The types of insulators used in transmission stations are:

- Rigid support insulators mostly used for rigid bus support.
- Disc types for strain bus connections and for idler strings associated with strain buses

Rigid Insulators

Rigid insulators consist mostly of the "newer" station post type as shown in Figure 15 or the "older" cap and pin type as shown in Figure 16. These insulators isolate live apparatus from station structures and provide support for electrical conductors and equipment. They are also an integral component of disconnect switches, and capacitor banks etc., and these are also discussed as part of each asset class. Demographic data includes all insulators, irrespective of application.

Figure 15: Station Porcelain Post Insulator

Figure 16: Station Cap and Pin Insulators

Cap and Pin

The cap and pin insulator forms the majority of the station insulator population. Single units are applied at the low voltage levels below 50kV and cap and pin insulators are capable of modular stacking for use at 115kV and 230kV. Cap and pin insulators were manufactured from the early 1900's to the 1980's but this design of insulator is no longer available.

Cap and Pin insulator failure modes include radial cracking, circumferential cracking (also called doughnut cracking), head cracks, and punctures. Radial and circumferential cracks occur in the shed and although very fine, they are usually visible upon close inspection. Radial cracks can extend up into the insulator head. Head cracks and punctures are often hidden beneath the cap, and therefore are not amenable to detection by inspection. In addition, a large percentage of cap and pin insulators manufactured between 1965 and 1980 are experiencing premature end of life due to a condition called "cement growth", which causes the cement that holds the metal cap to the porcelain skirt to expand when moisture penetrates the cement, thereby separating, or breaking the insulator. Over 17% of the cap & pin insulator population fit into this profile. Failures of cap and pin insulators are of particular concern where they support under-hung buses or disconnect switches since personnel safety and damage to adjacent equipment is a major risk.

Station Post

These are one-piece or multi-piece porcelain or polymeric insulators with relatively small but numerous rainsheds and fitted with metal caps and base at the ends. The end caps and bases have tapped mounting holes to facilitate various mounting configurations. The number of insulators used in a stack depends on circuit voltages and design standards. These insulators are available with a variety of voltage ratings and cantilever strengths.

The post type insulator is used as a replacement for aging or defective cap and pin insulators. All new insulators purchased are of the post type. Single post insulators are used from 7.5kV to 115kV and stacked together for use at 230kV and 500kV. Polymeric post insulators are typically only applied at the low voltage level.

Post type insulators are constructed in a variety of ways as described below:

- **Multi-cone –** these insulators were developed as an alternative to cap and pin and station post type insulators. The multi-cone post insulator is an assembly of porcelain cones stacked together to form the desired insulator length and loading characteristics. The porcelain cones are held together with a cement compound. Multi-cone insulators are used at 230kV with BIL ratings of 900kV and 1050kV and 500kV having BIL ratings of 1550kV and 1800kV. One of the problems associated with this type of insulator construction is the effect of cement expansion on the porcelain due to temperature cycling, including freezing and thawing of the insulator. This expansion is caused by moisture being absorbed in the cement during its many years of life. The expansion causes longitudinal cracks to appear and weaken the insulator electrically. The insulator will weaken mechanically as more cracks develop. These insulators are no longer available.

- **Hollow Core** post insulators were developed to improve the firing and curing process during manufacture. Hollow core insulators allow for a more even heating of the porcelain due to its thinner walls. Fusing a porcelain or rubber plug into the hollow post during firing prevents breathing and ensures a clean, dry interior. The sealing process on some of the insulators was substandard and allowed moisture ingress, which caused a reduction in its dielectric properties and ultimately electrical failure. These insulators are usually installed at the low voltage levels (below 50kV) and were supplied as part of the disconnect switch by some manufacturers. Only a few such hollow core insulators exist on Hydro One disconnect switches. It is not possible to visually distinguish hollow core from solid core insulators. These type of insulators are also used as the support insulators for air blast and live tank SF6 circuit breakers

- **Solid Core** - this post insulator is solid porcelain with the metal flanges cemented directly onto the porcelain. Because of the size and thickness of the porcelain, curing of this type of insulator is critical to ensure a high quality product. Improperly cured porcelain will allow for some give, which can progress into circumferential cracking which reduces the mechanical strength. To date, few problems have been found with this type of insulator. These units are installed at all voltages from 7.5kV to 500kV and Hydro One is currently purchasing these insulators from several manufacturers.

- **Conductive/Resistive Glaze type –** post insulators can also be supplied with a semi-conductive glaze, which inhibits arcing, and flashover caused by pollution, contaminants and high humidity. These insulators are known as conductive glaze/resistive glaze (RG insulators). A small current flow over the resistor created on the surface of this type of insulator warms the surface to a few degrees above the ambient temperature. This discourages moisture accumulation. Moisture accumulation is usually necessary to make contaminants conductive. These insulators are installed at selected, high contamination locations

- **Polymeric – these** insulators were developed in the early 1970's and are used in stations rated between the 15kV to 115kV levels. The insulator is constructed around a fiberglass reinforced resin core rod. The outer shell is made from polymeric or silicone based polymeric material. The polymeric type is equivalent in voltage characteristics, strength and physical size to standard porcelain insulators. Silicone base type is equivalent in withstanding contamination to the RG (resistive glaze) insulators. The silicone based insulator releases silicone from its base polymeric material, which encapsulates any contaminates. This hydrophobic property prevents moisture clinging to the contaminants and reducing the dielectric strength. Polymeric insulators are lighter and less susceptible to damage during installation and maintenance than the porcelain type. These insulators are in limited use at Hydro One stations, primarily being applied at the low voltage levels.

Strain Insulators

These are insulators installed on station structures, in either a horizontal or vertical position, and under continuous tension, suspending a flexible wire conductor. Strain insulators may also be installed as mid-span openers. Insulators installed in this manner are not normally electrically stressed, as they are by-passed by a conductor or switch blade and used to sectionalize or isolate sections of a bus or distribution feeder. During the isolation or switching process, the jumper / blade is removed or opened, thereby putting the insulator under electrical stress.

Strain insulator units may be damaged by electrical puncture, cement growth, breakage, or severe deterioration of the porcelain, which weakens the dielectric strength of the insulator string. As the number of defective individual units in the string increases, there is an increased risk of flashover, particularly under stress conditions, e.g. lightning or faults. These insulators may also lose mechanical strength due to cement growth under the cap or around the pin. Mechanical failure can result in the conductor falling on other live conductors or transmission equipment. Because of past failures, mid span porcelain insulators must pass electrical testing before they can be used as electrical isolation. Glass and polymeric insulators installed in this manner do not have to be tested prior being used as isolating points. This makes glass and polymeric the preferred choice for these installations.

Approximately 99% of station strain insulators are porcelain, with the remaining 1% made of glass or a polymeric material. Over 30% of strain insulators in the stations are 50 years of age or greater, and are considered to be at the end of their design life.

- **Porcelain –** these are modular solid heat-treated porcelain insulators with a ceramic glaze surface and metal fittings cemented onto both ends. The metal fittings facilitate connecting individual insulators together to form a string of insulators. The number of units assembled into a string is dependent on the circuit voltage and design standards. The assembled length can vary from 300mm for 7.5kV to 5 meters for 500kV. The strength of the strain insulator is classed as KIP (thousand inch pounds) and is available in 15, 25, 36 and 50 KIP ratings.
- **Glass** These are modular high impact glass insulators with metal fittings cemented onto both ends. Application and rating of glass insulators closely follows that for porcelain but their condition can be more readily assessed. Glass insulators are understood to be in good condition as long as they are visually intact. Glass insulator skirts shatter if there is a defect, making visual inspection a satisfactory test.
- **Polymeric** - these insulators are constructed around a fiberglass reinforced resin core rod. The outer shell is made from polymeric or silicone based polymeric material. Metal end fittings facilitate connecting and mounting of the insulator. The equivalent polymeric must be longer than the glass or porcelain type it replaces. This longer length is required because the polymeric has smaller skirts, which reduces the tracking length and wet/dry creepage distance. Similar to glass, polymeric insulators are understood to be in good condition as long as they are visually intact. The polymeric insulator is much lighter than the porcelain or glass type.

Hydro One and many other utilities have experienced the failure of polymer strain insulators (also called composite or non-ceramic insulators) used as dead-end and as suspension insulators. The root cause of the failures is aging of the rubber material as a result of high electric fields (E-fields) close to the energized end. These failures have raised concern about the health of the insulators remaining in service and stressed the need to determine actions for either life extension or replacement in order to maintain high system reliability. The failure of dead-end insulators poses a larger threat to system integrity than the failure of suspension insulators because failures may result in a downed conductor. In addition, studies have shown that dead-end insulators are exposed to higher E-field magnitudes than suspension insulators. These high E-field magnitudes may result in corona discharge activity that damages the polymer housing and end fitting seal. In the past, most work focused on insulators installed at 230 kV and above, resulting in the use of corona rings at these voltages. Recent experiences indicate that 115- units may be more susceptible because they are generally installed without corona rings and often on structures with closer phase spacing.

2.6 Station Cables and Potheads

Station cables and potheads are associated with equipment located within the confines of a transmission station, such as station service transformer feeds, transformer to switchgear connections, and capacitor bank connections. Hydro One manages transmission station cables and potheads typically with voltage between 13.8 kV to 44 kV. Cables and potheads are typically used when air insulated bus cannot be utilized, because of space limitations.

Transmission Stations cables are typically short (in length) and are usually enclosed, in ducts. Typically, the cables are inspected visually as part of regular station inspection. The inspections include checking for visual evidence of cracks, corrosion, overheating or distortion of the visible sections of the cables and physical damage or compound leaks from the potheads. These practices are consistent with the practices of other leading electric utilities.

Cables consist of the following systems:

- Cables
- Splices/Joint connections
- Potheads and Terminators.

Station cable systems are subjected to a number of stresses. The type of cable selected for each application must normally consider electric, thermal, mechanical and environmental stresses.

2.7 Capacitor Banks

Capacitors are static devices whose primary purpose in power systems is the compensation of inductive reactance of other system components. They are a static source of reactive power on the transmission system that balance the inductive demand on the system and provide the necessary voltage support needed for efficient power transmission.

In general, system operators try to balance the capacitive and inductive demand on the system at all points on the system. The active power portion of the electricity supply is the portion that allows the power system to do work, for instance turn a shaft in a paper mill. The reactive component is a requisite of the power system; and its instantaneous demand quantity must be met at the load.

Most loads are inductive in nature due to the significant use of induction motors for fans, pumps, compressors and other rotating machines. Most electric motors require an inductive component to perform work. With the volume and universal presence of electric motors in our lives, the adequate supply of capacitive VARs to balance the needs of induction motors is necessary for the efficient operation of the electric power supply system. Fortunately, it is possible to produce capacitive VARs by adding shunt capacitors to the system at a reasonable cost.

There are basically two ways that the level of VARs generated on a system may be varied. The first is by manipulating the field excitation of synchronous machines, either motors or generators; the second is to obtain the needed VARs from transmission lines. Using synchronous machines to produce VARs can be inefficient, particularly when the loads are remote from the VAR source. Transmission of VARs over a distance has a price because of the increased losses caused by VAR transmission. Further, transmission of VARs in a power system reduces the system's capability to transmit active power.

All transmission lines produce VARs continuously. Inductive VARs are produced proportional to current levels, and capacitive VARs are produced proportional to voltage. To some extent, voltage levels in lines can be varied to produce the VARs required. During light load hours, e.g. overnight when loads are light and there isn't much demand for inductive VARs, lines can be run at reduced voltage levels to reduce the capacitive demand on the system; the converse is true during peak load hours when the number of motors connected to the system, and thus the inductive demand, is at its peak. Unfortunately, it is often not possible to meet the inductive demand on the system without the addition of shunt capacitors. Further, given that it is more efficient to balance the inductive/capacitive needs of a system at any given point on the system, shunt capacitors often are added at different voltage levels to balance capacitive and inductive VARs out at each voltage level. The reason for this practice is that the greater the VAR demand at any point on the system, the greater the losses at that point. In most systems most capacitive compensation is installed either at the load, or at the distribution voltage level. In lightly loaded systems the level of VAR transport and thus loss at the transmission voltage level is not sufficiently of concern to justify the addition of transmission level capacitors. Hydro One however has a system that is sufficiently heavily loaded as to justify the addition of shunt capacitors at the transmission voltage level at some of the transmission stations.

A capacitor consists of two conductive plates with a dielectric material in between. The closer the plates approach and the thinner the materials the more efficient the capacitor is at producing VARs, and the lower the real power losses. In modern capacitors the plates are in fact thin gauge aluminum foils separated by thin, but effective polypropylene insulating film, impregnated with a non-PCB fluid with high insulating strength. These capacitor packs or elements are then connected together in an appropriate series-parallel arrangement and installed in a stainless steel can and the bushings are welded into position. The primary objective of the can mechanical design is to avoid fluid leakage and corrosion. Capacitor units can be obtained in the voltage range of 120 volts to 27.6 kV, and at VAR ratings ranging from a few kVAR to 625 kVAR. The most common capacitor cans in the transmission and distribution voltage range is 13.8 kV. The

Hydro One capacitor banks consist of capacitor cans and interconnecting buses mounted on racks which are stacked on support insulators which are typically mounted on steel support structures so as to be usable at transmission system voltages such as 115 and 230 kV.

Individual capacitor cans, in the past, were either internally or externally fused to ensure that should a capacitor fail it will not cause a can to rupture or cascading failure of the group of capacitors. The more recent development of the fuseless design has resulted in simplification of the bank configuration and has been applied successfully at several locations. The fusing alternatives currently on the Hydro One system are described as follows:

Externally Fused

This design was the technology of choice in Hydro One for many years. Each can has its own current limiting or expulsion fuse to disconnect a failed capacitor can from the bank. When one or more capacitor units are removed, the remaining parallel capacitors are subjected to an overvoltage which must be limited to a maximum value of 110% of rated voltage. External fuses provide a visual indication of a failure but banks tend to be larger, more costly, subject to animal outages and have higher installation and maintenance costs.

Internally Fused

The internal fuses are current-limiting fuses in action. One fuse is connected in series with each element within the capacitor. They are designed and coordinated to isolate internal faults at the element level and allow continued operation of the remaining elements of that capacitor unit. This results in a very small part of the capacitor being disconnected; therefore, the capacitor and the bank remain in service.

Fuseless

As a result of the high reliability of today's all film dielectric, the use of fuseless capacitors (many elements in series), combined with the typical HV banks configuration (many "strings" of capacitor units in series), account for this design's good performance. Some fuseless designs are based on connecting the internal elements in parallel strings, resulting in limitation of parallel energy inside the unit and not imposing restrictions on bank connections or on capacitor can size. A bank containing failed elements can operate continuously and with reduced risk of can rupture. Advantages are reduced installation and maintenance costs, less space, fewer live parts, small animal resistance and lower losses.

In order to make up shunt capacitor installations at transmission voltage levels individual capacitors cans are connected in series and parallel with each other to form capacitor banks, to achieve suitable ratings of reactive power and voltage. Small banks can be seen on distribution lines directly connected through fuses to the phase conductors. At transmission voltages capacitor banks can run to hundreds of MVAR. These capacitor banks are essentially three phase loads, which vary in reactive power and in voltage levels, ranging anywhere between 5.0 MVAR (18 cans) at low voltage level to one of the highest rating worldwide, 411.6 MVAR (1,300 cans) at 230 kV level. Figure 17 shows a typical Hydro One 230 kV ungrounded wye, shunt capacitor bank.

Figure 17: Capacitor Bank

Capacitor banks are connected to the Hydro One transmission system at various transmission stations, depending on the proximity and size of the inductive load to be compensated. Since the inductive portion of the power level that requires compensation varies throughout the day, the amount of capacitance in the system must also be varied. This variance is for the most part achieved by varying the excitation of synchronous machines, and (more economically) by controlling the operating voltage levels of transmission lines through the switching in of capacitor banks. This means that capacitor banks could be switched daily.

2.8 Station Buses

The air insulated station (AIS) buses carry electrical energy from the incoming transmission line terminations to the substation disconnect switches, circuit breakers, transformers, reactors, capacitor banks, feeders and other associated power equipment. The buses operate at voltages ranging from 500kV down to 5kV and typically at continuous currents of up to 4000A. Normally three stranded or rigid tubular bus conductors constitute a single circuit. In most cases one conductor per phase is adequate but for some situations, such as stranded conductors used at 500kV or for very high continuous current requirements, bundled conductors of up to 4 per phase are required. The bus conductors are insulated from, and arranged on support steel structures with sufficient structural strength and clearance dimensions to prevent normal and abnormal operating currents and voltages from resulting in dielectric, thermal or mechanical failure. Rigid buses of either copper or aluminium tubing are supported on rigid support insulators of either the cap and pin or station post design. Strain buses of either copper, aluminium or aluminium conductor steel reinforced (ACSR) are supported by strain insulators.

The modern outdoor air insulated switchyards typically employs a modular, low profile bay design. This modular design concept is based on the idea of having identical bays mounted together in a manner that accommodates both the single line diagram and the available space requirements. The current design relies on the extensive use of rigid aluminium tubular buses supported by station post insulators on tubular support steel sections. The design philosophy results in a reduction in the number of different structural pieces and allows for easier and safer access to electrical components. All rigid bus connectors and other hardware are welded type to achieve higher ampacity ratings. The older high profile bus arrangement primarily consists of stranded strain bus and employs strain insulators supported on lattice type steel structures.

The conductor spacing, line-to-ground and line-to-line and the bus support intervals are determined by a variety of factors. The spacing must take into account the ability of conductors to gallop or move either vertically or horizontally during short circuit, snow, icing or wind conditions. As current passes through the conductor the resistance of the conductor causes its temperature to rise and expansion of its length. This results in increased sag for stranded conductors and increased mechanical loading of terminals, connectors, hardware and insulators supporting rigid bus conductors. Vertical safety clearances between conductor and ground must not be compromised during any abnormal operating or environmental conditions. The bus conductors must have both tensile and ductile properties in order to withstand longitudinal forces and bending movement without failure. Support intervals as well as the electrical and mechanical characteristics of the support insulators must be selected to provide an adequate safety margin when exposed to these abnormal operating and environmental conditions.

2.9 Station Surge Protection

Surge arresters on the Hydro One transmission network protect equipment costing several magnitudes more than the arresters themselves, from the effects of lightning and switching overvoltages. Surge arrester overvoltage protection is employed on the HV and LV terminals of all power transformers, on capacitor banks, at underground cable terminations and on some critical overhead transmission lines. Over the past twenty years Hydro One has replaced the majority of the high voltage rod and pipe gap and silicon carbide arrester overvoltage devices by the more reliable and cost effective metal oxide arresters.

When properly selected, manufactured and configured, they are extremely reliable devices and can offer decades of service without causing any problems. Surge arresters constitute an indispensable aid to insulation coordination in the power systems. The overvoltages caused by lightning and switching surges can cause failures of expensive equipment such as power transformers without the use of arresters The arresters intervene to limit the overvoltages to a safe margin below the rated insulation withstand ratings of the equipment they are protecting.

Arresters being installed today are all gapless metal-oxide (MOA) arresters. The distinctive feature of a MOA is its extremely nonlinear voltage-current characteristic which eliminates the need for the disconnection of the arrester from the line through serial spark-gaps. A leakage current of about 100 μA flows when the normal line-to-ground voltage is applied. Equipment such as power transformers have a standard lightning impulse withstand level (sometimes referred to as "BIL") based on their rated operating voltage, e.g. 900kV BIL for a 230kV rated unit. In accordance with the international standards on insulation coordination, the highest voltage in operation of an oil insulated transformer should stay below this value by a factor of at least 1.15.

The arrester has a rated residual voltage based on a standard lightning impulse test current of 10 kA. This voltage is called the lightning impulse protection level of the arrester. The protective margin of a properly rated and configured MOA located close to the transformer terminal will exceed the minimum international standard requirements by a wide margin. Operating reliability and safety of the MOA has been further enhanced by the adoption of high mechanical strength, explosion and contamination resistant polymeric housings instead of the previous porcelain housings.

Other than the periodic washing required in the more highly contaminated locations, monitoring of leakage current in some special situations and periodic station thermo-vision inspection, there is little or no maintenance required for surge arresters.

Over the past twenty years the failure rate of surge arresters has been considerably reduced by the adoption of the metal oxide technology. The failure prone silicon carbide gapped arresters currently applied on many medium voltage installations are being replaced by the metal oxide technology. Surge arrester replacement is generally integrated with other substation upgrading projects. For surge arresters the issues of degradation and assessment are similar in some respects to those for insulators and some instrument transformers. Methods of assessment and procedures for determining end-of-life based on remnant strength are well established.

2.10 HV/LV Station Structures

The majority of transmission station structures are reinforced concrete, galvanized steel and some wood poles. These are subject to inspection as part of routine substation inspection, typically on a 3-month cycle.

Degradation resulting from corrosion of the reinforcing bars in the concrete can be a very destructive process. Visual inspection can only detect this at a relatively advanced state. Deformation or cracking of the concrete is indicative of an advanced corrosion situation. Treatment is difficult and expensive, involving the removal of the concrete and treatment of the reinforcing bars. In most cases when evidence of such damage is noted the initial reaction is to make short-term repairs. These are not usually very successful and ultimately more significant refurbishment or replacement will be required. End-of-life for these structures can be defined by the presence of widespread damage (cracking of concrete spalling). Other than this, concrete structures would normally only be replaced as part of major substation refurbishment usually initiated by the need for replacement or refurbishment of the major plant or by significant development of the system.

The degradation of steel structures is mainly as a result of corrosion. The rate of degradation is very dependent on the environmental conditions to which the structures are subjected. Industrial pollution is a particular problem for galvanized steel.

For wood poles or structures the issues of degradation and assessment are the same as those for wood poles on overhead lines

2.11 Ancillary Systems - High Pressure Air Systems

Centralized HPA systems are installed at all locations that have a population ABCBs. These breakers employ compressed air as an interrupting and insulating medium. This requires a high-pressure compressed air supply consisting of a centralized HPA compressor/dryer plant as well as an air storage facility. The HPA systems are usually comprised of multi-stage compressors, chemical or heated dryers, numerous air storage receivers, extensive piping and valving arrangements, and controls.

A typical HPA system used by Hydro One is illustrated in Figure 18.

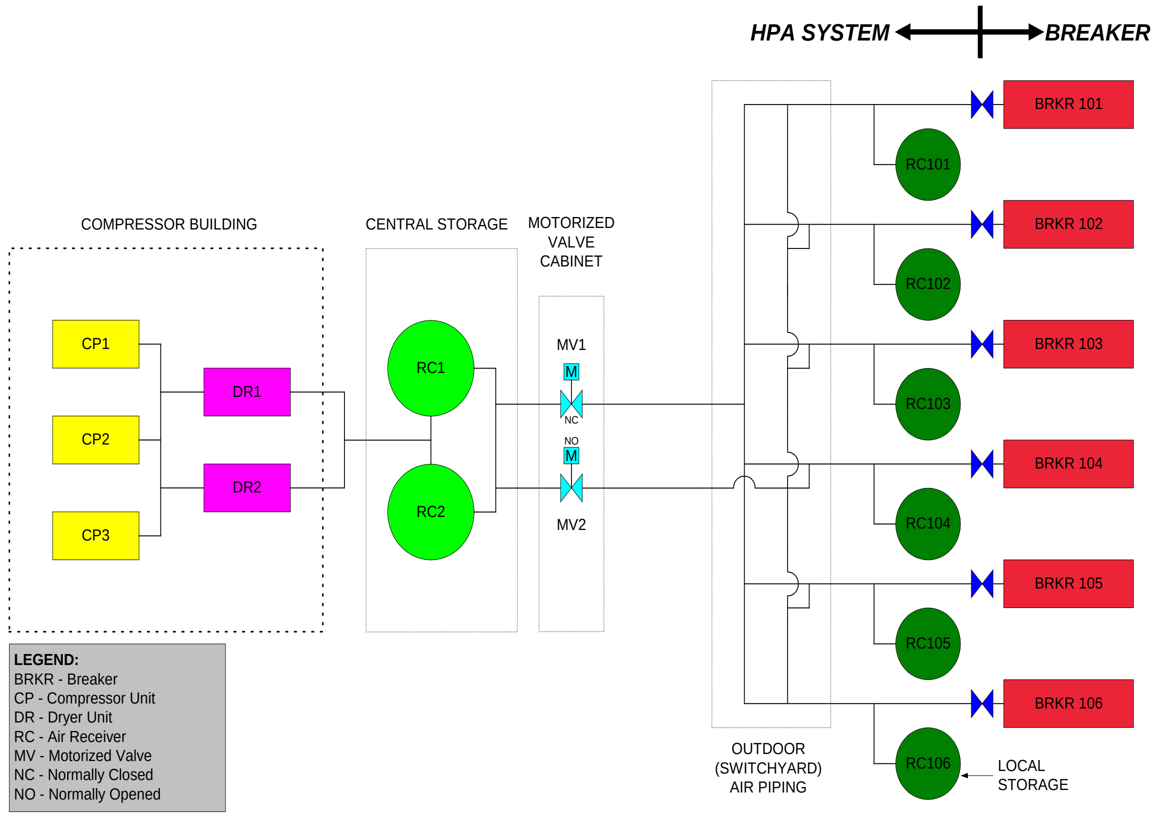


Figure 18: HPA System Block Diagram

Depending on the particular vintage, manufacturer, as well as the specific design, HPA systems operate from between 600 psi (4,143 kPa) to 3600 psi (24,821 kPa).

In order to ensure reliable operation of ABCBs, it is essential that the compressed air is free from contaminants and that it contains minimal amounts of moisture. Since the air, which exits the compressors is 100% saturated with moisture vapour, a reduction of relative humidity is required to make the air suitable for operation. Filtering and drying of the air during and after compression accomplish this. Chemical dryers are now primarily used to remove moisture vapour from the compressed air. Many of the original dryers were "heated-type", where heat was used to dry the air instead of chemical desiccant. These dryers had extensive piping and valving arrangements, which had to be switched manually on a regular basis, making them both prone to leaks and breakdowns, and very labour intensive to maintain and operate. These dryers are now older than 25 years and replacement parts and labour skilled in this old technology are no longer available. Most of these dryers have been replaced with the "heatless-type" or desiccant-based dryers. The dryer units consist of dual chambers filled with activated alumina desiccant, which dry the compressed air as it passes through the desiccant.

Storage receivers are located at the centralized compressor buildings, to ensure an adequate supply of air exists at all times. The criterion for volume availability is defined as the adequate supply for 5 C-O operations of each breaker.

The isolating valves allow portions of the air system to be isolated for maintenance, or redirected in case of a system problem. There are three dominant manufacturers that have supplied valves over the last 30 years. Two of the manufacturers have used a valve design whereby the valve seat, seals both the ball and the body of the valve. Due to this dual function of the seat, many of these valves' body seals leak and need to be replaced.

Storage receivers are located at the individual circuit breakers, to ensure that an adequate supply of air is available to the breaker in the event of multiple, rapid succession operations. Each breaker is provided with enough air for 4 consecutive C-O (close-open) operations. The circuit breaker itself can store 2 C-O operations internally and the local storage receiver holds the other 2 C-O operations.. Following the 4th successive C-O operation, the air for the next operation comes from the central air storage.

Protective devices are required to automatically prevent the supply of energy to the prime mover of the compressor when an abnormal condition occurs during the compressor operation. All air compressors are required to have protective devices for the following:

- High discharge air pressure
- High discharge air temperature
- High discharge cooling water temperature
- Low lubricating oil temperature

Hygrometers are used to measure the dew point at the outlet of desiccant air dryers to insure the air is correctly conditioned.

2.12 Batteries and Chargers

Circuit breakers, motorized disconnect switches, transformer tap changers, and in particular the communication, protection, and control systems in transmission stations must be provided with a guaranteed source of power to ensure they can be operated under all system conditions, particularly during fault conditions. There is no known way to store AC power thus the only guaranteed instantaneous power source in switchyards must be DC, based on batteries. All Hydro One' transmission stations are provided with at least one DC system, comprising a battery, battery charger, and a DC distribution system made up of DC breakers, fuses and associated cable distribution system. Battery systems designated as Station Batteries supply all protection and control and other station ancillary DC services while Telecom designated batteries supply communication system DC requirements at selected stations.

Transmission stations typically have two redundant sources of AC station service power. Bulk Electricity Supply (BES) stations have duplicate station chargers and batteries, whereas Dual Element Spot Network (DESN) stations have only one battery-charger system, in compliance with the requirements of the Northeast Power Coordinating Council (NPCC). The chargers are fed from the AC auxiliary system at 600, 208 volts (3 phase) or 240, 120 volts (1 phase). Typical battery output voltages are 48, 125 and 250 volts. The 48 V battery voltage is usually reserved for communications (Telecom) service, however on the Hydro One system, there is a large number (approximately 70) legacy 48V station batteries used for supply of control panel boards and associated relays. The Station 48V batteries are completely separate and distinct from the Telecom 48V battery systems. The 125V and 250V batteries are used for station protection and control and other ancillary DC services.

A battery charger is an electronically controlled rectifier that is designed to carry the continuous station load over a specified period while simultaneously recharging its battery. The charger has controls that regulate its output voltage to ensure constant voltage irrespective of current output, and current output limits to protect the charger from excessive output demand. It normally also has a boost voltage setting to ensure occasional battery conditioning charging sessions. Chargers are also usually fitted with assorted alarms, including a ground detector alarm for use in ungrounded systems. Figure 19 shows a typical battery charger.

Figure 19: Battery Charger

Transmission stations require rechargeable batteries. There are only two basic types of rechargeable batteries: the nickel–cadmium type and the lead-acid type. In common with most utilities Hydro One use the lead-acid rechargeable cells due to the higher cost and perceived problems with the operation of nickel–cadmium cells.

There are two types of lead-acid cells: lead-antimony and lead-calcium. Hydro One prefers lead-calcium cells due to their longer life, and lower maintenance requirements. Historically, the vented (flooded or wet cell) type battery has been used exclusively by utility users of batteries. A newer type of cell, the valve regulated lead antimony (VRLA) cell was introduced and a number of utilities have migrated to their use because this type of cell has the advantages of a lower space requirement, lower rates of gas evolution, lower safety related costs, and expected lower maintenance requirements. Hydro One has discontinued such installations due to the fact that the life expectancy of valve regulated cells to be significantly less than that of wet cells. Figure 20 shows a typical wet cell battery installation:

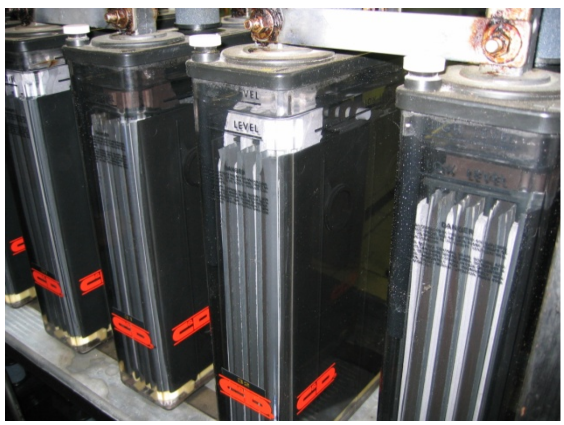


Figure 20: Typical Battery System

The Hydro One standard for battery sizing is in-line with industry standards and ensures that a single battery can carry the entire station load without any AC feed to the chargers for 6 or 8 hour period depending on the station criticality. Typical protection and control battery sizes for step down transformer stations range from 30 to 900 Ampere Hours (AH) while the BES stations are normally equipped with redundant battery systems that range between 180 and 1495AH.

2.13 Station Grounding Systems

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. The basic design of an effective grounding system is required to:

- Provide grounding of all conductive enclosures that may be touched by public or staff personnel thereby eliminating shock hazards.
- Limit voltage in the electrical system to definite fixed values of step and touch potentials to ensure public and staff personnel safety.
- Limit voltage to within insulation ratings of equipment.
- Provide a more stable system with a minimum of transient over-voltages and electrical noise.
- Provide a path to ground for fault currents to allow quick isolation of equipment with operation of ground fault protection.
- Reduce static electricity that may be generated within the facilities.
- Provide protection from large electrical disturbances (such as lightning) by creating a low resistive path to earth.

The Canadian Electrical Code (Sections 10 and 36) and IEEE Guide for Safety in AC Station Grounding (IEEE STD 80) stipulate the requirements for the design of these systems. Hydro One has followed its own standard "Ontario Hydro Transmission and Distribution Grounding Guide, 1994" for design of these systems at its stations.

Soil resistivity measurements at the station location are a required to design an adequate grounding system. Once the grounding system has been installed, it is tested and verified with 'fall of potential' measurements.

Over the period that Hydro One' transmission stations have been in existence there have been some changes in the applicable standards. These, in general, have led to reductions in the permitted maximum potential rise and in step and touch potentials. However, the biggest change during this period has been the ability to accurately model the effectiveness of grounding systems. Traditional "manual" calculations will have been used to design many of the existing stations. These were not able to provide complete definition of potentials and fault conditions. Grounding system installations are typically classified as permanent or temporary systems, as described below.

Permanent Grounding Systems
Grounding systems are comprised of predominantly copper conductors connected together into a mesh that is buried and bonded to all station structures. A typical station grounding system is depicted in Figure 21 and consists of the following:

- 4/0 AWG bare copper conductors buried 12 to 18 inches below grade in a grid pattern that are spaced 10 to 20 feet apart.
- At ground conductor crossings, the conductors are securely bonded to each other.
- Ground rods are securely bonded to the grid at corners, and at junction points along the perimeter. Redundancy in these connections is a requirement.

- Fences, buildings (control, maintenance or administration) are tied to the main grid as well as to water service pipes.
- Any outgoing circuit shield wires and cable shields, as well as station fence ground are also bonded to the station ground grid.

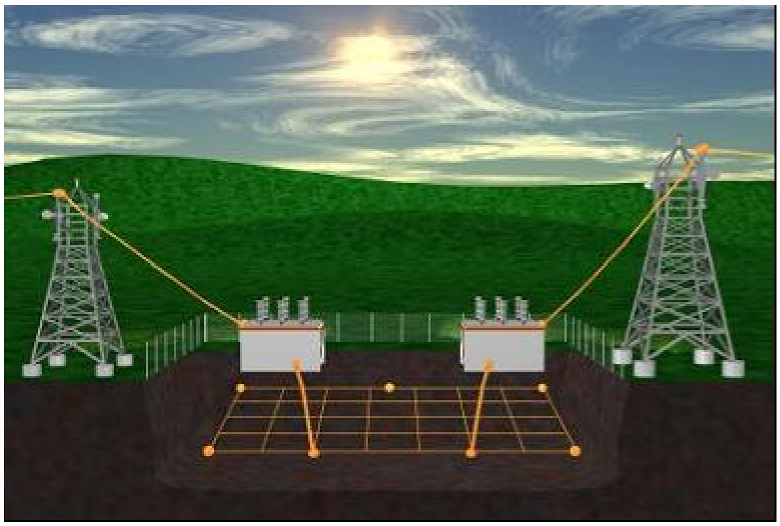


Figure 21: Typical Station Ground Grid

All above grade metallic facilities including structures, transformers, breakers, and fencing would be securely bonded to the grid with grounding conductors as shown in Figure 22. Additional ground rods would be securely bonded to the grid at major facilities and particularly at surge arrester locations. One type of service that is normally isolated from the ground grid is telephone service using metallic pair cable. Such cables are typically isolated from ground in order that exterior telephone equipment is not damaged by the high voltage spikes that are observed in ground grids during faults.

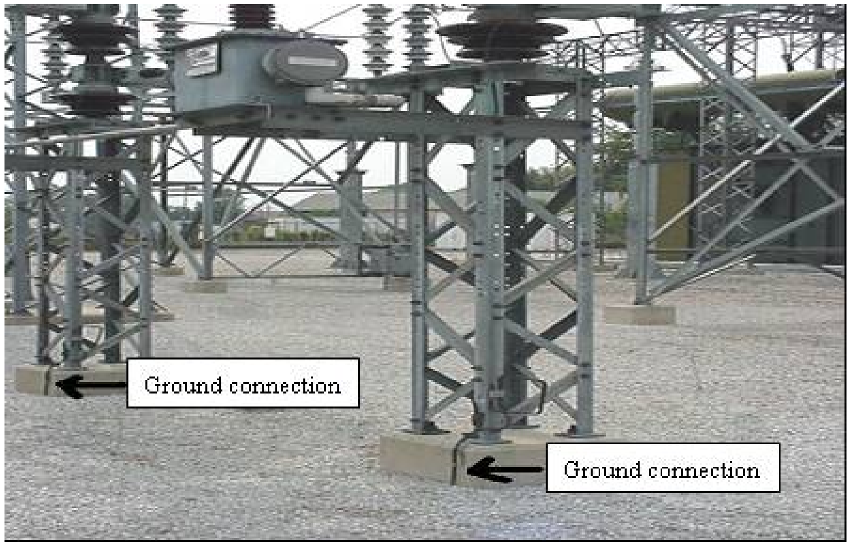


Figure 22: Typical Ground Connection of Switchyard Structures

The station security fence may, or may not, be bonded to the station ground grid depending on several factors such as the minimum distance from the fence to grounded station equipment, whether a rail siding enters the station or whether the gates incorporate telephones, card readers or electric gate locks.

Temporary Grounding Systems

Temporary grounding and bonding systems are installed for personnel safety when working on de-energized apparatus. These are required to eliminate hazardous induced potential differences caused by adjacent energized conductors, residual charges on capacitive circuits or accidental re-energization of circuits or apparatus.

2.14 AC/DC Station Service Equipment

All Hydro One transmission stations are provided with designated AC and DC station service systems. These are the supply systems that provide AC power to the auxiliary equipment in the station such as battery chargers, fans, pumps, HVAC and lighting and DC power from the batteries to control, metering, telecommunication, SCADA, circuit breaker and switch control and operation.

The rating and configuration of these station service systems depends on the function, criticality and rating of the specific transmission station. The stations are categorized as bulk electricity system (BES) stations and dual element spot network (DESN) step down transformer stations. Several of the station service systems are dual feed arrangement to ensure reliability and to minimize the impact of any local supply problems. In all cases, any loss of supply would automatically trigger an alarm.

DC Station Service

The DC station service (DCSS) supplies critical transmission station protection, control and annunciation equipment that operate (trip and close) circuit breakers, circuit switchers, motor operated disconnect switches and emergency lighting.

The main components of DC Station Service distribution system (excluding the batteries and chargers which are evaluated in a separate document) are transfer switches, main and subordinate distribution panels, cables, fuses and other service breakers etc. The DC station service must remain functional for a period of time (6-8 hours) after the initial loss of the charger supply, and capable of operating breakers to re-establish AC supply at the end of that period.

Typical battery output voltages are 48, 125 and 250 volts. The 48 V battery voltage is usually reserved for communications (Telecom) service, however on the Hydro One system, there is a large number (approximately 70) legacy 48V station batteries used for supply of control panelboards and associated relays. The Station 48V batteries are completely separate and distinct from the Telecom 48V battery systems. The 125V and 250V batteries are used for station protection and control and other ancillary DC services.

The DC Station Service reliability requirements are determined based on compliance with regulatory and planning requirements For bulk electricity system (BES) stations, the DC station service design requirements must comply with the TSC, NPCC and IESO to maintain the adequacy and security of the transmission system. The design of the station service system shall ensure that if either the battery charger fails or the AC supply source fails, the station battery bank shall have enough capacity to allow the station to operate for at least eight hours for a single battery system or at least six hours for each of the batteries in a two battery system.

Hydro One is obligated to comply with various NERC Standards and NPCC Criteria related to emergency operating procedures and system restoration. More specifically, the NPCC Criteria Document A-03 “Emergency Operation Criteria”, section 4.10.1 (System Restoration - Testing Requirements), details a number of tests that must be performed regularly at certain stations to ensure that facilities are available when required. Hydro One has identified a total of 70 stations that are on the list of key facilities needed to initiate restoration following a blackout (Basic Minimum Power System, BMPS).

The DC station service must ensure a high degree of dependability and must ensure that no single contingency or common mode failure results in the loss of critical relay protection or automatic tripping of power circuit breakers. This is achieved by having duplicate battery banks and rectifier / charger sets (“A” and “B”) ,each capable of supplying the **total** DC station load, with a DC transfer scheme to switch the supply between the “A” and “B” sources.

For BES stations, this requires that “n-2” system design criteria be applied to the design of the DC station service. That is for pre-contingency planned or forced outage of the station “A” battery or associated charger or AC supply source, loss of a subsequent DC supply element (i.e. “B” battery or associated “B” charger or AC supply source) must not result in loss of critical relay protection or automatic tripping of power circuit breakers.

For Dual Element Spot Network (DESN) transformer stations a single battery / charger system is to be used. AC supply to the charger is to be from an automatic transfer switch fed from both AC station service panels. The single station battery must have enough capacity to allow the station to operate for at least eight hours following the loss of the charger or the AC supply source.

Where a single battery system is used, the following conditions shall be met:

a. It can be tested and maintained without removing it from service;
b. Each protection system shall be supplied from physically separated and separately fused direct current circuits;
c. No single contingency other than failure of the battery bank itself shall prevent successful tripping for a fault.
d. Critical DC supplies shall be monitored and annunciated such as relay protection circuits and high voltage interrupters (HVIs).
e. For tap transformer stations, one protected (fuse/breaker) monitored DC station battery system is required unless two systems are provided.

The Transmission System Code (TSC) Section 10, “Protection System Requirements” requires that telecommunication battery and DC system design shall ensure that systems are:

(a)designed to prevent unwanted operations such as those caused by equipment or personnel,
(b) powered by the station's batteries or other sources independent from the power system, and
(c) monitored in order to assess equipment and channel readiness.

DC transfer switching refers to the station service level transfer of DC load supply from its “normal” supply source to an alternate source of supply following an equipment outage (and loss of the “normal” supply) or for the purpose of carrying out maintenance. Hydro One currently has three types of DC transfer schemes installed; these are:

(i) **Automatic:** Upon loss of “normal” supply this scheme automatically transfers to an alternate source of DC supply.

(ii) **Semi-Automatic:** Operator intervention is required once to transfer to an alternate source of DC supply.

(iii) **Manual:** Operator interaction is required to transfer load supply to an alternate source of DC supply.

AC Station Service Systems

All transmission stations (BES and DESN) have at least two redundant AC station service systems comprising station service transformers, fuses, LV circuit breakers, transfer switches, load centers, panelboards and associated cable distribution system. An additional third source of AC station service such as diesel generators or supply from the local area distribution system must be provided for Bulk Electricity Supply (BES) stations

Hydro One reliability requirements for AC station service systems are established to comply with regulatory requirements of the Ontario Transmission Code, NPCC criteria for bulk power and interconnected system protection, design and operation and also with the requirements of the Independent Electricity System Operator (IESO)of Ontario

In general requirements for bulk power system facilities are that there shall be two sources of station service AC supply, each capable of carrying at least all the critical loads associated with protection systems.

For existing BES stations there are two common variations of the standard AC Station Service supply configuration. The configuration for the larger existing BES stations, having more than two autotransformers consists of three independent sources of AC supply and LV switchgear configured to provide supply to four main AC load distribution centres/panels. Another variation also incorporates three sources of AC supply but provides supply to two main AC load distribution centres/panels

In the future the new, larger BES stations will be supplied by three independent sources but with a less complex and cost effective switchgear configured to supply three load centers/panels only. For new BES Switching Stations or new BES Stations with two or fewer autotransformers, the standard configuration requires that only two independent AC sources of supply be provided to supply two main AC load distribution centres/panels

For DESN stations the configuration provides two independent AC station service supplies connected so that an outage to a single element will not result in the prolonged loss of both supplies. An emergency connection between the AC supplies is provided so that either supply can be connected to supply the entire station service load. New DESN stations are being supplied by simpler and more cost effective load transfer switchgear.

AC transfer switching refers to the station service level transfer of AC load supply from its "normal" supply source to an alternate source of supply following an equipment outage (and loss of the "normal" supply) or for the purpose of carrying out maintenance. Hydro One currently has three types of AC transfer schemes installed; these are:

(iv) **Automatic:** Upon loss of "normal" supply this scheme automatically transfers to an alternate source of AC supply.

(v) **Semi-Automatic:** Operator intervention is required once to transfer to an alternate source of AC supply.

(vi) **Manual:** Operator interaction is required to transfer load supply to an alternate source of AC supply.

To comply with regulatory requirements that specifies eliminating the possibility of a single contingency or common mode failure disabling the entire AC system, fully automatic AC transfer schemes are to be avoided or eliminated. Manual only AC transfer schemes are also to be avoided for switching safety reasons.

The standard for all new and replacement installations requires semi-automatic AC transfer schemes to be provided with remote-OGCC and remote-local initiation and full manual mode override capability. Simple, double throw positive action, automatic transfer switches are to be used downstream of the station service supplies and directly for essential/critical AC loads (e.g. transformer cooling, circuit breaker heaters and auxiliaries, battery chargers). All AC transfer switching schemes use "Break-Before-Make" type switching to prevent paralleling of station service sources.

Each DESN TS has two independent AC station service supplies fed from adequately rated station service transformers connected separate buses on the LV switchyard and arranged so that an outage to a single element will not result in the prolonged loss of both supplies.

The station service transformer ratings are selected to cater for the ultimate DESN TS loads. The secondary system is 120/208V, 3-phase, 4-wire. The transformers are typically rated at 200kVA, with a secondary voltage of 120/208V, 3-phase. Typically there is a 600A transfer switch connection between the two AC supplies is provided so that either supply can be connected to supply the entire station service load.

2.15 Station Buildings

Hydro One owns a number of buildings of different types and sizes, located in or adjacent to transmission stations, and spread throughout the province. These buildings can generally be categorized as:

- Control Buildings
- Auxiliary Systems Buildings
- Occupied Buildings
- Ancillary Buildings.

The Control Buildings are used primarily to house protection and metering equipment, batteries, and control and communication systems. Auxiliary Systems Buildings are buildings used for housing technical equipment such as metalclad switchgear, air compressors and dryers, and oil processing and storage equipment. Occupied buildings include maintenance centers, operation centers, and offices. Ancillary buildings include garages, stores etc.

These buildings have been constructed over a long period of time to meet the particular needs of the time and constructed in accordance with required building standards. Thus, the buildings consist of a wide variety of designs and construction materials e.g. size varies from less than 100 sq. ft. to several thousand sq. ft. depending on the application and these may be made from ornamental brick, concrete block, engineered metal or other prefabricated material.

2.16 Fences

It is Hydro One's practice to erect security fences around their electrical plant facilities, including transmission stations and exposed high voltage cable terminations. This practice is for the purpose of protecting the public from hazardous electrical contacts, and to protect these facilities against intrusion and vandalism.

Types of Fence

The security fences can be of several types such as steel chain link, aluminum chain link, wood, masonry and Durisol. All the above types of fence have been installed at transmission stations owned by Hydro One. Chain link fences are by far the most widely used type of fence and constitute about 99% of the total length of fence installed. This type of fence comprises fence fabric, galvanized support posts and top rail, bottom tensioning wire, barbed wire on top, support brackets, concrete foundations, gates, warning signs and grounding mechanisms. The fence fabric is generally galvanized steel, but aluminum fabric is also used in certain cases.

The other types of fence such as walls of either solid masonry, metal or Durisol may provide an additional degree of security. Solid walls are generally more difficult to breach and also prevent a direct line of sight to equipment inside the station. Solid walls may also prevent vandalism from outside the fence, such as by projectiles (e.g. rocks). The probability of such damage actually occurring depends on a number of variables including the height of the wall, surrounding terrain, and elevation of the equipment inside the station. The material utilized for this type of fence is generally commensurate with the evaluated security risk of the area. As stated earlier, most of the fences at the stations owned by Hydro One are of the chain link type.

Technical and Legal Requirements

The minimum design height of the fence specified by Ontario Electricity Safety Code is 1.8 metres. The standard fence design adopted by Hydro One follows IEEE Standard C2-1997, which requires a minimum chain link fence height of 2.13 metres of fabric, with an additional 0.3 metres extension composed of three-strands of barbed wire at the top. The other important requirements in fence design are: the gap under the fence, between the fence and grade must be less than 25 mm, a 50 mm maximum gap between the gate pipe frame and the gate support posts, and lastly a proper grounding system for the safe grounding of the fence.

Gates are provided at suitable locations around the fence to allow access to authorized persons and vehicles. Depending on security requirements at a particular site, the gate control mechanism is designed to provide one of: automatic vehicular access, manual vehicular/personal access, manual personal access, or manual vehicular access.

In order to warn the public of the danger and to discourage entry by unauthorized persons, approved danger and warning signs are posted at all gates that allow access to transmission stations and other hazardous locations. Such signs are further posted at regular intervals (normally 10 m) along the fence.

2.17 Station Fire and Security Systems

The Security and Fire Protection asset class includes systems for protection of transmission facilities from the threats of fire, break-ins and vandalism. Hydro One owns a large number of transmission stations and buildings of different types and sizes and has installed some form of security and fire prevention measures for protection of the various facilities at each of these locations as described in this Asset Description.

Security Systems

The primary physical barriers provided at all locations to prevent unauthorized entry into Hydro One facilities are the site perimeter fencing or walls. These fences and walls constitute a separate asset class, and thus are not further discussed herein. The security systems in the asset category include additional measures ranging from conventional simple door control security systems to video surveillance facilities.

The form and degree of sophistication of the security systems at these stations/buildings varies widely. The primary reason for this degree of latitude being that, in the beginning, security systems at many locations were installed as a result of 'reactive after the fact' approaches following incidents. Another factor to consider is that a significant number of stations in the past were manned thus no extra security arrangements were required. This is no longer the case. Security requirements have therefore changed in recent years resulting in a need to develop a strategy for standardization for security systems. This standardization process is still in the evolving stages.

Generally, three types of security systems have been employed at transmission stations. The simplest types include simple door and gate control systems, often padlocks, to permit entry to authorized personnel only, and motion sensor triggered lighting installations. Note that in many cases, there are third parties that have access to the station premises. Typically, the third party installs its own lock and opening either lock provides access to the site. A first step in enhancement of the security level at transmission and distribution stations is the replacement of the locks and the implementation of a new key management system to control access to the sites. The second types include motion detection and alarm systems within buildings. The third type includes microprocessor surveillance of the motion detection and modern slow scan video surveillance systems, with both of these types of systems wired to supervisory control and data acquisition systems (SCADA) to allow central monitoring. The latter types of systems are installed at only a few sites at present.

At a number of locations, security monitoring is part of the fire detection system or the heating, ventilation and air-conditioning system. Hydro One has control centers at 10 locations; and each of these centers monitors a number of stations. As part of the development of a standardized security policy and system, it is planned to centralize the monitoring function to a master control centre.

Fire Protection Systems

Fire protection systems at transmission facilities are primarily of two types; those associated with buildings and those associated with equipment.

2.18 Buildings and Indoor Equipment

In a manner similar to the practices followed by Hydro One for security systems no standardized practices for fire detection and prevention have been established for general building areas. Buildings constructed after 1985 have fire detection systems installed; whereas some of the older buildings do not have even simple smoke detectors. Other types of systems installed for fire control in buildings include:

- Carbon dioxide based systems
- FM 200 systems. These have replaced the now unacceptable Halon based systems that had been installed at some locations.
- Sprinklers. These are normally installed in all basements with areas over 300 square feet.
- Fire hoses connected to municipal water systems are provided inside some buildings.

Certain indoor equipment, such as oil-filled transformers and oil-filled cable potheads, require dedicated fire protection systems such as water deluge systems with associated hose cabinets. Such systems are provided to meet the requirements of National Fire Protection Association (NFPA) Standard No. 15; and they include fully automatic air supervised, or electrically supervised, cycling type, dry pipe, open head deluge systems for all major indoor fire hazards, such as those noted above.

Deluge systems generally consist of open head spray nozzles attached to a piping system that is connected to a water supply through a deluge valve. The valve is opened by the operation of a fire detection system installed in the same area as the nozzles. When this valve opens, water flows into the piping system and discharges from all nozzles. This type of system uses high-velocity water sprays of a relatively large droplet size directed against convection air currents; and the system is designed to extinguish fires on, under, or immediately around protected equipment.

Outdoor Equipment

Oil filled transformers in outdoor stations are equipped with fire detection systems. The monitoring of heat detectors is handled through SCADA systems to the respective control centres, or through the dedicated fire detection panel to the SCADA system and then to the control centres. Only a few transformers, at attended, rather than unattended, Stations, are without this system. Other outdoor equipment, with the exception of oil filled cable terminations are not considered vulnerable to fire and thus they are not fitted with fire detection systems.

2.19 Station Drainage, Oil Spill Containment and Geotechnical Systems

The Transmission Drainage and Geotechnical asset class includes drainage facilities for the removal of surface and ground water, and civil work facilities such as roads, yard compaction and surfacing, and footings.

Drainage Systems

Transmission and switching stations require drainage facilities for the removal of surface and ground water. Drainage is a practical and economical way of improving and maintaining firm, dry, stable sub grades for support of roads, railways, and foundations for structures and buildings.

The two basic sources of subsurface water are the presence of a high ground water table, and precipitation (rain or snow melt) seepage into the soil. When water seepage encounters an impervious layer of soil, water is retained and forms pools, which increases the ground water table level. Occasionally, subsurface soil formations result in upward water flows, or springs. These, when they occur within stations, must be capped and the water diverted off site to ensure the water doesn't compromise the subsurface soil integrity, or cause grounding problems. Foundation under-drainage protects basement slabs against hydrostatic uplift and flooding of basements. Road under-drainage helps to minimize frost heaving and frost boils. Inadequate drainage can compromise maintenance and construction access for heavy equipment; and thus can cause a personnel safety hazard.

Many stations have drainage systems, which consist of main drainage and under-drainage. Main drainage is a system of catch basins, buried piping and manholes, including necessary pumps, all as required to suit the station site. The system also includes connections for building rainwater drains and transformer oil spill containment system drains. Under-drainage consists of buried perforated piping connected to the main drainage. This type of drainage pipe is provided to allow drainage of sub-surface water from graded areas, roads, parking areas, railroads and cable trenches. Sumps and sump pumps are included in under-drainage systems, where required.

Many stations exist without a main, or under-drainage systems. In such cases, runoff percolates over the yard surface, which is sloped to ensure drainage, and the water finds its way to a ditch off the station active surface.

Over the past 20 years there has been growing awareness of the need to contain oil spillage from major plant. Growing awareness of environmental issues and tightening of legislation and increased penalties have forced electric utilities to address this issue in a more systematic and consistent fashion. Prior to this period, oil containment was a feature for major transformers but the application was varied and non-uniform. Over the past 20 years, the onus has been on ensuring that the oil containment systems for all major transformers are to a uniformly high and acceptable standard.

Transformer spill containment systems are operated to release runoff to drainage systems, except during oil spills when the containment connection is shut off by a special pump located in a sump. This sump may be connected to one or several spill containments; and it is not considered part of the drainage system.

Maintenance and ongoing management of oil containment systems is generally limited to visual inspection as part of routine substation inspection with functional checks on pumps used to remove rainwater. As part of the program to ensure that oil containment systems are to a uniformly high and acceptable standard, an overall assessment of their condition would have been undertaken resulting in upgrading or replacement as necessary. As most systems will therefore have been subject to relatively recent assessment, and if necessary upgrade/refurbishment, condition based end-of-life would not normally be considered a significant issue. However, if a major defect or damage was detected during routine inspection a full assessment, and if necessary appropriate repair or replacement, would be undertaken.

Layout of a typical drainage system for a Hydro One station is shown in Figure 23.

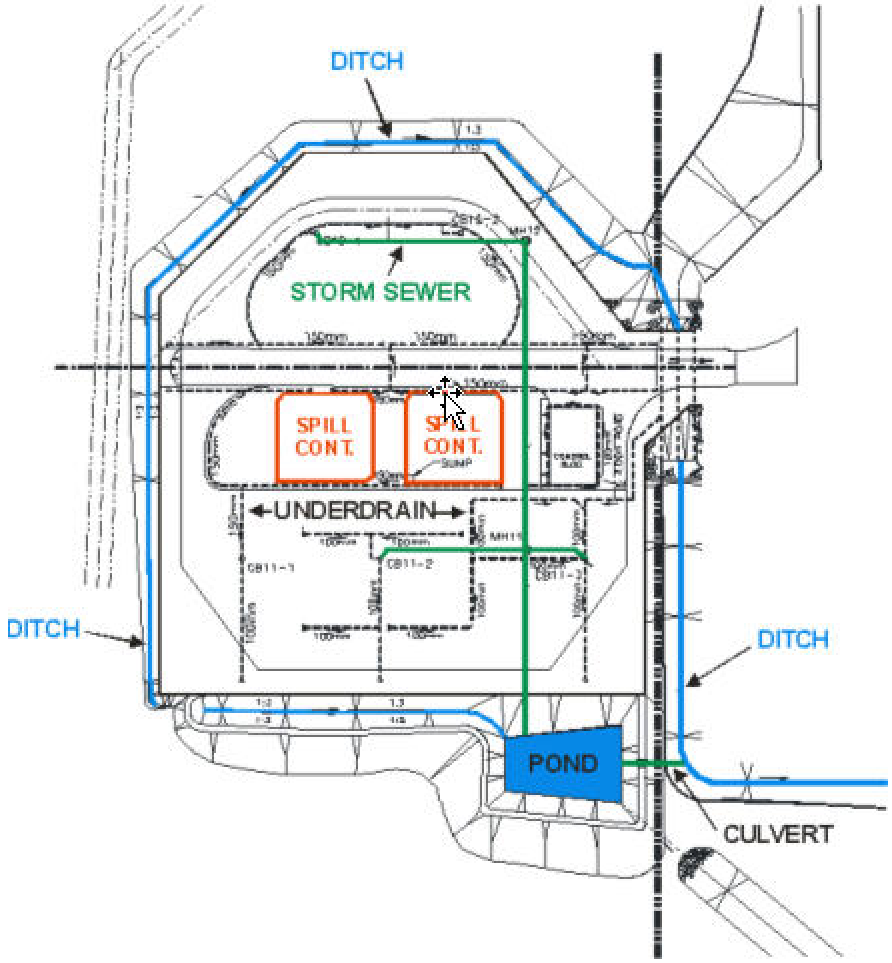


Figure 23: Components of Drainage Systems

2.20 Yards

Transmission station yards, when first constructed must initially be stripped, compacted, and graded. Stripping involves removal of the vegetation including roots and top soil, including all undesirable other soil elements, such as rock, boulders, organic materials, and scrap, as well as items such as bog and quicksand. After the removal of undesirable soils elements is completed, the site is graded to the final design sub-surface elevation(s). This generally involves movement of subsurface soils from some areas of the site to other site areas and occasionally the addition of extra fill, or removal of unneeded fill. Drainage, including ditches around the site would be added at this point in the process. During the process of grading the site is also compacted to ensure soils stability and bearing capability. The last stage in yard preparation is the addition of suitable toppings, such as crushed rock to ensure a high resistance cover over the ground grid.

Guidance during this process is provided by the interpretation of geotechnical tests carried out prior to the start of site works. These tests involve drilling and excavations of soils at site as well as extensive analysis of the soils to determine their suitability for inclusion in the final site subsurface.

2.21 Roads

Roads into and inside station sites are conventionally divided into two types, surfaced and un-surfaced. Both types of road are built in approximately the same manner up to the final surface layer. The sub-surface layers are specially compacted and normally special fill is brought in to ensure sufficient subsurface bearing capacity is provided. Occasionally, special geotechnical fabrics are installed below the road to ensure adequate bearing capability. Un-surfaced roads are finished with gravel to provide a drivable surface. Surfaced roads are conventionally surfaced with asphalt, or sometimes concrete.

2.22 Footings

Footings for equipment support are almost always made out of reinforced concrete. Very occasionally in locations where soils conditions are poor pile foundations are provided, with a variant of this type of foundation provided by the use of screw anchors. It is understood there are very few piled foundations, and no screw anchor foundations used within the Hydro One system. A typical footing is shown in Figure 24.

There are two basic variants for the installation of footings. One involves excavation of the entire site and then the installation of the footings at the base level, with soils installed and graded from this level. The other involves excavation into the compacted sub-grade and installation of the foundations in the sub-grade materials. Footings installed in this manner may either be excavated or they may be augured. Auguring is generally preferred on a cost basis; but both are viable methods of footing excavation. The first type of foundation installation practice is generally only used in granular soils; the second type, the excavated or augured type, is generally used in more cohesive soils, such as clay.

Footings of course must be carefully designed to match the soils in which they are placed and also they must be adequate for the ultimate loads they must carry, under extreme conditions of weather as well as electromechanical loadings. Appropriate safety factors are always applied.

Figure 24: Damaged Footing of a SF_6 Bus Duct

3.0 PROTECTION SYSTEM ASSET DESCRIPTIONS

This section provides descriptions of Protection and Control assets that are found at Hydro One Stations. Protection systems consist of either a single or multiple primary measuring relay units and a host of auxiliary devices that provide logic functions. Primary measuring relays are complex devices with predictable expected life spans. Auxiliary devices such as simple relays and timers are considerably more robust.

The major components in protection system are:

- Primary measuring relays - Electromechanical, Solid State, Digital
- Auxiliary devices - Simple relays, Timers, Logic Controllers
- Panels or Racks - 19 inch rack, Steel panel, Ebony asbestos
- Mounting hardware - Primary relay cases, Auxiliary relay cases

3.1 Protection Relays

Protective relays and their associated systems are devices connected throughout the transmission system for the purpose of sensing abnormal conditions. They detect and isolate in conjunction with circuit breakers any abnormal conditions resulting from natural events, physical accidents, equipment failure or mal-operation due to human error. Protective relays and their associated protection systems are therefore indispensable for the safe and healthy operation of the transmission network.

The maximum time allowed for power system protection to correctly sense and isolate faulted equipment whether a transmission line, power transformer etc. is measured in a fraction of a second. High-speed isolation is necessary to protect and mitigate damage to expensive system equipment, reduce the health and safety risks to public/personnel and to maintain power system security/reliability.

Both failure to operate and incorrect operation can result in major power system upsets involving increased equipment damage, increased personnel hazards and possible long interruption of service. These stringent requirements with high potential consequences make it imperative that protection systems be extremely reliable. Protective devices come in three forms or technologies described as follows.

Electromechanical: Utilizes the principles of electromagnetic induction to convert electrical energy to mechanical movement to provide fault detection. An example of this type is shown in Figure 25.

Figure 25: Electromechanical Relay Panel

Solid State: Transistor and integrated circuit technology provide the means of fault detection. An example of this type is shown in Figure 26.

Figure 26: Solid State Relay Panel

Digital: The latest microprocessor based technology provides advanced fault detection capability. An example of this type is shown in Figure 27.

Figure 27: Digital Primary Schweitzer Relays

Protection relays may be either rack mounted, or located in the instrument compartment of switchgear. Older style electromechanical primary measuring relays are also mounted in cases specifically made for them that then mount on panels or racks.

3.2 Auxiliary Devices

Auxiliary devices include relays and timers that are usually mounted in auxiliary cases that in turn are mounted on panels or racks.

Three broad categories of auxiliary devices exist.

Type 1: Auxiliary relays and timers manufactured by ASEA used in their modern combliflex method of case mounting known as RX. This type is shown in Figure 28.

Figure 28: ASEA RX Type Auxiliary Relays

Type 2: Auxiliary relays and timers manufactured by ASEA used in their original method of case mounting known as RR. This type is shown in Figure 29.

Figure 29: ASEA RR Type Auxiliary Relays

Type 3: Auxiliary relays and timers directly panel mounted which include, Westinghouse, General Electric and English Electric type.

The vast majority of these auxiliary devices are either RX or RR.

3.3 Panels or Racks

Protection systems are assembled with the various components such as primary measuring relays, auxiliary devices, terminations and isolation devices mounted on panels or racks. Panels may be 24 inch painted steel, or ebony asbestos. Racks are 19 inches free standing painted steel. A typical installation is shown in Figure 30.

Figure 30: 24 Inch Steel-Type Panels with Protection, Auxiliary Relays, Flexitest Switches and Current Links

3.4 Mounting Hardware

Auxiliary devices such as relays and timers are usually mounted in auxiliary cases that in turn are mounted on panels or racks. Older style electromechanical primary measuring relays are also mounted in cases specifically made for them that then mount on panels or racks.

3.5 Control System: Remote Terminal Units (RTUs)

RTUs are located at all transformer stations to allow operating control from a centralized master control centre where the operators are located. The RTU provides status indication, alarm and control of all equipment located at the local station. The RTU transmits telemetry quantities such as Watts, VArs, Amps and Voltages used for indicating metering. The RTU may also perform certain control functions such as voltage regulation and breaker synchro-check depending on the station operating requirements.

Most RTUs are microprocessor or PC based and self-diagnosing. Microprocessor based RTUs may be single or dual-redundant depending on the reliability required in each installation. Dual redundant RTUs are also multi-ported to support communications to other electronic devices including Human-Machine Interfaces (HMI) used for local station control. Redundancy is provided in the processors only, since the input and output RTU architectures may be concentrated or distributed depending on the economies related to space constraints and cabling. The PC based installations will have a shorter life cycle and lower reliability than the microprocessor based devices as they have electromechanical data storage mechanisms and a relatively short obsolescence cycle. In some cases, the RTU function is performed as part of a distributed system, or integrated as a secondary function into another P&C system.

Distributed systems consist of networked stand-alone microprocessor-based IEDs that are dedicated to the control metering and annunciation function. In some cases, a protection IED provides a subset of the RTU data as a secondary function as shown in Figure 31.

Figure 31: GE D25 Distributed RTU Installation - 1999

Most RTUs are not subject to regular maintenance intervals and are only serviced upon failure. The new generation of RTU uses non-volatile memory that must be secured in order to operate reliably. The non-volatile memory (NVRAM) will have a life expectancy as short as eight years, and, in some cases, as long as the service life of the equipment. Devices with NVRAM with a service life that is less than the RTU will be scheduled for preventative maintenance to ensure that failures do not occur.

3.6 Protection System Monitoring

Protection system monitoring devices, including annunciators, digital fault recorders (DFRs) and sequence of events recorders (SERs) are widely deployed in transmission stations to provide detailed information on protection operation. The annunciators currently in use are ***solid-state*** electronic devices and the DFRs and SERs are microprocessor and PC based. The capability and sophistication of these devices has been rapidly developing over the past 15 years. As a result of this rapid development, issues of obsolescence, functionality, spare parts and support, particularly related to compatibility with modern IT and communication systems, are the main end-of-life factors. Condition is not normally a significant issue.

Fibre Optics

In the 1990s many electric utilities installed fibre optic links using either a wrap around on the overhead groundwire of their transmission lines, an underslung self-supporting cable or fibres integral with the overhead groundwire. In some cases these were comprehensive systems linking all the main sites in the company, in others it was limited to a few experimental links. There were some initial problems related to the installation processes causing damage to the fibres and some difficulties with splices, but subsequently we believe that the systems have proved reliable and effective.

Metallic Cables (Pilot Cables)

These are used to provide telecommunication channels for protection and control purposes. Based on UK and North American company experience, these are subject to periodic insulation resistance tests and continuity checks. These measures enable degradation to be detected and monitored, with unacceptable levels stipulated in the maintenance manuals. In many cases metallic cables are self-monitored, any indication that they are outside specified limits would trigger an alarm.

Site Entrance Protection Systems

This category consists of equipment required to protect metallic telecommunication cables (Hydro One and those of the telephone companies) that enter high voltage transmission facilities. The predominant equipment type is the neutralizing transformer; other types include isolating transformers and optical isolators. The most important functions performed by this equipment are safety of people and sustaining the operation of teleprotection systems during power system faults.

Teleprotection Tone Equipment

This equipment is a system utilizing telecommunication systems (usually owned by telecommunication companies) to send blocking or tripping signals to remote locations for protection purposes. The equipment owned by the electric utility is typically limited to the ‘send and receive’ multi-channel electronic devices in the transmission stations. The system is quite widely used as an alternative to metallic (pilot) wires.

Timing tests are carried out during commissioning and on watchdog monitors once the system has been commissioned. Some utilities carry out regular ‘timing’ tests to check the performance and functionality of the system. As with other electronic equipment these are repaired or replaced when failures occur. As they are multi-channel devices there is often some built in redundancy allowing flexibility in managing failures.

4.0 LINES ASSET DESCRIPTIONS

This section provides descriptions of Overhead and Underground Transmission assets that are found at Hydro One Stations.

4.1 Overhead Transmission Lines

The primary elements of overhead transmission lines include conductors, supporting structures, insulators, shieldwire hardware and the rights-of-way upon which they are constructed. The bulk of Hydro One's overhead lines are constructed using aluminum conductors reinforced with a steel core. The conductors are supported by steel structures, porcelain insulators and connecting hardware. The lines are protected from lightning strikes by shield wires mounted above the conductors.

Conductors

Transmission line conductors carry electrical energy from generating stations to transformation stations where the transmission voltage is lowered and the energy is redistributed to customers through distribution line conductors, generally of smaller capacity than the transmission conductors. Normally three conductors (one for each phase) constitute a single circuit, with an operating voltage on the circuit that results in phase-to-phase voltages between the conductors.

Figure 32 shows the Aluminum conductor, steel reinforced (ACSR) in a cut view. ACSR is the most prominent type of conductor used on transmission systems.

Figure 32: ACSR Conductor

In ACSR conductor the steel core strands supply the majority of the conductor's strength, which enables it to withstand the forces applied from wind, snow and ice as well as its own weight. The steel strands have both tensile and ductile properties so that they are able to withstand longitudinal forces and bending movements respectively, without failure. Individual aluminum strands of wire are laid over the core of galvanized steel wires, with a pitch length that is dependent on the diameter of the core over which it is arranged. Subsequent additional layers of aluminum wire strands are then applied with a reverse pitch, alternating with each additional layer.

The alternating pitch of the aluminum layers create a design that has some capability to reduce movement of the conductor as a result of the friction between the layers of aluminum strands. Some conductors are constructed with flat segmented aluminum strands that result in a smaller diameter for the same cross-sectional area and, as an added bonus, also increases the frictional surface areas between layers of the strands thus improving resistance to conductor swing and vibration. This design also has a reduced tendency for radio and television interference, as the corona discharges are less on a smooth round outer conductor surface.

The determination of the number of steel wires in the core is dependent on the strength of conductor required whereas the number of layers of aluminum is dependent on the amount of current the conductor is designed to carry.

Conductor sizes used in the transmission system range in diameter from 1.43 cm (just over half an inch) to 4.069 cm (just over one and a half inches).

The conductors are supported from structures at intervals (175 metres to 325 metres depending on operating voltage and height of supporting structures) and at tensions up to 222 kN that result in the conductor being elevated a minimum safe distance above the ground at its lowest point between structures at its design operating temperature, with a safety factor.

Conductors are arranged on the supporting structures with sufficient clearance from the structures, ground, overhead shieldwire and other phase conductors to prevent the operating voltage from flashing over between the various elements. The spacing arrangement also takes into account the ability of conductors to gallop (move in an up and down and/or sideways motion) during icing and wind conditions. Insulators with adequate strength to support the physical loads that will be encountered during anticipated weather conditions support the conductors. Between the supporting structures (spans) the insulating medium is air and this insulating quality is taken into account in the separation of the conductors along the route of the circuit.

As load current passes through the conductor the resistance of the conductor causes its temperature to rise. The change in temperature is proportional to the square of the load current passing through it. This rise in temperature causes the conductor to lengthen and to sag between the points of support, thus reducing the height of the conductor above ground. This factor can easily result in a reduction of clearances from ground in the order of 3 metres or more depending on the temperature increase of the conductor, the ambient temperature, wind and solar conditions and the distance between points of support. It is critical, therefore, to limit the amount of load carried by each transmission circuit to a level that is within its design capability.

The energy transported on the conductors consists of electrons that have a tendency to travel through the outer layers of the current carrying aluminum strands (skin effect). This results in the inner layers of the aluminum strands not being utilized to their full extent. To overcome this phenomenon the 500 kV system, a design is used where each phase consists of two or more individual conductors of smaller diameter that are held close to each other (approximately 45 cm apart) by means of mechanical connectors. Not only is this type of construction more efficient, it has better (reduced) corona performance and an ability to reduce the amount of conductor movement during wind and ice conditions.

The design most commonly used by Hydro One in the above situations is where four individual conductors form one phase conductor and are held apart in the shape of a 45 cm square which is shown in Figure 33. The surface area available for the current (energy) to flow in this design is now much greater than in a single conductor of equivalent size and thus the efficiency in transporting energy is enhanced.

Figure 33: Four conductor bundle with spacer

Shieldwires

Shield wires are either smaller ACSR conductors or galvanized steel stranded conductors mounted above the phase conductors and solidly connected to ground through the tower steel or ground conductor. Their function is not to carry load current but rather to shield the current carrying conductor from lightning strokes and safety dissipate the energy to ground.

4.2 Supporting Structures

A transmission line represents a mechanical system made of components such as conductors, ground wires, supporting structures (including wood poles, steel towers, and steel poles) with foundations, insulators, hardware and fittings. These transmission lines transport electrical energy from the generating facilities to transformation stations, large industrial customers and to municipal electric utilities.

The wood poles are harvested from various species of trees grown naturally in many parts of Canada. The tree species in use include Western Red Cedar, Jack Pine and Georgian Yellow Pine. These different species of trees have different strength and performance characteristics that are considered in the overall design of a transmission line. The mechanical and structural designs of overhead transmission lines are based on safety, reliability and security requirements. Wood has been a popular material for use in building transmission lines because of its cost effectiveness and reliability over the life of the asset, i.e. low capital and maintenance costs and ease of construction. Wood is a renewable resource and Canada has traditionally had a large supply of suitable trees for this purpose.

Wood poles are graded according to strength by class numbers (i.e. Class 1, 2, 3,...), where the smaller the number, the stronger the pole. Transmission wood pole lines are usually constructed with Class 2 or stronger poles to meet the design loading requirements of the transmission line.

Wood poles and cross-arms are normally treated with preservatives (e.g. creosote, pentachlorophenol or most recently, chromated copper arsenate) in order to prevent premature decay and extend their useful lives.

Wood structures also have a copper or aluminum wire installed across the cross-arm and down the length of the pole to connect all metallic materials and hardware to a metallic ground rod. This arrangement conducts any stray leakage currents to ground to prevent a wood pole or cross-arm fire.

The two basic transmission wood pole design types in use by Hydro One are “H Frame” design and “Single Pole” design. These are used for all tangent (in line) and small angle applications. For larger angles and dead-ending, a 3-pole semi-strain or dead-end structure design is used.

- H-Frame Structures (Figure 34) consist of two poles and a cross-arm. In some cases there are guy wires attached to the poles near the cross-arm and then attached to ground anchors located at 90 degrees from the direction of the line. Other means of reinforcing such structures incorporate cross-braces installed in an X configuration between the vertical poles. Due to the design of such structures they require more materials, occupy more right-of-way and are stronger than single pole structures.

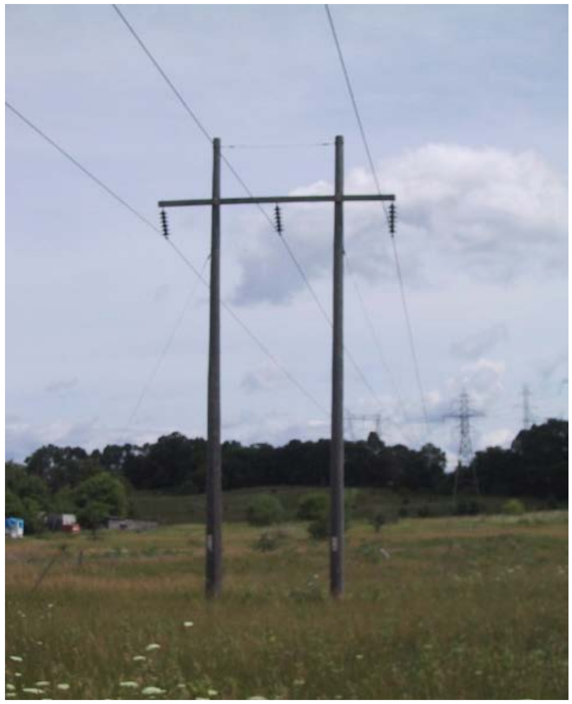
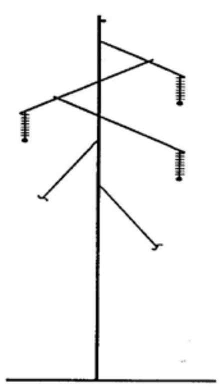
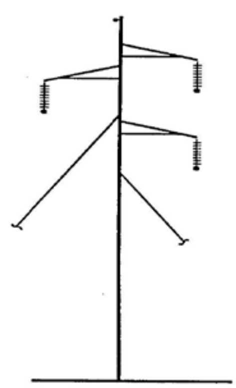


Figure 34: Transmission Line H–Frame Structure

- The “Single Pole” design uses a single pole of suitable height, in the range of 17 to 30 metres. Conductors are then suspended using steel arms with suspension insulators (Figure 35); the older “wishbone” design using two cross-arms attached at different points on the pole and slanted to provide spacing for the attachment of the three phase conductors they support (Figure 35; or standoff insulators (Figure 36). These structures are less expensive due to the use of less material, are not as strong and occupy less right of way than the H-frame structures.



115kV 1CCT. SUSPENSION STRUCTURE
(WISHBONE TYPE)



115kV 1CCT. SUSPENSION STRUCTURE
(WITH STEEL ARMS)

Figure 35: Single Pole Designs, "Wishbone" and "Steel Arms"

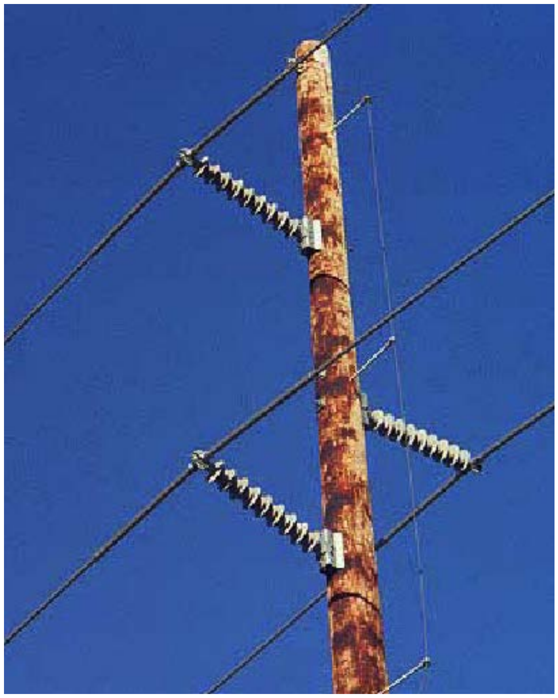


Figure 36: Single Pole Design, "Standoff"

4.3 Rights-of-Way

An overhead transmission line right-of-way (Tx-ROW) is a continuous, urban or rural land corridor with an established legal right for Hydro One to construct, operate, and maintain electrical utility transmission lines. The primary function of these corridors is for the transmission of electrical energy in a safe and reliable manner. The Tx-ROW asset provides the land base for building and/or installing structures and stringing conductors at a variety of voltage levels with appropriate access for operating and maintaining those facilities.

The Tx-ROW corridor is required as part of the transmission system whereby conductors at voltage levels of 115 kV, 230 kV and 500 kV are used to transmit electrical energy to customers from the various generation and supply sources throughout its service territory. Engineering and Design standards and the type of supporting structures determine Tx-ROW corridor width requirements. Conductors energized at voltage levels of 115 kV, 230 kV, and 500 kV require Tx-ROW widths averaging 30 m, 46 m and 64 m respectively. Tx-ROW corridors may contain one or more circuits. These circuits may form a single or multi-circuit line and they may or may not be at the same voltage levels. Multi-circuit line corridors vary in width and may require Tx-ROW clearing as wide as 220 m.

All new high voltage transmission line projects are required to go through an Environmental Assessment and approval process. This is to ensure that the potential social and economic impact of transmission line facilities and corridors have been addressed and have been dealt with in a satisfactory manner. The steps of the Environmental Assessment and approval process ensures that the selection of a preferred route for the new transmission line is determined after considering all environmental, cultural, social and economic impacts. This process may also rely on public hearings to assess alternative routes and to determine the final preferred route. The outcome of this process is an Order in Council (OIC) from the government that gives Hydro One the rights to acquire property and/or easements for the purpose of constructing the transmission line facilities. The OIC gives Hydro One the right to clear property of woody vegetation; to acquire and construct access; to erect or install overhead and underground conductors.

The OIC also gives Hydro One the authority to operate and maintain the equipment and the Tx-ROW within prescribed guidelines. Operation and maintenance of the transmission line includes the requirement to maintain clearances between vegetation and the transmission facilities and the rights of access.

Hydro One’s Tx-ROW properties occupy Crown Lands, (through License of Occupation), patent lands, (through easement rights), First Nation Lands (through easements), and lands owned outright by Hydro One.

All agreements governing Tx-ROW must have rights to conduct vegetation maintenance activities on the Tx-ROW and the right to manage trees on adjacent lands that pose a threat of falling into the line or growing into the minimum allowable side clearances thereby interfering with the safe operation and reliability of the line. Where vegetation has been allowed to encroach on the originally constructed width of the Tx-ROW, re-establishing the Tx-ROW to design width is an important aspect to the successful and safe operation of the transmission system.

Managers of vegetation programs are dealing with a biological system that is constantly changing. If a Tx-ROW is not maintained, in short time, through natural succession, it will revert back to the original forest cover.

Tx-ROW in Rural Areas

Tx-ROW in rural areas traverse both long narrow paths (single transmission lines with one or two circuits on one line) and wider Tx-ROW and shorter distances (multiple transmission lines on one corridor). However, some of the multi line corridors traverse long paths such as the lines between Otto Holden to North Bay to Sudbury to Missisauga.

The Tx-ROW system touches on many of the geological landforms found in Ontario as well as all forest regions ranging from deciduous to boreal to tundra. Local topography associated with any one Tx-ROW can range from low to high relief, from poorly drained bogs to well drained eskers, and from bedrock ridges to sand flats. Extreme topography, rivers, streams, wetlands, lakes and lack of road development can restrict Tx-ROW access. The adjacent land uses can also vary widely from rural residential developments, agriculture, managed woodlots, orchards, and mining to remote wilderness.

On Tx-ROW in rural areas, additional management constraints can apply in response to land owners when dealing with Tx-ROW located on First Nations lands, Federal lands, railway lands, Provincial lands and patented lands. The change in vegetation species mix through each of the Forest Regions in the Province results in different maintenance cycle requirements and a need for a variety of methods and tools for managing vegetation.

Tx-ROW in Urban Areas

Hydro One has transferred all its urban transmission corridors to Provincial ownership but still remains responsible for their maintenance. These urban corridors have essentially become grassed open areas, designated green belt and industrial or commercial lands. Urban corridors support a wide range of vegetation ecosystems associated with stream valleys, steep slopes, naturalized areas, maintained grasslands, un-maintained grasslands, scrub lands, recreational/park lands and industrial lands. Urban corridor land uses range from leases to cover commercial parking lots, transportation and industrial uses to agriculture, golf courses and landscaping nurseries to areas of “quiet enjoyment” and green belts. All urban Tx-ROW must be managed to the conditions and standards of the community within the bounds of local municipal bylaws and approvals. These owned properties total approximately 9,300 hectares in large population centres such as Metro Toronto and Greater Toronto Area, Ottawa, and Niagara Falls and 10,900 hectares in smaller population centres.

However, the high cost of lands in urban areas also provide an opportunity for compatible secondary land uses that generate revenue and, when successfully pursued, also reduces the total land area requiring maintenance expenditures by Hydro One. These factors lead to a different strategy for conducting ground maintenance and vegetation control on urban Tx-ROW, than rural Tx-ROW.

4.4 Underground Cables

Transmission underground cables are typically extensions to, or links between, portions of the Networks' overhead transmission system operating at 115 kV and 230 kV. There are no underground cables in the 500 kV system. Underground cables are mainly used in urban areas where it is either impossible, or extremely difficult to build overhead transmission lines due to legal, environmental and safety reasons.

The initial capital cost of a transmission underground cable circuit is about 10 times higher than the cost of an overhead transmission line of equivalent capacity and voltage. Transmission underground cables are also more costly to maintain/repair than an overhead transmission line and they pose environmental risks not present with overhead transmission lines as some are filled with pressurized insulating/cooling liquids.

Depending on the cable design the three phase conductors may be contained together within a steel pipe or each phase conductor is self-contained in its own sheath and installed separately underground. Transmission underground cables are systems, similar to transmission lines, made up of numerous components, all of which need to integrate and function properly in order to deliver the electric power with the reliability that is demanded.

There are several different types of high voltage underground cables in use on the Networks' transmission system:

- Low-Pressure Liquid-Filled (LPLF) Cables
- High-Pressure Liquid-Filled Pipe-Type (HPLF) Cables
- Extruded Cross Linked Polyethylene (XLPE) Cables:

Low-Pressure Liquid-Filled (LPLF) Cables

This design features a hollow core conductor to carry insulating liquids, which saturates and maintains the dielectric strength of the lapped paper insulating layers over the cable core. The cable is mechanically protected by an aluminium or lead shield, which in turn is protected from corrosion by an insulating polyethylene or rubber jacket.

The cable system is maintained continuously under positive liquid pressure from liquid reservoir tanks, either gravity fed or pressurized tanks situated at the terminal ends, and occasionally along the cable route. In unusual situations, due the cable route, elevations and length, a low pressure pumping plant may be used.

This type of cable is almost invariably installed as three individual phases in a horizontal configuration with a separation of 15-20 cm directly in an excavated trench or in a concrete encased duct bank. The trench is backfilled with material that retains moisture and conducts heat away from the cables.

An example of this type of cable is shown in Figure 37.

Figure 37: Low-Pressure Liquid-Filled (LPLF) Cables

High-Pressure Liquid-Filled Pipe-Type (HPLF) Cables

This cable design features the three phases of a cable circuit installed within a steel pipe. The pipe not only holds the cable phases, but also liquid maintained under high pressure (200 psi) by pumping plants located at the cable terminations. The pipe is a welded carbon steel pipe, coated on the exterior with protective coatings, and cathodically protected to prevent corrosion. The three phase conductors contained within the pipe are each wrapped with lapped paper taped insulation and an outer metallic foil tape to control voltage gradients between the conductor and the outer layers of paper insulation.

The free space surrounding the phase conductors is pressurized with insulating liquid supplied from an electrically controlled pumping plant located at the cable terminal end. Some of these pumping plants are now equipped with PLC and computer control systems, which improve operational efficiency, and have an early leak detection system.

An example of this type of cable is shown in Figure 38.

Figure 38: High-Pressure Liquid-Filled Pipe-Type (HPLF) Cable

Extruded Cross Linked Polyethylene (XLPE) Cables

This cable type is a simple design which consists of a extruded polyethylene insulation covering the phase conductor, mechanically protected by a lead sheath and covered with a polyethylene jacket to provide corrosion protection. Similar to LPLF installations, XLPE cables are installed as three individual phases in an excavated trench or concrete encased duct bank.
An example of this type of cable is shown in Figure 39.

Figure 39: Extruded Cross Linked Polyethylene (XLPE) Cables

SUMMARY OF OM&A EXPENDITURES

1.0 SUMMARY OF OM&A EXPENDITURES

The proposed OM&A expenditures result from a rigorous business planning and work prioritization process that reflects risk-based decision making to ensure that the most appropriate, cost effective solutions are put in place. This process is described in detail at Exhibit A, Tab 15, Schedules 3 through 6.

The proposed OM&A programs represent the work required to meet public and employee safety objectives, maintain transmission reliability at targeted performance levels, and to comply with regulatory requirements (such as specified within the Transmission System Code), environmental requirements and Government direction.

The development of asset maintenance programs, as described in the following schedules of this Exhibit, is based on equipment specifications coupled with comprehensive asset condition information, as well as information on asset demographics, component performance and reliability, and equipment utilization.

Hydro One Transmission's OM&A budget is grouped into different investment categories: Sustaining, Development, Operations, Customer Care, Shared Services and Taxes Other than Income Taxes. Table 1 provides a summary of Hydro One Transmission's OM&A expenditures for the historical, bridge and test years.

Table 1
Summary of Transmission OM&A Budget ($ Million)

Description	Historic			Bridge	Test	
	2009	2010	2011	2012	2013	2014
Sustaining	215.6	204.2	228.2	214.6	233.5	237.6
Development	14.0	15.7	12.6	11.2	13.4	14.4
Operations	53.0	58.1	61.0	61.8	64.3	66.4
Customer Care	1.5	1.5	1.5	1.2	1.3	1.4
Shared Services and Other OM&A	67.7	74.8	43.7	71.8	69.5	67.6
Property Taxes & Rights Payments	65.2	66.5	67.5	70.7	71.5	72.3
TOTAL	**417.1**	**420.8**	**414.5**	**431.3**	**453.3**	**459.7**

Total OM&A expenditures for test year 2013 have increased by $22 million, or approximately 5% over the 2012 bridge year. Total OM&A expenditures for test year 2014 increase by $6 million, or 1%, over 2013. The test year expenditures are required to address the increasing maintenance requirements of an aging and expanding transmission system.

Sustaining expenditures increase slightly over 2011 levels as some programs are growing due to asset demographics and regulatory requirements (i.e. conductor testing and assessment, addressing defective components, physical security and cyber security programs), however a number of initiatives are being undertaken to contain increases in maintenance costs associated with the aging system and increased regulatory requirements.

2.0 SUSTAINING

The Sustaining OM&A budget represents investments required to maintain existing transmission lines and stations facilities so that they will continue to function as originally designed. The proposed investments are intended to ensure that the overall reliability of the system is maintained, that customer commitments are achieved, and that all legislative, regulatory, environmental and safety requirements are met. Details are provided at Exhibit C1, Tab 3, Schedule 2. Details on Sustaining Investment Structure are provided at Exhibit C1, Tab 2, Schedule 1, and Transmission Assets and Sustaining Investment Overview are discussed in Exhibit C1, Tab 2, Schedule 2.

3.0 DEVELOPMENT

The Development OM&A budget funds research and development, as well as the development of new standards. The Development OM&A is described in detail at Exhibit C1, Tab 3, Schedule 3.

4.0 OPERATIONS

The Operations OM&A program represents the annual expenditures required for the Central Transmission Operations function, operated out of Hydro One's Ontario Grid Control Centre. The Transmission Operations function is concerned with the real time operations of the Hydro One Transmission system equipment, including the monitoring, control, detection and response to equipment operational issues. Details of the expenditures under this program are filed at Exhibit C1, Tab 3, Schedule 4.

5.0 CUSTOMER CARE OM&A

The Customer Care OM&A Work Program represents the set of work activities required to provide customer care services to the almost 1.2 million customers connected to the Hydro One Transmission and Distribution Systems. The main Customer Care service programs are meter reading, billing, settlements, customer contact handling and collections largely in connection with Hydro One’s distribution operations. Details of the expenditures under this program are filed at Exhibit C1, Tab 3, Schedule 5.

6.0 SHARED SERVICES AND OTHER OM&A

The Shared Services and other OM&A program includes: Common Corporate Functions and Services, Asset Management, Information Technology, Cornerstone, Cost of Sales and Other OM&A expenses. CCFS includes Corporate Management, Finance, Human Resources, Corporate Communications and Services, Legal, Regulatory Affairs, Corporate Security, Internal Audit, and Real Estate. Common Asset Management services include System Investment, Business Performance, and Asset Strategies. IT and Cornerstone activities include providing and managing computer systems (for example, hardware and software) and IT infrastructure. Other OM&A programs include credits for overheads capitalized as capital projects are built and the cost of goods sold in support of external revenues. Details of the expenditures under this program are filed at Exhibit C1, Tab 4, Schedules 1 through 6.

7.0 TAXES OTHER THAN INCOME TAXES

This program consists of property and proxy taxes, and indemnity payments to the Province. Details of the expenditures under this program are filed at Exhibit C1, Tab 4, Schedule 7.

8.0 COMPARISON OF OM&A COSTS TO BOARD APPROVED

Table 2 compares 2011 actual costs to the 2011 OM&A expenditures approved by the Board in their Decision on Hydro One Transmission's previous application in Proceeding EB-2010-0002.

Table 2
2011 Board Approved versus 2011 Actual OM&A Expenditures

OM&A Categories	**2011 Board Approved** ($ million)	**2011 Actuals** ($ million)	**Variance** ($ million)
Sustaining	229.7	228.2	(1.6)
Development[1]	18.1	12.6	(5.4)
Operations	66.6	61.0	(5.6)
Customer Care	1.1	1.5	0.4
Shared Services & Other Costs	32.6	43.7	11.1
Taxes other than Income Taxes	70.8	67.5	(3.2)
Total OM&A	**418.8**	**414.5**	**(4.3)**

Hydro One Transmission's actual 2011 OM&A costs are $4 million lower than the $419 million approved by the Board in Proceeding EB-2010-0002. The reduction in the Sustaining, Development, and Operations work program spend was driven by the need to stay within the overall Transmission business OM&A envelope approved in the Board's last Decision which also reflects Cornerstone savings (both are included in the Board Approved Shared Services and Other total in Table 2). This is partially offset by higher Shared Services and Other costs due to a lower amount of cost capitalized reflecting the overall work program mix between capital and OM&A.

Table 3 compares 2012 projected costs to the 2012 OM&A expenditures approved by the Board in their Decisions on Hydro One Transmission's previous applications in Proceedings EB-2010-0002 and the subsequent EB-2011-0268.

[1] Development costs are net of Licence Amendment to Upgrade TS's to Facilitate Renewable Generation amounts

Table 3
2012 Board Approved versus 2012 Projected OM&A Expenditures

OM&A Categories	**2012 Board Approved** ($ million)	**2012 Projected** ($ million)	**Variance** ($ million)
Sustaining	239.7	214.6	(25.2)
Development[2]	18.8	11.2	(7.6)
Operations	67.9	61.8	(6.1)
Customer Care	1.2	1.2	0.0
Shared Services & Other Costs	27.2	71.8	44.6
Taxes other than Income Taxes	72.2	70.7	(1.5)
Total	**427.1**	**431.3**	**4.2**

Hydro One Transmission's projected 2012 OM&A costs are $4 million higher than the $427 million approved by the Board in Proceeding EB-2010-0002 and EB-2011-0268. The 2012 Board Approved amounts include the envelope OM&A adjustment as per EB-2010-0002 and EB-2011-0268 (which is reflected in the Board approved Shared Services and Other total in Table 3 along with Cornerstone savings).

The reduction in the Sustaining, Development, and Operations work program spend was driven by the need to stay within the overall Transmission business OM&A envelope approved in the Board's last Decision, which also reflects Cornerstone savings. These variances are offset by an increase in Shared Services and Other Costs (excluding the envelope OM&A adjustment) primarily due to an increase in Cost of Sales for a metering project planned for 2012 and a lower amount of overheads cost capitalized reflecting the overall work program mix between capital and OM&A.

[2] Development costs are net of Licence Amendment to Upgrade TS's to Facilitate Renewable Generation amounts

SUSTAINING OM&A

1.0 INTRODUCTION

Sustaining OM&A consists of expenditures required to maintain existing transmission system facilities so that they continue to function as originally designed. The expenditures covered under Sustaining OM&A are intended to maintain equipment performance at appropriate levels, thereby maintaining the overall reliability and service quality while satisfying all legislative, regulatory, environmental and safety requirements.

Hydro One Transmission manages its Sustaining OM&A program by dividing the program expenditures into three categories:

- Stations, which funds the work required to maintain existing assets located within transmission stations including power system telecommunication facilities;
- Lines, which funds the work required to maintain overhead transmission lines and underground cables, including vegetation management on transmission line rights-of-way;
- Engineering and Environmental Support, which funds the specialized and administrative support needed to assist with decision making processes in managing the transmission assets.

2.0 SUSTAINING OM&A SUMMARY

The rigorous investment planning, prioritization and approval process described in Exhibit A, Tab 15, Schedules 3 to 5 has been completed for all Sustaining OM&A programs to ensure that assets are managed prudently while meeting customer, operational and regulatory needs.

Exhibit C1, Tab 2, Schedule 1, contains an outline of the sustainment investment structure. Exhibit C1, Tab 2, Schedule 2, provides a combined Sustaining OM&A and Capital investment overview, along with demographic, performance, and condition information for key transmission assets. Furthermore, Exhibit C1, Tab 2, Schedule 2, Appendix A provides asset descriptions for all transmission assets.

Sustaining transmission assets is essential to the long term viability and performance of these assets and this is reinforced by the Transmission System Code that requires Hydro One to "inspect, test and monitor its transmission facilities to ensure continued compliance with all applicable standards and instruments". Over the long term, an adequately maintained transmission system that performs to a level of its original design is in the best interest of Hydro One and its customers. As outlined in Exhibit C1, Tab 2, Schedule 2, a greater portion of Hydro One's transmission system is reaching an age where the deterioration in condition is taking place at an increasing rate. This will place added cost pressures on future maintenance programs to maintain equipment performance and reliability until such time that the assets can be replaced. In addition, the transmission system continues to expand and there is a need for increased maintenance expenditures when these new assets are placed into service. At the same time, Hydro One is continuously looking for improvement opportunities that improve the Hydro One system, minimizing risk and adding value for Hydro One's customers. Many of these have been outlined in Exhibit C1, Tab 2, Schedule 2 and in this exhibit. The programs proposed to sustain the assets address those needs identified in the test years, and do not address expected increases in future volumes of work. It must be recognized that any reductions applied to the test years spending will have a compounding effect on cost pressures in the future.

The required funding for the Sustaining OM&A in the test years, along with the spending levels for the bridge and historic years are provided in Table 1 for each of the major sustaining categories.

Table 1
Sustaining OM&A ($ Millions)

Description	Historical Years			Bridge Year	Test Years	
	2009	2010	2011	2012	2013	2014
Stations	153.7	150.3	166.7	155.0	165.6	169.6
Lines	49.4	43.9	49.4	49.7	55.6	57.1
Engineering and Environmental Support	12.5	10.0	12.0	9.9	12.3	10.9
Total	**215.6**	**204.2**	**228.2**	**214.6**	**233.5**	**237.6**

Overall Sustaining OM&A expenditures in 2011 were within one percent of the Board approved total, whereas 2012 work program is forecast to be 6.0% lower than in 2011. The 2012 Sustaining work program was adjusted to stay within the overall Transmission business OM&A envelope approved by the Board's Decision in the EB-2010-0002 proceeding. Overall Sustaining OM&A requirements for the test year 2013 have increased 9% over projected spending in 2012; however this represents a 3% decrease from OEB approved levels for 2012. The spending requirements for 2014 have increased by 2% over the 2013 requirements but are still 1% less than 2012 OEB approved levels.

While some Sustaining programs are growing through the test years due to asset demographics and regulatory requirements (i.e. conductor testing and assessment, addressing defective components, physical security and cyber security programs), a number of initiatives are being undertaken to contain increases in maintenance costs associated with the aging system and increased regulatory requirements. These include:

- Optimized maintenance frequencies impacting overall costs and resource utilization, and additional moves to condition based maintenance.
- Increased bundling opportunities through alignment of maintenance activities and improved visibility of bundling opportunities. These provide efficiencies in the planning and execution of outages as well as with staff mobilization.
- Increase in capital replacement of assets mitigates the need for increases in corrective maintenance costs and equipment refurbishment activities through addressing worse performing assets and facilitates the integration of new equipment with lower lifecycle maintenance costs.

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

3.0 STATIONS

Transmission Station facilities are used for the delivery of power, voltage transformation, switching, and as connection points for both load and generation. Station facilities contain many of the following major components: power transformers, circuit breakers, ancillary systems, disconnect switches, bus work, insulators, potheads, surge arrestors, capacitor banks, reactors, instrument devices, protection systems, control systems, station service, grounding systems, site infrastructure and buildings.

Sustaining OM&A funding for Stations covers expenditures required to maintain the performance of the assets located within transmission stations. Hydro One Transmission manages its Stations OM&A program by dividing the program into six categories:

- Land Assessment and Remediation, a specific program that focuses on identification, mitigation and remediation of *historical* contamination located both inside and outside the station fence;
- Environmental Management, an on-going program that focuses on the mitigation and remediation of contamination located both inside and outside the station fence and manages, tests for and disposes of PCB and other regulated waste that develops as part of Hydro One Transmission's normal business practices;
- Power Equipment Maintenance, which focuses on sustaining power equipment performance through planned and demand/corrective maintenance work and equipment refurbishment;
- Ancillary Systems Maintenance, which focuses on sustaining the performance of ancillary systems through planned and demand/corrective maintenance work;
- Protection, Control, Monitoring, Metering and Telecommunications Maintenance, which funds the planned and corrective maintenance work required to sustain power system protection, control, metering and telecommunication facilities and provides Hydro One Transmission with the information, and communication necessary to operate the transmission system; and
- Site Infrastructure Maintenance, which focuses on maintaining the infrastructure at stations through planned and demand/corrective work.

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

Table 2
Stations OM&A ($ Millions)

Description	Historic Years			Bridge Year	Test Years	
	2009	**2010**	**2011**	**2012**	**2013**	**2014**
Land Assessment and Remediation	2.0	1.7	1.5	1.0	2.4	3.3
Environmental Management	5.7	13.5	15.2	13.7	13.6	13.4
Power Equipment	67.9	59.4	68.1	54.2	55.8	56.1
Ancillary Systems Maintenance	12.4	10.0	11.2	10.4	11.6	11.2
Protection, Control, Monitoring, Metering and Telecommunications	38.6	40.6	43.9	48.7	52.0	54.8
Site Infrastructure Maintenance	27.0	25.1	26.9	26.8	30.3	30.8
Total	**153.7**	**150.3**	**166.7**	**155.0**	**165.6**	**169.6**

Overall, sustaining OM&A requirements for Stations for the test year 2013 have increased 7% over projected spending in 2012. The spending requirements for 2014 have increased by 2% over the 2013 requirements. However the 2013 & 2014 levels are 4% and 2% respectively less than the 2012 OEB approved level. Spending increases are in areas including:

- Security including Cyber Security, which is required to meet regulatory requirements, and station physical security to help defend against the dramatic increase in break ins,
- Land Assessment and Remediation which is required to address contamination resulting from past operations,
- In addition, there are escalation pressures. These increases are offset for the most part through improved maintenance planning practices that include a more granular risk based approach to maintenance planning.

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

3.1 Land Assessment and Remediation

3.1.1 Introduction

The Land Assessment and Remediation ("LAR") program is primarily focused on the mitigation and remediation of historical discharge of contaminates from station yards that may pose a risk to the public or Hydro One Transmission staff. On-site management controls are typically implemented to eliminate or mitigate on-site contamination that could result in unacceptable risks to staff, the public and/or the environment should no action be taken.

As a responsible steward committed to protecting the environment for current and future generations, Hydro One Transmission manages its operations in an environmentally responsible manner. The LAR program meets Hydro One Transmission's environmental policy objectives by assessing and mitigating on and off-property historical contamination at switching and transformer station sites. The LAR program also funds assessment and remediation work to address contamination at real estate facilities which include field service centres, administrative buildings and garage facilities.

3.1.2 Investment Plan

The LAR Program utilizes a multi-phased approach involving successive levels of environmental site assessments, risk evaluation/prioritization and remedial option evaluations, leading to the selection of the preferred remedial/mitigating solution. The prioritization and selection process for environmental site assessment / remediation work is based on two factors: type and level of contamination that exceeds MOE standards; and the potential for the contaminants to cause adverse effects on human health and/or the environment. The MOE supports Hydro One Transmission's risk-based approach and planned programs.

The LAR program includes the following work:

Site Management

Once a site has been assessed or remediated, there are often regulatory requirements imposed by the MOE to monitor groundwater quality in the area of the former contamination to ensure that groundwater is not impacted. The station-specific groundwater monitoring program may be required for a period of 3-5 years, and typically involves well installations, MOE registration, groundwater measurements and sample analysis, and eventual decommissioning of the monitoring wells. Site management plans are developed to monitor and manage residual on-site contamination and to manage installed controls, such as barriers and long-term treatment systems.

Site Assessment and Remediation

In order to fully understand the implication of the new regulations, site assessment is planned at a number of stations and junctions that have been identified as potential remediation sites. The assessment involves gathering information to identify actual or potential contamination and sources of contamination. This is done through a review of the site records, previous environmental reports and by analyzing soil and groundwater extracted from and around Hydro One transmission properties. Soil and water samples are taken as surface grab samples or by drilling to obtain samples from various depths. The information is analysed, risks assessed and sites prioritized for remediation. Considering that the new regulations place a higher standard for environmental management, it is expected that the outcome of the work planned in the test years will result in increased future expenditures to address those sites determined to be contaminated above thresholds.

Where contamination is identified, a remediation plan is developed and implemented to treat, remove or otherwise manage the contamination. The primary focus of the LAR program is to address off-site impacts and mitigate/manage on-site contamination. Where appropriate, co-ordination of LAR work with end-of-life refurbishment and capital upgrade projects are considered. Site remediation costs differ depending upon the size of the site and the remediation effort required.

3.1.3 Summary of Expenditures

The spending requirement for the LAR program for test years 2013 and 2014 is $2.4 million and $3.3 million respectively. This is an increase of $1.4 million in 2013 over the bridge year and a further $0.9 million increase from 2013 to 2014. Spending on this program fluctuates year to year depending on the number of sites selected for remediation and the extent of the remediation work required at each site. The test year increases are required to remediate historic contamination and remain compliant.

The risks of not proceeding with this work in a proactive manner would subject Hydro One to punitive MOE action and/or civil litigation. As well, contaminants addressed under this program have the potential to have adverse effects on humans and must be dealt with in a proactive manner.

Table 3
LAR OM&A ($ Millions)

Description	Historic			Bridge	Test	
	2009	**2010**	**2011**	**2012**	**2013**	**2014**
Land Assessment & Remediation (LAR)	2.0	1.7	1.5	1.0	2.4	3.3
Total	**2.0**	**1.7**	**1.5**	**1.0**	**2.4**	**3.3**

3.2 Environmental Management

3.2.1 Introduction

Environmental Management focuses on mitigation and remediation of contamination located both inside and outside the station fence. This program covers station waste management (PCB and regulated wastes), transformer oil leak reduction, corrective maintenance that addresses spill containment and piping deficiencies and provides funding for demand activities and to manage environmental compliance.

Table 4 outlines the proposed funding for 2013 and 2014 for the specific elements of the program, as well as the spending levels for the bridge and historic years.

Table 4
Environmental Management OM&A ($ Millions)

Description	**Historic**			**Bridge**	**Test**	
	2009	**2010**	**2011**	**2012**	**2013**	**2014**
PCB Retirement and Waste Management	2.4	4.3	5.2	6.7	5.2	5.1
Oil Leak Reduction	1.1	4.0	2.2	2.5	3.3	3.3
Preventive and Corrective Maintenance	1.5	4.0	6.8	3.7	4.0	4.0
Environmental Compliance & Response Plan Updates	0.8	1.3	0.9	0.8	1.0	0.9
Total	**5.7**	**13.5**	**15.2**	**13.7**	**13.6**	**13.4**

3.2.2 Investment Plan

The Environmental Management Program consists of the following work:

PCB Retirement and Waste Management

In response to Environment Canada's new PCB Regulations, Hydro One Transmission initiated the PCB retirement program to identify and phase-out its PCB inventory to comply with the new Regulation's End of Use requirements, with the exception of bushings as noted below. In accordance with the Regulations, oil-filled power equipment (transformers, breakers, instrument transformers, and associated capacitors, bushings, reclosers) located at Hydro One's Transformer Stations that contain greater than 500 parts per million (ppm) PCB are to be retrofilled or replaced by December 31, 2014 (based on an extension granted to Hydro One by Environment Canada from the original date of December 31, 2009). Devices that contain greater than 50 ppm PCB are to be retrofilled or replaced by December 31, 2025.

The PCB and waste management program funds the inspection, testing and equipment retro filling of PCB-impacted oil and the proper disposal and decommissioning of PCB contaminated equipment, as well as managing the disposal of non-contaminated oils and other wastes. Hydro One Transmission's daily activities generate regulated waste, such as lead, PCB, cadmium, mercury, etc. These must be managed and disposed of in accordance with Provincial and Federal regulations. This program represents the largest component of the Environmental Management program. The expenditures for 2013 and 2014 are $5.2 million and $5.1 million respectively.

Test year expenditures are lower than previously requested during EB-2010-0002 as well as the planned 2012 bridge year expenditures. The primary reason for the reduction is a lower number of assets requiring retrofill due to high PCBs, and a greater number of planned Sustaining Capital replacements prior to the regulated end of use dates.

It should be noted that the above expenditures are based on anticipated regulatory relief from Environment Canada on one remaining key issue. Hydro One Transmission and CEA-member utilities are lobbying for a regulatory amendment that would extend the end of use date for bushings and instrument transformers to 2025 based on outage and resource constraints. Discussions are on-going with Environment Canada and Hydro One is confident the regulations will be amended. Since the previous proceeding, Hydro One has been successful in working with Environment Canada to obtain a more favourable interpretation to the removal of oil > 2 ppm PCB for maintenance purposes. This resulted in an avoided OM&A cost of several million dollars per year. These avoided costs were not included in 2011 or 2012 revenue requirements as described in Exhibit I, Tab 1, Schedule 39 from the EB-2010-0002 proceeding.

<u>Oil Leak Reduction</u>

As transformers age, they are susceptible to leaks along seal gaskets and access covers, due to the effects of thermal cycling and gradual gasket deterioration. The main tank, access covers and fittings on most power transformers over 25 years of age utilize organic seal components as gaskets between flanges to retain oil. These transformers typically begin to leak oil after performing well for the first 20 - 25 years.

Transformer oil leaks are repaired on a temporary basis when first discovered under the demand program in order to expeditiously respond to the environmental risks. These repairs are usually stop-gap measures until a more permanent solution is implemented. Permanent repairs generally require outages and staff with a specific skill set to work on transformers. The transformers that merit permanent repairs have been identified and prioritized based on environmental and equipment considerations. Planned expenditures for each of the 2013 and 2014 test years is $3.3 million, and will result in eight transformers being refurbished.

Oil leaks are one of the most common deficiencies on transformers, and are a significant contributor to transformer forced outages. Multiple transformer failures have been attributed to aged gasket systems that can allow oil to leak out, and free water to enter the transformer (in the form of snow and rain). Test year expenditures are higher than historic and bridge years to further mitigate the reliability and environmental risks associated with these defects.

<u>Preventive and Corrective Maintenance</u>

The preventive maintenance program is in place to ensure that

- spill containment systems are inspected and operate as designed,
- underground oil piping within transmission stations that is no longer in use is removed to eliminate risk of contaminating the surrounding environment,
- repair or replace non-functioning mechanical components (pumps, sensors, relays) used in oil/water separators that control effluent from the transformer spill containment pits. Because these units do not provide the required functionality, rain and melt water that collects in the containment units have to be pumped out manually.

The corrective maintenance program includes spill containment repairs, maintaining spill containment capacity for non-functioning spill containment systems by removing and disposing of the rainwater, containing and cleaning up insulating fluid spills as they occur and all other actions necessary to mitigate environmental risks posed by transmission equipment problems and failures.

Preventive and corrective maintenance allows Hydro One Transmission to meet its Environmental Policy objectives, maintain compliance with the MOE, minimize the risk to human health and the environment and mitigate corporate exposure to legal and reputation risks. Planned expenditure for each of the 2013 and 2014 test years is $4.0 million, which is consistent with historic and bridge year spending.

The increased spend in 2011 was $1.3 million of incremental corrective maintenance due to an underground cable leak Toronto, and $2.1 million associated with the environmental clean-up following the Richview T7 & T8 failure.

Environmental Compliance and Response Plan Updates

The environmental compliance program encompasses activities necessary to allow Hydro One Transmission to remain in compliance with Ministry of the Environment (MOE) Certificate of Approvals (C of As) for various Transmission Stations throughout the province. Hydro One Transmission is required by the MOE to regularly test effluent as a requirement of site specific C of A documents.

Emergency Response Plans (ERPs) are documents that contain important station specific information that is kept at each transmission station in the Hydro One network. The ERPs are an effective tool for planning and responding to emergencies and contain important internal and external contact information, station maps and drawings as well as emergency response and evacuation procedures. The plans ensure that risk of harm to employees, contractors, the public, the environment and the physical assets of Hydro One is minimized. Funding under this program ensures that all ERPs contain up to date and accurate site-specific information.

Planned expenditures for these activities for 2013 and 2014 are $1.0 million and $0.9 million respectively.

3.2.3 Summary of Expenditures

The Environmental Management spending requirement for test year 2013 is $13.6 million and for 2014 is $13.4 million. These expenditures are consistent with the 2012 bridge year, and less than 2011 and 2010 historic years.

Further reduction of this program would hamper Hydro One's ability to remain compliant with environmental obligations and reduce the work that mitigates the risks of major oil spills through on-going inspection and repair of environmental control systems and update of procedural manuals and documentation.

3.3 Power Equipment

3.3.1 Introduction

Transmission power equipment includes maintenance on Hydro One Transmission's 719 transmission transformers, 4,490 circuit breakers, about 14,000 switches and station bus work, as well as capacitor banks and reactors at the 285 stations. The maintenance of Hydro One Transmission's power equipment is the most significant program within the Stations OM&A category of expenditures. This program covers costs to sustain in-service power equipment performance through preventive maintenance, corrective maintenance work, and refurbishment work.

Table 5 outlines the proposed funding for 2013 and 2014 for the specific elements of the program as well as the spending levels for the bridge and historic years.

Table 5
Power Equipment Maintenance OM&A ($ Millions)

Description	**Historic**			**Bridge**	**Test**	
	2009	**2010**	**2011**	**2012**	**2013**	**2014**
Preventive Maintenance	21.9	17.4	18.3	18.6	19.6	20.3
Corrective Maintenance	24.6	23.7	26.0	22.6	20.4	21.4
500kV (750MVA) Transformer Refurbishments	7.4	8.3	8.8	1.3	1.3	1.3
115kV & 230kV Transformer Refurbishments	6.4	5.2	6.9	6.1	6.9	6.9
Breaker Refurbishments	2.4	1.5	3.3	1.7	3.1	1.7
Other Maintenance and Inspection Programs	5.2	3.3	4.9	4.0	4.5	4.5
Total	**67.9**	**59.4**	**68.1**	**54.2**	**55.8**	**56.1**

3.3.2 Investment Plan

The power equipment maintenance programs are categorized as follows:

Preventive Maintenance

Preventive maintenance is conducted to meet Hydro One's obligations defined by the Transmission System Code to "inspect, test and monitor its transmission facilities to ensure continued compliance with all applicable standards and instruments". The following equipment has either time based or condition based maintenance activities defined for them: breakers, capacitor banks, instrument transformers, reactors, switches and station transformers. There is also a small amount of maintenance done on general power equipment such as station bus structures.

Hydro One Transmission's Preventive Maintenance Optimization (PMO) program for power equipment is based on industry recognized Reliability Centered Maintenance (RCM) principles. The effectiveness of the PMO maintenance program depends on a continual improvement process and how consistently asset condition and performance information is collected and analyzed. The RCM principles utilized in the PMO program provides structured methodology to ensure that equipment functionality requirements are met and to determine inspection criteria based on known equipment failure modes.

PMO places a priority on the performance of predictive/diagnostic activities (condition based monitoring) such as visual inspections, oil analysis, function testing and equipment performance monitoring rather than the more intrusive time based activities. Different equipment types within the Power Equipment program have varying maintenance activities and in many cases at different frequencies. More specifically, examples of maintenance activities for transformers, breakers and switches include:

- Regular visual inspections on all equipment to identify and record defects
- Identify oil leaks and record pressure (oil and air), temperature on specific equipment types.
- Function test various equipment elements and alarms to ensure continued operation, reliability and identify issues, and top up oil as required.
- Selective intrusive maintenance to assess equipment condition, check contacts, test components, clean and lubricate, replace seals and complete minor repairs as required.
- Diagnostics include oil analysis for dissolved gas, moisture content, dielectric strength assessment and insulator testing.

The frequencies of these activities vary depending upon the make, model type and condition of the subject equipment.

The planned expenditure in 2013 and 2014 is $19.6 million and $20.3 million respectively. Costs are based on the volume and type of maintenance work to be completed during the calendar year, and additional work of higher complexity is required to be completed in the test years.

While the demographics and condition of the fleet, as well as the expanding asset base, would typically be indicators of a need for significant increases in these programs, increases are minimized through value being realized in preventive maintenance programs through a variety of means including:

- shifting to more condition based maintenance (not carrying out costly intrusive maintenance activities until such time that diagnostic testing indicates a condition warranting this inspection),
- the installation of modern technologies with lower lifecycle maintenance costs (such as replacing air blast circuit breakers with SF6 breakers which results in a 90% reduction in maintenance costs),
- improved ability to bundle activities making the most effective use of outage planning and mobilization of crews.

Corrective Maintenance

Corrective Maintenance work is required to repair equipment defects and return equipment condition and performance to an acceptable state. Corrective maintenance is a combination of planned and demand work, including emergency response.

Unplanned Corrective Maintenance results from all unscheduled, non-programmed maintenance necessitated by unforeseen problems and/or equipment failure. Corrective maintenance is required to address the risk of harm and / or damage to any or all of employee safety, public safety, system reliability or the environment. Emergency response may include preliminary investigation and minor or make safe repairs following equipment failure. Expenditures for corrective maintenance for 2013 and 2014 are $20.4 million and $ 21.4 million respectively.

With the increase in capital replacement programs and the focus that the replacement and refurbishment programs place on addressing the worse performing assets, a reduction in the corrective maintenance program is anticipated. Air blast circuit breakers and their associated high-pressure air ancillary systems are such a specific example, and is outlined in further detail in Exhibit C1, Tab 2, Schedule 2.

500 kV (750 MVA) Transformer Refurbishments

Refurbishment of the 750 MVA autotransformer fleet over the past several years was required to address the high failure rates of this critical class of equipment. Since 2000 there have been four 750 MVA transformer failures. Investigations that included third party design reviews revealed a number of design limitations and that moisture levels in these units can reach unacceptably high levels and can lead to catastrophic failure. The failure of a 500kV autotransformer can jeopardize the reliability of the backbone 500 kV system and impact the stability of the electricity grid. Interface limits may be affected and/or generation may be constrained. Because of the large amount of energy involved, failures have historically resulted in tank splits and oil spills, creating both safety and environmental hazards. A remediation program which includes a thorough dry out was started in 2006 to address the primary deficiencies and has been successful at reducing the risk of failure until such time the transformers are replaced. As indicated in the EB-2010-0002 proceeding, this program was expected to conclude by 2012. Further assessment has indicated that additional transformers not originally included in the program's scope require varying degrees of modifications to reduce their risk of failure. Planned expenditures for 2013 and 2014 are $1.3 million in each year.

115 kV & 230 kV Transformer Refurbishments

Transformers have several components (gaskets, gauges, bushings, fans, pumps, etc.) that typically require major refurbishment or replacement within the expected service life of the transformer, approximately 50 years. These refurbishments are cost effective, and allow the transformer to remain in-service through its expected service life while maintaining equipment and customer reliability. During the refurbishment, Hydro One takes the opportunity to outfit the transformers with modern accessories, leading to various benefits as part of the transformer's life-cycle. For example, modern temperature monitors are installed and wired back to the Ontario Grid Control Centre to give the Operations staff additional information to make real-time operating decisions with. In the case of transformer temperature, a measured reading is more accurate than a theoretically modelled measurement and may allow for additional transformer loading or alternatively, will ensure that equipment is operating within its ratings as to not unknowingly sacrifice equipment life. Eight major refurbishments are planned over the 2013 and 2014 test years.

In addition to refurbishments, a number of programs are being implemented to reduce the risk of equipment failure. These programs have been developed as a result of learning from failure investigations or from industry partners. Programs targeted at upgrading fall-arrest safety systems, proactive off-line dry-outs, installation of maintenance-free self-regenerating breathers, installation of under load tapchanger (ULTC) filtration systems, and the planned implementation of manufacturer recommended modifications to ULTCs are examples of such activities.

Planned expenditures for 2013 and 2014 are $6.9 million each year. This level is in line with historic accomplishment levels. Spending is based on the number and type of transformers scheduled for refurbishment and upgrade activities during the specific calendar year.

Breaker Refurbishments

Some specific models of circuit breaker are targeted for planned refurbishment outside of their normal preventive maintenance program to allow them to reach their expected service lives. There are six types of different breaker refurbishment activities planned in the 2013 and 2014 test years, each focused on mitigating a specific reliability or condition risk.

Consistent with transformer refurbishments, a significant portion of work is as a result of Corrective action plans developed during Hydro One root cause failure investigations. For example, following the July 2010 circuit breaker failure at Manby TS and resultant interruption to the City of Toronto, an investigation team was formed to determine root cause and provide recommendations to reduce the chance of a similar event occurring. One of the recommendations involved performing a specific set of modifications to the remaining 39 in-service breakers of the same make and model, given that immediate replacement wasn't viewed as the appropriate solution relative to other investment needs. A three-year plan was developed that would allow these modifications to be executed in a prioritized and controlled manner. The majority of the expenditure in this category of work is specific modifications and upgrades coming as a result of these similar investigations and is performed on air blast, oil, GIS, and SF6 circuit breakers. Planned expenditures for 2013 and 2014 are $ 3.1 million and $ 1.7 million respectively, about the same in total as 2011 and 2012.

Other Maintenance and Inspection Programs

Maintenance activities under this category include nuisance wildlife control, maintenance required for strategic spares and miscellaneous maintenance as outlined below.

Nuisance wildlife control programs are in place to combat the effects of both equipment interruptions and customer outages that can result when wildlife enter Hydro One transmission stations for various reasons such as shelter, food, breeding and hibernation. This program also helps towards eliminating health and safety risks, e.g., racoon round worm, and provides training to employees to assist with the overall control efforts. Animal related outages have averaged about 25 per year prior to preventive action being taken at targeted sites. Since the inception of the program, the number of outages has reduced by about 50% at the targeted sites. Hydro One Transmission is very proud of the industry leading innovative approach that has been taken, significantly reducing the number of animal contacts, which typically cause delivery point interruptions, in a cost effective manner.

An inventory of circuit breakers and transformers is maintained in storage to enable timely response to system component failure. Maintenance is required to ensure that these components are available for service at any given time and not to void manufacturer warranties.

There are several other programs within power equipment that account for the remainder of the funding requirement. These include capacitor bank maintenance, insulator contamination monitoring and power washing, station string insulator testing program and station asset condition assessment activities. Although smaller, these activities are important to ensure equipment and customer reliability and manage equipment in a prudent and sustainable manner. Planned expenditure for these programs in 2013 and 2014 is $4.5 million each year.

3.3.3 Summary of Expenditures

The spending requirements for the test years 2013 and 2014 are $55.8 million and $56.1 million respectively. These spending levels are close to that of the bridge year but substantially lower than historic years. As noted in Exhibit C1, Tab 2, Schedule 2, it is apparent that the demographics and condition trends of the stations power equipment is placing added pressures on maintenance with corresponding increasing pressures on expenditures. However, the following activities are expected to enable the proposed reductions in overall maintenance costs while continuing to manage reliability and safety risks to acceptable levels over the two test years:

- the benefits of lower costs maintenance associated with newer technologies,
- the efficiencies from condition based maintenance and increased visibility of work bundling opportunities,
- increase in capital replacement programs, and
- focus on the replacement and refurbishment of the poorest performing assets.

The risks of not proceeding with these levels of work include:

- Scheduled power equipment maintenance will not be completed, resulting in increased risks to equipment unavailability and degradation in equipment performance. Currently Hydro One's primary station equipment performance is below CEA average (refer to Exhibit C1, Tab 2, Schedule 2) and further reduction in maintenance will lead to a continuation of poor performance, placing added risks on customer and system reliability.
- Reductions in transformer and breaker mid life refurbishment will ultimately increase life cycle costs for these assets as they will require replacement prior to their expected service lives.
- Increased failures of transformers, oil circuit breakers and SF6 breakers may have an adverse effect on the environment and will result in increased expenditures associated with clean-up and added mitigation to prevent re-occurrence.
- Corrective maintenance expenditures will increase if preventive maintenance is deferred; corrective maintenance is typically more costly than preventive.
- Reduced diagnostics and asset condition assessments will result in suboptimal decisions on capital replacements and maintenance.

- Reductions in this program will manifest themselves in the form of reduced system and equipment performance with a reoccurrence of transformer failures as experienced in the past.

3.4 Ancillary Systems Maintenance

3.4.1 Introduction

Ancillary Systems are required at all Hydro One Transmission's 285 stations. These systems are comprised of AC & DC station service systems, high pressure air systems supplying air blast circuit breakers, grounding systems, batteries, battery chargers, instrument transformers, and oil processing facilities. These systems provide key services and operating support to all of the various station components.

Table 6 outlines the proposed funding for 2013 and 2014 for the specific elements of the program as well as the spending levels for the bridge and historic years.

Table 6
Ancillary Systems Maintenance OM&A ($ Millions)

Description	**Historic**			**Bridge**	**Test**	
	2009	**2010**	**2011**	**2012**	**2013**	**2014**
Preventive Maintenance	5.0	4.2	4.6	4.5	4.7	4.6
Corrective Maintenance	4.0	4.4	4.8	4.3	4.6	4.6
Other Maintenance Activities	3.4	1.5	1.8	1.7	2.4	1.9
Total	**12.4**	**10.0**	**11.2**	**10.4**	**11.6**	**11.2**

3.4.2 Investment Plan

The Ancillary Systems Management Program consists of the following work.

Preventive Maintenance

Similar to Power Equipment, the preventive maintenance program is founded on RCM principles and is established to ensure expected equipment life is realized. This is done through periodic tests and inspections required to satisfy reliability, safety and regulatory requirements. The requirements of oversight bodies such as the Technical Standards and Safety Authority, IESO, NPCC, Ministry of Health (Occupational Health and Safety Act) and the MOE impose regulatory requirements and in some cases mandated inspection and testing cycles on ancillary equipment. The total number of planned maintenance activities per year in ancillary maintenance is in the order of 5,000. Planned expenditures in 2013 and 2014 are $4.7 million and $4.6 million respectively.

Corrective Maintenance

Corrective Maintenance work is required to repair equipment defects and return equipment condition and performance to an acceptable state. Corrective maintenance is a combination of planned and demand work, including emergency response. Corrective maintenance is required to address the risk of harm and / or damage to any or all of employee safety, public safety, system reliability or the environment. Expenditures for corrective maintenance for 2013 and 2014 are $4.6 million and $4.6 million respectively.

Other Maintenance Activities and Costs

Other maintenance activities includes grounding studies, funding for Hydro One's oil storage and processing operation at its Central Maintenance Facility, required upgrades to backup diesel generators, to and fees paid for services at facilities shared with OPG or Bruce Power.

Hydro One has a number of sites located within or adjacent to generating stations (Hydraulic, Thermal and Nuclear) where services are purchased directly from the plant in order to maintain switchyard operations. These services include AC/DC station service, water and snow removal. Agreements are in place between Hydro One Transmission and the generating entities with respect to what services are shared and appropriate compensation. Hydro One Transmission is billed on an annual basis for these services.

Planned expenditures in this category for 2013 and 2014 are $ 2.4 million and $ 1.9 million respectively. 2013 is higher than previous years due to the need to complete upgrades to the fleet of backup diesel generators to maintain NPCC / NERC regulatory compliance and rectify safety issues raised by joint health & safety committees.

3.4.3 Summary of Expenditures

The spending requirement for test year 2013 is $11.6 million, which is an increase of 11% over the bridge year 2012 but in line with historic years spend, despite inflation. The increased expenditure in 2013 is primarily due to the need to complete upgrades to the fleet of backup diesel generators to maintain NPCC / NERC regulatory compliance and rectify safety issues raised by joint health & safety committees, as previously mentioned. Spending for test year 2014 is $11.2 million which is a decrease of 3% over the spending in test year 2013.

Continued funding at 2012 levels for Ancillary Systems Maintenance will increase the risk of system or customer impactive events resulting from inadequately maintained systems, as well as increase risk of regulatory non-compliance issues and potential fines.

3.5 Protection Control, Monitoring, Metering and Telecommunications

Protection, Control, Monitoring, Metering and Telecommunications funds the programs required to sustain power system protection, control, metering and telecommunication facilities. Hydro One Transmission manages these OM&A programs by dividing them into three categories:

- Protection, Control, Monitoring and Metering Equipment Maintenance, which funds the planned and demand/corrective maintenance work required to sustain the performance of protection, control, monitoring and metering equipment;
- Cyber Security, which funds the planned and demand/corrective maintenance work to sustain the systems and facilities required to achieve and sustain compliance with the NERC Critical Infrastructure Protection (CIP) Standards; and
- Telecommunications, which funds the planned and corrective maintenance work required to sustain power system telecommunication facilities which provides Hydro One Transmission with the information, and communication necessary to operate the transmission system.

Required funding for the test years, along with the spending levels for the bridge and historical years are provided in Table 7 for each of these categories.

Table 7
Protection, Control, Monitoring, Metering, and Telecommunications OM&A ($ Millions)

Description	**Historic**			**Bridge**	**Test**	
	2009	**2010**	**2011**	**2012**	**2013**	**2014**
Protection, Control, Monitoring and Metering Equipment Maintenance	18.7	20.2	20.8	20.2	20.4	21.1
Cyber Security	1.9	3.2	3.6	7.3	9.8	11.4
Telecommunications	18.1	17.2	19.4	21.2	21.8	22.2
Total	**38.6**	**40.6**	**43.9**	**48.7**	**52.0**	**54.8**

Protection, Control, Monitoring, Metering and Telecommunications spending for 2013 is increasing by about 7% over the bridge year 2012. The spending requirement for test year 2014 is 5% over the 2013 requirements. Spending increases are in the areas impacted by the new regulatory requirements mandated by NERC and the expansion of the grid.

Details concerning the changes in spending over historic and the bridge year are provided in the remainder of the section.

3.5.1 Protection, Control, Monitoring and Metering Equipment

3.5.1.1 Introduction

Protective relays and their associated systems are critical in sensing abnormal conditions and taking the appropriate actions in response to those conditions. This may be isolating a fault from the system or notifying the control room at the OGCC that there is an abnormal condition that they may need to act on. They protect local supply, supply within Ontario and the potential impacts of problems on the Hydro One system to the rest of the interconnected grid. As such, a significant portion of these programs are regulated and non-discretionary. Similarly programs to manage wholesale revenue meters, used to measure energy flow between the IESO controlled power grid and metered market participants in accordance with Measurement Canada requirements for transaction settlements, are based on regulatory requirements.

Table 8 outlines the proposed funding for 2013 and 2014 for the specific elements of the program as well as the spending levels for the bridge and historic years.

Table 8
Protection, Control, Monitoring and Metering Equipment OM&A ($ Millions)

Description	**Historic**			**Bridge**	**Test**	
	2009	**2010**	**2011**	**2012**	**2013**	**2014**
Re-verifications	7.8	5.7	6.4	6.0	5.6	6.0
Corrective Maintenance	6.2	8.3	7.1	7.4	8.3	8.4
Support Processes and Systems and Preventative Maintenance	4.7	6.2	7.2	6.8	6.5	6.6
Total	**18.7**	**20.2**	**20.8**	**20.2**	**20.4**	**21.1**

3.5.1.2 Investment Plan

The expenditures for maintenance of Protection, Control, Monitoring and Metering Equipment fall into three categories:

Re-verifications

Protection systems spend most of their service life in a dormant state, yet must be relied upon to perform flawlessly during a fault or other abnormal condition. The only means to maintain a high degree of certainty that the scheme will operate correctly when called upon, is to perform a test. For those portions of the grid designated as Bulk Power System, NPCC mandates the frequency at which these tests must be performed. For other portions of the Grid, the testing frequency follows Hydro One policy. For portions of the grid where a protection failure can have only very localised impact, protections are verified by a combination of visual inspections and detailed analysis of events. This is the case for protections on feeders that emanate from a transformer station to supply the distribution system.

Revenue Meters are also subject to periodic re-verification of their accuracy. These re-verifications are referred to as “re-seal” and are done at a frequency mandated by the Electricity and Gas Inspection Act and regulations overseen by Measurement Canada.

The planned expenditure for re-verifications is $5.6 million in 2013 and $6.0 million in 2014, which is less than the historic average. The cost of this program fluctuates based on the actual numbers of protections and meters that come due for re-verification each year and it is expected this program will increase in the future due to the added protection schemes resulting from the expansion of the grid, and due to increased need for feeder protection event analyses due to distribution connected generation.

Corrective Maintenance

All P&C and telecommunication assets experience some rate of failure or defect during their normal useful life. As they approach end of life the rate of failures increases and the cost of correcting failures increases due to lack of vendor support and difficulty obtaining spare parts. Due to the criticality of P&C assets and their large population sizes, increasing rates of failure cannot be tolerated as the consequences would include equipment damage and wide spread power outages.

Corrective work is driven by the historic rate of correctives plus information on specific corrective issues that need to be addressed. Specific corrective issues discovered include problems discovered from analysis of events and defects with certain makes and models of protections which have been identified to be problematic and jeopardize reliability of the electrical system. Expenditure for corrective maintenance is $8.3 million in 2013 and $8.4 million in 2014. Based on the demographic, the increase in failures seen on some types of protections, this 12% increase from 2012 is required to manage the system with the same risk profile as historic levels of spend.

Support Processes and Systems and Preventive Maintenance

Hydro One Transmission maintains systems to manage change control of the settings and configuration of protection and control systems, keeps records of events, as well as the inventory and re-seal schedule for revenue meters. Processes are in place for carrying out event analyses and follow-up actions, doing routine inspections, managing spare parts and tracking vendor advisories. The cost for support processes and systems is increasing due to new processes and systems required to meet new or more stringent reliability standards, and due to expenditures to augment the asset condition assessment of protection systems.

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

The planned expenditure for support processes and systems and preventative maintenance is $6.5 million in 2013 and $6.6 million in 2014, which is less than bridge year spend.

3.5.1.3 Summary of Expenditures

The spending requirement for this program for test year 2013 is $20.4 million and $21.1 million for 2014 which is comparable to historic expenditures despite inflation. The spending increase has been contained with a decrease in the bridge year as a result of the increase in capital replacement projects, an anticipated change in lifecycle costs of newer technology installations, and the impact of addressing worse performing installations combined with new processes related to events tracking and reporting.

Further reductions in this program will lead to an increase in protection and control failures which will result in one or more of: equipment outages, equipment damage, load interruption and a wide spread interruption to the interconnected electrical system. Furthermore, reductions in these programs will result in Hydro One Transmission failing to comply with NPCC and NERC reliability requirements.

3.5.2 Cyber Security

3.5.2.1 Introduction

Cyber Security assets include firewalls, electronic intrusion detections system, and facilities for virus scanning, event logging, physical access control and video surveillance. The Canadian and US Federal governments categorize the energy sector as a critical infrastructure. To protect the reliability of the interconnected grid, the North American Electric Reliability Corporation (NERC) developed an initial set of eight new Critical Infrastructure Protection standards (CIP002-CIP009), also referred to as the "Cyber Security" standards. Hydro One Transmission has implemented cyber and physical barriers for critical cyber assets in order to comply with the 80 plus requirements of these standards. The standards require regular testing and updating of the security systems and procedures for changes that occur in staffing as well as in the transmission assets that require security. The requirement for full compliance came into effect on December 31, 2009.

3.5.2.2 Investment Plan

Maintenance and system support for Cyber Security include the following:

- Maintaining the various Cyber Security assets (e.g. Firewalls, Intrusion Detection Systems, Malware detection systems, Physical Security systems);
- Conducting required annual surveys of critical cyber assets and security perimeters;
- Recurring tasks associated with systems management (e.g. maintaining personnel access lists, patch management, maintaining logs, updating firmware, periodic tests).

3.5.2.3 Summary of Expenditures

Cyber Security for test years 2013 and 2014 are $9.8 and $11.4 million which is an increase of 34% and 56% over the bridge year 2012.

Actual spend in 2011 was $3.6 million compared to a planned spend of $6.0 million. This reduced spending was due to delays in achieving full operation of central security management systems and under-spend on the annual cyber asset survey program. These have resulted in the continuation of inefficient manual processes for activities such as the management of passwords, and other issues.

Central security management systems will be fully operational in 2012 and the annual survey program will be reinforced to achieve its full objectives. Consequently, the full program costs for efficient ongoing security management of Critical Cyber Assets as required by the NERC CIP standards will be realized late in 2012. An additional program was started in 2012 for audit readiness and establishing an Internal Compliance Program in Hydro One for all NERC and NPCC Reliability Standards. The ongoing cost for this program is planned to be $2 million per year.

The increase in 2013 over the bridge year is due to the required expanded coverage of the Cyber Security process to include critical telecommunication systems and the addition of a number of critical assets. The further increase in spending in 2014 is for further growth in the number of critical assets and the implementation of mature security event management operations for all grid cyber systems. Cyber Security expenditures are required to be compliant with standards defined by NERC and NPCC.

3.5.3 Telecommunications

3.5.3.1 Introduction

Telecommunication systems provide high reliability and high-speed communications required for the protection of Hydro One Transmission's system and for monitoring and control of the power system. Hydro One Transmission's telecommunication system consists of digital fiber-optic networks, Power Line Carrier (PLC) systems, owned or leased metallic cables, digital microwave, and the associated auxiliary telecommunication equipment for each. Table 9 outlines the proposed funding for 2013 and 2014 for the specific elements of the program as well as the spending levels for the bridge and historic years.

Table 9
Telecommunications OM&A ($ Millions)

Description	**Historic**			**Bridge**	**Test**	
	2009	**2010**	**2011**	**2012**	**2013**	**2014**
Maintenance	4.5	5.2	4.5	5.6	5.9	6.1
Leased Telecommunication Circuits	8.7	6.7	8.6	8.8	8.9	9.0
Hydro One Telecom Contract	4.9	5.4	6.2	6.7	6.9	7.2
Total	**18.1**	**17.2**	**19.4**	**21.2**	**21.8**	**22.2**

3.5.3.2 Investment Plan

The expenditures for Telecommunications fall into three categories:

Maintenance

Telecommunication Assets include the terminal equipment for Power Line Carrier Systems, SONET equipment, Multiplexors, Neutralizing Transformers, Tone Equipment, Radios and DC power supply for these devices, as well as, inspections and repair of microwave radio towers. The scope of maintenance of these assets covers re-verification of equipment that supports protection systems directly, corrective maintenance as well as replenishing spare parts inventories. The planned cost for maintenance of telecommunication assets is $5.9 million in 2013 and $6.1 million in 2014.

Leased Telecommunication Circuits

Leased telecommunication circuit costs include the monthly fees of the various telecommunications required for protection and control as well as for the provincial mobile radio system. These costs are $8.9 million in 2013 and $9.0 million in 2014.

Hydro One Telecom Contract

Hydro One Networks acquires monitoring and alarm response for the power system telecommunication circuits, outage management, vendor management, and system analysis services under contract from Hydro One Telecom (HOT). In addition, services related to updating the computer systems used in management of the telecom circuits are also provided by HOT. The cost for these services by HOT is $6.9 million in 2013 and $7.2 million in 2014.

3.5.3.3 Summary of Expenditures

Telecommunications expenditures in test years 2013 and 2014 are $ 21.8 million and $22.2 million respectively. Spending in the test year 2013 is increasing 3% over the bridge year 2012, while expenditures in 2014 are increasing 2% over the test year 2013. These increases are driven primarily by an increase in corrective maintenance to address known deficiencies of telecom assets (such as upgrades to microwave tower marking to comply with revised NavCan regulations), restoration of communication system reliability, an increase in monitoring and management effort of additional equipment being deployed as part of system growth, and new more rigorous reporting requirements in support of protection systems (scope and timelines of reportable events are changing under new NERC/NPCC regulations).

Reductions in this program would elevate the risk of loss of communication with significant impacts on the power system and worker safety. Loss of OGCC communication with control equipment at stations could violate IESO market rule requirements and would result in workforce inefficiency (staff would need to be deployed to stations for the purpose of switching). Loss of communications with and between protections would result in a requirement to remove lines from service until protections are restored.

3.6 Site Infrastructure Maintenance

3.6.1 Introduction

The Transmission Site Facilities & Infrastructure Systems are comprised of yard surfacing, drainage, fire protection and detection, station security systems, structural footings, station buildings, cranes, elevators, heating ventilation and air-conditioning (“HVAC”), access roads, water supplies, sewage, oil systems, spill containment systems and fences at Hydro One’s 285 transmission stations. These systems provide the infrastructure required to prevent unauthorized access, enable access for authorized staff and make the station site functional for equipment and staff.

This program funds planned and demand maintenance at station facilities to ensure that these remain in a safe condition and in compliance with regulations, as well as grounds maintenance and site security at transmission stations.

Table 10 outlines the proposed funding for 2013 and 2014 for the specific elements of the program as well as the spending levels for the bridge and historic years.

Table 10
Site Infrastructure Maintenance OM&A ($ Millions)

Description	Historic			Bridge	Test	
	2009	2010	2011	2012	2013	2014
Facilities and Infrastructure Maintenance	23.1	20.6	22.0	20.5	23.0	23.5
Grounds Maintenance	3.8	3.6	4.0	4.3	4.5	4.6
Site Security	0.2	1.1	1.0	2.1	2.8	2.7
Total	**27.0**	**25.1**	**26.9**	**26.8**	**30.3**	**30.8**

3.6.2 Investment Plan

The investment plan for this work program is extensively driven by assessment of data collected, historical levels of spending for demand work, as well as regulatory requirements (such as building and fire codes, the Occupational Health and Safety Act and the Ministry of Environment requirements, as well as community by-laws) and corporate standards.

The Site Infrastructure Maintenance Program consists of the following:

Facilities and Infrastructure Maintenance

Data and information on the condition of station sites and buildings is collected through regular inspections, as well as information gathered during maintenance work and trouble call response. Contracted inspections and asset surveys are also conducted.

The preventive and corrective maintenance program for site infrastructure and site facilities is the dominant program and contains a wide variety of activities such as building maintenance and facility improvements, HVAC maintenance, inspections, janitorial services, water system maintenance and testing, roads, bridges and railway maintenance and station Civil/Geotechnical and Asset Condition Assessments. The corrective maintenance program for site infrastructure is based upon historic averages for demand corrective including trouble calls related to station infrastructure facilities. The planned corrective is based on identified defects that need to be addressed in the test years. Spending for preventive and corrective maintenance on facilities is $23.0 million in 2013 and $23.5 million in 2014. Funding levels are contained with relatively minor increases over historic levels despite costs pressures associated with aging infrastructure through optimization of maintenance cycles and more granularity in assessment of asset condition, prioritization and options to address condition.

Grounds Maintenance

Grounds maintenance involves the application of herbicides to control weeds and vegetation inside Hydro One's transformer stations. Weed and vegetation control is required to keep step and touch voltages at safe levels for workers and others that enter the station. In addition, grounds maintenance includes snow removal to allow access to and within a station, grass cutting, clean-up and general maintenance that may be required for site drainage and grading. Spending for grounds maintenance on transformer station facilities is $4.5 million in 2013 and $4.6 million in 2014.

Site Security

Site security encompasses a number of activities. These include preventive and corrective maintenance at station perimeters, (e.g., fences and gates) to prevent unauthorized access and in some cases includes security guards at locations where there is a high occurrence of vandalism. Furthermore, this program includes a number of security measures to deter theft of copper and to control entry of nuisance wildlife that have and continue to be responsible for equipment and station outages.

Hydro One is experiencing a high number of occurrences of copper theft. Not only does theft of copper result in significant damage to site facilities, but missing copper on equipment and a break in the ground grid creates unsafe conditions for workers and the public, and in some cases requires that equipment be taken out of service until repairs are made. Copper theft is dangerous to thieves, creates unsafe conditions for workers and has negative implications on equipment and system reliability. Considering the frequency that these incidents are occurring, Hydro One Transmission has and will continue to implement deterrents and measures to reduce theft. As a result of the increased rate of security breaches, costs have increased in this area over historic spending. Increased funding covers both corrective actions following breaks and increased costs for monitoring required with new security installations. Spending for site security at transmission stations is $2.8 million in 2013 and $2.7 million in 2014.

3.6.3 Summary of Expenditures

The spending requirement for test years is $30.3 million for 2013 and $30.8 million for 2014. The primary reasons for these increases relative to the historic years average of $26.4 million is a need to increase in the amount of site security expenditures, increased need to maintain the aging Station buildings and associated switchyard infrastructure, as well as year over year escalation.

4.0 LINES

Transmission lines are used to transmit electric power, via integrated network and radial circuits, to either transmission-connected industrial or commercial customers, or to local distribution companies, including Hydro One Distribution, who in turn distribute the power to end-use customers. Hydro One's Transmission lines primarily operate at voltages of 500 kV, 230 kV, and 115 kV, with minor lengths operating at 345 kV and 69 kV. The company's transmission line system consists of approximately 29,000 circuit km of overhead transmission lines located on about 21,000 km of rights of way, and 292 circuit km of underground transmission lines.

Overhead transmission line components include structures (primarily steel or wood) and corresponding foundations, conductors, shieldwire, insulators, lightning arrestors, hardware, switches, and grounding systems. Underground transmission line components include cables, terminations, oil pressure systems and grounding systems. The underground transmission lines are generally located in large urban centres.

Sustaining OM&A funding for Lines' expenditures is required to maintain existing overhead and underground transmission lines assets. Hydro One Transmission manages its Lines OM&A program by dividing the program into three categories:

- Vegetation Management, which ensures that clearances to energized equipment are maintained and includes brush control, line clearing, condition patrol, demand maintenance and ground maintenance.
- Overhead Lines Program**s**, which includes Preventative Maintenance & Asset Condition Assessment, Trouble Calls, Planned Corrective Maintenance & Projects.
- Underground Cable Program**s**, which focuses on inspections, analysis, tests, surveys and diagnostics of cables, vaults, jackets and potheads as well as condition and route patrols and corrective maintenance.

Required funding for 2013 and 2014, along with spending levels for the bridge and historic years for each program are provided in Table 11

Table 11
Lines Sustaining OM&A ($ Millions)

Description	Historic			Bridge	Test	
	2009	2010	2011	2012	2013	2014
Vegetation Management	25.7	24.0	26.6	26.2	29.0	29.3
Overhead Lines Programs	19.4	15.9	16.1	20.0	22.3	23.4
Underground Cable Programs	4.4	4.0	6.6	3.6	4.3	4.4
Total	**49.4**	**43.9**	**49.4**	**49.7**	**55.6**	**57.1**

Overall, sustaining OM&A requirements for Lines for the test year 2013 have increased 12% over projected spending in 2012 and the requirement for 2014 increased by 3% over the 2013 requirement. The primary reasons for the increases are to account for increases in vegetation management to accommodate additional inspections anticipated to be required by the pending FAC-003-2 NERC standard and additional line clearing and brush control to meet target clearing cycles. There is also a requirement to carry out increased levels of conductor testing on aged conductors and to replace defective u-bolts and conductor dampers.

4.1 Vegetation Management

Hydro One Transmission has approximately 21,000 km of transmission lines that occupy approximately 82,000 hectares of rights of way. These lands contain varying types of vegetation, from forests to grass lands, some of which can grow into the proximity of transmission lines and threaten system reliability. To ensure a sustainable level of reliability, a vegetation management program is required to ensure that clearances between vegetation and energized equipment are maintained. The program controls vegetation growth in a manner that considers environmental, ecological and social impacts, by undertaking various activities including tree removal and trimming, brush control, condition patrols, grounds maintenance and responding to reliability and landowners concerns. These activities are separate packages of work and are generally not completed at the same time. In addition, staff required to complete the work have a varying degree of skills depending on the type of work involved.

Table 12 outlines the proposed funding for 2013 and 2014 for the specific elements of the program as well as the spending levels for the bridge and historic years.

Table 12
Vegetation Management ($ Millions)

Description	**Historic**			**Bridge**	**Test**	
	2009	**2010**	**2011**	**2012**	**2013**	**2014**
Brush control	16.0	15.5	17.0	15.2	17.0	17.2
Line Clearing	3.9	3.2	4.3	4.1	4.7	4.7
Property Owner Contact	1.0	0.6	1.2	1.1	1.2	1.3
Condition Patrols & Annual Inspections	0.9	1.1	1.3	1.9	2.1	2.1
Demand Maintenance	1.3	1.3	1.0	1.3	1.3	1.3
Grounds Maintenance	2.7	2.3	1.9	2.7	2.7	2.7
Total	**25.7**	**24.0**	**26.6**	**26.2**	**29.0**	**29.3**

4.1.1 Brush Control, Line Clearing, & Property Owner Contact

4.1.1.1 Introduction

Brush Control, Line Clearing, and Property Owner Contact are three distinct yet closely related activities in the Vegetation Management Program.

Brush control refers to managing the growth of trees and shrubs on the right of way so that they do not grow to a height that would cause an outage to the transmission line. Funds are used to maintain access along the right of way for inspection, maintenance activities and emergency response. A number of different methods are used to manage rights of way vegetation, including selective herbicide application, species management, and mechanical clearing.

Line clearing refers to the activity of assessing and removing "Danger Trees" that grow at the side of the right of way or on the right of way to protect water courses or act as visual screens. Danger trees are trees of questionable soundness and health, which could fall and contact line conductors, causing an outage. In addition, line clearing may include the removal or trimming of any trees that may pose a threat to the line. In some cases, removed trees are replaced with compatible vegetation to address local and environmental concerns. Line clearing is carried out as a separate activity from brush control, as it requires a higher level of skill to identify and remove trees that may jeopardize the security of a transmission line.

The activities of brush control and line clearing must comply with the new requirements of the NERC Vegetation Management Standard that came into effect during 2006. These requirements followed the August 14, 2003 northeast blackout in which a tree contact with energized conductors was found to be one of the significant causes. Since that time, the management of vegetation has received added regulation to prevent blackout reoccurrences.

Property Owner Contact is undertaken to acquire approval for access onto private property, obtain input concerning any restrictions and environmental concerns, and to communicate maintenance plans to property owners. During this activity, job planning and project layouts are completed, a detailed work package is prepared, and approvals are obtained from stakeholders such as property owners, municipalities, and the Ministry of Natural Resources where applicable.

4.1.1.2 Investment Plan

Brush control, line clearing, and property owner contact activities are generally performed on a cyclical basis as rights of ways are maintained on approximately 4, 6 and 8 year cycles depending on the region and its associated growth cycle. These cycle lengths are considered to be appropriate for the system, as they provide a cost-effective and sustainable level of reliability and are generally consistent with past accomplishment. It should be noted that some of these cycle lengths are longer than the 5 year average used at other major utilities but they have been assessed as being appropriate at Hydro One.

4.1.1.3 Summary of Expenditures

The spending requirements for the brush control for test years 2013 and 2014 are $17 million and $17.2 million respectively. The test year 2013 spending is 12% more than for the bridge year 2012, and the test year 2014 is 13% more than the 2012 proposed spending but in line with historic spending.

The spending requirements for line clearing for test years 2013 and 2014 are $4.7 million for each year. The test year 2013 and 2014 spending is 14% greater the bridge year 2012 spending. Spending can vary significantly from one year to the next depending on the complexity of the work that may be required, e.g. urban versus rural. The increase in the test years is in part attributed to more complex projects than historic, as well as a slight increase in accomplishment.

For Property Owner Contact, the 2013 and 2014 spending is $1.2 million and $1.3 million respectively. These amounts vary depending on the population density of the areas being addressed which do vary from year to year.

The proposed levels are required to mitigate the risk of tree related outages to the transmission network The current proposed program meets the requirements of the NERC regulations. Reductions would result in an increased risk of tree contacts resulting in outages and regulatory intervention with potential fines, as well as a reduction in customer and system reliability. The vegetation management program has been designed to maintain reliability as well as minimize life cycle costs. Reductions would result in an increase in life cycle costs, and reduced efficiencies attributed to higher volumes of trees and brush to be treated as a result of less frequent line clearing and brush control.

4.1.2 Condition Patrols

4.1.2.1 Introduction

Condition patrols are conducted along rights of way to identify, assess and document potential risks to the security of a line, as well as to obtain information concerning the condition of the vegetation on rights of way. Patrols are carried out by experienced staff to assess the condition of the rights of way and schedule the removal of vegetation that may pose a threat before the next clearing cycle. Data is captured on vegetation growth rates, quantities of danger trees, species of brush and trees, and clearance conditions. This is the accepted practice for controlling vegetation through the utility industry. As well, vegetation that poses a threat prior to the next scheduled line clearing/brush control treatment is addressed to ensure the reliability of the electrical system.

A new pending regulatory requirement stipulated by NERC will require annual inspections on applicable lines to identify emerging issues and clearance violations. Historically, inspections of this type for vegetation assessment have not been a part of Hydro One's practices.

4.1.2.2 Investment Plan

Patrols are carried out near the mid-cycle of right of way work (i.e. brush control and line clearing) as determined by historical accomplishment data and forecasted future maintenance dates. A mid-cycle condition patrol is considered optimal as it strikes a balance between having to forecast too much future growth in order to schedule the next set of maintenance activities and the risk of leaving excessive growth on the system too long.

Analysis of condition patrol data provides an indication of growth rates, clearances, and other vegetation conditions that will need to be addressed. If this analysis indicates particularly poor conditions on a right of way, then brush control, line clearing, and property owner contact may be brought forward on the schedule. If the opposite occurs, and a right of way is found to be in good condition despite not having been maintained for a lengthy period of time, then line clearing and brush control may be pushed back on the schedule to make room for higher priority work.

As well, the upcoming revision to the NERC FAC 003 Vegetation Management standard will require Hydro One Transmission to inspect its applicable lines on an annual frequency, which is not part of the current maintenance program, but has been added to the test year's maintenance plans.

4.1.2.3 Summary of Expenditures

The proposed 2013 and 2014 spending is $2.1 million for each year. The 2012 bridge year and the test years are higher than historic expenditures, primarily due to the pending NERC regulatory requirement to inspect circuits on an annual basis.

Reductions in this program will have adverse impacts on the efficiencies of the larger program, i.e., brush control and line clearing, as job plans will not be of a quality to plan work efficiently. As well, some condition information will not be collected and some vegetation that pose a risk of causing an outage will not be addressed, thereby increasing system and customer reliability risks.

4.1.3 Demand Maintenance

4.1.3.1 Introduction

Demand maintenance work is required to address vegetation management issues that cannot wait until the next scheduled maintenance activity (e.g. line clearing or brush control). Issues addressed through demand work arise as a result of problems identified by the public, storm damage, urban development, tree caused outages and problems identified during annual and condition patrols.

4.1.3.2 Investment Plan

The primary information required for assessing program needs are demand expenditures from recent historic years, explanations and data related to variances in particular years (e.g. impact of major storms), along with knowledge of any existing or projected factors that would impact future expenditures.

4.1.3.3 Summary of Expenditures

The proposed 2013 and 2014 spending is $1.3 million for each year. These amounts are based on historic expenditures under this category.

4.1.4 Grounds Maintenance

4.1.4.1 Introduction

Grounds maintenance funds activities on transmission rights of ways such as grass cutting in urban areas, security patrols, maintenance of access barriers and fences, snow removal, and garbage removal.

4.1.4.2 Investment Plan

Maintenance decisions are made considering regulatory requirements, local by-laws, and customer requirements. For example, grass cutting must be carried out during the growing season to comply with local by-laws with respect to weed control. Generally, grounds maintenance requirements are consistent from one year to the next and as a result forecast expenditures are largely based on historic expenditure levels.

4.1.4.3 Summary of Expenditures

Proposed spending for 2013 and 2014 is $ 2.7 million for each year which is based on historic average spend with a minor increment due to an increase in the need for sidewalk snow clearing.

Reductions in this program would result in an increase in complaints by the public and municipalities, as garbage could not be removed in a timely manner, or grass cut to meet municipal by-laws. This may result in fines and more costly response of an unplanned nature, as compared to planned.

4.2 Overhead Lines Program

The overhead lines program provides funding to maintain the reliability of transmission lines, address safety issues, meet regulatory and legal requirements, and ensure the financial long term viability of the overhead lines system. The program includes funding for activities such as overhead lines inspections to identify defects, emergency response, and the gathering of information that will enable funding to be allocated on a priority basis to maximize the life of the lines assets and maintain performance. The program also provides for repair or replacement of defective equipment and components.

The Overhead Lines Program is divided into three programs: preventive maintenance and asset condition assessment; trouble calls; and planned corrective maintenance and projects. The proposed 2013 and 2014 funding along with the bridge and historic spending levels for each of the categories is provided in Table 13 below.

Table 13
Overhead Line Programs ($ Millions)

Description	Historic			Bridge	Test	
	2009	2010	2011	2012	2013	2014
Preventative Maintenance & Asset Condition Assessment	9.7	8.7	9.0	9.5	9.5	9.8
Demand Maintenance	4.4	3.8	2.9	4.2	4.0	4.1
Planned Corrective Maintenance & Projects	5.3	3.5	4.2	6.2	8.8	9.6
Total	**19.4**	**15.9**	**16.1**	**20.0**	**22.3**	**23.4**

4.2.1 Preventative Maintenance & Asset Condition Assessment

4.2.1.1 Introduction

Preventative Maintenance and Asset Condition Assessment encompasses a number of activities that are undertaken to keep lines assets in working order and to identify conditions that may impact their operation and reliability, as well as acquiring condition information needed to identify components in need of replacement or refurbishment. The activities include foot, helicopter and thermovision patrols, insulator washing and switch maintenance, and the assessment of various transmission line components that include poles, steel towers, insulators, conductors, shieldwires, anchors, and guys.

4.2.1.2 Investment Plan

Preventative Maintenance

Preventative maintenance includes an annual helicopter patrol and in areas where flight restrictions exist, lines are patrolled on foot. The patrols identify any public safety issues and defects that may jeopardize customer and system reliability.

Thermovision patrols are carried out with the purpose of identifying condition "hot spots" (e.g. loose connections) that put line components at risk of failure and that are not visible to the naked eye. Predicting imminent failures has tremendous reliability benefits and as a result, thermovision patrols are conducted on an average 3-year cycle. More critical lines such as those on the 500 kV system, inter-ties (i.e. inter-provincial or international lines), and those servicing critical generating plants have thermovision patrols conducted on an annual basis.

Furthermore, preventative maintenance includes insulator washing in areas where salt contamination has been identified as a problem, inspections of aviation lighting on towers, switch maintenance and climbing inspections.

Asset Condition Assessment

Asset condition assessment includes a number of activities that have been designed to provide the information needed to manage the transmission system and to identify defects that jeopardize public and worker safety and the reliability of the system. Specific activities include:

- Steel tower assessments examine tower components above ground and at the ground line. Assessments are carried out on those lines that show signs of noticeable corrosion and that have structures in swamps, standing water or are located in known corrosive areas.
- Shieldwire and conductor testing targets conductors that have been in service for more than 50 years and shieldwires in service for more than 30 years. Once tested, those conductors and shieldwires determined to be at end of life, and pose a risk to the reliability of the system as well as a hazard to the public and employees, are scheduled for replacement under the appropriate capital programs.
- Insulator testing is conducted on specific line sections where annual assessments of reliability performance or patrol observations suggest insulator conditions may be deteriorating.
- Periodic field survey of electrical clearances of transmission lines are required to ensure that clearances are adequate for current operating conditions, or in response to proposed increases in operating conditions.
- Wood pole line assessments include detailed helicopter inspections of the condition of cross-arms and pole tops, and individual pole testing to evaluate the soundness of the wood near the ground line. The lines selected for detailed helicopter inspections are identified based on accessibility, pole ages, and reliability information. Ground inspections target about 3,000 to 4,000 structures a year.

Wherever possible, condition assessment activities are scheduled in a complementary fashion such that cyclical and non-cyclical needs are addressed as efficiently as possible. For example, a line section that requires pole and cross-arm assessments will be scheduled for a detailed helicopter patrol and pole testing such that both assessments are met and the need for the separate cyclical helicopter patrol is avoided.

4.2.1.3 Summary of Expenditures

Proposed spending for preventative maintenance and asset condition assessment for 2013 and 2014 is $9.5 million and $9.8 million, respectively. The test year 2013 spending is the same as the bridge year 2012 and the test year 2014 is 3% more than the 2012 proposed spending, with moderate increases from historic spending. The primary reasons for these increases are cost escalation and a requirement to carry out more conductor testing given the age profile of lines assets. Additionally certain types of polymeric insulators, faulty conductor dampers and worn u-bolts continue to be problematic. In order to manage these issues and to limit the number of component failures, continued inspections and condition assessments are required.

Reductions in this program will result in added reliability risks and failures that could impact public safety. The transmission system is located in the public domain and a number of the maintenance activities have been designed to identify possible failures before they occur. Failure of insulators, wood arms and conductors will bring energized conductor to the ground creating a hazardous situation for the public.

4.2.2 Demand Maintenance

4.2.2.1 Introduction

Activities in this program are needed to respond to emerging problems and to restore power should it become necessary. Lightning storms, ice build up on lines and high winds can result in the failure of transmission line components, which requires immediate response and repair. This program also provides funds to address problems identified during line patrols that need a short term response to prevent a potential outage or to address a serious safety issue.

4.2.2.2 Investment Plan

This program is reactive in nature and varies due to weather, equipment deterioration and equipment failures. Funding is based on historic volumes of work and expenditures.

4.2.2.3 Summary of Expenditures

The proposed 2013 and 2014 spending is $4.0 million and $4.1 million respectively and is consistent with historic expenditures.

4.2.3 Planned Corrective Maintenance and Projects

4.2.3.1 Introduction

Planned Corrective Maintenance and Projects includes funds for minor corrective work (e.g. ground wire replacements, clearance corrections, planned defect corrections), larger scale projects needed to address wide spread design, manufacturing, or condition deficiencies, and safety issues such as replacing worn u-bolts, which support the insulator strings and conductors, as well as damper replacement. In addition, this program includes funds for technical support to resolve reliability problems with transmission line assets.

4.2.3.2 Investment Plan

Planned corrective maintenance activities and projects are developed using the data collected through the patrols and asset condition assessment activities discussed in Section 4.2.1.2 of this Exhibit, as well as information on equipment reliability performance, and findings of expert analysis. Defects corrected under this OM&A

program may include loose guy wires, broken strands of conductor, damaged insulator strings, dislodged tower members, and broken ground wire.

Other corrective maintenance activities include tower anchor bolt security to deter vandalism and the installation of anti-climbing barriers to prevent public access to towers. Maintenance of this type is targeted to specific locations that have been identified as high risk.

Issues requiring more specific actions are addressed separately through targeted projects. One such project involves corrective action to address deteriorated and worn U-bolts that support insulator strings and conductor on the 500 kV lines between Barrie and Sudbury. This problem stems from a metallurgic deficiency in the metal and must be rectified to maintain integrity of this important line.

Furthermore, conductor damage has been discovered on several lines, which is caused by vibration stemming from aged defective conductor "torsional" damping devices. These units must be identified, assessed and replaced as required with the upgraded "stockbridge" design.

4.2.3.3 Summary of Expenditures

The test year spending requirement for this program is $8.8 million in 2013 and $9.6 million in 2014. The test year 2013 spending is 42% more than the bridge year 2012 and the test year 2014 is about 55% greater than the 2012 proposed spending. The primary reason for these increases is attributed to problems as identified above on the 500 kV lines u-bolt problems as well as the faulty dampers, conductor damage and worn u-bolts. Reductions in this program will result in defects remaining on the system for extended periods of time and thereby increasing the likelihood of failures resulting in increased reliability risks and public safety issues. For example, deferring repairs on the 500 kV lines would increase the likelihood of failures, as occurred during 2009 when a u-bolt supporting the insulators broke, resulting in a circuit outage.

4.3 Underground Cable Programs

Hydro One's Transmission High Voltage Underground ("HVUG") Cable system consists of 115 kV and 230 kV cables. Underground cables are located in the urban centres of Toronto, Hamilton and Ottawa, with short sections in London, Sarnia, Picton, Windsor and Thunder Bay.

This program reduces the risk of cable equipment failure which can seriously impact service and reliability to a large number of urban areas. The activities within this program ensure that corrective action is taken when component failure is imminent or when defects are discovered during routine inspections. Timely response to external requests for a cable locate is included in these activities. Preventative Maintenance activities such as cable diagnostics are also included as part of this program. Since most of the underground facilities are not visible or easily accessible, these activities provide an indication of the state of the cable components.

The proposed funding levels for 2013 and 2014 along with the spending levels for the bridge and historic years are provided in Table 14 below.

Table 14
Underground Cable Programs ($ Millions)

Description	Historic			Bridge	Test	
	2009	2010	2011	2012	2013	2014
Cable Locates	0.4	0.9	0.8	0.8	0.9	0.9
Preventative Maintenance	1.3	0.8	0.7	0.4	0.8	0.8
Corrective Maintenance	2.7	2.3	5.1	2.4	2.5	2.7
Total	**4.4**	**4.0**	**6.6**	**3.6**	**4.3**	**4.4**

4.3.1 Cable Locates

4.3.1.1 Introduction

This program provides funding to respond to external requests for locating Hydro One Transmission's underground cable facilities. Responding to these requests is in everyone's best interest as anyone excavating near a cable may cause damage to these costly assets and harm themselves or members of the public. Hydro One Transmission uses the services of "Ontario One Call" to field requests for cable locates and then completes the field identification as required.

4.3.1.2 Investment Plan

This program is driven by external demand and the costs are not recovered by end use charges, which is consistent with the practice of other utilities. The "no fee" policy is in place to encourage contractors to make use of the service and avoid costly and hazardous situations. Historic expenditures and numbers of requests are analyzed and used to forecast future expenditures.

4.3.1.3 Summary of Expenditures

The proposed 2013 and 2014 spending is $ 0.9 million each year, which is 12% higher than the bridge year for this demand driven program. This level is expected to effectively manage the demand for cable locates related to the increased construction activity that has been occurring in major centres such as Toronto, Ottawa and Hamilton where the majority of cables are located.

Reductions in this program present unacceptable risk to contractors and the public digging in and around Hydro One's high voltage cables.

4.3.2 Preventive Maintenance

4.3.2.1 Introduction

Underground cables are made of a number of components and subsystems, the condition of which can deteriorate during the cables' service life. Preventative maintenance activities are aimed at determining cable condition and ensuring system reliability.

4.3.2.2 Investment Plan

Underground cable condition information is determined through a number of activities as listed below.

- Condition patrols focus on underground cables and their auxiliary systems such as the oil pumping plants and cathodic rectifiers.
- Cable pipe polarization spot checks are required to monitor the corrosion protection that is installed on the cable pipes.

- Cable pipe corrosion surveys are conducted on the protective steel pipes that protect many of Hydro One's Transmission cables.
- Oil testing and analysis is carried out to determine if there is any accumulation of dissolved gases in the insulating oil, which may be a sign of deteriorating condition.
- Route patrols at ground level are conducted to look for any unknown excavations near the cables or any evidence of oil leaks that would indicate a breach in the piping system.
- Jacket tests are conducted on cables in the system that are not protected by a steel pipe. These include oil filled cables protected by a metallic sheath and an outer PVC jacket.
- Infrared tests are conducted on cable components called potheads, which mark the transition of a conductor from overhead to underground, to determine if the materials that make up the pothead are exceeding thermal limits.
- Vault inspections are carried out on cable systems having splice locations that are enclosed in a concrete vault.
- Cable diagnostic activities are carried out on the cable systems to assess condition and maintain reliability. Tests include oil leak detection, sheath current measurements and laboratory insulation assessment.

The large majority of preventative maintenance activities are cyclical in nature (e.g. route patrols are conducted twice per month) and expenditure levels are set to maintain these cycles. However, condition data and reliability performance may drive the need to adjust the frequency of maintenance activities for specific cables that may be a source of concern.

4.3.2.3 Summary of Expenditures

The preventative maintenance spending for 2013 and 2014 is $0.8 million for each year. Spending during the test years is aligned with historic expenditures.

Any reductions to the proposed plan would have financial, reliability, environmental and safety implications. Preventative maintenance programs have been instrumental in the past in identifying emerging issues within the cable system and permitting repairs to be made, thereby avoiding high impact failures. Failures result in unplanned circuit outages, potential explosive situations with safety implications, as well as oil spills which impact the environment. Such events can be expensive to deal with, are disruptive to the network, and reduce the service life of the cables which are very expensive to replace.

4.3.3 Corrective Maintenance

4.3.3.1 Introduction

Corrective maintenance work includes repairs of defects discovered through preventative maintenance activities, and may involve repairing oil leaks, coating of cable terminations, repairing of cable sheath and pipe coating, and topping up oil levels. These repairs are essential to keep the cables and their associated components in a reliable state of operation.

4.3.3.2 Investment Plan

The activities included under corrective maintenance are primarily reactive and demand in nature, but also include planned corrective activities. Planned corrective work is done where problems arise and there is adequate time to correct defects without significantly jeopardizing reliability and safety.

Demand elements of the program include responding to oil leak alarms by topping up oil reservoirs that feed oil filled cables, leak locating and repairs, as well as site cleanup.

Planned repairs include removal and replacement of oil that has unacceptable concentrations of harmful gases, sheath repairs that have been damaged through corrosion, and adjustment and repairs to monitoring equipment.

4.3.3.3 Summary of Expenditures

Proposed spending for corrective maintenance for 2013 is $2.5 million and for 2014 is $2.7 million. The 2013 cost is in line with historic spending and the bridge year 2012 planned spend, with the exception of 2011. Costs in 2011 were higher in order to find and fix multiple oil leaks on two circuits that are planned for replacement in the 2013 and 2014 test years.

Reductions in this program will hamper the ability to repair defects, which will shorten the life of these critical assets, and will cause premature deterioration leading to oil leaks, insulation damage and the risk of loss of supply to the downtown areas in major centres of Ontario.

5.0 ENGINEERING AND ENVIRONMENTAL SUPPORT

5.1 Introduction

This program funds support activities, including management of records and drawings, CAD drawing support, data base management and provision of specific technical information (e.g. preliminary costing of potential investments for selecting the most cost-effective alternative). In addition, this program funds technical support including specialized studies, outage assessments conducted by the IESO, event investigation and incidents response and external consulting services that provide technical expertise not available within Hydro One Transmission.

All of this work will be impacted by the increase in capital expenditures as these projects will require drawings, and in-turn increased drawing maintenance. The technical support and specialized studies are completed on an ad-hoc basis to aid in the decision making process for capital investments.

Required funding for the test years, along with the spending levels for the bridge and historic years are provided in Table 15.

Table 15
Engineering and Environmental Support OM&A ($ Millions)

Description	Historic Years			Bridge Year	Test Years	
	2009	2010	2011	2012	2013	2014
Engineering and Environmental Support	12.5	10.0	12.0	9.9	12.3	10.9

5.2 Investment Plan

This program is primarily driven by demand work and the level of funding is based on historical trends with adjustments to incorporate expected changes in the Transmission work programs.

The historical level of usage is reviewed annually to assess if the historical spending level needs to be adjusted to recognize any incremental requirements related to the magnitude and scope of the planned Transmission work program.

5.3 Summary of Expenditures

The spending requirements for Engineering and Environmental Support are $12.3 million for 2013 and $10.9 million for 2014. Projected spending is generally consistent with historic expenditures and it is expected that the increasing capital work program can be managed within the historic levels of spending. The level of funding requested will ensure that the investment decisions made are based on accurate information and that customer, legal, environmental and regulatory requirements are met.

The 2013 test year expenditure is higher than the 2012 bridge year and 2014 test year primarily due to the fact that Hydro One must meet the obligation set forth by the Ministry of Environment (MOE) to update processes and documentation associated with Class EAs (environmental assessments) during the approval of Transmission capital projects. This work will update any documents that do not conform to the current MOE code of practice, particularly in the consultation requirements with First Nations and Métis Communities. Hydro One Transmission will benefit through greater clarity in requirements for First Nation and Métis consultation, the consideration of new environmental technologies, improved process flexibility and removal of outdated information and requirements.

DEVELOPMENT OM&A

1.0 INTRODUCTION

Development OM&A provides the funding for work in the following key areas:

- Technology Program-Transmission Studies (formerly Research, Development and Demonstration)
  These investments are undertaken for advanced studies to investigate, understand and solve emerging technology requirements of the transmission system including renewable generation integration, and address current issues of the grid involving asset management, planning, operation and sustainment to improve overall reliability and performance. The Technology Program also provides direction for effective development of new and/or revised physical asset standards.

- Transmission Standards Program (formerly Technical Standards Development)
  These investments are undertaken for development, update and maintenance of transmission technical standards to align with advanced technology deployments, integration of increased renewable generation and the evolving Advanced Distribution System (ADS). This work is required to meet mandatory standards for safety and reliability, and to meet the regulatory and compliance requirements of the transmission system.

- ADS (Smart Grid) -Transmission Studies (formerly Smart Zone Development)
  These investments are undertaken to enable feasibility studies to identify new approaches, technology applications and products related to the transmission system with enhanced protection, control and communication performance that is required for the implementation of an ADS. This work is needed to develop promising technologies and validate them through pilot demonstrations prior to larger scale field trials and eventual deployment across the transmission system.

2.0 DISCUSSION

A summary of Development OM&A is presented in Table 1 below for the historical, bridge and test years.

Table 1
Summary of Development OM&A ($ Million)

Description	Historic			Bridge	Test	Test
	2009	**2010**	**2011**	**2012**	**2013**	**2014**
Technology Program – Transmission Studies	5.3	6.7	3.1	3.6	3.6	3.7
ADS (Smart Grid) – Transmission Studies	0.0	1.5	3.2	3.3	3.3	3.6
Transmission Standards Program	8.7	7.5	6.4	4.3	6.4	7.0
Total	**14.0**	**15.7**	**12.6**	**11.2**	**13.3**	**14.3**

Spending in the Technology Program – Transmission Studies area is required to increase slightly in the test years to continue funding the assessment of emerging technologies and products necessary for enhancement of the transmission system to permit integration of renewable generation in response to government direction under the GEGEA. There is also a need to provide technology solutions to current issues in asset planning, development, operation and sustainment. Although funding requirements in the test years increases slightly from the bridge year, it remains below the average spending of the historical years.

Spending level for the ADS (Smart Grid) – Transmission Studies area is also required to increase slightly in the test years to focus on development and validation of advanced technologies to enable enhanced protection, control, communication and monitoring that will be required by the evolving ADS project.

There is an increased funding requirement for the Transmission Standards Program area in the test years from the bridge year to accommodate the need for an increased number of standards for renewable generation integration and development of the ADS. The level of funding requested will allow continued development of new standards as well as revision of existing standards. This will enable transmission work associated with distributed generation projects and minimize the risk of not meeting legal, regulatory and work execution needs due to the unavailability of required standards. Furthermore, this funding could lead to opportunities to reduce future costs through standardization in the use of emerging technologies. Although spending in the test years increases from the bridge year, it remains lower than spending levels in the historical years.

2.1 Technology Program – Transmission Studies

Actual spending in Technology Program – Transmission Studies for 2011 was $3.1M while the forecast for 2012 program spending is $3.6M.

The objectives of the Technology Program – Transmission Studies are to undertake advanced studies to assess and evaluate the feasibility of emerging technologies. This work enables Hydro One to implement new approaches, tools, equipment and practices that result in efficient and effective utilization of the transmission system. The program also enables Hydro One to optimize investment decisions regarding transmission system performance and reliability improvements. These objectives are met through:

- Leveraging investments in transmission studies in collaboration with other electrical utilities with common objectives;
- Conducting assessment of imminent issues and feasibility of emerging technologies;
- Investigating continuous improvements to transmission planning, system design, maintenance and operations practices;
- Developing assessment tools and managing risks; and
- Forging partnerships with universities, research institutes and centers of excellence.

Hydro One participates in Canadian and international industry interest groups to pool knowledge. Two such interest groups are the Centre for Energy Advancement through Technological Innovation ("CEATI") and the Electric Power Research Institute ("EPRI"). Hydro One's investments are leveraged through joint funding of projects with other utilities and having access to the broader expertise of companies with similar interests or challenges.

The CEATI platform is shared by Canadian and US electrical utilities to assess new technologies, techniques and best practices for transmission line and underground cables design, inspection, life-cycle monitoring and diagnostics to improve overall reliability and performance. One specific initiative with CEATI undertook development of inspection techniques to detect latent damage to transmission lines due to ice and wind storms. This has resulted in more efficient and effective sustainment programs.

We have collaborated with EPRI to undertake studies in support of overall asset management sustainment, development, planning and operation of transmission lines including relevant technology transfers on emerging technologies. One such study has been to assess and continue to develop high temperature conductors and associated hardware to enhance transmission line capacity. This has led to in depth learning of material behaviour under high temperature conditions and will be used in subsequent development phases of the program.

Hydro One has collaborated with the University of Western Ontario to assess an effective deployment strategy for Synchro-Phasor capability to prevent a repeat of a major blackout in 2003, which affected 55 million people in the north-east of Canada and the US at a total cost of $6 billion. The project involves monitoring of wide area events and/or system conditions that may result in cascading outages. This work is part of a North American wide initiative in collaboration with other Canadian and US utilities and the U.S. Department of Energy (DOE) and the North American Electric Reliability Corporation (NERC).

Hydro One completed its required province-wide installation in 2011 to integrate it to the North-American hub for monitoring of the north-east power system's "vital signs" on a 24/7 basis. Hydro One now benefits from capabilities in;

- early detection of potential blackouts resulting from potential power system instability,
- improvement of power system reliability, monitoring and control,
- coordination with other North American utilities to provide effective solutions for avoiding potential cascading outages
- prevention of potential equipment damage in the order of magnitude of tens of millions of dollars per occurrence

Other projects that improve design, operation and maintenance practices and/or better risk assessment tools have also been completed. An example of such a project is the Dynamic Transformer Rating ("DTR") project for which the initial development work was concluded in the historical years. The final testing and validation are planned in 2012 prior to field deployment. This project will enable Hydro One to establish real time ratings of transformer and transmission line assets based on real time operating and ambient conditions without compromising their performance at critical peak load times. Benefits to Hydro One will include optimization of transmission asset operating capability while ensuring safe and reliable supply.

This work program also funds Hydro One's partnerships with universities to support the Power System courses in electrical engineering at selected universities and to make students available to Hydro One Transmission for research-oriented work. Hydro One is committed to training undergraduate and graduate students as potential future employees for the company. Funding is leveraged with the Natural Sciences & Engineering Research Council (NSERC) grants awarded to research associates.

Funding Level for 2013 and 2014

Funding levels required for the Technology Program in the test years 2013 and 2014 are $3.6M and $3.7M respectively. Although the level of funding increases slightly from the bridge year, it remains below the historical spending level.

TECHNOLOGY PROGRAM	**SCOPE / VALUE**	**2013**	**2014**
External Program: Includes EPRI, CEATI, Kinetrics and other smaller service providers	Transmission Studies cover Power Delivery, Utilization, Safety and Environmental Studies, which assess and evaluate; Feasibility of grid technologies to enable new tools, equipment and practices that result in efficient / effective use of the grid and its components to optimize reliability and performance as well as to comply with regulatory requirements Specific areas of studies include Transmission lines, underground cables, renewable generation, safety and reliability, environmental impacts, energy storage and power quality.	$3.6	$3.7
R&D Program- Internal Service providers	Transformer Station strain bus capability under short circuit conditions for safety and reliability. Assessment of mechanical strains of fiber optics in optical ground wires.		
Transmission Rights of Way - Vegetation Optimization	Re-engineering of vegetation in transmission lines rights of ways for efficiency and effectiveness of operations and maintenance while protecting endangered species.		

Technology Studies in the test years will focus on assessment and evaluation of emerging grid technologies to enable new methodologies and to deploy new diagnostic tools and more intelligent devices and equipment.

One such study will be undertaken jointly with EPRI to continue research on earlier development of the “High Temperature Low Sag (HTLS) Conductors” project by validating the prior results and observing the performance on a full scale field pilot installation at Hydro One. The HTLS solution is a cost efficient way to gain higher transmission capacity with minimal construction and outage requirements and potential savings of millions of dollars.

Another study which Hydro One will be participating in is an EPRI “Sensor Project” for developing and testing low cost intelligent sensor devices capable of real time monitoring of lines and stations assets for temperature, contamination and vibration. These sensors can be installed with easy clamp on installations that do not require outages. In light of the increasing need to deliver higher capacity of power through existing corridors and lines, “sensors” become essential pieces to success by allowing maximum power flow on existing lines and equipment.

2.2 Transmission Standards Program

Spending in 2011 was $6.4M for the development and updating of Transmission Standards in engineering, asset management, grid operations and sustainment areas. Spending for 2012 is forecast to be $4.3M.

The objective of the Transmission Standards Program is to develop and maintain technical standards in support of operating, maintenance and capital programs as well as enhancement of the transmission system to permit integration of renewable generation under the government’s GEGEA, and the evolution of ADS (Smart Grid).

The Transmission Standards Program covers the development of new standards and the revision of existing technical transmission standards in response to technological advancements. This program also funds development of standards due to revisions to the Transmission System Code or changes to regulatory and reliability standards from organizations such as the North American Electric Reliability Corporation (“NERC”), the Federal Energy Regulatory Commission (“FERC”) and the Northeast Power Coordinating Council (“NPCC”). Revisions to existing

transmission standards are also required for public and worker safety, equipment obsolescence, and changes in construction and work methods.
Hydro One Transmission monitors and influences emerging industry standards and requirements for new standards mainly through its participation in the Canadian Standards Association ("CSA"), the International Electro-technical Commission ("IEC") and the Institute of Electrical and Electronics Engineers ("IEEE") working groups.

Some examples of work delivery in this area have been the development of technical standards to provide guidelines for ampacity limits for underground transmission cables and overhead transmission lines to support transmission planning, operation and sustainment. This program has also developed protection and control standards to meet requirements of integrating Distributed Generation onto the grid in response to government direction and the OPA's FIT program.

Funding Level for 2013 and 2014

Funding required for the test years is $6.4M and $7.0M for 2013 and 2014 respectively.

SERVICE PROVIDER	AREAS of FOCUS / VALUE	2013	2014
HONI INTERNAL	Development / Revision of Engineering Design, Construction, Safety and Security standards required for transmission system enhancement to enable renewable generation integration and support ADS evolution. Estimate of Standards developed: 100 / 110 for 2013 / 2014.	$6.4M	$7.0M
HONI EXTERNAL	Development / Revision of Industry and Functional standards related to transmission enhancement to accommodate renewable generation and ADS; and also for power quality, reliability and asset sustainment. Estimate of Standards developed: 30 / 30 for 2013 / 2014.		

SERVICE PROVIDER	AREAS of FOCUS / VALUE	2013	2014
HONI INTERNAL	Development/ Revision of lines and cables maintenance standards, work methods and safety guidelines Estimate of Standards developed: 8 / 8 for 2013 / 2014.		
HONI INTERNAL	Development/Revision of standards for grid planning and operations, station automation including switching, voltage controls and regulatory compliance Estimate of Standards developed: 22 / 22 for 2013 / 2014.		

The required level of funding will ensure that a continued focus on development and revision of technical standards is maintained in the areas of Distributed Generation connections as it directly impacts transmission operation, protection & control, safety and overall reliability. In addition, this program will fund development of standards to support a substation automation platform in support of the ADS project. Although spending in the test years increases from the bridge year, it remains lower than historical spending levels. Spending in the bridge year is lower due to delays in the ADS project.

2.3 ADS (Smart Grid) – Transmission Studies

Spending for the year 2011 was $3.2M and the forecast for 2012 is $3.3M. The work in 2011 and 2012 in the ADS (Smart Grid) – Transmission Studies program is described in the attachment to this exhibit, the Smart Grid Development Report. In the EB-2010-0002 Decision, on page 14, the Board directed Hydro One to file a report on what activities were undertaken in 2011 and 2012 with the Smart Grid funding that was approved for those years.

Funding Level for 2013 and 2014

Funding requirements for ADS (Smart Grid) Studies- Transmission Studies in 2013 and 2014 is $3.3M and $3.6M, respectively.

ADS (SMART GRID) - TRANSMISSION STUDIES	SCOPE / VALUE	**2013**	**2014**
MOU Programs by Ontario Universities; Ryerson University, University of Waterloo and University of Western Ontario	Studies on the use of IEC 61850 international standards for station protection and controls. Technology development and systems analysis for Smart Grid infrastructure modeling and Distributed Generation Modeling for ADS.	$3.3M	$3.6M
CEATI, EPRI, ERI Applied Research Program – Participation of Universities, Utility members and private sector	Renewable Generation technology assessment and integration studies for ADS impacts on the transmission system		
Flexible AC Transmission System (FACTS) Technology and Device Studies	Performance assessment, impact and validation of FACTS devices in collaboration with universities, industry partners and OCE / EPRI		
Advanced Grid Studies	Validation for grid integration and impact of renewable generation on the transmission system related to energy storage devices, intelligent electronic devices and sensors in collaboration with universities, NSERC and OCE		
Integration Studies (Wind, Solar, Biomass Generation connections impact studies)	Specific impact and integration studies of renewable generation as they relate to power quality, dispatch, protection and control, and communications on the transmission system		

The funding in the test years is required to assess and evaluate the feasibility of emerging technologies to enhance the transmission system for protection, control, communication and monitoring. This work is required to maintain reliability and security of supply while accommodating the increased number of renewable generators connecting to the system.

A number of studies will be undertaken by Hydro One on the IEC 61850 international standards to support development of a protection, control and relay communication platform. This will allow deployment of Intelligent Electronic Devices (IED) on the grid to support the evolution of the ADS project. Hydro One also plans further testing to develop maintenance and commissioning requirements based on the IEC 61850 standards for transformer stations in support of the ADS project.

Another study will continue to investigate the performance of IEDs installed on the system and focus on understanding how microprocessor based devices such as IED’s age in order to establish methodologies to determine end-of–life for asset maintenance and replacement planning.

SMART GRID DEVELOPMENT REPORT

1.0 INTRODUCTION

In the EB-2010-0002 Decision, on page 14, the Board directed Hydro One to file a report in its next rate case to outline what activities were undertaken in 2011 and 2012 with the transmission Smart Grid funding that was approved for these years.

This report provides details of investments undertaken in 2011 and 2012 under the category of Smart Grid Studies / Smart Zone Development.

2.0 ADS (SMART GRID) -TRANSMISSION STUDIES (FORMERLY SMART ZONE DEVELOPMENT)

These investments are undertaken to enable feasibility studies of new approaches, emerging technologies and products related to ADS. This work is needed to assess and identify promising technologies and confirm their viability for potential field deployments through pilot demonstrations prior to larger scale trials and eventual integration into the transmission system.

These technologies are required on the transmission system to support the development of an Advanced Distribution System (ADS) to provide enhanced protection, control, reliability and security.

ADS (Smart Grid) – Transmission Studies also respond to the Ontario Government's direction under the GEGEA to facilitate development of a Smart Grid.

3.0 DISCUSSION

The strategic approach used for these investments is to identify and effectively manage the potential risks in emerging technologies prior to full scale field implementation and final integration onto Hydro One's Grid. This allows a front-end proofing of the technologies which support Hydro One's ADS (Smart Grid) deployment initially in the Owen Sound Smart Zone pilot project.

Where possible, investments are undertaken in a leveraged manner through participation and partnership with other utilities, universities, government agencies and industry partners to make more effective use of the funds.

4.0 INVESTMENTS IN 2011

The funding approved for ADS (Smart Grid) – Transmission Studies in 2011 was $4.0M. The actual spending in the year was $3.2M and included the areas of investment described below.

4.1 Partnership with Ontario Universities (UW / UWO /RU)

University of Waterloo (UW), University of Western Ontario (UWO) and Ryerson University (RU) through multi-year partnerships with Federal and Provincial granting agencies (NSERC/OCE/NRCan) facilitated a high degree of cost leveraging in undertaking the applied research projects identified below.

4.1a University of Waterloo:

- Energy Hub Project in development of Sustainable Energy Centres
- Modelling and Optimization of Distributed Generation Connections
- Assessment and Mitigation of Power Quality Impacts / Issues

4.1b University of Western Ontario:

- Large Scale Solar Project with novel innovation to support grid voltage
- Protection and Control Studies including IEC61850 based Stations platforms
- Renewable Energy Regulation and Wide Area Protection and Control
- Various Protection Studies related to Distributed Generation Anti-Islanding

4.1c Ryerson University (Centre for Urban Energy):

- Energy Storage Control Systems development
- Assessment and development of Flywheel Technology as Energy Storage
- Intelligent Control Algorithms for integration of Renewable Energy
- Urban Energy Infrastructure Assessments and Developments

A total of $1.5M was spent for these Ontario Universities to conduct applied research under Memorandum of Understanding (MOU) Agreements with each University.

4.2 Energy Storage Initiative

- NRCAN / Electrovaya Large Scale Energy Storage. This is a development and demonstration project with a multi-year project partnership co-funded by Hydro One, federal / provincial government agencies, Manitoba Hydro, LDC's and private partners with the objective of developing a viable Lithium-Ion battery which will potentially serve to support voltage on the Hydro One grid as a part of the ADS evolution.

A total of $650K was spent in 2011 to co-fund this project.

4.3 CEATI Program

The CEATI (Centre for Energy Advancement through Technological Innovation) multi-year program is a platform from which a number of Canadian and American utilities share knowledge and develop technologies with high leveraging. Studies focus on reinforcement and enhancing the transmission infrastructure to allow the ADS to manage the integration of renewable generation including protection, control and security to improve system performance and reliability. Other projects focused on, i) intelligent electronic devices and applications on the grid, ii) solar power variability impacts and integration, iii) examination of anti-islanding schemes for renewable generation, iv) dynamic models for variable renewable generation, v) power systems harmonic load flow analysis, vi) inverter testing and certification gap analysis and vii) power quality issues.

A total of $400K was spent in 2011 on these multi-year projects.

4.4 Large Scale PV Integration Project

This is a multi-year development and demonstration project in partnership with Bluewater Power, Energent, Milton Hydro, the Ontario Power Authority and Hydro One executed by UW and UWO with project coordination by the Ontario Centre of Excellence (OCE). It focuses on the utilization of Solar Farms as potential storage devices on the electrical grid.

A total of $135K out of the $400K total cost total was spent in 2011 for completion of this 3 year project.

4.5 Inverter Performance Evaluation

Assessment of impacts on power quality and evaluation of the performance of commercially available Inverter devices through in-laboratory testing under energized conditions. This work will allow the connection of increased levels of renewable generation by identifying modifications to transmission protection and control equipment to facilitate ADS evolution.

Total cost of the study in 2011 was $458K.

4.6 Relay Alternative to Renewable Generator Transfer Trip

Study conducted to evaluate Transformer and Feeder Relays as a potential alternative to installing elaborate and costly Transfer Trips to isolate renewable generators as dictated by grid operating constraints and taking advantage of the new technology provided by the ADS.

Total cost of the study completed in 2011 was $57K.

5.0 INVESTMENTS PLANNED IN 2012

The funding approved for ADS (Smart Grid) – Transmission Studies in EB-2010-0002 for 2012 was $4.0M. The 2012 forecast for spending for investments in this area is $3.3M.

The areas of focus for new investments in 2012 are identified below. The continuation of 2011 multi-year projects described above under the Ontario Universities work is $1.5M and under the CEATI work it is $250K.

5.1 Transmission Capacity Enhancement

This is a new project spun-off from the Large Scale Solar Project which was undertaken from 2009 to 2011 with valuable deliverables on potential voltage support by generators. This new project is coordinated by the Ontario Centre of Excellence (OCE), co-funded by Hydro One and executed by UW and UWO. This multi-year project involves development of approaches to increase the existing transmission capacity to accommodate Distributed Generation connections through the use of Innovative DG Controls as well as mitigating short circuit currents that impact the transmission system.

Hydro One's share for co-funding of this initiative in 2012 is $300K.

5.2 Clean Energy Initiatives

This program focuses on assessment, development and integration of Clean Energy technologies including geothermal, compressed air and cryogenics which could potentially facilitate energy storage and grid voltage support when needed to reinforce Hydro One's ADS development. Clean Energy initiatives are sponsored by interest groups including Pollution Probe, Centre for Clean Energy and the Toronto Atmospheric Fund and are funded by federal and provincial agencies.

The 2012 spending for this program is $200K.

5.3 Energy Reserch Initiative

This program funds Hydro One's participation in the Energy Research Initiative (ERI) a consortium of leading private sector and university partners to address the need for new modeling and simulation tools to support the development and integration of technologies to enable ADS.

The 2012 spending for this program is $100K.

5.4 FACTS Technology and Devices

Assessment of technology, impacts and evaluation of performance through in laboratory testing under energized conditions of commercially available "Flexible Alternating Current

Transmission System (FACTS) devices used by renewable generators in support of transmission enhancements to accommodate the development of ADS.

The 2012 spending for this program is $350K.

5.5 Green Energy Impact and Integration

This program covers impact, mitigation and integration studies to accommodate increased levels of renewable generation being integrated within the future ADS environment and to identify transmission enhancements that will be required to support the ADS.

The 2012 spending for this program is $300K.

5.6 Advanced Grid Studies

This program focuses on studies to assess and utilize advanced asset solutions for transmission reliability and performance in support of ADS as identified below:

- Analysis and Standardization of Protection, Control and Telecommunications
- Reactive Power Control Coordination with Variable and Intermittent Generation
- Underground Transmission Cables Ring-Gap Reinforcement
- Improved Utilization of Transmission Lines Capacity

The 2012 spending for this program is $300K.

OPERATIONS OM&A

1.0 INTRODUCTION

The Operations OM&A program funds the operations function, which manages the transmission assets in real time on a continuous basis. This includes monitoring and controlling the transmission assets, coordinating and scheduling planned maintenance outages, and monitoring and reporting on the performance of the transmission system. These expenditures fund the operation of Hydro One's transmission system consistent with good utility practice and within the requirements established by the reliability authorities, operating agreements and the market rules.

Operations OM&A also includes initiatives to support environmental, health and safety activities that are required to meet legal obligations, due diligence and aligns with Hydro One's strategic objectives. Lastly, this funding supports Hydro One programs for managing its relationship with its large customers and generators.

2.0 DISCUSSION

Operational activities associated with the transmission system are carried out centrally at the Ontario Grid Control Centre ("OGCC"). The OGCC is a shared facility which allows central operations of the transmission and distribution systems and is backed up by facilities located at a separate site. Back-up operating facilities are provided at a separate facility as required to meet North American Electricity Reliability Corporation ("NERC") standards and is consistent with good utility practice.

The 2013 and 2014 test year costs for transmission operations at the OGCC is based on the cost allocation methodology proposed by Black and Veatch, updated in 2011 and accepted by the Board during the previous three transmission applications under Proceedings EB-2006-0501, EB-2008-0272 and EB-2010-0002 and as discussed further in Exhibit C1, Tab 7, Schedule 1.

The OGCC is the operating authority for Hydro One's transmission system including interconnections to other neighbouring transmission systems in Canada and the United States. Using the Network Management System, the OGCC monitors and controls Hydro One's transmission system and transformer supply stations in real time to maintain acceptable voltage levels and equipment loadings, and manages forced and planned equipment outages The OGCC performs the transmission Outage Planning ("OP") function to facilitate the maintenance and capital work programs. In addition, the OGCC develops Utility Work Protection Code documentation including switching orders for transmission planned and forced outages to ensure a safe working environment for employees.

The Operations OM&A program is divided into four categories:

- Operations, which funds the work required to conduct the safe and reliable operation of the transmission system, including the planning and scheduling of transmission outages;
- Operations Support, which provides for the maintenance of the computer tools and systems for the operations function;
- Environment, Health and Safety, which funds programs to support environmental, health and safety activities that are required to meet legal obligations, due diligence requirements and to assist in achieving corporate health and safety objectives; and
- Contracts and Customer Business Relations, which funds Hydro One's efforts to manage its relationships with transmission-connected industrial customers, LDC's, and transmission-connected generators.

The required funding for the test years, along with the spending levels for the bridge and historic years, are provided in Table 1 for each category.

Table 1
Operations OM&A Allocated to Transmission ($ Millions)

Description	Historic			Bridge	Test	
	2009	2010	2011	2012	2013	2014
Operations*	30.6	30.9	33.0	31.9	32.7	33.6
Operations Support	16.6	21.0	23.3	24.2	25.7	26.8
Environment, Health and Safety	1.5	1.8	1.0	2.2	2.2	2.2
Large Customer & Generator Relations*	4.3	4.5	3.7	3.6	3.6	3.7
Total	**53.0**	**58.1**	**61.0**	**61.8**	**64.3**	**66.4**

*Due to an organizational change, in the previous application (EB-2010-0002), the costs associated with Large Customer & Generator Relations have been reduced as the Customer Operations Support (COS) group has moved under Operations in 2011.

- The increase in Operations expenditures from 2010 to 2011 is attributed to an organizational realignment. Customer Operation Support (“COS”), formerly part of the Large Customer & Generator Relations group, has moved under Operations.
- The decrease in Operations expenditures from 2011 to the 2012 bridge year is related to a corporate initiative to reduce controllable Operations costs (i.e. Overtime, Sundry’s etc.). These areas have been reduced and form the baseline for the test years.
- The increase in expenditures from 2012 Operations spending levels to the test years is related to collective agreement obligations.
- The Operations Support spending shows an increase in the bridge year and similar increases in the test years is due to standard cost escalation.
- The health, safety and environment increase from historic spending is a result of the introduction of some new training initiatives, most notably Motor Vehicle Operator training and Ice & Water Rescue which is being delivered across Networks and the

development of new training packages for Protection and Control and Central Maintenance Services. Work preparation for OHSAS 18001 registration and Journey to Zero initiatives has also increased. All programs are targeted to help Hydro One achieve its strategic objective of creating an injury-free workplace and maintaining public safety.

- Large Customer & Generator Relations decreases from historic spending as a result of the realignment of the Customer Operations Support ("COS") group to Network Operating.

The description and details for individual Operations OM&A programs and year-to-year changes are provided below.

3.0 OPERATIONS

This program funds the work required to conduct the safe and reliable operation of the transmission system, including the planning and scheduling of transmission outages. It also includes maintenance and support for the Network Management System ("NMS") and Network Outage Management System ("NOMS").

The NMS is a mission critical application for monitoring and control of the Hydro One transmission system and NOMS is an essential tool for execution of the Outage Planning ("OP") function at the OGCC.

In addition, Hydro One is registered with NERC as a Transmission Owner and Operator. This registration requires that the control room operators be NERC certified as transmission operators. Aside from the initial cost of the NERC certification training for new hires, there is an on-going mandated requirement to provide continuing education hours annually, to maintain NERC certification.

Staffing levels in the test years are planned to be maintained despite meeting an increasingly demanding work load as a result of larger Sustaining and Development capital work programs and Green Energy related work. This increase in work program has required added outage planning and scheduling, and increased efforts to adequately manage the power system. This trend is expected to continue into the test years. This is discussed in more detail in Exhibit A, Tab 17, Schedule 1.

The spending requirements for test years 2013 and 2014 are $32.7 million and $33.6 million. These increases in planned Operations expenditures over 2012 levels are largely due to collective agreement obligations.

Operations staff has skill sets and experience that make them attractive for promotion into other lines of business. This, as well as the large percentage of employees becoming eligible to retire, may result in a higher than average attrition rate. This risk is mitigated through Hydro One's Controller Trainee ("CT") program which hires new controller trainee's on an annual basis. The program requires the candidates to complete a three year training course, including successful completion of NERC certification and therefore requires hiring candidates three years prior to anticipated position needs.

The risk of not proceeding with this plan would result in a critical shortage of skilled resources and the failure of the operating centre to function efficiently.

4.0 OPERATIONS SUPPORT

This program provides funding for the maintenance of, and minor enhancements to, the operating facilities at the OGCC and back-up centres, as well as services essential to the planning and execution of outages.

The primary operating facilities are the Network Management System ("NMS"), the Network Outage Management System ("NOMS"), the Utility Work Protection Code System, the Electronic Log ("EL"), the OGCC Integrated Voice System and the OGCC Emergency Services Information System ("ESIS"). Details concerning each of these systems are provided as part of the discussion on Capital investments in Exhibit D1, Tab 3, Schedule 4.

The essential services to support the day to day operation of the transmission system are described in the sections below.

4.1 Operating Facilities

Operating Facilities maintains all of the facilities required to support the day-to-day operation of the transmission system. These facilities include the various computer systems required for real-time monitoring and control, communications, training, and outage scheduling. Funding for the software licenses, vendor maintenance contracts, consumables and staff labour to support the operating facilities for the OGCC, the back-up centres and the remote operating data collection sites are included in this service.

The costs for Operating Facilities in 2013 and 2014 are $14.2M and $15.0M respectively.

4.2 Field Switching

Many elements of the transmission system cannot be remotely controlled. In order to fully carry out its accountabilities related to the provision of safe working conditions and reliable operations, the Operations function directs staff in the field to carry out required manual switching. Field switching primarily supports the maintenance program but may also respond to forced outages and third party requests.

The costs for Field Switching activities in 2013 and 2014 are $6.1M and $6.3M respectively.

4.3 Load Transfer Studies

Load transfer studies are required to assess the feasibility of electrical configuration changes when forced and planned outages are required on the Hydro One Transmission system due to maintenance, new connections, device installations and abnormal system conditions. The benefit of carrying out these studies is continued system reliability, reduced impact to customers and safer working environments for Hydro One Transmission employees.

The costs for Load Transfer Studies in 2013 and 2014 are $1.5M and $1.6M respectively.

4.4 Maintain Operating Diagrams

Operating diagrams show the interconnectivity of transmission elements and the devices that isolate them from the system.

The operating diagrams are maintained on the following systems:

- The Computer Aided Design (CAD) system, which contains the transmission diagrams for auxiliary facilities within transmission transformer stations such as dc/ac station service diagrams, air systems, protection and control systems, etc.; and.
- The NMS, which contains all transmission system related drawings used for real time control.

One of the primary uses of operating diagrams is the specification and execution of the Work Protection Code procedures required to provide safe working conditions for maintenance and construction crews. The Development and Sustainment programs result in several thousand changes to the transmission system each year. It is critical to worker safety that these changes be reflected on the operating diagrams correctly and in a timely fashion.

The costs for Maintenance of Operating Diagrams in 2013 and 2014 are $0.5M for each year.

4.5 Miscellaneous

The remaining miscellaneous expenditures include; Voice Communications System Support, Control System Technical Support, Customer Event Investigation, Emergency Preparedness, Field Verification and Level II Inspections.

The costs associated with these investments in 2013 and 2014 are $3.4M and $3.5M respectively.

4.6 Summary of Expenditures

The spending requirement for test year 2013 is $25.7 million and for 2014 it is $26.8 million. The Operations Support funding levels in the test years are higher than the 2012 bridge year due to standard cost escalation.

The risks of not proceeding with these levels of work would result in the failure of the Operating Centres to function as required, including:

- Failure to maintain software licenses and vendor maintenance contracts and appropriate support staff would result in prolonged unavailability of critical facilities (i.e. NOMS & NMS) required to support the operation of the transmission system.
- Failure to adequately support the Field Switching program would have a severe negative financial impact due to long delays in performing planned work.

- Failure to perform load transfer studies would result in diminished system reliability, increased negative impact on customers and would adversely affect worker safety.
- Failure to maintain the accuracy of operating diagrams in a timely fashion would seriously affect worker safety, e.g. potential for incorrect switching or re-energizing a system element while others are working on the equipment.

5.0 ENVIRONMENT, HEALTH AND SAFETY

This program supports environment, health and safety programs that are required to meet legal obligations and ensure a level of due diligence commensurate with the size and scale of Hydro One Transmission. In addition, the program funds activities to assist in meeting the corporation's Environmental and Safety performance targets as described in Exhibit A, Tab 4, Schedule 1.

Activities funded by this program include:

- Occupational and non-occupational injury/illness support which includes medical assessments of workplace injuries; the Care Management Program which provides the right care at the right time for Hydro One employees who suffer a major medical absence of five days or more; and Pandemic planning;
- Hazardous Materials Management which identifies hazardous materials and establishes a protocol for on-going management of these materials in the workplace as per the Occupational Health and Safety Act and the Workplace Hazardous Material Information System (e.g., asbestos, lead, mercury);
- Public safety which includes school presentations, media campaigns and the development and production of educational material to inform and educate members of the public about the hazards associated with Hydro One's assets;
- Proactive forums to assist the health and safety of employees by raising awareness and providing education about health, wellness and lifestyle issues;

- Hydro One's Learning Management System (HOLMS) supports learning management, performance management, content authoring and analytics. This funding helps to support the implementation of new reports.
- E-learning modules continue to be developed and or refreshed to enable employees to be trained remotely and to allow for timely and immediate delivery of required training. E-learning contributes to employee competence and reduces delivery costs.
- Development of new training media is being evaluated and implemented to improve the effectiveness of trades training. Web casting, video streaming, mobile learning, simulation and knowledge transfer technologies are being considered.
- The Journey to Zero initiative which supports the objective to eliminate workplace injuries and illnesses through the use of cross-functional teams carrying out review of specific functional areas impacting on safety performance.
- OHSAS 18001 registration process which includes a complete review of Hydro One's Health & Safety Management System. Registration requires an analysis of Hydro One's current management system compared to the standards, field audit of execution and closing any identified gaps; and
- Ice and Water rescue training for staff who work on and around water and ice so that they are prepared to meet the hazards in these environments.

Also included are trades and technical training programs. Training requirements are increasing due to the addition of new staff required to complete the planned work program and replace those who will retire in future years.

The expenditure requirement for this program is $2.2 million in test years 2013 and $2.2 million in 2014. This funding level is being maintained over the test years to build and improve on the existing safety culture and maintain high standards for public safety, as well as the increased workloads due to the addition of new staff.

Reductions in this program would present significant risks of noncompliance with safety regulations, especially considering that Hydro One Transmission is undertaking increased work programs with a number of new staff that need support and direction.

Hydro One's Strategic Plan identifies that nothing is more important than the health and safety of our employees and those who work on our property, as well as maintaining a safe environment for the public.

6.0 CONTRACTS AND CUSTOMER BUSINESS RELATIONS

Improving the level of service that the Company provides to customers is a key objective of Hydro One. While it is the role of each employee to ensure they work towards improving customer satisfaction, Customer Business Relations focuses its efforts on managing the relationship with the Large Customer segment. This includes Hydro One Transmission-connected industrial customers, LDC's and transmission-connected generators.

The transmission industrial and LDC long term satisfaction target of 90% was met in 2010 at 92%, with a sharp decline in 2011 to 83% with increased concerns of power quality and reliability of service. The transmission generators score remained static in comparison with 2010 at 93% and 2011 results at 91%.

The objective of Customer Business Relations is to maintain satisfaction levels and improve in areas where necessary, while working within regulatory boundaries to ensure compliance. The core work programs include contract management, program implementation, customer communications, operational and business support and customer connection project coordination. Planned long term initiatives involve improved customer communications through enhanced Web self service, skills training and a new Customer Relationship Management system to increase customer knowledge and improve commitment tracking and reporting.

6.1 Contracts and Customer Business Relations Activities

Contracts and Customer Business Relations activities include:

- Coordinating new and modified connection requests.
- Managing transmission connection agreements.
- Implementing and administering a new tracking process for customer contracts.
- Enhancing customer account management and commitment tracking systems to improve customer service and sharing of customer information within Hydro One.
- Meeting with customers to identify any issues and follow up on satisfactions surveys.
- Managing Hydro One's large customer web services, including annual enhancements to improve customer experience with web access.
- Continuing to manage transmission customer programs and communications.
- Managing the Wholesale Meter Exit program and the Transitional Meter Service Provider (MSP) fee program.

Bridge year spending has decreased relative to historical years as a result of a corporate realignment, as the Customer Operations Support (COS) group has moved from Customer and Business Relations (CBR) to Network Operations. .

The spending requirement for this program for test year 2013 is $3.6 million which is the same as bridge year 2012. The spending requirement for 2014 is $3.7 million largely due to cost escalation.

The improvement in customer satisfaction over the past five years and continued performance above 90% for large customers has shown that satisfied customers are less work. The risks of not proceeding with this work would result in lower customer satisfaction and a subsequent increase in work load, as well as reduced efficiencies in meeting customer needs in terms of longer term planning to coordinate customer connections and modifications and Hydro One Transmission's work.

CUSTOMER CARE OM&A

1.0 OVERVIEW

The Customer Care OM&A Work Program includes work activities that provide customer care services to the approximately 1.2 million customers, including residential, commercial, large industry and local distribution companies, connected to the Hydro One Transmission and Distribution Systems. The Customer Care work programs incude meter reading, billing, settlements, customer contact handling and collections.

Only a small part of the Customer Care Work Program is associated with Hydro One Transmission business, as shown in Table 1 below. Customer Care costs allocated to Transmission are $1.3 million and $1.4 million in 2013 and 2014. A description of the transmission-related work follows.

Table 1 provides a summary of Customer Care costs:

Table 1
Customer Care Work Program ($ Millions)

	Historic			Bridge	Test		TX Allocation	
	2009	**2010**	**2011**	**2012**	**2013**	**2014**	**2013**	**2014**
Customer Care Services	101.7	95.5	90.1	108.2	101.3	96.4	0.5	0.6
Customer Care Mgmt	7.7	9.4	6.8	7.5	7.5	9.4	0.3	0.4
Conservation Demand Management	0.9	1.6	1.5	3.4	3.4	3.4	0.4	0.4
Total Cost	**110.3**	**106.5**	**98.4**	**119.1**	**112.2**	**109.2**	**1.3**	**1.4**

2.0 CUSTOMER CARE SERVICES

Customer Care Services costs allocated to Transmission of $0.5 million in 2013 and $0.6 million in 2014 relate primarily to the settlements function activities.

The Settlements function ensures the integrity of financial transactions between Hydro One, the IESO, and applicable transmission-connected customers. Transmission-related settlements activities include:

- Calculation of gross load billed quantities at specific delivery points and submission to the IESO;
- Reconciling transmission delivery point quantities and charges, and allocation of transmission pool revenues according to Ontario Energy Board approved allocations; and
- Identifying anomalies and exceptions in metering data used by the IESO to bill Hydro One transmission-connected customers.

3.0 CUSTOMER CARE MANAGEMENT

The Customer Care Management function is accountable for customer policy, planning, work program budgeting, service performance management, settlement services, customer research, project management and responding to escalated customer complaints.

Customer Care Management costs are considered Common Costs, and are included in the corporate cost allocation method for Common Costs.

The time allocation study completed in 2011 identified four per cent of Customer Care's time as attributable to transmission. This allocates $0.3 million in 2013 and 0.4 million in 2014, and represents the following transmission-related work:

- Specifying appropriate transmission tariffs to be applied by the IESO for each transmission delivery point per the corresponding Transmission Connection Agreement,
- Updating, reviewing and approving transmission totalization tables plus related IESO transmission delivery point site registration reports, meter connectivity and wholesale meter registration information for each transmission delivery point,
- Identifying transmission tariff gross-load billing for specific transmission delivery points as a result of the connection of non-renewable and renewable generators; and
- Customer surveying and research of transmission-connected Hydro One customers.

4.0 CONSERVATION DEMAND MANAGEMENT

Under the Green Energy Act (GEA) the Conservation Demand Management (CDM) targets for the period 2011-2014 (energy and peak reduction for Distribution customers only) are a condition of the Distribution Licence Agreement. On September 16, 2010, the Board issued a CDM Code that asked LDCs to meet the four year targets targets through the delivery of OPA-Contracted programs, and Board-Approved programs. As a result, Hydro One will continue participating in current and potential OPA-administered CDM programs and will look for opportunities to expand this program portfolio as appropriate. Funding for these initiatives will be recovered through the OPA and is not included in revenue requirement requested in this Application.

The proportion of the CDM function attributable to Hydro One Transmission is $0.4 million in 2013 and 2014 and represents the following transmission-related work:

- Development and coordination of strategic plans for Hydro OneTransmission;
- Developing strategies that support the corporate goals related to the transmission function;
- Assisting in improving industry efficiencies within the utility sector; and
- Overseeing the operation of the Customer Advisorty Board for transmission.

SUMMARY OF SHARED SERVICES – OM&A

Hydro One Shared Services are comprised of Common Corporate Functions and Services ("CCFS"), Asset Management Services, Information Technology ("IT"), Cornerstone, Cost of Sales to external parties and Other OM&A. Other OM&A includes the capitalized overhead credit, the environmental provision credit, indirect depreciation and other costs.

CCFS includes Corporate Management, Finance, Human Resources, Corporate Communications and Services, Legal, Regulatory Affairs, Corporate Security, Internal Audit, and Real Estate. Common Asset Management services include System Investment, Business Performance, and Asset Strategies. IT and Cornerstone activities include providing and managing computer systems (for example, hardware and software) and IT infrastructure.

Hydro One utilizes a centralized shared services model to deliver its common services. The common services are delivered to the Transmission and Distribution businesses within Hydro One Networks Inc., and to the legal entities Hydro One Inc., Hydro One Telecom Inc., Hydro One Networks Brampton Inc., and Hydro One Remote Communities Inc. The centralized shared services model has allowed Hydro One Inc. to efficiently deliver key common services across the whole company in a cost-effective manner.

Many organizations have adopted a shared service model as an effective method of delivering common services to multiple subsidiaries and/or multiple business units. Hydro One adopted this model when it was established in 1999. The additional cost to establish the common functions in each of its subsidiaries would be cost prohibitive. In addition, the shared service model allows for the delivery of specialty services (i.e. Tax, IT systems and processes) without the need for having multiple experts in many areas.

This shared services model is a recognized business concept which has many benefits including:

- Minimization of the work force through commonly available specialist expertise and resources;
- Ensuring consistent policy and governance framework processes;
- Rationalizing and providing consistent levels of service across the organizations (for example, consolidation of office space, centralization of human resources, pay and financial services, infrastructure support);
- Using common technology systems and platforms and providing better access to information (for example, implementation of common financial and work material management systems);
- Synergies from economies of scale (for example, accounts payable processing, common procurement process and management of supplier relationships); and
- Increased flexibility to pursue outsourcing of services where appropriate.

Shared services cost levels are fully reviewed as part of the annual business planning process (see Exhibit A, Tab 13, Schedule 1).

Table 1 summarizes the Transmission portion of the Shared Services and Other OM&A Costs over the Historic, Bridge and Test years

Table 1
Allocated Transmission Shared Services and Other OM&A Costs ($ Millions)

Description	Historic			Bridge	Test	
	2009	2010	2011	2012	2013	2014
Common Corporate Functions and Services	71.2	74.8	72.3	83.1	86.1	86.1
Asset Management	38.5	28.3	25.0	35.3	35.8	37.0
Information Technology	57.2	61.2	57.3	60.3	64.1	62.6
Cornerstone	4.0	1.0	0.3	0.3	0.4	0.3
Cost of Sales	13.5	14.6	12.8	21.0	10.8	10.8
Other OM&A	(116.8)	(105.1)	(124.0)	(128.2)	(127.8)	(129.2)
Total	**67.6**	**74.8**	**43.7**	**71.8**	**69.5**	**67.6**

For the 2009-2014 period, Hydro One has applied a cost allocation methodology developed by Black and Veatch Corporation (B&V) which utilizes a breakdown of activities and drivers. In 2012, the Company commissioned B&V to update the methodology to allocate common costs among the business entities using the common services (as discussed in Exhibit C1, Tab 7, Schedule 1). The approach utilizes a further breakdown of activities and drivers and is used in this application.

The following Table 2 provides an overview of the various shared services cost categories for 2013 and 2014 showing the total costs as well as the allocated Transmission costs.

Table 2
Shared Services and Other OM&A Costs ($ Millions)

Function / Service	2013 Total	2014 Total	2013 Tx Allocation	2014 Tx Allocation
Common Corporate Functions and Services	164.8	167.9	86.1	86.1
Asset Management	62.5	62.7	35.8	37.0
Information Technology	142.4	138.8	64.1	62.6
Cornerstone	10.4	0.8	0.4	0.3
Cost of Sales	16.9	16.9	10.8	10.8
Other Shared Services	(231.1)	(246.9)	(127.8)	(129.2)
Total	**165.9**	**140.2**	**69.5**	**67.6**

The change in 2013 as compared to 2011 is primarily related to:

- Higher CCFS costs due mainly to higher Real Estate costs for additional work space as a result of the growth in the company's work program; increased Corporate Communications costs related to long term relationship building and negotiations with First Nations and Métis groups and improvement in customer communications regarding power outages and operational issues affecting their service; and higher OEB/NEB costs allocated to Hydro One Networks. These increases are partially offset by decreased costs due to a reduction Inergi contract fees. (See Exhibit C1, Tab 4, Schedule 2 for details);
- Increased Asset Management costs due to growth in the Transmission Sustainment & Operations work programs, as well as the increased work program to adapt to changing industry and regulatory standards, government policy, and an aging workforce and asset base (see Exhibit C1, Tab 4, Schedule 3 for details);
- Higher IT costs due to increased sustainment work effort due to additional storage requirements to support enterprise applications and an increase in the development activities associated with SAP upgrades (see Exhibit C1, Tab 4, Schedule 4 for details);
- Lower Cornerstone costs for Transmission due to a reduction in overall development costs, compounded by greater savings as process improvements from Cornerstone are leveraged in the business (see Exhibit C1, Tab 4, Schedule 4 for details);
- Reduced Cost of Sales activities related the planned shift in resources towards Hydro One Transmission's growing work program (see Exhibit C1, Tab 4, Schedule 6 for details);
- Lower Other Shared Services resulting from the growth in the capital work, thus generating higher overhead credits.

In the exhibits following, information is provided on the following areas:

- Common Corporate Functions and Services;
- Asset Management Services;
- Information Technology;
- Cornerstone;
- Cost of Sales;
- Other OM&A.

SHARED SERVICES - COMMON CORPORATE FUNCTIONS AND SERVICES & OTHER OM&A

The Corporation has identified certain functions that provide common services to all business units. It was determined that these functions could be shared effectively by all business units, avoiding costly and unnecessary duplication. These costs are referred to as Common Corporate Functions and Services ("CCFS"). Included in this exhibit is a discussion of CCFS costs and activities as well as Other OM&A which is comprised of credits associated with Capitalized Overhead, Environmental Provisions, Indirect Depreciation and Other Costs.

1.0 COMMON CORPORATE FUNCTIONS AND SERVICES

Table 1 presents, for comparison purposes, the total Common Corporate Functions and Services ("CCFS") costs over the Historic, Bridge and Test years as well as the 2013 and 2014 Transmission allocation amounts.

Table 1

Total 2009 - 2014 CCF&S Costs and
2013/2014 Allocation to Transmission ($ Millions)

Description	Historic			Bridge	Test		TX Allocation	
	2009	2010	2011	2012	2013	2014	2013	2014
Corporate Management	6.0	5.0	5.1	5.2	5.3	5.4	2.7	2.8
Finance	30.7	31.4	31.9	34.3	34.0	34.0	19.5	19.5
Human Resources	15.6	16.4	11.0	10.9	10.9	11.2	6.4	6.5
Corporate Communications*	8.9	9.6	8.7	9.1	11.4	12.6	5.3	5.7
General Counsel and Secretariat	6.6	7.5	7.4	8.7	8.9	9.1	4.7	4.8
Regulatory Affairs	19.5	21.3	20.1	22.4	23.6	23.0	11.5	9.7
Security Mgmt.	2.1	2.4	3.0	3.7	3.8	3.9	1.8	1.8
Internal Audit	2.7	2.8	3.1	4.2	4.3	4.4	2.5	2.6
Real Estate & Facilities	50.6	49.9	51.6	60.2	62.5	64.3	31.8	32.7
Total Cost	**142.7**	**146.3**	**141.9**	**158.7**	**164.8**	**167.9**	**86.1**	**86.1**

** Corporate Communications re-stated to exclude certain costs associated with VP Corporate Relations & Regulatory Affairs which are now included in Operations Exhibit C1-3-4 and the work associated with External relations and portion of the Corporate Communications group which can now be found in Shared Services Asset Management C1-4-3.*

Total CCFS costs increased by $22.9 million from 2011 to 2013 primarily due to the following factors: higher Real Estate costs for additional work space as a result of the growth in the company's work program; increased Corporate Communications costs related to long term relationship building and negotiations with First Nations and Métis groups and improvement in customer communications regarding power outages and operational issues affecting their service; and higher General Counsel & Secretariat costs related to the records management project and increased workload due to the facilitation of renewable energy connections. These increases are partially offset by decreased costs due to a reduction in Inergi contract fees.

From 2013 to 2014, total CCFS costs increase by $3.2 million primarily due to increases in the area of Outsourcing services as the Company prepares for the expiration of the current Inergi outsourcing contract, and an increase in Real Estate and Facilities funding in order to respond to work space accommodation needs.

Details on costs and work in each CCFS function are provided in the following sections.

1.1 Corporate Management

The following Table 2 provides a summary of Corporate Management costs:

Table 2
Corporate Management Function ($ Millions)

Description	Historic			Bridge	Test		TX Allocation	
	2009	2010	2011	2012	2013	2014	2013	2014
Total Cost	6.0	5.0	5.1	5.2	5.3	5.4	2.7	2.8

Corporate Management represents those functions responsible for providing overall strategic direction to the corporation, including the Board of Directors, Treasurer's Office, the Chief Executive Officer ("CEO"), Chief Financial Officer ("CFO"), the General Counsel and Secretary as well as the costs of certain supporting functions, such as Executive Office support.

The President, CFO and General Counsel & Secretary are considered to be part of Hydro One Inc. and provide services to Hydro One Networks Inc.

The General Counsel and Secretary function provides advice and support to the Board of Directors and Corporate Officers. It provides advice and training, reports on Code of Conduct, reports on activities related to the Freedom of Information and Privacy Act as well as the Federal Personal Information Protection & Electronic Documents Acts ("PIPEDA").

The CFO is responsible for the oversight of the Finance function and the reporting of information to Hydro One subsidiaries, regulators, investors and the shareholder. This includes the review and approval of financial and investment decisions, business and strategic plans and ensuring integrity of, and compliance with, internal controls over regulatory, financial and accounting activities.

The allocation of the costs associated with the activities of Corporate Management are governed by a Service Level Agreement between Hydro One Inc. (HOI), Hydro One Networks Inc. (HONI) and the legal subsidiaries as outlined in Exhibit A, Tab 8, Schedule 3. This exhibit also describes the activities performed by HOI, HONI and the amounts allocated to the various subsidiaries.

1.2 Finance

The following Table 3 provides a summary of Finance costs:

Table 3
Finance Function ($ Millions)

Description	Historic			Bridge	Test		TX Allocation	
	2009	2010	2011	2012	2013	2014	2013	2014
Total Cost	30.7	31.4	31.9	34.3	34.0	34.0	19.5	19.5

1.2.1. Overview

Finance provides strategic advice and services related to the planning, processing, recording, reporting and monitoring of all financial transactions taking place within the organization. Clients include parties both internal and external to the organization, depending on the service provided. Services are provided through the following specialist functions:

- Corporate Controllers;
- Corporate Tax;
- Treasury.

Finance costs increased slightly from 2011 to 2013 primarily due to the realignment of work from the Asset Management and Human Resources functions into Corporate Controllers, offset by a decline in the Inergi service fees.

1.2.2. Corporate Controllers

Corporate Controllers provides leadership and direction regarding all business planning, financial reporting, accounting and internal control policies and procedures to ensure statutory and regulatory compliance and consistency with generally accepted accounting principles.

The function oversees the development of actual and forecast financial information and manages reporting processes to appropriate audiences or stakeholders. This function is also responsible for managing and providing direction to the company with respect to matters of internal control, including Organization Authority Registers, financial policies and procedures and providing leadership regarding compliance with Bill 198 and associated Ontario Securities Commission ("OSC") related rules.

Routine financial services, such as Accounts Payable, Accounts Receivable, Fixed Asset Accounting, General Accounting, Planning Budgeting and Reporting support, Pension support and a number of administrative procedures are outsourced to Inergi. These services are a major portion of the Corporate Controllers costs.

The total cost of Corporate Controllers activities in 2013 and 2014 are $28.8 million and $28.7 million respectively, of which $16.6 million is allocated to Transmission for each year. From 2011 to 2013, Corporate Controllers costs increase by $1.4 million due to increases in the 2012 and 2013 plan for the assumed placement of 2011 vacancies, partially offset by the negotiated decline in the fees per the Inergi outsourcing contract. In addition, in 2011, certain functions were added to the Corporate Controllers organization compared to the previous transmission rate application EB-2010-0002. These included the addition of HR Pay Services previously included in Human Resources, and the addition of the Program Results functions and Corporate Business Planning functions previously included in the "Business Integration" category from Asset Management. These transfers were made to better align the Finance function within Corporate Controllers.

1.2.3 Corporate Tax

Corporate Tax manages the tax affairs (compliance, audits and planning), for each corporation within the Hydro One group including corporate income taxes, federal and provincial sales taxes, debt retirement charge, payroll and non-resident withholding tax and the employer health tax. Corporate Tax ensures that internal and external tax compliance requirements are met.

The costs associated with Corporate Tax activities are $2.1 million in 2013 and 2014 with approximately $1.0 million charged to Transmission in both years.

1.2.4 Treasury

Treasury total costs are $5.3 million in 2013 and $5.5 million in 2014. Of these amounts, $2.1 million for 2013 and $2.2 million for 2014 represent costs incurred to:

- execute borrowing plans and issue commercial paper and long-term debt;
- ensure compliance with securities regulations, bank and debt covenants;
- manage the company's daily liquidity position, control cash and manage the company's bank accounts;
- settle all transactions and manage the relationship with creditors; and
- communicate with debt investors, banks and credit rating agencies.

The remaining $3.2 million for 2013 and $3.3 million for 2014 include costs incurred in relation to assessment of risk, negotiation and purchase of insurance policies, claims management and settlement. These costs represent the premiums paid for corporate shared services coverage including; third party liability, fiduciary liability, directors and officers insurance. They also include the cost of self-insurance for liability exposures that are either not covered by insurance policies or fall below the specified deductibles.

The cost of other insurance coverage is captured and reported by the lines of business where the coverage is applicable.

Hydro One Transmission Business is allocated $1.85 million of the $3.2 million Treasury budget for 2013 and $1.90 million of the $3.3 million budget for 2014.

Table 4 shows the premium for Hydro One Inc.'s corporate shared services insurance policies and the cost of self insurance for the 2009 to 2014 period. Self insurance costs for the 2013 to 2014 period take into consideration the company's risk exposures, the long-term historical claims experience, the deductible on the liability policies and the costs of insuring the self insured exposures.

Table 4
Hydro One Inc.
Corporate Shared Services Insurance Costs ($ Millions)

	2009	2010	2011	2012	2013	2014
Premiums paid for Corporate Shared Services Insurance Policies *	1.2	1.2	1.2	1.2	1.3	1.3
Self Insurance Cost	1.2	1.1	0.8	1.8	1.9	2.0
Total	**2.4**	**2.3**	**2.0**	**3.1**	**3.2**	**3.3**

Note: * The cost of other insurance coverage is captured and reported by the lines of business where the coverage is applicable.

1.3 Human Resources

The following Table 5 provides a summary of Human Resources costs:

Table 5
Human Resources Function ($ Millions)

Description	Historic			Bridge	Test		TX Allocation	
	2009	**2010**	**2011**	**2012**	**2013**	**2014**	**2013**	**2014**
Total Cost	15.6	16.4	11.0	10.9	10.9	11.2	6.4	6.5

The Human Resources ("HR") function exists to ensure that Hydro One has the policies, systems and programs to attract, manage, engage and retain high performing workforce to deliver the corporate strategy. HR provides consulting, leadership development and recruiting, diversity and resourcing programs, compensation and benefits and labour relations services.

One of the greatest challenges facing Hydro One is in an area where HR will be expected to play a significant role – the dramatic demographic transition that will be occurring in the Hydro One workforce over the next few years. By December 31, 2013, approximately 1,460 Networks staff (transmission and distribution) will be eligible for undiscounted retirement. By December 31, 2014, approximately 1,633 Networks staff will be eligible for undiscounted retirement. HR also partners with universities, colleges, trade schools and high schools to promote the development of the skill base and expertise required by Hydro One and the electricity sector in general.

The total costs for 2013 and 2014 are $10.9 million and $11.2 million respectively with $6.4 million and $6.5 million allocated to Transmission. HR costs remain relatively stable throughout the bridge and test years, with a decrease shown in historical year 2011 due to the transfer of the HR Pay Services function into the more appropriately aligned Finance function and other administrative savings.

1.3.1 HR Consulting

Hydro One's HR Consultants provide advice and guidance to managers, supervisors, and employees on a myriad of issues related to HR policies and procedures, collective agreement administration, staffing and other large initiatives that impact staff. Alongside the Generalist consulting group, Hydro One HR contains a number of smaller 'specialist' support/service activities. The Pension and Benefits Section administers the Hydro One Pension Plan for approximately 7,100 pensioners. In addition, this section also administers the benefits programs for all employee groups.

1.3.2 Leadership Development and Recruiting

This function recommends and administers policy in areas related to external hiring and leadership development; in addition it manages all of Hydro One's management/leadership development activities including assessment of high-potential succession candidates and miscellaneous specialized one-off hiring initiatives, as required.

1.3.3 Diversity & Resourcing Programs

This function manages Hydro One's principal[1] cyclical hiring and on-boarding processes - the New Graduate, the Co-Op Student, Internship and Developmental Student programs, and the Summer Student Hiring program. Additionally, the unit is accountable for managing Hydro One's Two-year New Grad Training and development Program and implementing Hydro One's Diversity Plan which includes Aboriginal recruitment and the Women in Leadership program.

1.3.4 Compensation & Benefits

Compensation and Benefits provides administration of the Pension Plan as it is a key compensation item for our employees and a critical income stream for our pensioners.

Compensation and Benefits also provides regular strategic reporting of HR and Pay data for Senior Management in such areas as retirement demographics, headcount, overtime reports, data for OEB submissions, etc., as well as participating in industry wide compensation, benefit and pension surveys. The same group also manages the Short Term Incentive Plan for Management Compensation Plan staff.

[1] Trades staff are hired through the Power Workers' Union Hiring Hall processes.

1.3.5 Labour Relations

Labour Relations exists to provide advice, guidance and training to managers regarding collective agreements and labour legislation and manages the grievance and arbitration process. There are 24 collective agreements plus midterm agreements and letters of understanding that bind the company. Labour Relations is responsible for negotiating and administering all the collective agreements, midterm agreements and letters of understanding that bind the company. In addition, the company must comply with legislation such as the Ontario Labour Relations Act, the Employment Standards Act, the Human Rights Code, etc, all of which require interpretation and advice to Managers.

1.3.6 Human Resources Productivity Initiatives

Continuous improvement is a core value at Hydro One. Within the Human Resources function there have been a number of initiatives to enhance productivity:

- In 2011, the production of all job offers was centralized. Previously, hiring managers or administrative assistants throughout the organization would complete job offers. With this one centralized resource dedicated to all job offer letters, the error rate has dropped by 96%. As well, managers are now able to spend time on less administrative tasks.
- Human Resources introduced an online version of the Employee Benefits Information Report. This initiative resulted in a 75% reduction in FTE hours in producing this annual report as well as substantial reduction in printing costs.
- Pensioner records have now been digitalized with a resulting 90% reduction in direct costs.
- Human Resources will be launching new ‘smart forms” in 2012 which will enable single entry of data which will result in improved accuracy and reduction in

processing time. It is anticipated that the use of smart forms will ultimately result in a reduction in Inergi pay contract costs.

- The introduction of SAP has enabled the production of self service business intelligence (BI) reports. The BI reports provide managers with better data to manage their business.

1.4 Corporate Communications

The following Table 6 provides a summary of Corporate Communications costs:

Table 6
Corporate Communications Function ($ Millions)

Description	Historic			Bridge	Test		TX Allocation	
	2009	2010	2011	2012	2013	2014	2013	2014
Total Cost	8.9	9.6	8.7	9.1	11.4	12.6	5.3	5.7

This function comprises Corporate Communications, First Nations and Métis Relations and Outsourcing Services. The increase in costs from historical through bridge years is reflective of the activities in the First Nations and Métis Relations and Corporate Communications programs. First Nations and Métis Relations programs sustain long-term relationship building and negotiations with First Nations and Métis communities and are impacted by the growth of Hydro One core SDO work programs. This trend continues throughout the test years 2013 and 2014. Corporate Communications programs are targeting improvements in customer communications regarding power outages and operational issues affecting their service.

1.4.1 Corporate Communications

Corporate Communications is responsible for managing all communications initiatives for the corporation. Services are provided in respect of communications strategy; media and public relations; issues management; public affairs, community and government relations; corporate reputation; customer communications; advertising, graphic design; writing; employee communications; public consultation; and internet/intranet communications.

In 2010 Corporate Communications implemented a program to improve customers' understanding of power services and conservation opportunities, causing an increase in costs relative to 2009 and 2011. In 2012 costs are planned to increase as a new program is implemented to improve customer communications regarding power outages and operational issues and planned customer support system changes. Effective communication with customers on these matters is considered essential as Hydro One addresses its aging asset base and modernizes the applications that customers use for billing and customer service support.

1.4.2 First Nations and Métis Relations

Another important role that falls within the Corporate Communications function is First Nations and Métis Relations. Hydro One owns assets on reserve lands and within the traditional territories of First Nations & Métis Peoples. Hydro One recognizes that First Nation's peoples and their lands are unique in Canada, with distinct legal, historical and cultural significance. Forging relationships with First Nation communities based upon mutual respect, trust, confidence, and accountability is vital to achieving our corporate objectives. The First Nations and Métis Relations group encompasses the following functions:

- Develop, maintain and ensure implementation of Hydro One's First Nations and Métis Relations Policy;
- Build positive, mutually beneficial relationships with First Nations & Métis communities;
- Ensure Hydro One employees understand the unique legal, historical and cultural significance of First Nations and Métis peoples, for the purpose of promoting effective relationships;
- Provide strategic advice to Hydro One's lines of business vis a vis First Nations and Métis Relations;
- Ensure appropriate participation/communication with government, industry, First Nations and Métis provincial territorial organizations vis a vis First Nations and Métis Communities;
- Monitors jurisprudence which may impact on relationships and negotiations with First Nations & Métis communities;
- Where appropriate, undertake, together with the Crown, consultation with First Nations and Métis people and communities in the early stages of, and throughout, major project development;
- Supports procurement opportunities for qualified First Nations & Métis citizens and businesses; and
- Develops, in conjunction with the Human Resources and Labour Relations departments, a strategy and implementation plan to enhance the level of First Nations & Métis employment at Hydro One.

First Nations and Métis Relations costs are $2.6 million in 2013 and $2.6 million in 2014 of which $1.5 million is allocated to Transmission in both years. The increase in costs in 2013 and 2014 is required to sustain long-term relationship building, consultation processes and negotiations with First Nations and Métis as a result of the growth of the Hydro One core SDO work programs. Costs dropped from 2010 to 2011 due to the reduction in the number of projects that were originally forecast for 2011 in the previous transmission filing EB-2010-0002.

1.4.3 Outsourcing Services

Outsourcing Services manages the overall business relationship between Hydro One and Inergi LP. Outsourcing Services develops and implements best practice governance processes in order to maximize the value of the existing relationship with Service Provider(s) to the benefit of Hydro One. Outsourcing Services is responsible for the design, development, and implementation of new service delivery agreements with Hydro One's Outsourcing Service suppliers. Department costs are $1.9 million in 2013 and $2.7 million in 2014 of which $1.0 million and $1.3 million are allocated to Transmission in 2013 and 2014. Costs in 2011 dropped after the completion of the extended agreement as consultant costs associated with the negotiations were no longer necessary. Costs are expected to go up slightly in 2012 to account for the execution of a benchmarking study to ensure that costs of the overall Inergi contract are market comparable. Costs are expected to stay flat in 2013 as the company prepares for the sourcing exercises in 2014 and 2015 around the expiration of the current contract. The increase in 2014 is primarily due to anticipated consultant expenses associated with the end of term strategy, again associated with the expiry of the current contract in 2015.

1.5 General Counsel and Secretariat

The following Table 7 provides a summary of the costs of the General Counsel and Secretary function:

Table 7
General Counsel and Secretary Function ($ Millions)

Description	Historic			Bridge	Test		TX Allocation	
	2009	2010	2011	2012	2013	2014	2013	2014
Total Cost	6.6	7.5	7.4	8.7	8.9	9.1	4.7	4.8

1.5.1 Overview

The offices of the General Counsel and Secretary ("GC&S") provide legal advice and direction to Hydro One and its operating subsidiaries, as well as overall guidance in the areas of corporate structure, governance, business ethics and the business code of conduct. The GC&S function consists of two main functions: Law and the Corporate Secretariat. The Corporate Secretariat reports to the General Counsel.

The GC&S functions in Hydro One Networks Inc. consist of:

- Provision of legal services to all business units including the Company's major borrowing and financing initiatives, regulatory activities, distribution and transmission businesses (contracts, other commercial matters), employment, including pension and benefits, health, safety and environment, litigation, all Board of Directors related activities, and arranging for the provision of legal services to the Corporation. The volume of these services is driven by capital and OM&A activities, as well as increasing regulatory and legislative oversight functions.
- Overseeing the Law and Corporate Secretariat functions.
- Ensuring compliance with legal and regulatory requirements.

Hydro One does most of its legal work in-house, except when the in-house expertise is not available (for example, tax, labour) or when the workload exceeds the capacity of the internal legal group.

The increase in costs for General Counsel and Corporate Secretariat in 2011 through to 2014 as compared to 2009 is driven mainly by increased work requirements related to the GEA, employment matters and the Records Management project. Examples of the additional workload include, more procurement related work due to the larger work program, review of legal agreements associated with distributed generation and real estate related legal work to obtain land and land rights for new development projects.

1.5.2 Law

Law provides legal advice to all business units of the Corporation, acting as an internal "law firm" for the corporation. It advises on most aspects of law affecting the corporation, and relies on its experience and knowledge of the Company's business in providing economic and timely advice. The Law function maintains core knowledge of the law and the Company's business.

1.5.3 Corporate Secretariat

The Corporate Secretariat provides support to the Office of the Chair, the Board of Directors and its Committees, including the administrative aspects of the Board and its meetings. It provides advice and analysis with regard to a variety of board-related matters, including corporate governance best practices and emerging trends and issues. It provides advice and direction with regard to the business Code of Conduct, ensuring appropriate actions to resolve known or suspected violations. This group also has responsibility for Community Citizenship initiatives advising the Corporation on compliance with privacy legislation, and administering requests for information under the Freedom of Information and Protection of Privacy Act.

1.6 Regulatory Affairs

Table 8 provides a summary of Regulatory Affairs costs:

Table 8
Regulatory Affairs Function ($ Millions)

Description	Historic			Bridge	Test		TX Allocation	
	2009	2010	2011	2012	2013	2014	2013	2014
Regulatory Affairs	9.3	10.0	9.1	7.5	7.6	8.2	3.6	3.8
OEB/NEB Costs	10.2	11.3	11.0	14.9	16.0	14.8	7.9	5.9
Total Cost	**19.5**	**21.3**	**20.1**	**22.4**	**23.6**	**23.0**	**11.5**	**9.7**

1.6.1 Overview

Regulatory Affairs consists of Regulatory Affairs and the Pricing and Load Forecast Management functions. The costs of this function include Hydro One's share of the Ontario Energy Board ("OEB") costs, including the OEB quarterly assessment costs, OEB proceeding-specific costs and OEB-ordered intervener cost awards. OEB and NEB assessed costs are approximately $16.0 million of total 2013 costs and $14.8 million of total 2014 costs. The increase in Regulatory costs from 2011 to 2012 is due to cost related to rate case filings in 2012.

1.6.2 Regulatory Affairs Activities

Regulatory Affairs is responsible for managing the Company's relationships with the regulatory bodies with which it interacts, including the Ontario Energy Board, the IESO, the OPA, and the National Energy Board. Through this function, it is responsible for developing strategy and coordinating the Company's submissions to these bodies and participation in regulatory initiatives such as the development of the Distribution System Code ("DSC").

Regulatory Affairs is involved in the coordination, preparation and processing of applications, as well as providing support to witnesses and business support staff. Such proceeding-specific services are provided for a wide range of applications, including distribution and transmission rates, transmission leaves–to-construct, merger/ acquisition/ amalgamation/ divestiture applications and area and system supply planning. In addition to proceeding-specific work, Regulatory Affairs is responsible for a variety of ongoing reporting and other activities. The function prepares quarterly and annual reports required under OEB Reporting and Record-keeping Requirements. Work includes meeting, reporting on, and responding to Regulatory Compliance Issues. Pricing and cost allocation analysis and support are also provided within Regulatory Affairs for rate applications. This includes development of rate structures and rates for the regulated transmission and distribution tariffs applicable to the company and provides support in submitting and defending rate proposals. The function also assists with the implementation of approved transmission and distribution rates.

Load Forecasting and Load Data Management units are included within the Regulatory Affairs group. Load Forecasts are developed to enable system planning and financial planning which underlie the company's financial forecasts. The Load Forecast function provides load forecast data including the capture of CDM impacts. Load Forecast staff support Hydro One Networks business units and the OPA with forecasting analysis and evaluation covering time of use, bypass and embedded generation. Load Data Management provides analytical support for conservation and demand management projects and provides load research analysis.

Regulatory costs in 2012 through 2014 are being driven by an extremely aggressive regulatory program including transmission and distribution rate applications for 2013-2014. Moreover, costs that have been reported as regulatory affairs costs, such as intervenor cost awards and proceeding specific costs, are now more appropriately reflected in OEB/NEB costs accordingly thus the increase in OEB/NEB costs and the corresponding decrease in regulatory affairs costs from 2012 onward.

The OEB is continuing a busy and challenging program of reviews and initiatives, most of which involve Hydro One. In 2011 the Board began conducting several generic proceedings on issues such as:

1. Consultation on a Renewed Regulatory Framework for Electricity;
2. Consultation on Regional Planning for Electricity Infrastructure;
3. Developing system reliability standards for distributors;
4. Developing Guidance for the Implementation of Smart Grid in Ontario; and
5. Transmission Infrastructure: East-West Tie Line.

1.6.3 Ontario Energy Board Costs

Under the *Ontario Energy Board Act, 1988*, the Ontario Energy Board is required to recover all of its annual operating costs. Almost all of its costs are recovered from gas and electricity distributors and electricity transmitters. A small fraction of OEB costs are recovered from the IESO, the OPA, OPG and from licensing fees and penalties. OEB costs that are subject to recovery include its staff costs, office space costs, administration costs and overheads. These costs are allocated to one of six categories – electricity distribution, electricity transmission, gas distribution, IESO, OPA and OPG. Hydro One Networks' allocation arises from OEB costs related to electricity distribution and transmission.

1.7 Security Management

Table 9 lists the associated costs for Security Management program.

Table 9
Security Management
($ Millions)

Description	Historic			Bridge	Test		TX Allocation	
	2009	2010	2011	2012	2013	2014	2013	2014
Security Management	2.1	2.4	3.0	3.7	3.8	3.9	1.8	1.8
Total	**2.1**	**2.4**	**3.0**	**3.7**	**3.8**	**3.9**	**1.8**	**1.8**

1.7.1 Security Management

Security Management function (formerly referred to as Corporate Security Services) exists to enable the success of Hydro One primarily in the protection of assets (assets include people, property and information), development and maintenance of Business Continuity and Emergency Preparedness & Response Plans and assisting in the reliable delivery of electricity. Security Management adds value by providing advice, coordination, guidance, investigative, technical and intelligence gathering expertise and services to managers (and on their behalf, to employees) which support and optimize the reliable delivery of electricity, the protection of Hydro One assets and business resumption in the event of an all hazards (natural, technological or human-caused) incident. Effective asset protection and recovery can be the primary differentiating factor between success and failure for critical infrastructure organizations such as Hydro One. This is achieved by effective corporate security policies, directives, guidelines and services, which can significantly enhance employee and business productivity and safety.

The increase in costs from 2011 to 2012 through 2014 is a result of an increased focus on a variety of mitigating strategies to reduce the impact of metal theft (primarily copper) that threaten the reliability of the transmission system and the safety and security of staff, first responders and the general public.

The total costs in 2013 and 2014 are $3.8 million and $3.9 million respectively of which $1.8 million is allocated to Transmission in both 2013 and 2014. Incidents of copper theft dropped in 2010 due in part to adding security protection systems at heavily targeted transmission sites. However incidents were on the rise again in 2011, primarily targeting stations that do not have increased capital expenditures for protection systems. In the last decade there has been a dramatic increase in the focus on the protection of critical infrastructure and the industries that comprise these key social, safety and security functions due to the recognition of the criticality for electricity delivery assets and global and domestic terrorist activities coupled with the rise in copper theft and illegal activities that theft of electricity supports.

1.8 Internal Audit and Risk Management

The following Table 10 provides a summary of Internal Audit and Risk Management costs:

Table 10
Internal Audit and Risk Management Function ($ Millions)

Description	Historic			Bridge	Test		TX Allocation	
	2009	2010	2011	2012	2013	2014	2013	2014
Total Cost	**2.7**	**2.8**	**3.1**	**4.2**	**4.3**	**4.4**	**2.5**	**2.6**

Internal Audit reports to the CEO and the Audit and Finance Committee of the Board of Directors. It is an independent, objective, assurance and consulting activity designed to add value to and improve Hydro One's operations. The mandate for Internal Audit is to provide independent assurance to the CEO and Board that internal controls are adequate in areas of high risk and to follow-up and report on management actions to address findings from past audits.

The Corporate Risk Management function supports the CEO by:

- developing business risk management policies, frameworks and processes;
- introducing and promoting new techniques for assisting management to identify and evaluate risks within their operations;
- preparing corporate risk assessments; and
- maintaining a framework of key business risks.

The department helps the Company accomplish its objectives by bringing a systematic and disciplined approach to evaluating and improving the effectiveness of risk management, internal control and governance processes.

The increase in Internal Audit cost from 2011 to 2012 is driven by the increased work planned for safety and environment compliance audits. As part of the corporate strategy to move towards ISO 14001 and OHSAS 18001 quality and certification of our environmental and safety systems, our internal audit group has undertaken to implement a program of comprehensive compliance audits for these two key areas.

The total costs for this function in 2013 and 2014 are $4.3 million and $4.4 million, respectively, of which $2.5 million and $2.6 million is allocated to Transmission in 2013 and 2014 respectively.

1.9 Real Estate and Facilities

Table 11 provides a summary of Real Estate & Facilities costs:

Table 11
Real Estate & Facilities Function ($ Millions)

	Historic			Bridge	Test		TX Allocation	
	2009	**2010**	**2011**	**2012**	**2013**	**2014**	**2013**	**2014**
Real Estate	7.9	8.6	9.3	9.8	10.0	10.3	8.2	8.4
Facilities	42.7	41.3	42.3	50.4	52.4	54.0	23.6	24.3
Total Costs	**50.6**	**49.9**	**51.5**	**60.2**	**62.4**	**64.3**	**31.8**	**32.7**

1.9.1 Overview

The total cost for the Facilities and Real Estate function in 2013 is $62.4 million, with $31.8 million allocated to Transmission. The 2014 cost is $64.3 million, with $32.7 million of that allocated to Transmission.

The 2013 and 2014 funding is required for the expanded facilities work program that responds to current and future anticipated Company work space accommodation needs. This includes new facilities in the field. The facilities work program accounts for approximately 84% of total funding in test years 2013 and 2014.

The delta change in funding requirements in bridge year 2012 and test years 2013 and 2014 is mainly driven due to incremental increase of space in the field as result of new facilities and building additions being put in service providing for replacement facilities due to end of life, new and additional facilities to meet accommodation needs in terms of Company work program and operating requirements (which includes housing specialized work equipment). The change in funding requirements in bridge year 2012 and test years

2013 and 2014 is also contributed by planned office improvements, which are expected to result in additional swing space and office moves costs during bridge year 2012 and test years 2013 and 2014. The funding requirements in bridge year and test years takes also into consideration corporate health and safety initiatives and expected increases in fixed operating costs.

1.9.2 Real Estate Services ("RES")

Real Estate Services manages Hydro One's land rights portfolio across the Province. This involves ensuring that rights across over 200,000 acres of owned corridor, easement and "statutory right" properties are maintained, and that new rights are acquired as necessary to ensure the safe and reliable operation of the transmission system. In addition, Real Estate oversees the management of Hydro One's rights associated with distribution and transmission lands, stations and other property.

Key work activities include:

- Managing acquisition of new real estate rights. This includes Company transmission development and reinforcement project initiatives across the Province including enabling transmission for renewable power sources;
- Managing the Provincial secondary land use program on behalf of MEI/ORC e.g. leasing transmission corridor lands to external parties;
- Managing easement, other rights agreements on public/private sector, railway and other lands;
- Managing First Nations land use permit settlements on reserve lands;
- Managing about 500,000 unregistered, low-voltage, real estate rights agreements;
- Providing specialized real estate service activities including managing property tax payments to municipalities, appealing property tax assessments, and providing employee relocation services; and

- Maintenance of Geographic Information System (GIS) – property record database.

More specific support is provided on a selected project basis. This includes provision of land ownership information, damage claim settlement, road access and other rights acquisitions.

Specialized real estate services are provided as necessary. This includes assessment appeals, payment of property taxes on lands/buildings, and employee relocation services as appropriate.

1.9.3 Facilities

The Facilities work program includes all aspects of company work space requirements which comprise not only company-owned facilities, but management of the portfolio of leased facilities and oversight of the construction of new facilities. The Facilities function manages all of the building and site facilities across the Company. This includes leasing costs and contract management for head office. In addition, it includes costs for administrative facilities, service centres, and other work locations (for example, the London Call Centre). The Facilities organization is responsible to ensure program delivery in terms of service levels, planned capital improvements and providing for Company accommodation needs.

The Facilities program focuses on providing employee workspace at sites across the province including head office, administrative and service centres, the OGCC, and other work locations (for example, the London Call Centre).

Providing adequate workspace, storage and garage facilities for employees and trades is critical to the effective undertaking of organizational work programs. Equally important is ensuring that new or existing employee workspaces are consistently maintained to a standard that meets current work requirements and complies with all corporate, legislative and other related health, safety and environmental standards.

This Program includes:

- Providing accommodation strategies and acquiring new employee / trades workspace in line with operational requirements;
- Management of 46 contract lease agreements for workspace rented from other parties, including renewals and contractual obligations undertaken regarding payment of rent, operating expenses and taxes;
- Coordination of activities related to the ongoing management, operation, maintenance and inspection of 91 Administrative/Service Centres and Ontario Grid Control Centre;
- Provision of support services for Head Office space, such as provision of office supplies and equipment, coordination of office moves, records management and tenant services.

The facilities costs are largely driven by space (including workspace and housing space for material and work equipment) provided which is affected by company work programs and factors such as changing business and operating requirements and fixed cost contractual obligations. Also, the current regulatory environment (including health and safety requirements) ultimately impacts operating costs. Accommodation needs are influenced by the development and growth of Company work programs and initiatives.

The majority of facilities work program costs are fixed. The Facilities work program is extensively driven by fixed-cost contractual obligations which arise primarily through relationships with external landlords. For example, rent, operating and tax costs are specified in formal lease agreements and opportunities to significantly amend these set costs typically do not materialize until the agreement expires. Other fixed costs are represented by negotiated contracts with internal and external service providers for base level facility maintenance (for example, administrative/service centre building maintenance, janitorial and snow removal, minor repairs, building component inspections) and similar activities. These contracts focus on maintaining facilities in a condition that meets current employee work requirements and corporate/legislative requirements. Fixed facility cost components (for example, utilities, property taxes, operational costs) are expected to continue to rise. The 2013 and 2014 test year funding also takes into consideration changing factors in the operating environment.

2.0 OTHER OM&A

Other OM&A is comprised of Capitalized Overhead, Environmental Provisions, Indirect Depreciation and Other Costs as listed in Table 12.

Table 12
Total Transmission Other OM&A ($ Millions)

Description	Historic			Bridge	Test	
	2009	2010	2011	2012	2013	2013
Capitalized Overhead	(94.7)	(108.2)	(105.5)	(112.6)	(113.8)	(114.3)
Environmental Provision	(2.5)	(6.5)	(6.9)	(6.2)	(6.1)	(6.9)
Indirect Depreciation	(5.3)	(4.6)	(5.4)	(5.9)	(6.2)	(6.4)
Other	(14.3)*	14.1	(6.2)	(3.5)	(1.7)	(1.6)
Total	(116.8)	(105.2)	(124.0)	(128.2)	(127.8)	(129.2)

* Previously ($12.2 M) in EB-2010-0002. Updated historic actuals for insurance adjustment.

2.1 Capitalized Overhead Credit

Table 13
Transmission Corporate Overhead Credit ($ Millions)

Description	Historic			Bridge	Test	
	2009	2010	2011	2012	2013	2014
Transmission	**(94.7)**	**(108.2)**	**(105.5)**	**(112.6)**	**(113.8)**	**(114.3)**

Capitalized overheads represent that portion of allocated shared corporate and/or business unit functions and services that are deemed through the capital overhead rate to be supportive of Capital projects as opposed to OM&A based projects. These costs are included in shared services and in the lines of businesses. The capital overhead rate determines the costs capitalized. OM&A expense is thus reduced by the capitalized amounts.

The capitalized OM&A costs are distributed to Capital projects based on the allocation methodology derived through the accepted Black & Veatch study (See Exhibit C1, Tab 7, Schedule 1).

2.2 Environmental Provision

Table 14
Transmission Environmental Provision ($ Millions)

Description	Historic			Bridge	Test	
	2009	2010	2011	2012	2013	2014
Transmission	**(2.5)**	**(6.5)**	**(6.9)**	**(6.2)**	**(6.1)**	**(6.9)**

In 2001, Networks business recognized a liability on its balance sheet for the present value of future estimated environmental expenditures necessary to deal with legacy contaminated lands and the implementation of remedial measures to treat, remove or otherwise manage the contamination. The change in accounting policy from the previous as-incurred basis was adopted to align with the theoretically stronger U.S. generally accepted accounting principle that was expected to be imminent in Canada. Environmental work is initially recognized in the sustaining work program. The amount is then removed from OM&A and the liability / provision is amortized by the amount of the expenditures incurred. The resultant impact on OM&A expense of this environmental work is nil, since the amortization expense is grouped with 'Depreciation and Amortization' on the operating statement and the balance is transferred from OM&A to Depreciation expense.

2.3 Indirect Depreciation

Table 15
Transmission Indirect Depreciation ($ Millions)

Description	Historic			Bridge	Test	
	2009	2010	2011	2012	2013	2014
Transmission	**(5.3)**	**(4.6)**	**(5.4)**	**(5.9)**	**(6.2)**	**(6.4)**

Transportation and Work Equipment ("TWE") charges in the OM&A work programs include depreciation expense associated with the asset being used. For accounting classification purposes it is necessary to remove this depreciation amount from OM&A and appropriately charge it to Depreciation Expense.

2.4 Other

Table 16
Transmission Other Costs ($ Millions)

Description	Historic			Bridge	Test	
	2009	2010	2011	2012	2013	2014
Transmission	**(14.3)**	**14.1**	**(6.2)**	**(3.5)**	**(1.7)**	**(1.6)**

These costs represent material unexpected or non-recurring expenses. For example they include items such as insurance rebates, adjustments to provisions, vacation reserves, Gregorian or fiscal adjustments and inventory adjustments.

SHARED SERVICES OM&A - ASSET MANAGEMENT

1.0 OVERVIEW

The Transmission and Distribution businesses are operated using the Asset Management model, which the company adopted in 1998. The model separates the asset management functions of planning, decision-making, and approvals from the services functions of engineering, construction, and customer and grid operations, which execute approved plans. The functional areas work collaboratively in order to achieve corporate strategic objectives. This separation of functions is a common industry practice in today's utilities and reflects the different skills required by each functional area. By applying this model, Hydro One Networks Inc. can make management decisions involving customer and asset requirements on a consistent basis across its entire service territory. The Asset Management model is further discussed in Exhibit A, Tab 4, Schedule 1.

The Asset Management organization remains focused on ensuring and demonstrating that the necessary transmission and distribution assets are planned, acquired, constructed, maintained and operated such that they deliver the required function and level of performance expected by customers in a sustainable manner over the long term. Asset Management balances the needs of customers, various economic and regulatory bodies, the company's assets and systems, the shareholder, and the people of Ontario in delivering on the following accountabilities:

- Developing, integrating, and implementing asset strategies, long-term perspectives and investment plans to support corporate objectives, to execute OPA programs *(e.g. Integrated Power System Plan, Feed In Tariff (FIT) and Micro-FIT Programs*), and to fulfill government policy (e.g. *Green Energy and Green Economy Act, 2009, Ontario's Long Term Energy Plan*);

- Developing investment plans for the sustainment, development and operation of the Distribution and Transmission systems consistent with good asset stewardship practices;
- Interfacing and collaborating with external governmental, regulatory and planning authorities on matters of planning direction, requirements, policy and guidance, and integrating such into the investment plans
- Identifying, scoping and obtaining approval for specific projects and programs in support of approved investment plans;
- Engaging work execution lines of business to effectively undertake the programs and projects of the approved investment plan;
- Optimizing the release, bundling and sequencing of the work to ensure the effective delivery of the programs and projects within the plan;
- Redirecting projects and programs in response to new or unforeseen factors (e.g. major storms) and drivers;
- Monitoring, evaluating and reporting upon the progress, accomplishments and cost metrics of the various programs and projects;
- Monitoring, managing and demonstrating operating regulatory compliance (IESO/NERC/NPCC);
- Pursuing initiatives to improve the Asset Management information, reporting, analytics, processes and training that are required to support asset lifecycle planning decisions, business planning processes, rate filings, regulatory compliance and work execution;
- Pursuing business and industry development opportunities and productivity improvement initiatives;
- Influencing the business and regulatory environment to ensure customer needs and business objectives (safety, regulatory compliance, environmental performance, etc.) are met in an effective and efficient manner; and

- Collaborating with various industry, research and academic groups and association to advance utility practices (e.g. asset analytics) and technologies (e.g. energy storage), and to evaluate and address new industry drivers (e.g. plug-in electric vehicles).

Effective delivery of these accountabilities is key to the Company's success in achieving the balance noted above.

The cost profile for Asset Management is presented in Table 1 below.

Table 1
Asset Management Function ($ Millions)

Function/Service	Historic			Bridge	Test		TX Allocation	
	2009	2010	2011	2012	2013	2014	2013	2014
System Investment	32.8	37.7	37.0	43.0	41.8	42.0	25.6	26.9
Business Performance	20.5	13.8	16.1	15.3	15.4	15.3	7.4	7.4
Asset Strategies	3.7	7.4	6.5	5.9	5.3	5.4	2.7	2.8
Total Costs	**56.9**	**58.9**	**59.6**	**64.2**	**62.5**	**62.7**	**35.8**	**37.1**

As shown in Table 1, the cost associated with achieving Asset Management work in 2013 is $62.5 million, and $62.7 million in 2014. The portion of the total cost attributable to the Transmission business is $35.8 million in 2013, and $37.1 million in 2014. Refer to Exhibit C1, Tab 7, Schedule 1 for further details on the percentages used to allocate costs into Transmission and Distribution components.

The primary focus of Asset Management is on core work programs, with overarching initiatives that adapt the business to changing industry and regulatory standards, government policy, and an aging workforce and asset base. These initiatives have notable resource demands, and must therefore be strategically rolled-out to balance cost-effective and reliable electricity supply with efforts to improve, modernize, and address aging infrastructure. The overall resource strategy has therefore needed to target flexibility and adaptability so that costs, core work program impacts, and long term workforce capacity can be appropriately managed.

Major Overarching Cost Drivers:

Aging Assets and Increasing Complexity*:* Asset Management resources must manage the increasing complexities that result as large portions of Hydro One's asset fleet reach the end of their expected service lives and the transmission and distribution systems are further adapted to accommodate distributed generation. These complexities particularly impact the System Investment activities of replacement planning and decision making, evaluating modern technological developments, adapting to regulatory change, and strategies for enhancing performance. In addition, Asset Strategy and System Investment are currently undertaking enhancements in Hydro One's asset analytics and integrated planning capability to meet the increased demands of an aging asset base.

Aging Workforce: The bow-wave of end-of-life replacements that is expected in the next ten years, the increasingly stringent reliability compliance standards, and the opportunities for technological modernization have resulted in a need to augment staff resources and expertise in the System Investment area. However, this is complicated by the significant loss of experience that will result from the large portion of the workforce that is approaching retirement. The need for structured information transfer is particularly acute because our demographic composition involves marked segmentation between staff that have more than 20 years of experience, and staff with less than 5 years of experience. This experience gap drives the need for a period of overlap between the staff approaching retirement and staff that are intended to take over their workloads once they retire. Protection and Control staff for instance, require 7-12 years of development after graduation and therefore some hiring must occur in advance of the expected retirement dates to allow time for experience-building and knowledge transfer from current employees.

The 2013 and 2014 costs for Business Performance and Asset Strategy have begun to reflect the impacts of retirements, whereas for System Investment, the increased work demands associated with asset aging and the demographic management demands associated with workforce aging have offset any of the cost reductions brought about by retirements.

FIT and Micro-FIT: The decline in System Investment costs between 2012 and 2013 reflect assumptions regarding the OPA's timelines and program complexities, impacting the estimated need for non-permanent resources to support the FIT and Micro-FIT programs.

The historic reduction in Business Performance costs and the increase in Asset Strategy costs between 2009 and 2010 reflect a shift in resources across organizational units.

Asset Management Re-alignment (2010 to 2011)

In the current application, some of the functions in the Asset Management have been re-aligned compared to the previous transmission rate application EB-2010-0002. The financial changes in this application are outlined in Table 2 below:

Table 2

	Historic Plan	Historic Plan	Historic Plan	Bridge Plan
	2009	**2010**	**2011**	**2012**
Asset Management OM&A in EB-2010-0002	**59.4**	**69.7**	**74.9**	**75.8**
Minus:				
Business Transformation (1)	(1.9)	(2.1)	(2.4)	(2.9)
Strategy & Conservation (2)	(0.9)	(3.1)	(4.5)	(4.6)
Transfers in/out of Asset Management (3)	0.3	(5.9)	(4.5)	0.2
Asset Management Cost Reductions (4)		0.3	(3.9)	(4.3)
Asset Management OMA in this Application	**56.9**	**58.9**	**59.6**	**64.2**

(1) Business Transformation cost for the historic, bridge and test years was moved to Shared Services - Information Technology, see Exhibit C1, Tab 4, Schedule 4.

(2) Strategy & Conservation cost for the historic, bridge and test years was moved to Shared Services- Customer Care, see Exhibit C1, Tab 3, Schedule 5. In EB-2010-002 this was contained in the “Strategy & Business Development” category.

(3) These costs for the bridge and test years have moved in/out of the following:
   a. Program Results functions previously included in the “Business Integration” category have moved to Shared Services- Common Corporate Functions and Services & Other OM&A, see Exhibit C1, Tab 4, Schedule 2.
   b. Information System Support functions previously included in the “Business Integration” category have moved to Shared Services - Information Technology, see Exhibit C1, Tab 4, Schedule 4.
   c. Corporate Business Planning functions previously included in the “Business Integration” category was moved to Shared Services- Common Corporate Functions and Services & Other OM&A, see Exhibit C1, Tab 4, Schedule 2.
   d. Major Project Coordination functions previously included in Corporate Communications are now included in the “System Investment” as part of the Transmission Projects Development function.

(4) The cost reductions in Asset Management of $3.9 million in 2011 and $4.3 million in 2012 represent shifts in the timing of hires to later years in accordance with the demands of the sustainment, development, and operations work programs.

2.0 SYSTEM INVESTMENT

The following Table 3 provides a summary of System Investment costs:

Table 3
System Investment Function ($ Millions)

	Historic			Bridge	Test		TX Allocation	
	2009	**2010**	**2011**	**2012**	**2013**	**2014**	**2013**	**2014**
Total Costs	32.8	37.7	37.0	43.0	**41.8**	**42.0**	**25.6**	**26.9**

2.1 Overview

System Investment develops and scopes transmission and distribution plans to address equipment performance, system reliability, system capacity, system capabilities, compliance obligations, customer requests, as well as OPA and Government initiatives.

The total cost in 2013 for this function is $41.8 million, with $25.6 million allocated to Transmission and the cost for 2014 is $42.0 million, with $26.9 million allocated to Transmission.

System Investment cost trends are driven by the following:

- Year over year increases predominantly reflect the increasing levels of transmission and distribution capital and OM&A sustainment and development work relating to the refurbishment and replacement of assets to maintain condition and reliability. The resource demands for these functions have intensified in relation to the complexities brought about by an aging asset base and more stringent regulatory compliance requirements and industry standards and codes.
- The step increase in cost from 2011 to 2012 reflects the implementation of a demographic management initiative to address an aging workforce. This initiative involves structured information transfer from highly experienced employees nearing retirement age to newer employees to help mitigate the experience gap that is expected to result as large portions of the workforce retire. The need for this initiative is imminent given the current staff demographics.
- Increased resource demands are also driven by efforts to accommodate distributed generation:
  - Additional preparation of engineering protection and control specifications required to accommodate generators on a distribution system that was primarily designed for load customers;

    - Additional studies to determine the impacts of reverse flow on power equipment, as new local generation may exceed the load on a feeder which will result in power flows in the opposite direction to that designed;
    - Development of P&C standards for transmission and distribution stations, and other controllable elements;
    - An increase in the number of requests for generation applications, requiring connection impact assessments;
    - The need to develop new standards related to configurations or connections to the Transmission and Distribution networks;
    - The need to develop, scope and obtain approvals for distribution plans in response to Government policy decisions related to the province's generation mix, in consultation with the OPA;
- The decrease from 2012 to 2013 reflects assumptions regarding the OPA's FIT and Micro-FIT program timelines and complexities, impacting Hydro One's estimated need for non-permanent resources.

2.2 System Investment Activities

System Investments activities include:

- Developing Transmission and Distribution sustainment, development and operations investment plans consistent with Hydro One's objectives, constraints, strategies, and asset stewardship obligations, and obtaining approvals for such plans;
- Interfacing and collaborating with external governmental, regulatory and planning authorities on matters of planning direction, requirements, policy and guidance, and integrating such into the investment plans;
- Identifying, scoping and obtaining approval for specific projects and programs in support of approved investment plans;

- Engaging with service delivery units to ensure the effective execution of specific projects and programs;
- Analyzing the results of project and program execution and integrating these into future plans;
- Supporting the redirecting and re-prioritizing of projects and programs in response to unforeseen events and work execution opportunities;
- Planning and implementing utility and industry efficiency initiatives (e.g., smart meters, utility rationalization);
- Supporting the development of opportunities to optimize leveraging of Hydro One Networks' assets (e.g. distributed generation connections, secondary land use, and utility boundary adjustments);
- Performing technical studies to assess the viability of proposed connections, alternatives or investment plans;
- Investigating and addressing power system disturbances;
- Conducting various asset and system centered analytics including asset condition assessments in the context of the Reliability Centric Maintenance methodology and integrating the results into specific investment plans;
- Monitoring equipment and network performance and addressing issues as these are identified;
- Establishing performance standards that form the basis for detailed engineering designs;
- Responding to customer requests for new or expanded connections or customer concerns regarding connection security or power quality;
- Advising external agencies and customers of the Transmission and Distribution impacts of their plans;
- Consulting with affected stakeholders regarding new Transmission and Distribution facilities;

- Participating in the development of, and demonstrating compliance with North American or regional reliability standards (e.g. Market Assessment and Compliance Division (MACD) audits);
- Supporting regulatory filings; and
- Specifying technical requirements and work in such areas as new technologies (e.g. smart meters, IEC 61850), animal abatement, transformer refurbishment (core heating) and remote monitoring.

3.0 BUSINESS PERFORMANCE

The following Table 4 provides a summary of Business Performance costs:

Table 4
Business Performance Function ($ Millions)

	Historic			Bridge	Test		TX Allocation	
	2009	**2010**	**2011**	**2012**	**2013**	**2014**	**2013**	**2014**
Total Costs	20.5	13.8	16.1	15.3	**15.4**	**15.3**	**7.4**	**7.4**

3.1 Overview

Business Performance specializes in centralized performance reporting and investment planning coordination in accordance with the Asset Management model. As such, it provides asset stewardship, leadership, and integration of all aspects of Asset Management including investment planning, budgeting, execution planning, work bundling and releasing, monitoring, reporting, and control of the growing capital and OM&A work programs. Included are the functions of performance metrics management, operating compliance management, and process improvement.

Business Performance provides asset stewardship, leadership and integration of all aspects of Asset Management including investment planning, budgeting, execution planning, work bundling and releasing, monitoring, reporting, and control of the growing capital and OM&A work programs. Included are the functions of performance metrics management, operating compliance management and process improvement.

As shown in Table 4, the 2013 cost for this activity is estimated at $15.4 million, with $7.4 million allocated to Transmission, and the 2014 cost is estimated at $15.3 million, with $7.4 million allocated to Transmission.

Also included is funding for property, boiler and machinery insurance costs. The insurance amounts are $3.8 million in 2009, $3.6 million in 2010, $5.0 million in 2011, $5.0 million in 2012, $5.1 million in 2013, and $5.2 million in 2014.

The year over year cost trend from 2012-2014 is predominantly flat. The steady year-over-year trend indicates that assumed cost escalations are being offset by decreases in other base costs. The work undertaken within the Business Performance group is not expected to decline, however there are productivity initiatives underway that are expected to impact the resourcing and demographic management strategy for Business Performance. This strategy seeks opportunities to distribute the workloads of retiring staff among existing staff to mitigate the extent to which it is necessary to backfill for retirements and engage external resources. Given that workloads are not declining, this strategy is contingent on productivity realization, and reflects Hydro One's commitment to deliver value to rate payers.

The decrease in Business Performance spending from 2009 to 2010 must be considered in combination with the increase in Asset Strategy costs, as this reflects realignment of work between these two functions. Refer to section 4.1 for additional description.

3.2 Business Performance Activities

Business Performance Activities include:

- Development and leadership of strategies and plans that support corporate goals related to the Transmission and Distribution businesses;
- Advancing and integrating all Asset Management functions, initiatives, plans, processes and practices in support of overall asset stewardship;
- Evolving and enhancing the implementation of the asset management model;
- Advancing and leading the OM&A and capital Investment Planning process in the development of multi-year Transmission and Distribution Investment Plans;
- Performing business and operating analytics, producing reports and conducting special studies in such areas as reliability metrics, benchmarking, work program performance, productivity and cost savings management in support of Asset Management's asset stewardship role, corporate objectives and regulatory filings;
- Analyzing and managing project and program costs and results and collaborating with service delivery units to ensure targets are achieved;
- Managing the execution planning, work bundling and releasing processes, and redirecting projects and programs in response to unforeseen events and work execution opportunities;
- Managing the Operating Compliance Management function including the Compliance Management System (CMS) and supporting the demonstration of compliance with North American or regional reliability standards (IESO/NERC/NPCC) to external regulatory authorities (e.g. IESO's Market Assessment and Compliance Division (MACD)).
- Managing the business case approval and interim review of variance processes;
- Developing work collaboration tools, systems and processes to drive continuous improvements across the corporation;

- Developing and managing the Asset Management Quality Management System and performing Quality Assurance Reviews;
- Participating in the definition and scoping of cross-functional priority projects, or directly managing and mobilizing resources for large projects (e.g. Advanced Distribution System (ADS));
- Monitoring, evaluating and reporting upon a portfolio of cross-business unit and/or cross-corporate initiatives and projects in support of advancing asset stewardship capabilities and results;
- Ensure an integrated approach to data, systems, and processes as well as contributing to change management within Hydro One.

4.0 ASSET STRATEGY

Table 5 provides a summary of Asset Strategy costs:

Table 5
Asset Strategies Function ($ Millions)

	Historic			Bridge	Test		TX Allocation	
	2009	2010	2011	2012	2013	2014	2013	2014
Total Costs	3.7	7.4	6.5	5.9	**5.3**	**5.4**	**2.7**	**2.8**

Note: formerly Asset Management Processes and Policies

4.1 Overview

Asset Strategy supports asset stewardship by developing and advancing functional, business and technological strategies and plans, long-term transmission and distribution perspectives, as well as detailed policies and standards. This function also leads Asset Management's participation in the various regulatory processes including Transmission and Distribution rate applications and Section 92 Leave to Construct applications. Also included are research and development activities, and liaison with external industry organizations, government agencies and universities.

The total cost in 2013 for this function is $5.3 million, with $2.7 million allocated to Transmission and the cost for 2014 is $5.4 million, with $2.8 million allocated to Transmission.

The year over year trend from 2010-2014 reflects an overall decrease in Asset Strategy costs. As in the case of Business Performance (see Section 3.1), the work undertaken within the Asset Strategy group is not expected to decline. Rather, there are productivity initiatives underway that are expected to impact the resourcing and demographic management strategy for Asset Strategy. This resource strategy seeks opportunities to distribute the workloads of retiring staff among existing staff to mitigate the extent to which it is necessary to backfill for retirements and engage external resources. Given that workloads are not declining, this strategy is contingent on productivity realization, and reflects Hydro One's commitment to deliver value to rate payers.

The increase in Asset Strategy spending from 2009 to 2010 must be considered in combination with the decrease in Business Performance costs, as this reflects realignment of work between these two functions. In particular, the Asset Strategy group consolidated and intensified its focus in the areas of long term strategic planning, which includes strategic planning associated with the Ontario Power Authority's previous Integrated Power System Plan projects, the Government of Ontario's Green Energy Act, and the Long Term Energy Plan. It furthermore includes support for Ontario Energy Board regulatory proceedings, operating reliability compliance requirements, and the management of corporate operational policies.

4.2 Asset Strategy

Asset Strategy activities include:

- Developing and advancing technological, functional and business strategies for Asset Management and Hydro One;
- Providing regulatory support for Asset Management and others in Hydro One including evidence development for regulatory filings, expert witness support, and interrogatory response and undertaking preparation, and through preparing documentation and supporting the Section 92 Leave to Construct process for major transmission projects;
- Developing and advancing asset and business related policies, practices and standards for Asset Management and Hydro One;
- Developing and advancing better approaches and tools in such areas as asset analytics, leading to improved asset sustainment planning approaches;
- Supporting the planning and advancement of the Advanced Distribution System (ADS) initiative, including Hydro One's "Living Lab" in the Owen Sound and Walkerton areas as well as subsequent phases;
- Interfacing and collaborating with governmental agencies such as the OPA, ORF (Ontario Research Fund) and OCE (Ontario Centres of Excellence) on asset management matters, and research and development issues affecting the electricity industry;
- Providing expert participation in, and representing Hydro One's interests on, various national and international industry entities and standard-setting bodies including CIGRE, CEA, CEATI, IEEE, NERC, NPCC, the North American Transmission Forum, NIST, and the IESO. For example, this function participates in reliability standards development and compliance monitoring with NERC and the NPCC, and also represents Canada at the International Electrotechnical Commission (IEC). In addition, this function serves as the transmitter representative on the Independent Electricity System Operator ("IESO") Technical Panel, which reviews and recommends amendments to the Ontario wholesale electricity market rules, and advises the IESO Board of Directors on specific technical issues related to the operation of the Ontario Electricity Market;

- Providing oversight, overall management and subject matter expertise for interpreting, advising upon and demonstrating Hydro One's compliance with North American or regional reliability standards (IESO/NERC/NPCC) to external regulatory authorities (e.g. IESO's MACD) pursuant to Hydro One's license and market rules' obligations;
- Providing the longer-term perspectives for Transmission and Distribution facilities in terms of sustainment, development, and operating work programs;
- Managing or contributing to research and development in such areas as smart grid, electrical vehicles, energy storage and distributed generation, through industry and research organizations (e.g. EPRI and CEATI) and Ontario universities;
- Interfacing and collaborating with Ontario universities on matters of electrical or power-systems engineering;
- Supporting corporate reporting requirements by integrating and assessing reporting inputs from across Hydro One;
- Leading Asset Management's business improvement and employee engagement plans and initiatives; and
- Overseeing the governance of corporate standards and ensure appropriate standards are in place ahead of corporate requirements.

SHARED SERVICES OM&A - INFORMATION TECHNOLOGY

1.0 OVERVIEW

Information Technology ("IT") refers to computer systems (hardware, software and applications), data and voice communication systems that support business processes and allow employees to perform their work.

IT work programs include both OM&A and capital items and involve: the ongoing maintenance and sustainment of existing and newly commissioned applications and technologies; the development and implementation of new technologies or systems; the provision of Business Telecom services; and the overall management and control of the information technology program – including capital projects. IT capital investments are made in accordance with approved business strategies and are described in Exhibit D1, Tab 3, Schedule 6.

OM&A costs associated with supporting Hydro One's information technology assets are shown in Table 1 and are described below.

Table 1
Information Technology Summary of OM&A Expenditures
($ Millions)

Description	Historic			Bridge	Test		TX Allocation	
	2009	**2010**	**2011**	**2012**	**2013**	**2014**	**2013**	**2014**
Sustainment	81.9	84.6	81.7	87.3	86.3	84.2	34.4	33.6
Development	6.6	11.9	11.0	8.2	15.9	14.2	6.9	6.2
Business Telecom	20.8	16.9	18.5	18.0	18.0	17.5	10.4	10.1
IT Management & Project Control	21.3[1]	20.1	19.5	21.0	22.2	22.9	12.4	12.7
Total Cost	**130.6**	**133.5**	**130.7**	**134.5**	**142.4**	**138.8**	**64.1**	**62.6**

[1]Corporate Projects moved to IT from Asset Management at end of 2010

1.1 Sustainment

Sustainment costs are costs to support the Hydro One information technology applications and infrastructure. Some of these costs are paid to Inergi LLP ("Inergi") pursuant to the current outsourcing contract and they decrease from the bridge through the test years. The remaining costs are for third party software/hardware license and maintenance fees.

1.2 Development

The development budget is comprised of application upgrades, enhancements and the OM&A portions of capital projects. The funds are required to maintain the applications at vendor-supported levels and to support enhancements to those applications.

1.3 Business Telecom

Business Telecom costs include data and voice telecommunications and associated maintenance of Hydro One's telecom network. Changes in costs vary with the addition of data and voice telecom capacity at sites throughout the province, and the addition of security-related services for the expanding telecom network.

1.4 IT Management and Project Control

IT Management and Project Control costs relate to IT administration, outsourced services oversight, project governance and reporting, system and security architecture, program and spend coordination, and Quality Assurance ("QA")/Quality Control ("QC") processes.

Technology costs are validated through Hydro One's IT governance process. IT governance looks proactively at IT strategy, project expenditures and service delivery to align technology spend with business and corporate objectives. The IT governance model involves the senior business managers who provide guidance, direction and support to the decision-making for corporate technology decisions.

2.0 IT SUSTAINMENT OM&A

Table 2 shows the specific expenditures for IT sustainment of the Information Technology platform.

Table 2
OM&A Sustainment of Information Technology
($ Millions)

Description	Historic			Bridge	Test		TX Allocation	
	2009	**2010**	**2011**	**2012**	**2013**	**2014**	**2013**	**2014**
Base IT Sustainment Services	63.0	70.9	68.8	71.6	70.8	67.7	28.1	26.9
3rd Party Contracts	18.9	13.7	12.9	15.7	15.5	16.5	6.3	6.7
Total	**81.9**	**84.6**	**81.7**	**87.3**	**86.3**	**84.2**	**34.4**	**33.6**

IT Sustainment work includes: help desk and desk-side support; implementing system and security patches; applying fixes for applications, resolving application problems; decommissioning or installing software applications or equipment; maintaining and operating Hydro One's IT assets located at offices throughout the province and within the data centres; data storage capacity and data storage management; and disaster recovery.

3rd Party Contract costs include amounts which are paid to third parties for software and hardware licenses and annual maintenance fees.

2.1 Base IT Sustainment Services

The term "Base" IT Sustainment Services refers to those IT services outsourced to Inergi and which are scheduled in the negotiated contract

Base IT services are discussed under the four categories below.

Application Maintenance

Application maintenance includes the work to maintain, address and fix matters associated with approximately 855 (year ending 2011) business software applications (this includes core business applications, desktop tools, and specialty software) used by the various business units across the Province. Within these applications there are business critical software used in major functional areas, such as those shown in Table 3, which support business processes across the enterprise.

Based on support levels established by IT and the respective business operations, applications are managed in a problem management framework. Application problems and user inquiries are logged, prioritized, and managed through to resolution.

Table 3
Strategic Information Technology Systems

IT Systems	**Description**
Desktop Applications	These include Microsoft Office XP/2003 and the Windows 7 and Office 2010 platforms (for example, Word, Excel, Access, and PowerPoint), e-mail, Internet browser, and various other applications such as anti-virus and directory functions.
SAP™	This is an integrated Enterprise Resource Planning, Business Intelligence, and Enterprise Asset Management application suite that provides Asset and Work Management, Purchasing and Supply Chain as well as Inventory Management functions. It also provides General Ledger, Accounts Receivable, Fixed Assets, Project Accounting, Payroll, Time Reporting, Reporting, Human Resources and Pension functions.
Customer Information System	The CIS is an application suite providing billing and customer services support through sub-systems of Customer Service System (CSS) and Open Market Systems that interface with a number of other internal and external applications. The CIS application is scheduled for replacement under the Cornerstone Program and will be replaced by a SAP solution in late 2012.
Contact Centre Technology	This suite of applications enables contact centre operators to respond to customers (service requests, billing inquiries, information), including telephony interfaces and call centre technology and provides operators scheduling and service quality-monitoring functions.
Field Design Tool (ArcFM)	This is a geographic application that is used to design and modify customer connections to the electrical distribution system as part of the GIS suite of applications.
Work Execution Tools	Work Execution Tools consists of a collection of applications which are used to plan, schedule, dispatch and report on field work completion. The applications are linked to ArcFM, SAP and CSS through the use of enterprise middleware.
Smart Meter Head End System and MDMR Interface	The billing system produces bills for customers through its integration with the IESO meter data management repository (MDMR) and the Smart Meter Infrastructure.
Computer Aided Design and Drafting (CADD)	Computer Aided Design and Drafting is a suite of tools that aid in the design, engineering and construction of Transmission, Distribution, and Network infrastructure.

Data Centre Services

Data centre services include the operations, maintenance, and management of hardware (servers, mainframe, storage area network and data storage devices), operating systems, associated applications and infrastructure located at the data centre facilities. This hardware is used to run enterprise business applications, noted above, that are critical to operating the business.

Data Centre service levels have been established to ensure the reliable operation of business applications and are based on system criticality. The system hardware is located at production and backup data centres, which have the required system redundancies including 24/7 monitoring. Hydro One utilizes the backup data centre facility as a disaster recovery site in the case it is unable to operate from its production data centre.

Distributed Server Sustainment

Distributed server sustainment includes the support services that maintain and operate the application and file servers that are located at various Hydro One facilities across the province. The servers are used to run business applications and administration systems such as file sharing, e-mail exchange, web hosting and security monitoring systems. This work is required to maintain the reliability of the business applications supporting business operations.

Help Desk & Deskside Support

Help Desk and Deskside Support includes daily management and maintenance services delivered to employees across the Province.

The support function is provided through two key service areas: the Help Desk which provides centralized problem resolution by phone and through e-mail for all IT and telecom service areas; and Deskside Support which provides physical desk side support to fix hardware and software problems for laptops, desktops and rugged tablet computers. Deskside Support includes the support for IT peripherals such as printers, plotters, scanners and other equipment.

Deskside and Help Desk support is available to all users across the province and assistance can be provided by telephone, remotely through the data network, or if necessary through the use of Inergi field technicians. Effective and timely response ensures the efficient operation of the technology infrastructure which enables Hydro One staff to perform their work unimpeded.

The increase in cost from 2009 to 2010 for Base IT Sustainment Services was primarily due to the inclusion of a full year of SAP infrastructure and application management in 2010. In 2010 the Inergi Outsourcing contract was renegotiated and represents the decline in costs from 2010 to 2011. In 2012 there is an increase in cost due to additional storage requirements to support Enterprise Applications and from the addition of the Smart Meter Head-End system into sustainment. In 2013 and 2014 costs decline year over year due to the scheduled price reduction in the Inergi Outsourcing contract and the IT Sustainment savings realized for the CIS replacement project.

2.2 3rd Party Contracts

3rd Party Contracts are the fees related to hardware maintenance, application software license and maintenance fees that are paid to third party vendors for the IT infrastructure used by Hydro One.

License or maintenance agreements are usually subject to annual increases as part of the contractual terms with the vendor. These fees are subject to annual audits by the third party vendors to confirm the fees match the services provided.

From 2009 to 2011 costs decrease primarily due to legacy application and hardware rationalization made possible from the replacement of enterprise applications with SAP. Costs are also reduced over the 2009 to 2011 period due to contract re-negotiations with hardware and software vendors resulting in lower licensing and maintenance costs. In 2012, contract costs increase due to additional software license fees for Microsoft contract renewal and Smart Meter Head-end system license fees. License and maintenance growth in 2014 is expected when the contact centre technology is replaced and the mobile IT platform is expanded.

3.0 IT DEVELOPMENT OM&A

Table 4 lists the expenditures driven by non-Capital IT projects and the OM&A portions of capital projects.

Table 4
OM&A Development Expenditures
($ Millions)

Description	Historic			Bridge	Test		TX Allocation	
	2009	2010	2011	2012	2013	2014	2013	2014
Enhancements	3.5	8.6	9.5	4.2	7.5	7.1	3.3	3.1
Upgrades	3.1	3.2	1.5	3.8	8.0	6.6	3.3	2.7
Impact of Capital Projects	0.0	0.1	0.0	0.2	0.4	0.5	0.3	0.3
Total	**6.6**	**11.9**	**11.0**	**8.2**	**15.9**	**14.2**	**6.9**	**6.2**

3.1 Enhancements

Enhancements include required application, data and process changes to SAP and Non-SAP systems to meet legal/regulatory requirements as well as delivery of required business functionality to meet the objectives of both the lines of business and to enable the application rationalization strategy.

Enhancement costs increased in 2010 and 2011 as focus shifted from the SAP Capital projects to ongoing sustainment enhancements. 2012 has a reduced spend on enhancements as focus shifts to the implementation of the SAP Customer Information System Capital project. Enhancement costs for 2013 and 2014 resume required application, data and process changes to SAP and Non-SAP systems to meet legal/regulatory requirements as well as ongoing delivery of required business functionality.

3.2 Upgrades

Hydro One utilizes approximately 855 (year ending 2011) business software applications in order to equip its employees to perform their work functions. The upgrade program provides the needed software vendors' releases, periodic version upgrades, and replacement of applications that do not meet the total capital threshold of $2 million.

Applications are replaced or upgraded to ensure they 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 2012 are enhancement pack upgrades for modules of SAP as well as the Contact Centre Telephony application, and minor upgrades to other ancillary applications and infrastructure. In 2013 and 2014, planned costs include version upgrades of SAP Supplier Relationship Management (SRM), SAP Supply Chain Management (SCM), SAP Enterprise Portal, Trilliant Head-end system, enterprise mobile platform as well as minor upgrades to several other enterprise applications and infrastructure in order to keep them in a vendor-supported state.

3.3 Impact of Capital Projects

This includes business process re-engineering costs such as training and change management work efforts that are required to implement and train the line of business personnel when new or revised IT applications are introduced. These costs are associated with the IT capital projects discussed under Exhibit D1, Tab 3, Schedule 6.

In accordance with Hydro One's accounting practices, the cost associated with this implementation work (training and business process change) is not capitalized. The implementation work ensures each new business application or upgrade is properly introduced and has the necessary user understanding and support.

4.0 BUSINESS TELECOM

Business Telecom provides the data and voice telecommunications services, network operations management and field service repairs which are required for the company to operate from its province-wide locations. The business telecommunications data network is comprised of a mixture of company owned and leased facilities and equipment. Costs incurred in this area are primarily costs for third party services.

Table 5
Business Telecom OM&A Expenditures
($ Millions)

Description	**Historic**			**Bridge**	**Test**		**TX Allocation**	
	2009	**2010**	**2011**	**2012**	**2013**	**2014**	**2013**	**2014**
Operations and Carrier Management	4.8	5.0	5.5	6.9	7.5	7.5	4.3	4.3
Field Services	5.3	1.9	2.9	2.3	2.5	2.3	1.5	1.3
Voice and Data Network Services	10.7	10.0	10.1	8.8	8.0	7.7	4.6	4.4
Total	**20.8**	**16.9**	**18.5**	**18.0**	**18.0**	**17.5**	**10.4**	**10.0**

4.1 Operations and Carrier Management

Operations and Carrier Management costs relate to telecommunications management services provided by Hydro One Telecom (HOT) provides telecommunications monitoring and network operations for the power system and the business operations of Hydro One. Costs reflected in Operations and Carrier Management reflect the contracted costs with HOT to provide Hydro One with telecommunication management services and operations oversight and control for its business operations. The affiliate agreement is found in Exhibit A, Tab 8, Schedule 3.

In 2011, an independent industry review included as Attachment 1 to this Exhibit, was conducted which concluded that “the HOT Network Operation Center is performing networking monitoring functions at a more efficient level than comparable Canadian utilities’ 24x7 telecommunication operation.” The study also reaffirmed there are unique requirements for operating the telecommunication system of an electric utility which are not easily delivered through a third party non-electric utility carrier. The assessment process included looking at the service level agreements and statements of work for services to be covered in the regulatory review period. The report considered the revised services which will be performed in the years covered and the costs to be charged by Hydro One Telecom in providing those services.

The study states: “Cost of services increases to HONI since 2002 have been less than if the network monitoring function had remained within HONI. HOT continues to achieve efficiency gains relative to its peer group of utilities, and has now achieved the status of most efficient in performing the network monitoring function. The differentiating factor for the HONI operations as compared to the benchmarked utilities is that they have found a way to interject a commercial telecommunication approach with a solid power system telecommunication operation to bring a successful and cost effective solution to both businesses.”

The report reaffirmed that Hydro One obtains cost and operations benefit through its relationship with Hydro One Telecom.

Work performed by Hydro One Telecom includes operating and monitoring the business telecom and data networks, management of security firewalls, security patching, security event monitoring, management of network interfaces with third parties, managing data and voice system problems, obtaining and managing fibre services from third party vendors, and directing other telecom service providers and vendors to change, maintain, and restore the networks as required. On an ongoing basis, this function includes managing third party supplier contracts as well as analyzing and processing bill payments to 3rd party common carriers and other telecom service providers.

Telecom service firms who provide fibre and network access include common carriers such as Bell Canada, Telus and MTS/Allstream. These companies lease telecom data and voice circuits to Hydro One at competitive market rates. The management of these services requires the contracted services of Hydro One Telecom to proactively liaise with the many carriers in Ontario and other service suppliers.

Operations and Carrier Management also provides oversight of the Bell Field Services contract as described below.

In 2012 and 2013, there is an increase in cost attributed to increased work related to network and application security event management. Over these years, to address a heightened focus on information and cyber security, HOT will be playing a critical role in security event monitoring for Hydro One's critical networks and information systems. They will use security event detection tools, and the related process and procedures, to monitor, analyze, detect and alert based on trend analysis. This investment serves to enhance the existing security monitoring and will provide a more robust monitoring, escalation and management structure.

4.2 Field Services

Field Services includes the maintenance and repair of voice and data telecom equipment. Field Services also includes the handling of connection changes for moves, additions, changes, and deletions ("MACDs"). In 2009, an RFP was issued for Field Services and awarded to Bell Canada. As a result, Hydro One realized reduced rates in voice, data, and managed services. The year-over-year cost for Field Services has decreased due to the reduction in move/add/changes to voice and data.

The agreement calls for Bell Canada technicians to be dispatched across the province to resolve any telecommunications issues. These include MACDs and preventive maintenance at any of the Hydro One sites across the province. Selected Bell Canada staff has been specifically trained to work at the Hydro One sites and facilities in order to work safely in a high voltage environment.

In 2010, the reduction in cost is due to the contract negotiation with Bell Canada for the Field Service work and was the first full year of the new contract. In 2011, the cost increase is related to the increase in MACD work associated with facilities relocation and refresh work for aging telecom equipment. These costs stabilize in 2012 through 2014 based on expected moderate facilities changes and non-capital refresh work.

4.3 Voice Services and Data Network Services

Voice Services investments consist of payments made to common carriers and vendors to use and lease voice circuits and equipment. Rates charged by common carriers are competitive. Voice Services include monthly charges, usage fees and equipment rentals for voice grade business telecom (local and long distance). The local voice service rates are regulated under CRTC. Long distance rates were secured using a competitive bid process. Annual costs are volumetric and usage-based.

Data Network Services investments consist of payments made to third party common carriers such as Bell, MTS/Allstream, and Telus to lease data network circuits and equipment at market rates. The data network is used to connect servers and computers across the province for software applications.

Hydro One continues to monitor and upgrade bandwidth as applications are deployed to field offices in order to support business processes and business requirements.

While network capacity grows each year to accommodate sharing more data among more functions, the Company has maintained cost control on data network components.

Downward cost pressure is maintained through investments in efficient up-to-date IT platforms.

In 2012 to 2014 the costs for Voice and Data Network Services decrease due to contract negotiation with circuit carriers and also the expected reduction in leased circuits due to the Wide Area Network (WAN) project.

5.0 IT MANAGEMENT & PROJECT CONTROL

To manage the overall IT program and as the enabler and controller of IT projects, IT Management and Project Control develops and implements: IT strategies; policies and processes; IT architectural standards for application interoperability, infrastructure capacity, network security, regulatory compliance; and IT governance. Within the scope of these costs is work associated with hardware procurement, training, detailing vendor responsibilities, architecture development, and research services that are required to match IT solutions to known business needs for enabling business efficiencies. Work performed also includes keeping current on industry trends, product innovations, technology changes in infrastructure and applications, while researching industry best practices for future investments.

Table 6 lists the associated costs for IT Management and for Project Support and Control.

Table 6
IT Management & Project Control Expenditures
($ Millions)

Description	Historic			Bridge	Test		TX Allocation	
	2009	2010	2011	2012	2013	2014	2013	2014
IT Management	20.0	18.6	18.0	19.4	20.3	20.9	11.5	11.8
Project Support and Control	1.3	1.5	1.5	1.6	1.9	2.0	0.8	0.9
Total	**21.3**	**20.1**	**19.5**	**21.0**	**22.2**	**22.9**	**12.3**	**12.7**

5.1 IT Management

IT Management includes the cost to plan, coordinate and manage the extensive IT infrastructure and to manage the IT outsourced services. IT Management also performs work covered through needs assessment, solution architecture development, and service delivery to the lines of business.

Projects or programs that IT Management will manage or deliver in 2013 and 2014 include: lifecycle refresh and infrastructure upgrades; application rationalization; data architecture and data management; evolving business-technology roadmaps; ongoing security requirements and enhancements; negotiation of contracts; supporting hardware purchases for major projects and for growth; continuously improving the outsourced services; and implementation of more self-service and automation for end users.

From 2012 to 2014, the primary reasons for the increases in cost are due to incremental resources needed to support the expanding functions of the enterprise systems such as Mobile IT, SAP, GIS, and CIS.

5.2 Project Support and Control

Project Support and Control provides standard project management services for the delivery of any and all projects impacting information systems. It provides: project management processes, templates and tools; project governance and controls of scope, quality, effort, risk and schedule; change management processes to address project-related changes affecting organizational culture, business processes, organization and job design; training to both project staff and to the users of the systems and services being delivered; and transition of projects into sustainment and ultimate closure. The increases in cost in 2013-2014 are necessary for the project management services to support the required enhancements and upgrades outlined in section 3.0

Hydro One Telecom Inc. Services Review and Benchmarking

Prepared for:

hydro One

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THE SHPIGLER GROUP
STRATEGY MANAGEMENT CONSULTING SERVICES

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Executive Summary

Over time, nearly every electric utility has established some form of telecommunications capabilities in support of their normal operations. As the demands of operating an electric utility grow in complexity, many utilities have built extensive telecommunications transport networks in support of such applications as teleprotection, SCADA, telemetry, and others. As demands on these telecom networks have grown, the capital resources allocated to them and the staff that oversees their operations has grown in size and scope. As such, it is often useful to perform periodic studies to compare the efficiency of such telecom units to a group of similar utilities to ensure that existing cost levels are in line with industry norms and to identify emerging best practices. Hydro One Networks operates as the dominant provider of electricity within the province of Ontario, with 96% of the transmission system and about one-third of the province's distribution system, spanning 75% of the province. The transmission network involves 28,951 kilometers of lines and the distribution network supports approximately 1.3 million electric customers across rural Ontario. Hydro One Networks is the largest operating subsidiary of Hydro One Inc., which is wholly owned by the Province of Ontario. Hydro One, Inc. operates four distinct business lines: Hydro One Networks (transmission and distribution across the entire province), Hydro One Brampton (distribution network within the City of Brampton), Hydro One Remotes (electric operation in the Northern Ontario region), and Hydro One Telecom (fiber optic business).

Hydro One has an extensive telecommunications operation in place to serve its core energy business. The telecom group reached a point in its development where their capabilities had the potential to add value as a shared service in conjunction with the commercial telecommunications operations. The telecommunication group’s expertise in operating a sophisticated telecommunications network to commercial availability standards on a daily basis, its knowledge of the commercial market and of the special needs of electric power systems made the outsourcing of network and vendor management appealing. Hydro One Networks Inc. (HONI) determined that by having Hydro One Telecom (HOT) manage network control and third party telecommunications contracts, they had the opportunity to control costs and optimize their network monitoring.

Even as the telecommunications group supports the communications needs of Hydro One's Network, there is an ongoing desire to better understand the competitiveness of the group's operations. More specifically, HONI chooses to benchmark the performance of its telecommunications group to determine how it compares to peers with respect to operating efficiency. The Shpigler Group was engaged in 2005, 2006, and 2008 to research and analyze this issue by evaluating the group's performance as defined in the Service Level Agreement (SLA) and benchmarking the activities against similar operations. We have been re-engaged in 2011 to review the SLA for the upcoming term, to evaluate the competitiveness of HOT for the past period and assess the projected competitiveness for the new SLA duration. The following analysis is based on updated benchmarks from the 2008 report and compares expected future performance against the same peer group.

A close review of the proposed SLA to the prior SLA indicates that there were no material changes between the two SLAs except for the increase in the predefined work scope and wage and benefit labor increases. The similarity of the two SLAs allows a forward looking comparison to be made after verifying that the peer utilities were proportionately stable, which they are. Therefore, we determined that the updated benchmarking data along with our understanding of the projected changes for each utility would allow us to estimate the relative performance of utilities for the SLA and reach a conclusion.

In our opinion, the unique voltage potential of a power system has created the need for electric utilities to create their own telecommunications entities that can isolate and insulate the telecommunication infrastructure, which protects communications during electrical disturbances. Protecting electrical equipment requires sophisticated systems that need to communicate between substations and power plants. The need to isolate electrical and telecommunications facilities for safety and service reliability has supported the development of large utility telecommunication entities. Even with fiber optic channels negating some interfacing concerns, the need for end electronics equipment to interface with optical equipment at risk to voltage surges still exists. Network operation centers of public and private telecommunications companies rarely have the experience or knowledge necessary to manage a power systems telecommunication system. Therefore, for benchmarking purposes, we determined that the most meaningful and comparative data would need to be obtained from similar Canadian utility telecommunication entities.

Through this engagement, our efforts have centered on evaluating the existing service level agreement with HOT, evaluating the performance of HOT as compared to the defined deliverables and industry standards, analysis of the cost structure, and an audit of third party pass-through contracts and charges. The benchmarking data was collected from three comparable Canadian utilities and compared to results for the past year. The other utilities studied were Manitoba Hydro, Hydro Quebec, and BC Hydro; they were chosen for their similar telecommunications needs and service territories. The report and our conclusions are based on primary research from interviews, secondary data collection and benchmarking comparisons between these three utilities. In addition, we have included insights gathered from other utilities regarding "best practices" in network monitoring.

Analysis of HOT operations was centered on the following:

- SLA applicability to present services provided
- SLA deliverable performance
- HOT cost breakdowns
- HOT third party contract management, costs and savings
- HOT Network Management services benchmarking

Through interviews with top level management, detailed data analysis, and review of third party invoice handling practices and benchmarking, our findings are as follows:

- Benchmarking results continue to indicate that the HOT Network Operation Center is performing networking monitoring functions at a more efficient level than comparable Canadian utilities' 24x7 telecommunication operation centers.
- The Service Level Agreement was reviewed and is similar to past agreements. It is our opinion that the SLA has all of the necessary attributes of a well-written agreement.
- In the current benchmarking exercise the analysis included a review of costs, projected growth and shift coverage. The results of this exercise indicated that HOT is providing coverage similar to the other utilities that provide 24x7 services.
- HOT's competitive cost position, which existed from 2005-2011, even when increased for labor costs and scope changes will maintain a competitive cost of service when compared to other network monitoring operations.
- Benchmarking also indicates that the shared services concept has provided an advantage over other methods. HOT needs a fewer number of operations positions than other utilities that manage a power system-only workload, even as the amount of work and size of the telecommunications system increases.
- The pass-through costs for third party handling are in line with original billings from the third party. A review of invoices supported the conclusion that third party costs are passed through directly to HONI without markup.
- The HOT charge for handling third party contracts is significantly less than what they have been able to save in contract re-negotiations. Having a dedicated unit focusing on the telecommunications-related issues (like bill accuracies) coupled with the combined purchase power of a larger entity has proven beneficial to not just the HONI staff, but also to the efficiency of the telecom functions.
- Leveraging the commercial knowledge and acuity of the HOT staff continues to benefit the entire corporation.

We believe that the benefits of a commercial telecommunication approach of the HOT staff coupled with the power system knowledge is an effective tool in extracting value for both HONI and HOT in their respective areas of responsibilities. Through this review we do note some areas that should be addressed:

- Historically, HONI and HOT personnel have relied to some extent to utilizing verbal agreements to amend certain aspects of the formal SLA document; as a result, the language in the agreement previously had not always accurately matched the understanding of the parties regarding expected deliverables. The Shpigler Group's review of the SLA status suggests that HOT and HONI have made very good progress on improving on this issue and has made significant progress on documenting changes in the written SLA. The Shpigler Group advises that such issues should continue to be monitored so as to avoid any issues that could arise in the future when persons not privy to those agreements try to carry out the work or ensure compliance. In addition, it will be important to continue to improve on the timeliness of updating the SLA to reflect changes.
- To prevent further undocumented scope changes, it is just as important to establish those activities that are not within the scope of the SLA as those that are; the verbiage should be detailed enough to minimize interpretation.

Background on The Shpigler Group

The Shpigler Group is a strategy management-consulting firm focused on the telecommunications and technology sector. The Shpigler Group works with utilities, municipalities, telecom service providers, and infrastructure and technology developers in solving complex issues involving strategic assessment, market analysis, business case development, economic evaluation of network design, and competitive and partnership assessment. The Shpigler Group has been heavily involved in the utility telecommunications industry, dealing with operational and strategic issues involving networks with fiber, wireless, power line, satellite, microwave, and other access approaches. The Shpigler Group has been in business for ten years, since September 2001.

David Shpigler, President of the firm, brings an extensive background in strategy consulting to companies in high technology industries. Prior to founding The Shpigler Group, he was with Cambridge Strategic Management Group, Dean & Company, and Accenture, all leading strategy consulting firms focused on serving the telecommunications, high technology, and utility industries. In addition to his work with The Shpigler Group, David has served as the Director of Research for United Telecom Council, developing research studies for the utility telecommunications industry. He has also served as Adjunct Professor of Operations Management at Berkeley College. David has a B.S. in Business Economics from the University of the State of New York, Albany and an MBA from the Graduate School of Business at the University of Chicago.

Project Methodology

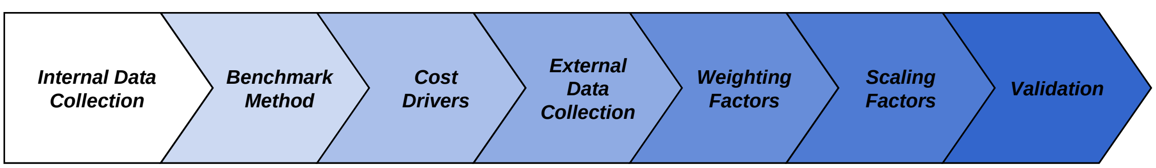
Some choices were made in the commission of this benchmarking report. Initially, the choice was made to focus on a smaller number of utilities and conduct detailed research gathering with each rather than try to generate higher-level surveys with a larger group of utilities. Even though the quantity would have been more statistically significant, we felt it might generate questionable findings. Next, the specific utilities targeted were chosen for the nature of their operations; that is, utilities with some critical mass with respect to overall service territory were targeted. Although the original desire was to benchmark cost positions of utilities relative to one another, it became apparent that to do so would lead to some questionable conclusions because the cost positions are driven by a number of completely unrelated and in some cases uncontrollable factors. For example, differences in accounting practices – like burden rates – can skew results, shielding us from gaining a complete understanding of true operational efficiency. As a result, the benchmarking study was based on headcount positions at each of the utilities as they related to network monitoring work output levels. Finally, since each utility profiled featured a very different organizational structure, we embarked to benchmark the job functions rather than individual work groups.

We believe that the information gathered in this report should offer a strong perspective for the desired benchmarking effort. Ultimately, the reader should be cautioned that the data collected and the resultant conclusions within this report represent important findings regarding overall trends, but with error margins due to the lack of complete "apples-to-apples" comparisons. Furthermore, each of the utilities profiled in many cases shared the fact that their operating practices are in flux, with many of the practices currently undergoing changes. As a result, the conclusions reached as part of this report reflect a current status of a "moving target" in many cases.

In order to thoroughly understand the services and charges for services from HOT to HONI we needed to ensure that we established a methodology that supported the key goals of the project. The key steps that we needed to account for as part of the process included:

- Analyze the Service Level Agreement (SLA) to determine required services and reporting
- Assess deliverables required by the SLA
- Analyze major cost component areas
- Collect data from key process owners
- Perform review of third party pass through costs
- Determine appropriate method for performing benchmarking
- Collect data from benchmark utilities
- Calculate weighting factors
- Perform scaling function to address discrepancies in volumes
- Compare results across benchmark companies
- Refine analysis as needed

In order to account for each of these issues, we followed a methodology involving a seven-step plan:



<u>Step 1</u> – To start, we conducted initial interviews with HONI and HOT staff to understand key processes, work functions, and output levels. In doing so, we were able to get a basic understanding of the tasks at hand and to understand the HOT- HONI relationship, organizational structure and work output. After initial discussions with HOT and HONI, it became apparent that the key operational function performed by HOT for HONI was the Network Monitoring function. All other functions found in the utility telecommunications groups (planning, engineering, construction etc.) were part of HONI, and, as result did not require benchmarking.

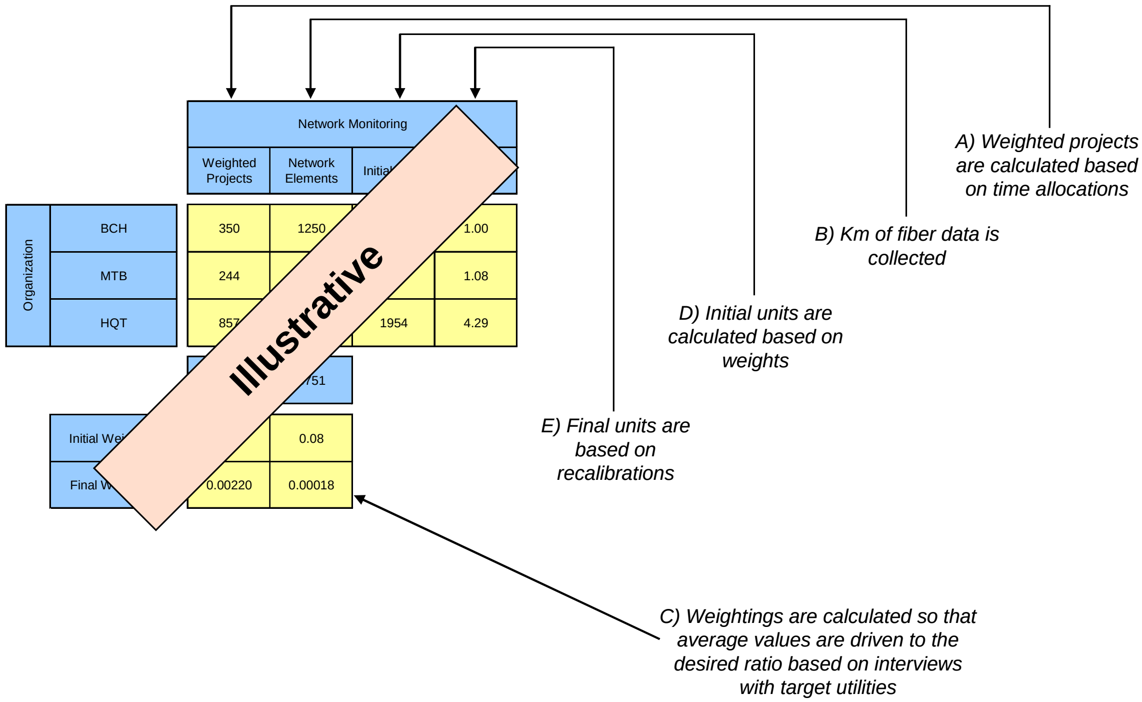
Step 2 – Next, it was necessary to develop a methodology for the overall benchmarking effort. Given that each utility had a different amount of work that it generated on an annual basis, applicable cost drivers needed to be established for each organization. Due to the potential differences in labor rates, cost allocation methodologies, and burden factors that are outside the control of HOT, we embarked on an effort to determine efficiency levels based on full time equivalents (FTEs) rather than on pure dollars.

Step 3 – Through interviews, a set of specific definitions was established for each activity area that was common to all electric utilities interviewed:

- Ensuring physical and logical security of network
- Conducting remote fixes of network when available
- Major alarm investigation
- Client services associated with network monitoring
- Monitoring technology platforms within the network

Step 4 – Having set up the overall methodology to process information and to structure the study, the next effort now focused on conducting detailed direct interviews with each of the targeted utilities. Our desire was to target as many Canadian electric utilities that would offer as fair a comparison to Hydro One as possible. Given that there is no utility that features a fully comparable mix of customer count and service territory size, it became apparent that a precise match would be impossible. However, we embarked on an effort to identify the most comparable utilities that would offer meaningful benchmarks based on having a service territory of some substance, a critical mass of customers, and some portion of the network in rural/remote areas.

Step 5 – Once the data was collected from each utility, we needed to calculate appropriate weightings to apply to work outputs in order to make cross-company comparisons. To illustrate the methodology on which these weightings were developed, the following is an example of how we approached the subject on calculating weighting factors:



In using weighting factors, certain issues need addressing:

- *Issue A* – First, we gathered data from each of the benchmark utility telecommunications groups related to the commission of project related work. This factor was determined to be significant in determining work load for a network monitoring function. We arrived at a measure of “weighted projects” by determining point values for large projects (25 points for projects lasting over 6 months), medium projects (4 points for projects lasting 6 weeks to 6 months), and small projects (1 point for projects lasting under 6 weeks). We then multiplied the point values for the number of projects and arrived at a weighted project value for each benchmark utility.

- *Issue B* – We also identified the number of managed network elements as a key factor involved in determining network monitoring workload. Accordingly, we collected information about the network elements in each benchmark utility’s telecommunications network.

- *Issue C* – Next, we needed to arrive at a methodology to calculate the combined effects of both factors of workload under consideration – projects and network elements. Based on interviews with each of the utilities as well as prior experience in the field, we concluded that these factors impacted workload equally. However, the difference in scale resulted in an inability to simply combine the totals of each measure. To normalize these factors, we used weighting multiples to arrive at an expression of relative workload that maintained the desired 50/50 split in impact.

- *Issue D* – We multiplied the benchmark results for weighted projects and network elements by the weighting factors to arrive at preliminary measures of relative workload for each of the utility telecommunications unit.

- *Issue E* – Because the work units are based on a somewhat arbitrary scale, the resultant numbers are meaningful when compared against one another, but not necessarily in isolation. In order to process the information using a more manageable scale, we reduced each of the work load unit counts by an equivalent coefficient so that the utility with the lowest work load among the peer group would be assigned a value of one and all other utilities would be indexed off of that value.

Step 6 – Calculating the relative workloads of each group required a scaling function be performed to compare differing levels of activities at equivalent rates. We know the total number of people performing various job functions at each of the utilities based on the interviews conducted. Then, based on the procedures in step # 5, we also know the amount of work conducted by each group. With these two pieces of information, we can calculate unit costs – the headcount per work unit – and make comparisons between utilities. However, doing so would lead to an error in methodology. Certainly, we are aware of the existence of scale efficiencies – the ability of organizations to perform functions at higher efficiency levels as they grow in size. To illustrate this concept, consider two utilities performing a certain job function at the same unit cost, but one utility is substantially larger in size than the other. This shows that the smaller utility operation is more efficient because it is able to achieve the same unit cost without the benefit of scale efficiency. To operate at the same efficiency level, the larger utility would need to leverage its size to amortize some of the fixed costs across the larger base of operations and achieve a superior cost position. In order to account for this issue, we then developed calculations concerning scale curves.

Step 7 – Once the data was collected from each utility and comparisons were made, a number of data points appeared to show questionable results – and were validated through additional interviews.

Network Monitoring

Workload: The complexity of HONI's network demands a high focus on network monitoring to support successful ongoing operation of the telecom transport network. Based on research into the amount of work output supported by each network-monitoring group, we calculate that HOT supports the second highest work output among the peer group based on work supporting HONI:

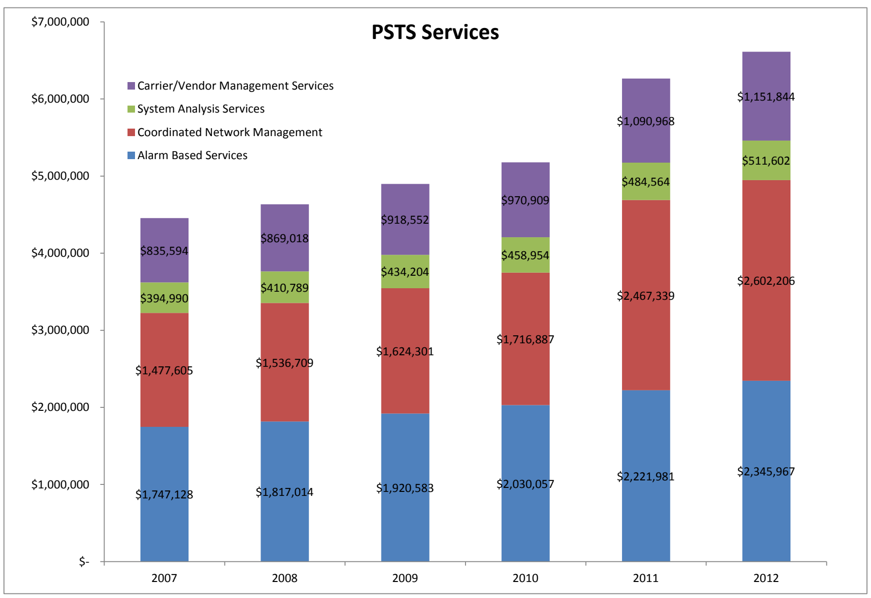
	Network Monitoring			
	Weighted Projects	Network Elements	Initial Units	Final Units
Hydro One	1,826	5,139	2,491	3.20
Manitoba Hydro	355	3,350	789	1.01
Hydro-Québec	1,199	21,025	3,921	5.04
BC Hydro	610	1,300	778	1.00

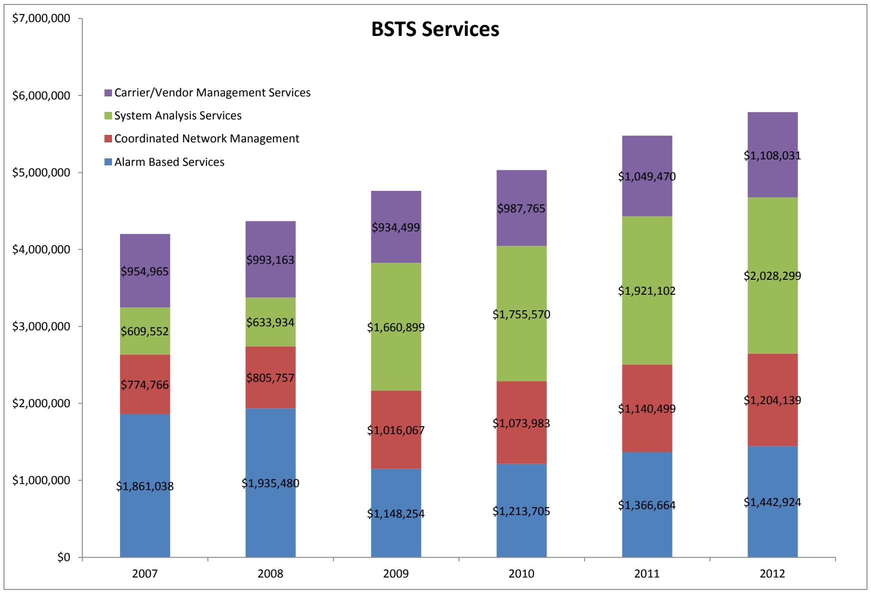
Initial Weighting	1	0.13
Final Weighting	0.00128	0.00017

Cost Positions: We calculate that the cost assumed by HONI as a result of HOT operation of the network monitoring the telecommunications network is based on supporting the equivalent of 14.75 FTEs. We conducted a similar analysis for each of the benchmark utilities and further adjusted the scale so that headcount equivalents were based on the average workloads in the industry. Based on this exercise, we calculate that HONI's operation of the network monitoring function is still comparable to the peer group. As a point of reference, the HONI's FTE count of 12.52 compares with an equivalent FTE count of 13.87 for Manitoba Hydro, 16.41 for Hydro-Québec, and 24.01 for BC Hydro. This shows that HONI features staffing levels that are more efficient than the group average by 2.67 FTE and ranks as the most efficient organization among the peer group.

	Unit Cost	Comparable FTEs	FTEs in Excess of Industry Average	% Difference from Industry Average
Hydro One	4.61	12.52	(2.67)	-17.55%
Manitoba Hydro	6.91	13.87	(1.32)	-8.67%
Hydro-Québec	5.36	16.41	1.22	8.04%
BC Hydro	12.00	24.01	8.82	58.11%

The breakdown of the HOT budget indicates that costs continue to be driven by the labor portion of the budget due to the demands of the required 24 x 7 network management coverage. Over the period 2007-2012, the average annual increase in charges for PSTS and BSTS services have grown in response to expanded services and labor growth. Below we can see the cost progression over time:





The compound annual growth rate of the cost of managed services by HOT to HONI is 7.45%. The total cost to HONI is strictly labor-related as all third party bills for maintenance and equipment are directly invoiced to HONI. Any and all replacements and additions are justified through analysis. The only opportunity for HOT to increase efficiency is from the labor portion of the budget, which it does not control because the labor force is represented by a group agreement with HONI. HOT's efficiency has improved over successive benchmarking studies conducted:

- 2007 – Hydro One ranked #3 out of 4 utilities
- 2008 – Hydro One ranked #2 out of 4 utilities
- 2011 – Hydro One ranked #1 out of 4 utilities

Technology continues to push more work into the Network Operations Centers with self-diagnosing field equipment, alarms, and remote servicing capabilities. As equipment replacements at HONI continue, workload has increased for HOT.

SLA Analysis

There are several key components in Service Level Agreements that are critical to the unique operational requirements of electric utilities when transferring responsibilities to a shared services organization. The key elements of developing a successful shared services understanding are as follows:

- *Service Level Agreement*: Planning and preparation for service provisions and service level agreements should be conducted once a year by both the shared service organization and the individually affected business units
- *Monthly Billing*: Costs for the provided services are charged to each client on a monthly basis via internet application which in turn files the invoice into an accounting system
- *Detailed Performance Reports*: A variety of monthly detailed charge-out reports are created which identifies costs charged to the client organization. Monthly reports on detailed charges are compared against previous work and standard marketplace costs
- *Markup for Third Party Costs*: Typically, shared services organizations are treated as a cost center with no markup included unless specifically agreed upon in the affiliate transactions related regulations
- *Key Performance Metrics are Established*: Establishing and agreeing upon clearly defined performance metrics is critical to the effective functioning of a shared services organization
- *Ongoing Efficiency is Expected*: Shared services performance should be measured for ongoing internal improvements in efficiency and effectiveness as well as overall improvements compared to the rest of the market place
- *Both Parties Share in Accountability*: Shared services performance measures should reflect shared accountability between the shared services organization and the different business units

The Shpigler Group has examined the past Service Level Agreements established in 2005 and 2008 against the above list of key SLA components and has determined that the SLA contains all the aspects of a sound service level agreement. Upon examination of the updated Service Level Agreement we determined it to be similar to the past SLAs. We focused our examination on the metrics and reporting that is prescribed in the agreement and found that HOT continues to provide the services and reports as agreed and will continue to be held accountable to those same standards.

Service Level Agreement – There are defined services related to the monitoring, management, and operation of the Power System:

- Alarm Based Services
- Coordinated Network Management Services
- Systems Analysis Services
- Carrier/Vendor Management Services

Monthly Billing – All charges for network management and business services are electronically charged to the HONI accounting systems as pre-determined by both parties and reviewed annually.

Detailed Performance Reports – The following is a list of examples of the reports that are provided as defined in the SLA:

- Vendor Invoicing Error Report and Service Billing Report– Monthly
- Bill Savings Report - Annual
- PSTS Significant Events – Daily & Annual
- Year to Date Costs – Monthly
- Business Telecom Significant Events Report – Daily and Annual

All reports were reviewed and found to be in compliance with prescribed metrics. Verbal arrangements regarding the frequency of some of these reports have been made. For instance, the significant events reports are generated on a request-only basis.

Markup for Third Party Costs – A thorough review of all third-party billing was conducted to ascertain that costs billed to HONI were without markup. It was determined that charges were incurred without markup.

Key Performance Metrics are Established – HOT has established a monthly meeting with large suppliers for resolution and correction of billing issues, meeting reports are issued, and followed to resolution. On the network services side, restoration metrics were incorporated for loss of critical services (4 hours) and loss of redundancy (next day resolution). Also, performance measures have been established for other trouble calls and corrective maintenance activities. Priority 2, 3, and 4 levels with corresponding services response of 8 hours, 5 working days, and 10 working days were established. A review was made indicating that HOT is performing these services as defined.

Ongoing Efficiency is Expected – Efficiency expectations are established through fixed annual contract cost discussion and agreement between both parties. Since the inception of the arrangement between HONI and HOT in 2002 an efficiency gain of 28.5% has occurred.

Both Parties Share in Accountability – Through annual discussion and adjustment memorandums, any change in scope of services is mutually agreed upon.

Cost Analysis

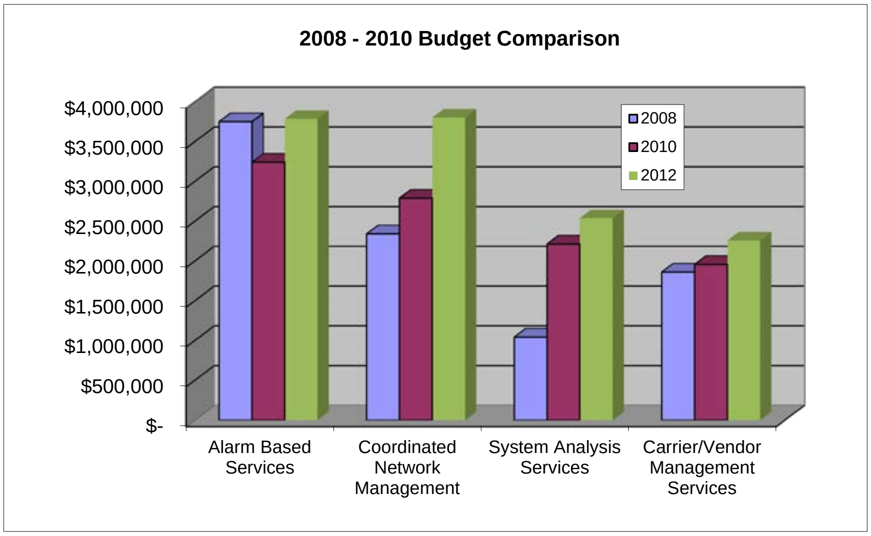
Our analysis on cost centered on the key components of costs and trends in costs.

HOT Vendor Management **–** The work performed by HOT is related to carrier and vendor management services. Since all bills and services are charged directly to HONI, HOT manages contracts, new orders, change orders, and bill analysis and payments. While there have been significant cost containment measures brought about by HOT contract negotiations, thorough bill analysis, and vendor interactions, the function remains labor intensive and is not conducive to ongoing efficiency increases or headcount reductions.

The vendor management services performed by HOT produces value for both organizations by increasing buying power. This is achieved by leveraging HOT's extensive commercial experience and thorough understanding of the market place.

Based on a Utilities Telecommunications Council (UTC) report on shared services within utility telecommunications, entities indicate shared services costs are typically 40% labor, 40% vendor management and 20% infrastructure. The budget breakdown for HOT's management of HONI's telecommunications has a labor related component of 78% and a vendor management portion of 22%. Infrastructure related expenditures are not a part of this budget, but the higher labor to vendor ratio indicates that HOT continues to be in line with industry practices and is cost effectively managing vendors.

Budget Review



A comparison of budgets for 2012 relative to prior years (2008 and 2010) indicates increases in all four functions, with an increase of 21.4% for the total cost for services. These functions tend to be driven by the size of the network scope, indicated by the number of network elements. Given that the number of network elements has increased by 17.4% over the same time frame and that wage increases have been set at 5.58%, it appears that the cost increase called for within the SLA appear to be justified.

Conclusion

The shared services concept for telecommunications operations between HONI and HOT initiated in 2002 is providing the benefits that were perceived at its inception with the network monitoring cost for HONI being contained while providing for the unique services of a power system network and meeting the demands of a customer oriented commercial telecommunications network. The vendor management function is also providing the envisioned savings of a larger telecommunications entity.

- The decision to house a 24 x 7 network operations center dedicated to telecommunications operations has resulted in cost savings with some utilities, while others have seen troubling results. In situations where the monitoring center for the power system operations can be well trained on alarm dispatch procedures for telecommunications, the handoff to this group can be a viable approach to saving on operating demands. By contrast, where the electric monitoring center staff is not well trained, the results can be disastrous, as dispatch procedures are not followed and actual costs and overall impacts to the viability of the network can be challenging. The HOT operations have developed operator expertise in both the power systems and commercial telecommunications areas. The cost advantage that HONI is realizing is in shared network monitoring with commercial system expansions.
- A factor that we see as a large driver of determining the appropriateness of a 24x7 network operations center deals with the size of the utility and its telecommunications needs. For a smaller utility like Manitoba Hydro, outsourcing many of the network operations center activities during off-hours is not yet seen as a large work burden for the electric NOC personnel. However, implementing such a practice at a larger utility like Hydro One would prove to be very cumbersome and not provide the level of service required for both a power system and commercial telecom operation.

- The differentiating factor for the HONI operations as compared to the benchmarked utilities is that they have found a way to interject a commercial telecommunication approach with a solid power system telecommunication operation to bring a successful and cost effective solution to both businesses.
- Benchmarking analysis to justify the specific expenditure for network monitoring services is difficult due to the wage and benefit structure among utilities; however our approach to base cost effectiveness on headcount and workload indicates that HOT is as good, if not better, than the other three Canadian utilities with network monitoring centers.
- Historically, HONI and HOT personnel have relied to some extent to utilizing verbal agreements to amend certain aspects of the formal SLA document; as a result, the language in the agreement previously had not always accurately matched the understanding of the parties regarding expected deliverables. The Shpigler Group's review of the SLA status suggests that HOT and HONI have made very good progress on improving on this issue and has made significant progress on documenting changes in the written SLA. The Shpigler Group advises that such issues should continue to be monitored so as to avoid any issues that could arise in the future when persons not privy to those agreements try to carry out the work or ensure compliance. In addition, it will be important to continue to improve on the timeliness of updating the SLA to reflect changes.
- Cost of services increases to HONI since 2002 have been less than if the network monitoring function had remained within HONI. HOT continues to achieve efficiency gains relative to its peer group of utilities, and has now achieved the status of most efficient in performing the network monitoring function.
- Vendor management services provided by HOT are enjoying advantages in both buying power and reduced unit costs for third party services.
- Bill monitoring and contract negotiations continue to result in considerable cost avoidance.

The Shpigler Group has extensive experience in utility telecommunications activities throughout North America and has investigated a number of integrations of commercial and utility network operations and vendor management. We believe that the benefits of a commercial telecommunication approach coupled with the power system knowledge is an effective tool in extracting value for both HONI and HOT in their respective areas of responsibilities. The key to any partnership is communication and pursuing common objectives. The HOT/HONI Service Level Agreement and its interactions, offers the potential to provide the direction and expectation for continued successful operations.

SHARED SERVICES OM&A – CORNERSTONE

Table 1 below identifies the OM&A expenditures for the Cornerstone project for the period 2009 to 2014.

Table 1
Cornerstone ($ Millions)

Description	Historic			Bridge	Test		TX Allocation	
	2009	2010	2011	2012	2013	2014	2013	2014
Development	7.1	1.8	1.4	13.9	10.4	0.8	0.4	0.3

* 2012 - $13.4M is directly allocated to Hydro One Distribution for Cornerstone Phase 4 (CIS)

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. A detailed description of the Cornerstone project is provided in Exhibit D1, Tab 4, Schedule 3.

2.0 DEVELOPMENT

In accordance with Hydro One’s accounting practices, the cost associated with a portion of implementation work is not capitalized. This exhibit presents the OM&A development costs of Cornerstone for process, change management and training activities that are treated as OM&A.

The differences in year to year expenditures are the result of the phasing of Cornerstone implementation and the majority of the expenditure in 2013 is allocated to Hydro One Distribution for the replacement of the Customer Information System.

3.0 VALUE REALIZATION

A description of the value realization methodology and Capital and OM&A value tracking is provided in Exhibit D1, Tab 4, Schedule 3

SHARED SERVICES OM&A - COST OF SALES – EXTERNAL WORK

1.0 OVERVIEW

Hydro One Transmission directly tracks cost of sales for unregulated revenues, which includes Station Maintenance activities, Engineering and Project Delivery work and other smaller activities. These are competitive services requested by customers and are individually priced. Exhibit E1, Tab 2, Schedule 1 describes the categories of external business and associated revenues over the 2009 to 2014 period, which also relates to the level of external costs.

Hydro One Transmission does not directly track costs for all its unregulated service revenues for Secondary Land Use and Other External Revenues. These costs are embedded in the Company's shared services costs.

The cost of sales for the 2009 to 2014 period is provided below.

Table 1
Cost of Sales – Transmission External Work ($ Millions)

Description	2009 Historic	2010 Historic	2011 Historic	2012 Bridge	2013 Test	2014 Test
Station Maintenance	9.7	11.4	8.7	9.1	7.3	7.2
Engineering & Project Delivery	2.9	2.7	3.8	11.2	2.9	2.9
Other	1.2	0.5	0.3	0.7	0.6	0.7
Totals	**13.5**	**14.6**	**12.8**	**21.0**	**10.8**	**10.8**

The 2009 to 2014 costs are consistent with the work categories identified in Exhibit E1, Tab 2, Schedule 1, except for Secondary Land Use, Inergi Royalties and a portion of Other External Work.

The costing of external work is calculated the same way as for internal work as described in Exhibit E1, Tab 2, Schedule 1 and Exhibit C1, Tab 6, Schedule 1.

2.0 STATION MAINTENANCE

Cost for Station Maintenance is directly related to the volume of work performed by Hydro One Transmission to support Ontario's key generating suppliers: Bruce Power LLP, Ontario Power Generation Inc. and Siemens Westinghouse Inc. The decrease in 2013 and 2014 costs reflect the planned shift in resources towards Hydro One Transmission's growing work program.

3.0 ENGINEERING AND PROJECT DELIVERY

Cost for Engineering & Project Delivery is directly related to the volume of work performed by Hydro One Transmission for the upgrading of revenue meters at various sites within the province per IESO requirements. The costs for historic, bridge and test years are outlined in Table 1. The costs for 2013 and 2014 are forecasted at $2.9 million each year based on the planned levels of revenue metering activities.

4.0 OTHER

Cost for Other represents work performed for Hydro One Network's affiliates and other miscellaneous cost of goods sold not included in external revenues. See the External Revenues Exhibit E1, Tab 2, Schedule 1.

PROPERTY TAXES

1.0 A SUMMARY OF TAXES OTHER THAN INCOME TAX

A summary of taxes other than income and capital taxes is presented below:

Table 1 ($ Millions)

Description	Historic			Bridge	Test	
	2009	**2010**	**2011**	**2012**	**2013**	**2014**
Property Tax	58.3	59.5	60.3	61.7	62.5	63.3
Indemnity Payment	4.5	4.5	4.5	4.5	4.5	4.5
Rights Payment	2.4	2.6	2.8	4.5	4.5	4.5
Total	**65.2**	**66.5**	**67.6**	**70.7**	**71.5**	**72.3**

Property Tax and Rights Payments funding levels generally reflect higher tax rates, increases in the assessed value of Hydro One properties and increases in land values.

2.0 PROPERTY TAX

Hydro One Transmission, like every other land owner within the Province of Ontario, is responsible for the payment of property taxes. Property taxes for Hydro One are regulated under the Electricity Act 1998, the Municipal Act 2001, and the Assessment Act 1990. Property taxes are levied on Hydro One Transmission's land and buildings, including service centre sites, transmission stations and transmission lines. Hydro One Transmission pays property tax to about 400 municipalities each year.

A summary of annual transmission property taxes is presented in Table 2, below:

Table 2
Breakdown of Property Tax Expense ($ Millions)

Description	Historic			Bridge	Test	
	2009	2010	2011	2012	2013	2014
Stations and buildings, including proxy tax	17.7	18.9	18.3	19.0	19.8	20.6
Transmission lines	40.6	40.5	41.9	42.7	42.7	42.7
Property Tax Total	**58.3**	**59.4**	**60.3**	**61.7**	**62.5**	**63.3**

2.1 Transmission Stations and Buildings

For municipal property tax purposes, transmission station buildings are assessed at a statutory rate of $86.11 per square metre, according to the Assessment Act R.S.O. 1990, Chapter A31, Section 19. The lands containing the transmission stations are assessed using the Current Value Assessment ("CVA") method -- the valuation method used for other property owners within the Province. Hydro One Transmission property other than transmission lines and not classified as a transmission station (for example, a service centre), is assessed using only the CVA method. The Municipal Property Assessment Corporation assigns the total assessed value, which is updated utilizing the same schedule as for the rest of the Province. Provincial reassessment was issued for 2012 tax year, the next scheduled province wide assessment is 2016. Under the Assessment Act, an increase in assessed value between January 1, 2008 and January 1, 2012 is phased in over four years, from 2013 to 2016, assuming the property characteristics and assessment evaluation stays the same.

Notices of Assessment are received and reviewed for accurate valuation and tax classification each year. Any incorrect classes and/or over-valuations are appealed through the Municipal Property Assessment Corporation, and/or the Assessment Review Board.

Additional property tax payments, called proxy property taxes, for owned transmission stations are levied and paid to the Minister of Finance, to be applied against the stranded debt of the former Ontario Hydro. The details of this additional assessment are contained within Ontario Regulation 224/00 under the Electricity Act, 1998. The additional tax is the difference between the statutory rate for transmission station buildings and the municipal tax that would apply to the buildings if they were taxed using the CVA method. This amount is calculated each year for each transmission station owned by Hydro One Transmission.

Ontario Power Generation Inc. ("OPGI") is the owner of various properties within the Province of Ontario, on which are located Hydro One Transmission's facilities. OPGI and Hydro One Networks entered into lease and easement agreements with respect to these properties, effective April 1, 1999. Under subsection 5.01 of the easements and subsection 8(b) of the lease agreements, Hydro One Transmission is required to pay realty taxes with respect to its occupancy, to OPGI.

Other municipal property tax costs relate to costs on other sundry properties, such as transmission communication towers, and administrative buildings.

2.2 Transmission Lines

Hydro One Transmission's line corridors are assessed, and municipal taxes are calculated at a rate per acre of owned corridor land. These rates were established by Ontario Regulation 495/98 made under the Municipal Act and Ontario Regulation 494/98 made under the Education Act, titled Tax Matter – Taxation of Certain Railway, Power Utility Lands. As payments are made based on an area of land multiplied by a legislated rate, appeals must be based on corrections to the area of the property, or on the decision to re-classify a property as outside the utility corridor tax class.

An additional amount is paid annually to various First Nations bands for Payment in Lieu of Taxes ("PILs"), covering transmission lines and transmission stations on reserves. Since June 1988, Section 83 of the Indian Act has provided for taxation by First Nations, of property interests on their Reserve lands. Hydro One Transmission makes payments in lieu of taxes similar to taxes paid to municipalities that have Hydro One Transmission facilities contained within them.

3.0 INDEMNITY PAYMENT TO PROVINCE

The Ontario Electricity Financial Corporation (OEFC) has indemnified Hydro One Transmission with respect to the failure of the transfer orders (orders used to establish the company as one of the successor companies to the former Ontario Hydro) in 1999. The OEFC indemnification covers any defects in the transfer orders encompassing the following areas:

- the transfer of any asset, right, thing, or any interest related to the business;
- some adverse claims or interests of third parties or based on property title deficiencies arising from the transfer orders, except for some claims and rights of the Crown; and,
- claims related to any equity account previously referred to in the financial statements of Ontario Hydro including amounts relating to any judgement, settlement or payment in connection with litigation initiated by certain utilities commissions.

The Province has unconditionally and irrevocably guaranteed to Hydro One Transmission the payment of all amounts owing by the OEFC under its indemnity. Hydro One Networks pays an annual fee of $5.0 million to the OEFC. As the transfer order relates primarily to land assets, the amount allocated to Hydro One Transmission is based on the proportion of Hydro One Transmission land assets in relation to the total land assets of Hydro One. This results in $4.5 million of the $5.0 million total being allocated to Hydro One Transmission.

4.0 RIGHTS PAYMENT

Through agreements or permits, Hydro One Transmission line facilities cross and/or occupy properties owned by railway companies (e.g. Canadian National) and/or governmental bodies (e.g. Federal Government, Rideau Canal). According to the terms of the individual agreements, Hydro One Transmission pays an annual fee to the railway companies and the government entities for the right to cross and/or occupy their properties. These agreements contain rental review provisions allowing for rent increases tied to increased land values, subject to negotiation by both parties. The Company anticipates increased costs as reviews within the individual agreements are triggered, due to recent increases in land values. Rights payments associated with the railway companies are currently under review and steps are being taken to reach new agreements.

At this point Hydro One is not able to predict the outcome nor the timing of the future negotiated agreements and the amount that it will have to pay to secure the crossing or occupation rights with railway companies. However, for planning purposes, the rights payments for the 2013 and 2014 test years are budgeted to be $3.0 million per year.

Through agreements or permits granted by the Department of Indian and Northern Affairs, Canada ("INAC"), Hydro One has approval for its transmission and distribution facilities (that is, lines and transformer and distribution stations), to cross and/or occupy First Nation Reserves. Some of these permits and agreements require Hydro One to pay annual rental fees, the payments of which are administered by INAC.

The transfer orders by which Hydro One acquired Ontario Hydro's electricity transmission, distribution and energy services businesses as of April 1, 1999 did not transfer title to some assets located on lands held for First Nations under the Indian Act (Canada). The transfer of title to these assets did not occur because authorizations originally granted by the federal Minister of Indian and Northern Affairs for the construction and operation of these assets could not be transferred without the consent of the Minister and the relevant First Nations or, in several cases, because the authorizations had either expired or had never been properly issued. The transmission portion comprises approximately about 82 kilometres of transmission lines, primarily, held by the OEFC. Under the terms of the transfer orders, Hydro One is required to manage these assets until it has obtained all consents necessary to complete the transfer of title of them to the Company. Hydro One is seeking to obtain from the relevant First Nations, the consents necessary to complete the transfer of title to these assets.

Hydro One cannot predict with accuracy the aggregate amount that it may have to pay to obtain the required consents; for planning purposes, however, the First Nations rights payments for the 2013 and 2014 test years are budgeted to be $1.5 million per year. This amount is based on continuing payments and the current status of the on-going negotiations with various First Nations bands.

CORPORATE STAFFING

1.0 OVERVIEW

Hydro One faces the prospect of unprecedented challenges in the years ahead associated with the availability of skilled and professional staff to operate, sustain and develop its transmission and distribution systems. Hydro One's greatest corporate risk with respect to its human resources continues to be an aging workforce and, with a world-wide scarcity of core skills in the electricity industry, a highly competitive labour market.

This issue and associated risks are not unique to Hydro One, but apply to the Canadian electricity sector as a whole. In its 2008 study of the Canadian electricity industry (*Powering Up the Future, 2008 Labour Market Information Study – Full Report*, available at www.brightfutures.ca), the Electricity Sector Council (ESC) states, "The Canadian electricity sector is about to enter into the eye of the perfect storm, whereby the supply of trained workers is decreasing just at the same time that a significant proportion of the current workforce is retiring, and the demand for electricity and investment in new capital and infrastructure projects is increasing". This has been borne out in a recently released update to the 2008 Labour Market Information Study (*Power in Motion – 2011 Labour Market Information Study)* where the ESC notes, "Between 2011 and 2016, Canada's electricity and renewable energy industry will need to recruit 45,000 new employees – almost half of the starting workforce, and more than twice the number recruited in the last five years. Of these new employees, 23,000 will be in critical occupations that are specific to the electricity industry. Many will replace a wave of specialized and experienced retirees. All will be on the leading edge of the Next Generation infrastructure". This study also highlights four key human resource challenges:

- Anticipate the pace of older boomer retirements, identify and prepare younger boomer replacements, and find additional Generation –X-ers.
- Plan technology training and certification programs to meet the needs of the next generation infrastructure and workforce
- Track labour market requirements and map recruiting plans for new IT occupations
- Plan strategies for competing with other employers and industries in a rapidly changing environment.

By December 31, 2011, approximately 1,150 Networks staff (transmission and distribution) were eligible for an undiscounted retirement. By December 31, 2013, approximately 1,460 Networks staff will be eligible for an undiscounted retirement. This number increases to approximately 1,633 by year end 2014. Hydro One is seeing a larger uptake in actual retirements. In 2009, 105 employees retired while in 2010, 137 employees retired. In 2011, 166 employees retired. This represents an increase of approximately 58% over the retirement uptake in 2009. To place this into context, between 2009 and 2011 cumulatively roughly 10% of the employees who were on staff at the start of 2009 have retired. This is a trend which is expected to continue through the next decade and is consistent with challenges faced by other utilities in the electricity sector throughout the world. Recent studies suggest that up to half the workforce in the North American electricity industry will be eligible for retirement in the next five years. Furthermore, it is anticipated that a greater number of staff eligible to retire will elect to retire sooner given the increased competition for these scarce resources in the marketplace.

Staff with new skill-sets and disciplines, in addition to traditional ones, will be required to work within the new infrastructure and with emerging technologies. Many of Hydro One's new employees will also be new to the transmission and distribution industry or to the workforce in general. As noted earlier, these problems are further exacerbated by competing demands for the same and limited supply of electricity sector workers, in Ontario, throughout Canada and globally.

To address this demographic challenge, Hydro One has been proactive by implementing a number of initiatives. These include implementation of a staffing strategy as well as recruitment and training of new staff. These initiatives are discussed in the sections which follow.

2.0 STAFFING STRATEGY

Hydro One has an integrated workforce for its transmission and distribution businesses. This allows Hydro One to take advantage of economies of scale and efficiencies that would not be available through separate transmission and distribution operations. Examples would include a centralized control centre, centralized fleet operations, and an integrated asset management strategy.

Hydro One utilizes a work-based approach to staffing, whereby the Company resources according to work programs rather than plans the work around the number of internal resources available. To address the fluctuating and seasonal nature of work programs, the Company maintains as much flexibility as possible by utilizing a variety of labour resources, including regular, temporary, hiring hall and contract staff.

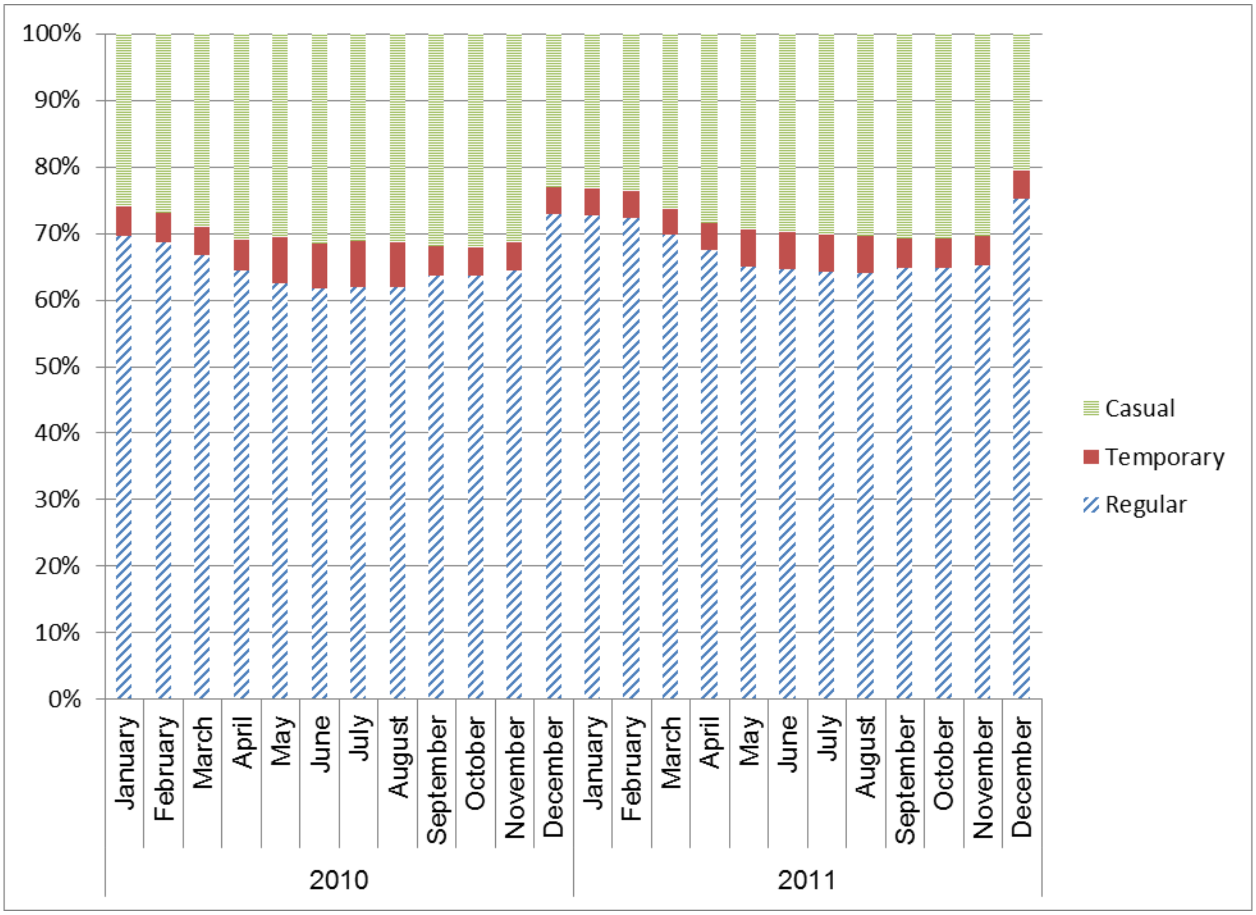
Matching staff to dynamic work programs requires a rigorous approach to staff planning. The company must consider the amount of work to be done, the nature of the work and the skills required, while at the same time looking for the most cost effective means of acquiring those skills, within the constraints of the collective agreements. Demographic and skills analyses are conducted annually to ensure that Hydro One retains the appropriate talent in the present and is positioned properly in the market to attract the talent we need in the future. In order to more accurately forecast retirements, human resources is developing a retirement forecasting model that will allow for more accurate data especially in key hiring classifications.

Progress has been made in attaining the optimal number and mix of staff required to complete the Company's increasing work programs. However, the increases in some of Hydro One's Transmission and Distribution programs will add additional challenges, given the tight competition for labour and power system professionals. It is essential because of the long learning curves required for competent performance of Hydro One's highly skilled jobs that the Company hires well in advance of expected retirements.

3.0 HEADCOUNT

Hydro One recognizes the concerns raised in previous Decisions with respect to increasing headcount. To that end, where possible, Hydro One uses non – regular resources (PWU Hiring hall, temporary employees, Consultants/Contractors). The chart below illustrates Hydro One employs a large number of non – regular staff through out the year to assist with its various work programs and match fluctuating requirements from month to month.

2010-2011 Headcount by Employee Classification



4.0 RECRUITMENT

To help address the significant wave of retirements in its critical trades, technical and engineering groups, Hydro One continues to hire, albeit at a lesser level than previous years, into its Apprentice and Graduate Training Programs. Since January 1, 2004, 311 graduate trainees have been hired through the Company's on-campus recruitment program. New Graduates bring not only much needed skills but also new perspectives and fresh energy to the work of Hydro One.

Hydro One also continues its recruitment into trades apprenticeship and technical training programs and has partnered with universities and colleges to develop curricula that educate students in areas where the Company faces a shortage of skilled professionals and trades people. Hydro One has taken a leadership role in support for power system engineering programs, assisting in developing on-line power system engineering programs and providing scholarships to encourage enrolment in key areas where the Company faces a labour shortage.

In addition, Hydro One, with the clear support of the PWU and the Society, has become a corporate participant in Career Bridge – a national, private-sector, non-profit initiative, which aims to provide internationally qualified professionals with Canadian work experience in their field of expertise in order to gain entry into the permanent workforce.

Hydro One will also continue its support of the University and College Co-Op Education Program, hiring approximately 300 co-op students a year. This is a mutually beneficial process in that Hydro One gains bright, skilled workers trained in the latest theories and practices for four-month or eight-month work-terms, while the students gain practical and relevant work experience that can be used to develop their future careers. Hydro One has also found that the Co-op programs have proven a rich source of talented candidates for Graduate Trainee positions by offering the Company an opportunity to assess the student's "fit" and long-term potential with the company. Once hired Hydro One's experience shows that these former co-op students have a shorter learning curve than other new hires with no previous Hydro One experience.

External recruitment into entry level new graduate or apprentice positions has been successful. Hydro One has had some difficulty attracting more experienced external candidates into higher rated technical, engineering and management positions. For these positions, factors such as compensation and head office location sometimes act as barriers to successful recruitment.

Hydro One believes a more sustainable and longer term strategy to deal with large scale retirements, is to invest in programs where knowledge transfer is the key objective. Programs such as new Grad and Apprentice Hiring, and knowledge documentation all contribute to ensuring knowledge is transferred to more junior staff.

5.0 TRAINING

To address the demographic issue, it is not enough to only hire new staff. Hydro One is active in developing current staff in order to enhance and/or develop new skills.

5.1 Trades and Technical Training

Hydro One provides a comprehensive selection of trades and technical training, designed to target the specific needs of field staff in relation to the work requirements of the asset base.

5.2 Leadership and Senior Management Development

The primary objective of this program is to ensure that Hydro One has a systematic management development framework. This helps ensure the Company retains a competitive advantage by developing, maintaining, and enhancing those management competencies deemed to be essential.

Hydro One has established a Management Development Steering Committee to oversee the identification of management development needs in the Company. The committee includes senior managers from both line and support functions, and is also responsible for the succession planning process.

5.3 Succession Planning

A Succession Planning Process has been developed for all senior management staff within the Company. The program's goal is to ensure that for each of the senior management positions, at least two successor candidates have been identified, and that a developmental plan for each of the candidates is developed and implemented.

5.4 Engagement

Hydro One has embarked upon a program committed to maintaining high levels of employee engagement. Employee engagement, which is a key differentiator in terms of business success, is the extent to which employees commit to someone or something in their organization. It can influence how hard they work and how long they stay as a result of that commitment. Engaged employees provide greater discretionary effort which often leads to increased productivity and other positive business outcomes. Hydro One has continued to make improvements to employee engagement.

5.5 Craft of Management

Since 2010, Hydro One has been active in implementing the *Craft of Management* program throughout the managerial levels. The *Craft of Management* is designed to introduce managers to a comprehensive and rigorous accountability based performance management system – a system that is based on clarity of accountabilities and authorities. The *Craft of Management* will lead to structures which better reflect the needs of the work and the accountabilities associated with the effective performance of that work, vertically and laterally within the organization. *Craft of Management* and Engagement are linked. Good managerial leadership – combined with an organization structures suitable to the needs of the work and with effective process to allow and encourage employees to do that work, together will drive engagement.

Other human resources productivity initiatives are described in Exhibit C1, Tab 4, Schedule 2.

6.0 HYDRO ONE'S LABOUR PROFILE

As part of Hydro One's strategy to efficiently and economically manage its fluctuating work requirements, Hydro One utilizes four broad groups of staff: regular employees, temporary employees, casual workers (the Building Trade Unions -BTU's under agreements with the Electrical Power Sector Construction Association – EPSCA, the Labourers' International Union of North America - LIUNA, the Canadian Union of Skilled Workers - CUSW, and Power Workers Union - PWU Hiring Hall employees) and contract staff, discussed below.

6.1 Regular Employees

Regular Employees of Hydro One can be placed in three categories:

i) PWU represented staff: The PWU is an industrial union that represents the trades, operators, technicians and clerical workers, totaling roughly two thirds of Hydro One regular staff. They perform line work, forestry, electrical, mechanical, protection and control, meter reading, stock keeping, system operation, technical and clerical/administrative work.

ii) Society represented staff: The Society is a professional union that represents engineers, technical, administrative and supervisory staff, totaling about one quarter of regular staff. They perform engineering, high level technical and administrative work as well as supervisory functions.

iii) Management staff, who are excluded from representation because they carry out managerial duties or work on confidential labour relations matters or legal matters.

6.2 Temporary Employees

Temporary employees are employees in any of the three categories set out above, engaged in work that is not of a continuing nature.

6.3 Casual Workers

Although the PWU does perform some construction work, the majority is performed by the PWU Hiring Hall, the Building Trades Unions (under agreements with EPSCA), the Labourers, and members of the Canadian Union of Skilled Workers

i) Hiring Hall Employees (PWU) are utilized to meet fluctuating work demands, performing primarily supplemental construction and maintenance work on the distribution system. Non-recurring work peaks and special projects are resourced through the hiring hall.

ii) Fifteen construction BTU's supply a contingent workforce through their hiring halls, negotiating their collective agreements with EPSCA. These represent the construction trades employed by Hydro One, with the exception of those represented by the CUSW and the Labourers.

iii) The Labourers' International Union of North America is a construction union that Hydro One negotiates with directly as opposed to via EPSCA.

iv) The CUSW represents lines and electrical tradespersons who work on transmission construction, including the construction of lines over 50kV, transmission stations, switchyards, substations, system control centres, and associated telecommunications systems. Construction employees are contingent workers, accessed through the hiring halls to perform specific work programs and then laid off. They are paid a total wage package (including benefits and pension payments) for each hour worked. This relationship ensures that workers with the required skill set are hired in the right location for only the exact duration of the work assignment and that Hydro One has no on-going obligations with respect to benefits or pension for them.

6.4 Contract Staff

Contract staff are individuals engaged as independent contractors, not on the Corporation's payroll. Contract staff are retained for their particular skill sets on projects, or to perform other work that is not of an ongoing nature. They are engaged at Hydro One for varying amounts of time and paid varying amounts commensurate with their skill sets and the market rate for that skill. Contract staff are tracked by work programs or activities and not by headcount. Where applicable, the procurement of contract staff is governed by the terms of the collective agreements between the Corporation and its respective unions.

7.0 SUMMARY

Attracting, motivating and retaining the right people is key to Hydro One's success. Despite the Company's efforts to date to ensure that it has an adequate supply of labour, it continues to face staffing challenges. Hydro One will continue to utilize a mix of regular, non-regular and contract staff in order to maintain the necessary flexibility to respond to this increased workload.

In an industry with aging demographics and a highly competitive labour market, Hydro One needs to be positioned as an attractive employer if it is to succeed in recruiting and retaining staff with the requisite skills. To do so, it must provide challenging and rewarding job opportunities and a competitive compensation package. Hydro One believes its staffing strategy will allow it the flexibility to respond effectively and efficiently to any scenario that will arise over the test years.

COMPENSATION, WAGES, BENEFITS

1.0 INTRODUCTION

In the last Transmission Decision, the Board expressed concern with rising compensation levels at Hydro One and directed the Company to update the compensation benchmark study completed by Mercer in 2008. Another study was conducted and the results show that Hydro One has succeeded in lowering total employee compensation as compared to market median. The results of this survey are detailed later in this exhibit as Attachment 1.

While lowering compensation cost relative to market median is desirable from a rate payer point of view, the fact remains, that Hydro One must attract and maintain a highly skilled workforce, in the face of an aging workforce and worldwide competition for similar skills. Coupled with the fact that Hydro One is heavily unionized and Hydro One was created with legacy collective agreements only adds to the challenge of further reducing compensation costs.

Despite these challenges, Hydro One has been successful in balancing the competing pressures of reducing compensation costs relative to market median at the same time as attracting and maintaining an engaged workforce. Ultimately, the rate payers benefit from the quality, expertise and reliability of Hydro One employees.

2.0 2011 COMPENSATION BENCHMARKING STUDY ("THE MERCER STUDY")

After consultation with intervenors, Hydro One issued an RFP in 2011 and selected Mercer to undertake a refresh of the compensation benchmarking survey. The full study report is provided as Attachment 1 to this schedule.

The Mercer study included approximately 2,200 Hydro One employees in 32 benchmark positions, representing 49% of Hydro One's employee population. In total, the Mercer analysis included approximately 10,400 incumbents employed in the Canadian energy and/or adjacent sectors.

The following table compares the latest survey results to those from the 2008 survey.

Mercer Compensation Benchmarking Survey Results vs. Market Median Total Compensation

Employee Group	2011 Survey Results	2008 Survey Results	Change
Management	-17%	-1%	-16%
Society	5%	5%	-
PWU	18%	21%	-3%
Overall	13%	17%	-4%

Findings showed that on an overall weighted average, Hydro One is positioned approximately 13% above market median. This is an improvement as compared to the 2008 Mercer survey where Hydro One's overall weighted average was found to be 17% above market median. Mercer stated the shift towards market median was notable, especially given the peer group, like Hydro One, had worked to minimize labour costs through the substantial economic downturn which began in 2008. In other words, Hydro One improved its standing against others in the peer group who were also attempting to reduce compensation costs.

For the individual groups, Hydro One management employees surveyed were found to be 17% below market median, a substantial reduction from the 2008 result of 1% below market median, reflecting the two year wage freeze and the impact of lower benefits available to management staff hired after January 1, 2004. Professionals (Society) were found to be 5% above market median (considered to be within the market median band) which was unchanged from the 2008 result which is not surprising given the Society collective agreement is effective until March 31, 2013. PWU staff were found to be 18%

above market median, an improvement from the 2008 result of 21% above market median reflecting the increased use of hiring hall staff and the increased pension contributions negotiated as part of the new collective agreement.

Study results are essentially determined by PWU compensation levels. The Mercer Compensation study found a few Hydro One classifications were above median, for instance, System Operator (30% above median), Regional Maintainer Lines (19% above median), Regional Maintainer Electrical (27% above median). However, Hydro One, where appropriate, is able to hire these similar classifications from the PWU Hiring Hall under a more favourable compensation model. Similarly, a few lower skilled positions are also above market median but again, Hydro One is able to utilize the PWU hiring hall to accomplish work when these lower skills are required. As Hiring Hall resources do not receive Hydro One benefits or join the Hydro One Pension plan, these resources are less costly.

3.0 KEY HIGHLIGHTS OF HYDRO ONE NEGOTIATIONS RESULTS

The collective bargaining relationships at Hydro One are very complex and sophisticated. Hydro One and the bargaining agents with whom the Company negotiate are professionals and very seasoned in the area of collective bargaining. Hydro One has been able to achieve reasonable settlements with incremental cost reductions and increased flexibility in a variety of areas in every round of collective bargaining since 2001. Examples include:

- elimination of costly incentive pay plans
- reasonable economic increases

- reductions and cost containment in benefits improvements
- introduction of new salary schedules with lower starting rates and lower maximum rates
- introduction of a less costly pension plan
- increased employee pension contributions
- increased flexibility to contract out work
- reduction in the hourly rate for a variety of jobs
- increased flexibility to move staff
- increased utilization of contingent workers
- introduction of less costly classifications
- greater shift scheduling flexibility
- reduction in temporary work headquarter costs

In the most recent round of collective bargaining with the Power Workers' Union, the parties agreed to increase the employee pension contributions by .5%. In the last Transmission Decision, the Board commented that it expects to see demonstrated measurable progress towards increasing employee pension contributions.

As discussed further in Section 7.0 in this schedule, Hydro One has also negotiated substantially lower PWU and Society wage scales than OPG and Bruce Power as well as eliminated other additional payments still in place at other companies.

4.0 THE UNIONIZED ENVIRONMENT

Approximately 90% of the Hydro One work force is unionized. By law, Hydro One must negotiate collective agreements with each of its bargaining agents. The collective agreements establish the terms and conditions of the employment relationship for a fixed period of time. It is critical to understand that Hydro One inherited collective agreements from Ontario Hydro which established terms of employment. These legacy collective agreements established a ‘floor’ upon which future negotiations were based. While legacy collective agreements continue to strongly influence current Hydro One collective agreements, Hydro One has done much to change the status quo. Hydro One has been successful in incrementally reducing costs and/or increasing productivity through collective bargaining. Obtaining dramatic compensation reductions in the environment facing Hydro One is unrealistic.

Collective Agreements are legal contracts. In labour agreements, more so than commercial contracts, parties must also consider their longer term relationship. Hydro One’s Human Resources strategy is to negotiate fair and reasonable collective agreements to foster and promote healthy union – management relationships.

5.0 COLLECTIVE BARGAINING

5.1 PWU

An attempt by Hydro One to achieve significant cost reductions in wages, benefits and pension would likely result in a strike. The last PWU strike was in 1985 and lasted 12 days. It was handled by placing management and Society-represented staff in key functions to maintain operations/service to the extent possible. However, as a result of numerous downsizing programs, and reorganization of work, there are far fewer management staff available today with the requisite skills and experience to occupy key PWU positions during a strike. Furthermore, unlike other industries, Hydro One does not have a product that can be stockpiled. As a result, the Company would be unable to continue operations for a sustained period of time during a PWU strike.

Rather than risk jeopardizing the supply of reliable electricity, the company has sought to achieve overall cost reductions by negotiating increased management flexibility to run the operations, as opposed to wide scale reductions in wages, benefits and pensions.

5.2 Society

The Society was governed by mandatory mediation/arbitration since the formation of Hydro One until 2005. Mandatory arbitration is another legacy issue that entrenched terms and conditions into Society collective agreements inherited by Hydro One. Interest arbitrators are generally reluctant to reduce existing wage levels. Similarly where a service is declared an essential service, thereby not having the ability to strike, collective bargaining disputes are resolved using mandatory interest arbitration. The C.D. Howe Institute issued a study that examined the impact on wages when declaring a service an ‘essential service’.[1] This study concluded that an essential service designation resulted in higher wage increases than would otherwise have occurred in traditional collective bargaining.

Hydro One ended mandatory arbitration commencing with the 2005 collective bargaining. In the first set of negotiations without this dispute resolution tool, the Society initiated a 15-week strike. The strike was primarily in response to Hydro One’s desire to reduce wages and benefits and increase hours of work for new employees. Hydro One was requested by the Shareholder to enter into mediation – arbitration to end the strike. The resulting arbitration award resulted in some cost savings for future hires, highlighted with less costly pension provisions for new Society employees.

[1] The C.D. Howe Institute. “No Free ride: The Cost of Essential Services Designation”, Benjamin Dachis 2008.

6.0 COMPENSATION STRATEGY

Hydro One has experienced rapidly increasing transmission and distribution work programs since 2004. Resourcing of these work programs must occur on the most cost effective basis possible within a highly competitive labour market.

Attachment 2 provides year end compensation costs for Hydro One Networks (Transmission and Distribution) from 2009 to 2011 and forecasted year end compensation cost for the bridge and test years. The Company believes that the upward trend in these costs is reasonable in light of the steadily increasing transmission and distribution work programs since 2009, as well as the negotiated increases in labour rates.

Note this data does not reflect the revenue requirement for compensation for this Transmission Application as it represents payroll costs for Hydro One Networks in total i.e. both Distribution and Transmission.

For the period 2011-2014, the total Networks (Transmission and Distribution) work program is expected to increase by approximately 15.8% while the regular headcount is only expect to increase from year end 2011 by 1.9% by year end 2014.

Hydro One believes that the goal of reducing overall wages, pension and benefits for future new hires reflects a reasonable balance between the need to attract and retain new staff while pursuing a more favourable cost structure. This is a difficult balance to achieve – too much of a reduction in compensation and benefits will impact the ability to attract the new skills necessary to replenish the workforce. However, as outlined in Exhibit C1, Tab 5, Schedule 1, as the proportion of Hydro One staff qualifying for and taking early retirement is growing substantially, the goal of reducing compensation for future new hires will reduce overall compensation costs for Hydro One and its ratepayers.

Hydro One's best performers are highly marketable, and a number of management staff has left the company in recent years. The Hydro One succession plan has facilitated internal promotion and a smooth transition in most cases, but our internal replacement capacity is now significantly diminished in key areas. External recruitment has proven challenging as our compensation levels and structures have fallen below the market for top people.

7.0 COMPARISON OF COLLECTIVE AGREEMENTS

When assessing the prudency of Hydro One's collective agreements, a useful comparison would be the compensation wage scales for similar PWU and Society classifications in the Ontario Hydro successor companies as Hydro One competes for staff with these companies and is vulnerable to losing staff to these organizations. Such a comparison is instructive since all these wage scales have the same starting point, which is the establishment of the successor companies in 1999. It is important to compare compensation escalation based on total "dollar" base rates of similar classifications. Simply comparing accumulated base rate percentage increases does not capture the true difference between total base compensation paid at the successor companies.

In the two wage scale comparison tables for each of PWU and Society staff which follow the wage scale rates shown are for the top end of the wage scale band.

Power Workers' Union – Wage Comparisons, 1999 and 2011

	1999	2011	Percent Change
Mechanical Maintainer/Regional Maintainer - Mechanical			
Hydro One	$ 28.23	$ 40.63	44%
OPG	$ 29.08	$ 47.44	63%
Bruce Power	$ 29.08	$ 53.69	85%
Shift Control Technician/Regional Maintainer - Electrical			
Hydro One	$ 28.23	$ 40.63	44%
OPG	$ 30.31	$ 47.44	57%
Bruce Power	$ 30.31	$ 53.85	78%
Clerical – Grade 56 (based on 35-hour work week)			
Hydro One	$ 21.46	$ 30.90	44%
OPG	$ 21.46	$ 30.30	41%
Bruce Power	$ 21.46	$ 33.47	56%
Clerical – Grade 58 (based on 35-hour work week)			
Hydro One	$ 24.20	$ 34.84	44%
OPG	$ 24.20	$ 36.90	52%
Bruce Power	$ 24.20	$ 37.73	56%
Regional Field Mechanic/Transport & Work Equipment Mechanic			
Hydro One	$ 26.20	$ 37.72	44%
OPG	$ 26.20	$ 47.44	81%
Bruce Power	$ 26.20	$ 45.07	72%
Stockkeeper			
Hydro One	$ 23.27	$ 35.16	51%
OPG	$ 23.27	$ 36.90	59%
Bruce Power *	$ 23.27	$ 42.20	81%
Labourer			
Hydro One	$ 19.03	$ 27.39	44%
OPG	$ 19.03	$ 36.90	94%
Bruce Power *	$ 19.03	$ 42.20	122%

* Assumes that the position falls within the Civil Maintainer II classification and corresponding wage rate

As shown above, for PWU staff, Hydro One has negotiated substantially lower wage scales than OPG and Bruce Power for all seven positions with the exception of one.

Society of Energy Professional – Wage Comparisons 1999 and 2011

	1999	2011	Percent Change
MP2			
Hydro One	$ 77,954.79	$ 95,747.68	23%
OPG	$ 77,954.79	$ 97,630.49	25%
Bruce Power	$ 77,954.79	$ 95,954.10	23%
IESO	$ 77,954.79	$ 112,545.43	44%
MP4			
Hydro One	$ 88,651.39	$ 108,844.49	23%
OPG	$ 88,651.39	$ 110,963.28	25%
Bruce Power	$ 88,651.39	$ 109,093.06	23%
IESO	$ 88,651.39	$ 127,940.01	44%
MP6			
Hydro One	$ 100,756.80	$ 123,715.39	23%
OPG	$ 100,756.80	$ 126,165.96	25%
Bruce Power	$ 100,756.80	$ 124,052.10	23%
IESO	$ 100,756.80	$ 145,478.84	44%

For Society staff, Hydro One, OPG and Bruce Power have successfully negotiated lower end rates as compared to the PWU wages. However, for all three Society categories, Hydro One does have lower wage scales than OPG and Bruce Power. The IESO has continued with the wage schedule structure that existed at demerger.

In addition to the comparison of base rate wage scales, the following two charts highlight significant additional incentives and allowances over and above the base rate wage scales for each of PWU and Society staff at other successor companies. These incentives are not reflected in the preceding wage scale comparison tables.

PWU– Additional Payments, 2009

	Incentive Pay
Hydro One	• No skilled based/competency payment.
OPG	• In 2002, OPG introduced Skill Broadening, which led to eligible employees receiving a $1,000 lump sum, as well as a wage increase of 5% (in addition to the general wage increase of 2% for that year).
Bruce Power	• In 2003, Bruce Power implemented a competency-based progression plan, which provided up to a 12% increase for journeypersons and a 6% increase for supervisors. • Bruce Power has also introduced Multi Trade rates for certain classifications, which are higher than the competency-based rates.

Society of Energy Professionals – Additional Payments, 2009

	Incentive Pay
Hydro One	• No incentive plan.
OPG	• Pays a number of bonuses for supervision, specialized work, training/certification and retention. • More provident benefit plans than Hydro One. For example, paramedical care: OPG provides $1500 per year; Hydro One provides $500 per year based on 50% co-insurance.
Bruce Power	• Has a bonus plan for 2009, which if Company targets are met, pays 2% for MP2 and MP3, 4% for MP4 and MP5, 6% for MP6 (additional 1% available if stretch targets met). • Pays a number of bonuses for supervision, specialized work, training/certification and retention.
IESO	• Has a Performance Pay Plan where the Company will make a minimum performance payout of 1.5% of base payroll.

It is quite clear that compared to these four other companies, Hydro One has been quite successful in controlling costs in collective bargaining over the past ten years to the benefit of all ratepayers.

8.0 POWERLINE TECHNICIAN RATE COMPARISON

Within Ontario, the largest LDC's are Hydro One Networks, Toronto Hydro, Hydro Ottawa, Enersource, London Hydro, Horizon Utility and Powerstream. Each of these LDC's employ Powerline Maintainers (PLM's). Table 1 compares the PLM rate at each of these LDC's to the PLM rate paid at Hydro One Networks. The PLM classification was chosen since it represents a highly skilled and highly populated classification that is core to the other LDC's.

Table 1

Company	Classification	Wage – 2012($hr)	H1 % Difference
Hydro One	Powerline Maintainer	38.75	-
Toronto Hydro	Power Line or Cable Person	40.26	-3.9%
Enersource	Power Line Technician	38.95	-.5%
Powerstream	Linesperson	38.31	+1.1%
Horizon	Powerline Maintainer	37.88	+2.3%
London Hydro	Powerline Maintainer	36.42	+6.0%
Hydro Ottawa	Power Line Maintainer	36.53	+6.0%

The Hydro One Powerline Maintainer classification has been used to compare the base hourly rate to the LDC's in order to have a proper comparison. Hydro One uses a multi skilled position called a Regional Maintainer – Lines classification (RLM). The RLM uses the PLM as the base job with additional duties such as lead hand, contract monitor, establishment and holding of work protection as well as additional technical, trade and customer relations skills beyond the Powerline Maintainer classification.

Table 1 illustrates that the PLM rate at Hydro One ranges from being slightly below to slightly above the larger LDC's in Ontario. Despite the rates being very close, the type of work and skills required at Hydro One are often more complex. Hydro One employees' often work in a more rural setting than their counterparts in other LDC's. As a consequence, Hydro One employees can work in conditions and with equipment not normally required at these LDC's. Trades employees working on lines maintenance often work on both Distribution and Transmission assets and are required to be knowledgable and proficient with overhead, underground and submarine cable. Again, this is not typical of the PLM role in other Ontario LDC's.

9.0 SUMMARY

Compensation levels at Hydro One are reasonable and appropriate given the environment in which the Company operates. In recent years, despite significantly increased work volumes, overall costs have been minimized by the simplification of required job skills and pay levels where appropriate. Hydro One's demographic challenge requires the Company to be active in the labour market place and with worldwide competition for these skills, there is a need for competitive compensation.

The updated Mercer Total Compensation Study demonstrates that there has been a significant improvement in total compensation costs at Hydro One relative to market median. It is important to emphasize that in a time where other organizations are facing similar cost pressures, Hydro One has lowered its overall total compensation by 4% against the peer group.

A strong barometer of Hydro One's ability to restrict compensation increases is a direct comparison to companies such as OPG, Bruce Power, and IESO. Hydro One competes directly with these organizations for skilled workers. Hydro One is also at risk of losing experienced staff to these organizations if our compensation is not competitive. Despite these competitive pressures, Hydro One has negotiated compensation levels that are less costly than OPG, Bruce Power and the IESO.

In addition, in a heavily unionized environment, there are significant constraints on an employer's ability to reduce compensation costs per employee. However, despite these constraints, the Corporation has made gains with the reduction in the area of compensation and benefit reductions.

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COMPENSATION COST BENCHMARKING STUDY

HYDRO ONE NETWORKS INC.

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Executive Summary

Hydro One Inc. ("Hydro One") has retained Mercer to prepare an independent, testable and repeatable market-based assessment of the reasonableness of Hydro One's total compensation levels including salary, short-term incentives, long-term incentives, pension and employer paid health and group benefits relative to a select peer group. This study was first conducted in 2008 and repeated, following a similar, but improved, methodology in 2011. Year-over-year trend analysis is provided.

The preliminary results of our analysis were presented at the October 19, 2011 stakeholder session in Toronto. This document represents the results of our analysis. Specifically:

Compensation Benchmarking

Consistent with the Stakeholder feedback, the compensation benchmarking component of the study compared Hydro One with the 2008 Transmission, Distribution and Generation market peer group, supplemented with participants from the Similar Regulatory Environment group.

The study reflected approximately 3,300 Hydro One employees in 32 benchmark positions representing 49% of Hydro One's employee population. In total, our analysis reflected approximately 10,400 incumbents employed in the Canadian energy and/or adjacent sectors.

On an overall weighted average basis, for the positions we reviewed in 2011, Hydro One is positioned approximately 13% above the market 50th percentile ("P50"). In comparison to the 2008 study, Hydro One's overall weighted average positioning has decreased from 17% above the market total compensation P50.

The Hydro One positioning shift towards the median is notable given that the peer group, like Hydro One, has worked to minimize labour costs through the substantial economic downturn which ensued between the 2008 and 2011 compensation cost benchmarking studies.

The overall Hydro One positioning is driven by a combination of competitive base salaries, especially for the most highly skilled Power Workers' Union ("PWU") positions, and the high relative value of legacy, pension and benefits programs (the legacy Management pension and benefit and Professional pension plans are now closed to new members).

The table below summarizes the results of the 2011 Compensation Cost Benchmarking Study compared to the results of the 2008 study.

Table 1

Legend
X 2011 Hydro One position relative to market P50
● 2008 Hydro One position relative to market P50

Total Compensation (Current)

Below P50 Compensation — Above P50 Compensation

#	Employee Group	(#) of Hydro One Incumbents	2011 Multiple of P50	2008 Multiple of P50	0.5	0.75	P50 = 1	1.25	1.5
	Weighted Average Non-Represented	137	**0.83**	0.99					
	Weighted Average Professionals	779	**1.05**	1.05					
	Weighted Average Power Workers	2,411	**1.18**	1.21					
	Weighted Average All	3,327	**1.13**	1.17					

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Introduction

Hydro One Inc. ("Hydro One") has retained Mercer to prepare an independent, testable and repeatable market-based assessment of the reasonableness of Hydro One's total compensation levels including salary, short-term incentives, long-term incentives, pension and employer paid health and group benefits relative to a select peer group. This study was first conducted in 2008 and repeated, following a similar, but improved, methodology in 2011. Year-over-year trend analysis is provided.

This report is intended to provide objective market analysis to assist Hydro One in responding to the request from the Ontario Energy Board ("OEB") EB-2010-002 Decision with Reasons [page 20] of December 23, 2010. We understand that Hydro One has been asked to provide "useful and reliable information conceming Hydro One's compensation costs, and how they compare to those of other regulated transmission and/or distribution utilities."

To provide independent and reliable information on Hydro One's relative compensation costs, Mercer has undertaken a customized survey of total compensation costs in the market ("Compensation Benchmarking").

The total compensation (i.e., base salary, short-term incentives, long-term incentives, pension and benefits) benchmarking analyses focused on assessing Hydro One's overall competitiveness in the marketplace.

The objective of this study was to provide independent compensation benchmarking information using generally accepted benchmarking approaches based on market practice. The objective was not to review the appropriateness of Hydro One's compensation levels.

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Guiding Principles and Stakeholder Requests

Based on our typical benchmarking approach and key points of agreement from the May 30, 2011 stakeholder meeting in Toronto[1], the benchmarking principles and stakeholder input that guided the compensation benchmarking, as well as how Mercer applied them, include:

1. Principle objective – to revisit the 2008 Mercer Study to appropriately compare Hydro One compensation costs to those of regulated Transmission and Distribution utilities in North America.
   - The 2008 Mercer Study was revisited following the same general overall methodology to provide appropriate study-over-study comparisons.

2. Keep it simple to entice survey participants.
   - The data collection process was reviewed and streamlined, where possible, to encourage survey participants to share data. Additional follow-up was provided by Mercer to support comparator participation in the study.

3. Be independent, testable, repeatable and market-based.
   - The study was conducted in a manner that meets each of the criteria listed.

4. Provide participants with the assurance that their information could not be attributable to them.
   - All participants were assured that data would be held confidentially by Mercer and only be shared in aggregate form.

5. Be based on the groups surveyed in the 2008 Mercer Study and expanded as deemed appropriate by the consultant.
   - All peers included in the 2008 Mercer Study were invited to participate in the 2011 study. In addition, the sample of invited peers was expanded to include large Ontario local distribution companies and other Canadian transmission and distribution companies. This resulted in four new participants.

6. Mirror the scoping in the 2008 Mercer Study for peer selection, job classes, etc. and changed as deemed appropriate by the consultant.
   - The same methodology as 2008 was followed in the 2011 Mercer Study to select peers and job classes for inclusion, resulting in participation from 4 additional comparator companies and inclusion of 5 new job classes representing 362 Hydro One incumbents.

7. Enable reasonable comparison to the last Mercer study and provide trending analysis for Hydro One.
   - By including approximately 70% of peers and 90% of jobs from the 2008 Mercer Study, reasonable comparisons have been made and trending has been assessed.

[1] Meeting Notes from May 30, 2011 meeting prepared by Optimus SBR.

8. Consider median, or the mean, or both.
   - The 2011 Mercer Study is based on a comparison of Hydro One median compensation against market median compensation. Comparison of medians is standard compensation practice; medians are representative of the middle data point in a sample and are less sensitive to outliers than the mean.
   - Appendix A provides a comparison of Hydro One median against market average. On an overall weighted basis, there is a 1% decrease in positioning relative to market when comparing Hydro One median to market median and market average.

9. Consider adjustments to reflect regional costs of living amongst the study participants.
   - The majority of large Canadian organizations do not administer regional pay, therefore, it is not meaningful to adjust market levels based on region of operations. Furthermore, Hydro One does not manage pay on a regional basis.

10. Request data about pension as a percentage of total benefits, and benefits as a percentage of compensation.
    - It is standard benchmarking practice to assess benefits and pension costs as a total compensation value provided to employees; therefore, we have not provided this analysis.

11. Rely on the expertise of the selected consultant to recommend appropriate changes in methodology and assumptions.
    - Hydro One relied on Mercer's expertise in conducting the study; however, material changes in methodology and assumptions were not recommended.

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Compensation Benchmarking

Peer Groups

Mercer typically selects peer organizations, for compensation benchmarking purposes, based on a stable metric that reflects the size and operating complexity of the organization (typically, this is revenue and/or total assets). Where there is a relatively small sample of relevant comparator organizations, Mercer establishes limits of 33% to 300% of the scope criteria for the organization we are analyzing.

As a result, to develop a single peer group for Hydro One, we considered all organizations, with 2009 or 2010 annual revenues or total assets between 33% and 300% of Hydro One's 2010 annual revenue or total assets, from the following areas:

1. Electric utilities, multi-utilities, and gas utilities industries in Canada as classified by their Global Industry Classification Standard ("GICS")

2. 80 Local Distribution Companies ("LDCs") in Ontario

3. Other comparable regulated businesses (i.e., integrated telecommunication services, railroads, etc.)

Overall, 19 organizations were invited to participate in the study:

- All 13 organizations included in the 2008 study were invited
  - Of these organizations, 4 declined (Bell Canada, TransCanada Corp., EPCOR Utilities and Bruce Power)
- Six new organizations were invited
  - Of these organizations, 4 agreed to participate (Altalink, Canadian Utilities, PowerStream and SaskPower)

Organizations that did not participate in the compensation benchmarking indicated that they were unable to participate due to either resource constraints or an insufficient number of relevant benchmark positions.

Following standard industry practice, comparisons were made between Hydro One's incumbents, at the 50th percentile, to the market peer group 50th percentile on base salary, total cash compensation and total compensation.

To ensure that no one organization biased the results, we have weighted our analysis by organization for each job class and not by incumbents to determine Hydro One's position relative to the market (i.e., the analysis is "Org Weighted"). To preserve the confidentiality of compensation data at both Hydro One and participating organizations, we have aggregated our results.

Market Sample

Summarized below are the participating organizations in the compensation benchmarking.

Table 2

All values in $CDmillions

Company Name	Revenue (1)	Total Assets (2)
Hydro Quebec	$11,790	$65,938
Enbridge Gas Distribution	$15,113	$30,093
OPG	$5,640	$27,584
BC Hydro	$3,822	$18,093
Manitoba Hydro	$1,737	$11,856
Transalta Corp.	$2,816	$9,884
Canadian Utilities	$2,657	$9,415
Saskpower	$1,751	$5,268
NB Power	$1,453	$5,190
ENMAX	$2,404	$3,883
Toronto Hydro	$2,612	$3,369
Altalink	$305	$2,377*
PowerStream	$778	$949*
75th %ile	$4,731	$22,839
50th %ile	$2,404	$6,436
25th %ile	$1,503	$4,312
Average	$4,435	$15,682
Hydro One	*$5,124 (3)*	*$17,322 (3)*

(1) Most recently reported annual revenue.
(2) Most recently reported annual total assets.
(3) Revenue and Total Assets as disclosed in Hydro One 2010 annual report.
(4) New participants in 2011: Altalink, Canadian Utilities, PowerStream, Saskpower.
(5) Participants in 2008 but not in 2011: Bell Canada/BCE, Bruce Power, EPCOR Utilities Inc., TransCanada Corp..
* Added on recommendation of Mercer.

Benchmark Positions

The compensation survey was designed to benchmark compensation levels from a cross-section of Hydro One's population. To determine the roles to be included in our benchmark analysis, we reviewed positions that represented all of Hydro One's major business units and at least 50% of Hydro One's employee population.

To assist with study over study comparisons, it was determined that Hydro One should collect incumbent data using the same 30 benchmark roles surveyed in the 2008 study. In addition to this list, Hydro One provided 5 additional benchmark roles to be included for the 2011 study:

- Senior Legal Counsel (Non-Represented)
- Area Superintendent (Non-Represented)
- Business Analyst A (Professionals)
- Electrical Apprentice (Power Workers)
- Lines Apprentice (Power Workers)

In total, 35 benchmark positions were included in the compensation benchmarking study and we were able to report data on 32 of these job. Due to limited data in the market, the following roles were excluded from the final analysis:

- Field Service Coordinator
- Tree Trimmer – Journeyman
- Network Mgmt Eng/Officer – this job was combined with the Engineer D job in our analysis due to a high overlap of responsibilities.

As a result, ***the 2011 Compensation Cost Benchmarking Study directly reflected approximately 3,300 Hydro One employees in 32 benchmark positions representing 49% of Hydro One's employee population.***

In the market, we collected over 10,400 individual incumbent observations across the benchmark positions (excluding the 3,300 Hydro One incumbents) ***employed in the Canadian energy and/or adjacent sectors.***

Summarized below are the benchmark positions organized by major employee group. The results in this report are summarized by the following employee groups. Specifically (sorted in descending total compensation by Group):

Table 3

Group	#	Job or Class
Non-Represented	1	Financial Director
	2	Top Rates and Regulatory Affairs Executive
	3	Senior Legal Counsel
	4	Engineer F
	5	Area Superintendent
	6	Human Resource Manager / Consultant
	7	Administrative Assistant
Professionals	8	Engineer E
	9	Business Analyst C
	10	Engineer D
	11	Engineer C
	12	Engineer B
	13	Business Analyst A
	14	Engineer A
Power Workers	15	System Operator (Controller)
	16	Regional Maintainer - Lines (Supervisor)
	17	Protection and Control Technician
	18	Area Distribution Engineering Technician
	19	Regional Maintainer - Lines
	20	Regional Maintainer - Electrical
	21	Fleet Mechanic
	22	Lineman - Journeyman
	23	Regional Maintainer - Forestry
	24	Service Dispatcher
	25	Drafter II
	26	Stock keeper
	27	Data Entry Clerk
	28	Production Field Administrator III
	29	Electrical Apprentice
	30	Lines Apprentice
	31	Meter Reader
	32	General Labourer

"Professionals" refers to Hydro One positions represented by the Society of Energy Professionals (i.e., "Society") and "Power Workers" refers to Hydro One positions represented by the Power Workers' Union (i.e., "PWU").

See Appendix B for a summary of position descriptions.

Methodology

As outlined in Appendix B, summarized below is the methodology used to determine compensation levels. Specifically:

Base Salary/Wage – Annual base salary at April 1, 2011. If an hourly rate was reported, we annualized the value by multiplying the standard number of work hours per week by 52 weeks per year. If a weekly rate was reported, we annualized the value by multiplying by 52 weeks per year.

- Data effective April 1, 2011 captures Hydro One's most recent collective agreement terms.

Total Cash Compensation - Base salary ***plus*** most recent short-term incentive or bonus paid where applicable.

- Hydro One does not provide short-term incentive or bonus programs to Professional or Power Worker positions.

Benefits and Pensions – To value benefit and pension programs, we applied a relative value process to a set of standard employer paid cost factors, plus actuarial and demographic assumptions to measure all financially significant features of benefit and pension programs based on open and closed plans.

Total Compensation – Total cash compensation ***plus*** estimated annual value of most recent long-term incentive grant (i.e., expected value of stock options or share awards) and pensions and benefits.

- Hydro One does not provide long-term incentive programs to any positions.

Findings

Summarized below are the results of our compensation benchmarking analysis.

Overall, **on a weighted average basis, Hydro One's total compensation cost is 13% above market median.** Hydro One's position relative to the market 50th percentile varies by employee group from a low of 17% below market P50 for the non-represented group and a high of 18% above the market P50 for the PWU.

In the 2008 study, Hydro One's overall weighted average was 17% above the market total compensation P50 – a 4% shift towards the market median has occurred since 2008.

Table 4

Legend
X 2011 Hydro One position relative to market P50
● 2008 Hydro One position relative to market P50

Total Compensation (Current)

Below P50 Compensation | Above P50 Compensation

#	Position	(#) of Hydro One Incumbents	2011 Multiple of P50	2008 Multiple of P50	0.5	0.75	P50 = 1	1.25	1.5
	Weighted Average Non-Represented	137	0.83	0.99		X	●		
	Weighted Average Professionals	779	1.05	1.05			X●		
	Weighted Average Power Workers	2,411	1.18	1.21				X●	
	Weighted Average All	3,327	1.13	1.17				X●	

The results are driven by a combination of competitive base salaries, especially for the most highly skilled Power Workers' Union ("PWU") positions, and the relatively high value of legacy collective agreement wages, pension and benefits programs (the legacy Management pension and benefit and Society pension plans are now closed to new members).

We understand that these legacy plans relate to collective agreements negotiated prior to the formation of Hydro One. All PWU employees continue to be covered by the legacy plans. Even if all Non-Represented and Professional employees were covered by the new plans, the difference in overall cost on a weighted average basis appears to be minimal as the high population Power Worker positions continue to be covered by the legacy plans; however, the use of the "hiring hall" for several of the PWU benchmarks does appear to reduce compensation costs relative to both other PWU positions and our market data.

For new employees hired into Non-Represented and Professional job classifications, the value of pensions and/or benefits, where applicable, have decreased due to recent amendments to these plans (see "Future" on the following pages).

Furthermore, the Hydro One Professional employee group surveyed positions include 115 incumbents compensated at legacy wage levels which exceed the current Hydro One salary bands (these incumbents continue to receive labour contract cost of living increases but no further step-ups in wages). Assuming all other variables remain constant, as these incumbents retire (resulting in fewer incumbents compensated above the salary bands), the Professional employee group positioning will shift 2% closer to market median on base salary, total cash and total compensation (current) and 1% closer to market median on total compensation (future). Note that the benchmarking survey did not gather legacy wage data from the peer group.

We note that, when measured on revenue, Hydro One is the fourth largest organization in the sample. Although size has a limited impact on middle management and unionized roles, size may have an impact on compensation for executive roles, as these roles tend to be larger and more complex in larger organizations.

At stakeholder request, in addition to comparing Hydro One P50 to market P50, a comparison was also made of Hydro One median to market average (mean). On a weighted average basis, Hydro One's total compensation cost is 12% above market average. Hydro One's position relative to market varies by employee group from a low of 16% below market average for the non-represented group and a high of 15% above the market average for the PWU. In conclusion, there is relatively little difference between the market median and market average. See Appendix A for detailed results.

Non-Represented

Summarized below are our results for the Non-Represented roles that we benchmarked at Hydro One relative to the market peer group.

In comparison to 2008, the 2011 Total Compensation (Current) results have decreased from 1% below market median to 17% below market median.

Table 5

		2011			
		Hydro One P50 Relative to Market P50[1]			
				Total Compensation[3]	
Position Title	**Hydro One # of Incs**	**Base Salary**	**Total Cash[2]**	**Current[4]**	**Future[5]**
Financial Director	3	-7%	3%	9%	5%
Top Rates and Regulatory Affairs Executive	4	-15%	-17%	-34%	-34%
Senior Legal Counsel	8	1%	5%	10%	6%
Engineer F	91	-22%	-25%	-21%	-23%
Area Superintendent	15	-2%	-8%	-3%	-3%
Human Resource Manager / Consultant	10	-28%	-35%	-30%	-34%
Administrative Assistant	6	8%	7%	6%	6%
2011 Weighted Average Non-Represented	**137**	**-17%**	**-20%**	**-17%**	**-18%**
2008 Weighted Average Non-Represented	**151**	**-2%**	**-4%**	**-1%**	**-5%**

Note:

(1) Market results weighted by organization (i.e., for each participating company we determined one average value per position).

(2) Base salary, plus short-term incentive (i.e., bonus) where applicable.

(3) Total cash compensation, plus estimated value of long-term incentives, benefits and pensions. (Note: Hydro One does not provide long-term incentives)

(4) Based on Hydro One's employee population assuming current pension and benefit program eligibility.

(5) Based on Hydro One's employee population assuming all in the new pension and benefits programs.

Professionals ("Society")

Summarized below are our results for the Professional roles that we benchmarked at Hydro One relative to the market peer group.

In comparison to 2008, the 2011 Total Compensation (Current) results have remained unchanged at 5% above market median.

Table 6

		2011			
		Hydro One P50 Relative to Market P50[1]			
				Total Compensation[3]	
Position Title	Hydro One # of Incs	Base Salary	Total Cash[2]	Current[4]	Future[5]
Engineer E	130	-3%	-9%	-3%	-6%
Business Analyst C	12	28%	19%	28%	28%
Engineer D	256	3%	-9%	-3%	-6%
Engineer C	15	16%	9%	23%	19%
Engineer B	239	13%	0%	12%	12%
Business Analyst A	13	6%	6%	14%	14%
Engineer A	114	8%	5%	14%	14%
2011 Weighted Average Professionals	**779**	**6%**	**-3%**	**5%**	**4%**
2008 Weighted Average Professionals	**578**	**8%**	**-2%**	**5%**	**3%**

Note:

(1) Market results weighted by organization (i.e., for each participating company we determined one average value per position).

(2) Base salary, plus short-term incentive (i.e., bonus) where applicable. (Note: Hydro One does not provide a bonus).

(3) Total cash compensation, plus estimated value of long-term incentives, benefits and pensions. (Note: Hydro One does not provide long-term incentives)

(4) Based on Hydro One's employee population assuming current pension and benefit program eligibility.

(5) Based on Hydro One's employee population assuming all in the new pension program (no change to benefits).

Power Workers

Summarized below are our results for the Power Worker roles that we benchmarked at Hydro One relative to the market peer group.

In comparison to 2008, the 2011 Total Compensation results have improved from 21% above market median to 18% above market median.

Table 7

	2011			
		Hydro One P50 Relative to Market P50[1]		
				Total Compensation[3]
Position Title	Hydro One # of Incs	Base Salary	Total Cash[2]	Current[4]
System Operator (Controller)	91	18%	18%	30%
Regional Maintainer - Lines (Supervisor)	89	20%	20%	31%
Protection and Control Technician	86	30%	27%	38%
Area Distribution Engineering Technician	179	15%	15%	27%
Regional Maintainer - Lines	756	10%	10%	19%
Regional Maintainer - Electrical	233	16%	16%	27%
Fleet Mechanic	66	15%	15%	27%
Lineman - Journeyman*	52	19%	17%	18%
Regional Maintainer - Forestry	304	-2%	-6%	4%
Service Dispatcher	21	40%	33%	45%
Drafter II	32	35%	31%	44%
Stock keeper	51	36%	36%	43%
Data Entry Clerk	79	16%	14%	27%
Production Field Administrator III	3	-7%	-7%	4%
Electrical Apprentice	71	1%	1%	-2%
Lines Apprentice	255	-6%	-6%	-5%
Meter Reader	15	-8%	-14%	-13%
General Labourer*	28	-1%	-5%	-13%
2011 Weighted Average Power Workers	**2,411**	**10%**	**9%**	**18%**
2008 Weighted Average Power Workers	**1,966**	**20%**	**16%**	**21%**

Note:
(1) Market results weighted by organization (i.e., for each participating company we determined one average value per position).
(2) Base salary, plus short-term incentive (i.e., bonus) where applicable. (Note: Hydro One does not provide a bonus).
(3) Total cash compensation, plus estimated value of benefits and pensions. Assumes current pension and benefits program eligibility.
(4) Based on Hydro One's employee population assuming current pension and benefit program eligibility.
*Hydro One data effective June 1, 2011.

APPENDIX A

Hydro One vs. Market Average

As requested by stakeholders, summarized below are the results of our compensation benchmarking analysis comparing Hydro One median to market average.

Overall, **on a weighted average basis, Hydro One's total compensation cost is 12% above the market average (mean)**. Hydro One's position relative to market varies by employee group from a low of 16% below the market average for the non-represented group to a high of 15% above the market average for the PWU.

Table 8

Legend
X 2011 Hydro One position relative to market average
● 2008 Hydro One position relative to market P50

Total Compensation (Current)

Below P50 Compensation | Above P50 Compensation

#	Position	(#) of Hydro One Incumbents	2011 Multiple of Avg	2008 Multiple of P50	0.5	0.75	P50 = 1 Avg = 1	1.25	1.5
	Weighted Average Non-Represented	137	**0.84**	0.99		X	●		
	Weighted Average Professionals	779	**1.06**	1.05			X ●		
	Weighted Average Power Workers	2,411	**1.15**	1.21				X ●	
	Weighted Average All	3,327	**1.12**	1.17			X	●	

Non-Represented

Summarized below are our results for the Non-Represented roles that we benchmarked at Hydro One relative to the market peer group.

Table 9

		2011			
		Hydro One P50 Relative to Market Average[1]			
				Total Compensation[3]	
Position Title	Hydro One # of Incs	Base Salary	Total Cash[2]	Current[4]	Future[5]
Financial Director	3	-5%	5%	2%	-1%
Top Rates and Regulatory Affairs Executive	4	-13%	-16%	-26%	-26%
Senior Legal Counsel	8	-5%	-3%	0%	-3%
Engineer F	91	-18%	-19%	-18%	-20%
Area Superintendent	15	-2%	-12%	-10%	-10%
Human Resource Manager / Consultant	10	-30%	-32%	-30%	-34%
Administrative Assistant	6	5%	2%	3%	3%
Weighted Average Non-Represented	137	-15%	-17%	-16%	-17%

Note:
(1) Market results weighted by organization (i.e., for each participating company we determined one average value per position).
(2) Base salary, plus short-term incentive (i.e., bonus) where applicable.
(3) Total cash compensation, plus estimated value of long-term incentives, benefits and pensions. (Note: Hydro One does not provide long-term incentives).
(4) Based on Hydro One's employee population assuming current pension and benefit program eligibility.
(5) Based on Hydro One's employee population assuming all in the new pension and benefit programs.

Professionals ("Society")

Summarized below are our results for the Professional roles that we benchmarked at Hydro One relative to the market peer group.

Table 10

		2011			
		Hydro One P50 Relative to Market Average[1]			
				Total Compensation[3]	
Position Title	Hydro One # of Incs	Base Salary	Total Cash[2]	Current[4]	Future[5]
Engineer E	130	-1%	-10%	-3%	-6%
Business Analyst C	12	24%	17%	24%	23%
Engineer D	256	3%	-5%	1%	-2%
Engineer C	15	15%	8%	18%	15%
Engineer B	239	10%	4%	11%	11%
Business Analyst A	13	10%	5%	12%	12%
Engineer A	114	8%	6%	11%	11%
Weighted Average Professionals	**779**	**6%**	**-1%**	**6%**	**4%**

Note:

(1) Market results weighted by organization (i.e., for each participating company we determined one average value per position).

(2) Base salary, plus short-term incentive (i.e., bonus) where applicable. (Note: Hydro One does not provide a bonus).

(3) Total cash compensation, plus estimated value of long-term incentives, benefits and pensions. (Note: Hydro One does not provide long-term incentives).

(4) Based on Hydro One's employee population assuming current pension and benefit program eligibility.

(5) Based on Hydro One's employee population assuming all in the new pension program (no change to benefits).

Power Workers

Summarized below are our results for the Power Worker roles that we benchmarked at Hydro One relative to the market peer group.

Table 11

		2011		
		Hydro One P50 Relative to Market Average[1]		
				Total Compensation[3]
Position Title	Hydro One # of Incs	Base Salary	Total Cash[2]	Current[4]
System Operator (Controller)	91	17%	17%	25%
Regional Maintainer - Lines (Supervisor)	89	22%	20%	29%
Protection and Control Technician	86	30%	28%	38%
Area Distribution Engineering Technician	179	15%	15%	24%
Regional Maintainer - Lines	756	10%	10%	17%
Regional Maintainer - Electrical	233	10%	9%	17%
Fleet Mechanic	66	16%	14%	21%
Lineman - Journeyman*	52	17%	13%	15%
Regional Maintainer - Forestry	304	-2%	-6%	4%
Service Dispatcher	21	32%	29%	39%
Drafter II	32	24%	19%	30%
Stock keeper	51	36%	34%	45%
Data Entry Clerk	79	19%	15%	27%
Production Field Administrator III	3	-6%	-6%	4%
Electrical Apprentice	71	-6%	-9%	-10%
Lines Apprentice	255	-2%	-2%	-5%
Meter Reader	15	-6%	-9%	-7%
General Labourer*	28	-2%	-3%	-12%
Weighted Average Power Workers	2,411	10%	8%	15%

Note:
(1) Market results weighted by organization (i.e., for each participating company we determined one average value per position).
(2) Base salary, plus short-term incentive (i.e., bonus) where applicable. (Note: Hydro One does not provide a bonus).
(3) Total cash compensation, plus estimated value of benefits and pensions. Assumes current pension and benefits program eligibility.
(4) Based on Hydro One's employee population assuming current pension and benefit program eligibility.
*Hydro One data effective June 1, 2011.

APPENDIX B

Position Descriptions

(#)	Survey Code	Generic Position	Generic Description
1	220.108.430	Administrative Assistant	Requires a general knowledge of departmental procedures, practices and office routine. Possesses good office and computer skills including word processing, spreadsheets, graphics software, dictaphone transcription, and filing. May provide assistance to a more senior Administrative Assistant in a large department.
2	999.999.001	Area Distribution Engineering Technician	Perform Technical support work for the Distribution Section of the area: such as monitoring the performance of the distribution system by performing various technical studies, identifying and recommending solutions to the supervisor, providing field data and preliminary analysis for engineering studies. Negotiate property settlements on distribution lines and perform joint use activities. Provide administrative support related to preparation of estimates and work orders (WO) work schedules, line layouts, joint use, provision of underground cable and fault location service. Perform staking activities and prepare design packages for new connections, service upgrades, extensions, betterments and relocations.
3	700.792.211	Area Superintendent	Responsible for providing construction management and supervision within the construction group. Administers construction contracts. Is accountable for construction costs, schedules, safety, product quality and environment performance. Provides input into Project Execution Plans and the associated schedules and estimates. Usual qualifications include 10 to 12 years of experience including supervisory experience. Requires experience in construction management and supervision of various trades.
4	320.392.360	Business Analyst A	Assists with analyzing internal metrics. Performs responsible and varied business analytical or administrative functions. Assists with preparation documents, forecast summaries, status reports, budget reports, etc. Duties may include interpreting and processing company contracts, AFEs, and government agreements. Assignments are given in terms of objectives and relative priorities. Problems may be solved by adapting standard methods or by practical applications of knowledge. Usual qualifications include a university degree.
5	320.392.340	Business Analyst C	Analyzes internal metrics. Performs responsible and varied business analytical or administrative functions. Prepares documents, forecast summaries, status reports, budget reports, etc. Duties may include interpreting and processing company contracts, AFEs, and government agreements. Assignments are given in terms of objectives and relative priorities. Problems may be solved by adapting standard methods or by practical applications of knowledge. Usual qualifications include a university degree with a minimum of 4 years' related experience; technical diploma with a minimum of 6 years' related experience.
6	999.999.002	Data Entry Clerk	Perform data processing services including inputting, updating, to various computerized databases and applications of external service providers. Perform clerical/administrative duties in support of system processes. Work with various internal and external contacts and customers in the set up, maintenance, reporting and follow up of non-electricity accounts, customer service orders, materials, corporate charge cards, time reporting, management reporting, damage claims, accounts receivable, etc. Perform administrative services for provincial client group and special projects.
7	510.656.420	Drafter II	Incumbent works on standard drafting assignments. Methods are detailed and standard but judgment is required in planning tasks and choice of methods. Accountable for accuracy and adequacy of work performed. May provide technical guidance to less experienced Drafters. Usual qualifications include a technical school diploma or equivalent, with a minimum of 5 years' related experience.
8	999.999.112	Electrical Apprentice	A five year apprenticeship leading to a Construction and Maintenance Electrician
9	510.780.360	Engineer A	Incumbent receives "on-the-job" training in various phases of office, plant or field engineering through assignments or, in some cases, classroom instruction. Tasks assigned are simple and routine in nature. Assists more senior engineers in the preparation of plans, calculations, reports, etc. Few technical decisions are made and these are routine, with clearly defined procedures and guidelines. Works under close supervision and work is reviewed for accuracy, adequacy and conformance with prescribed procedures. Usual qualifications include a university degree in engineering with minimal experience.
10	510.780.350	Engineer B	Uses a variety of standard problem solving techniques. May assist more senior engineers in carrying out technical tasks requiring computation methods. Duties are assigned with detailed oral, and occasionally written instructions. Work is reviewed in detail with guidance given. May give limited technical guidance to junior professionals or technicians working on a common project. Usual qualifications include a university degree in engineering with a minimum of 2 years' related experience.
11	510.780.340	Engineer C	Incumbent is responsible for varied engineering assignments requiring a broad knowledge of an engineering specialty and the effect the work has upon other fields. Solves problems using a combination of standard or modified procedures. Participates in planning objectives. Performs independent studies, and analyzes, interprets and draws own conclusions; more complex work projects are referred to more senior authorities. Not supervised in detail except on more difficult assignments. May give periodic technical guidance to less experienced professionals or technicians assigned to work on a common project. Usual qualifications include a university degree in engineering with a minimum of 4 years' related experience.

(#)	Survey Code	Generic Position	Generic Description
12	510.780.330	Engineer D	This is the first level of full engineering specialization and is considered the senior level position. Alternatively may be the level at which an individual acts as group leader or work task force leader of a small group of technical personnel. Requires application of well developed technical knowledge in planning, conducting and co-ordinating difficult assignments. The position requires the modification of established guidelines and initiation of new approaches. Makes independent decisions in planning, organizing and completing technical assignments. Work is reviewed for soundness of judgement but accepted technically as accurate and feasible. Work is assigned in terms of objectives and priorities but informed guidance is available. Advises on technical problems and supervision, and may plan, schedule and review work of professional engineers and technicians. May make recommendations concerning selection, training, discipline and remuneration of staff.
13	510.780.320	Engineer E	May have responsibility for co-ordinating engineering work assignments and making recommendations on technical applications developed by other professional personnel or consultants . May involve the direct supervision of a group of professionals. Provides guidance and training to less experienced staff. Checks work for accuracy and completeness. As a specialist, conducts special, complex and advanced level studies. Work is generally reviewed for results only. Makes independent decisions within broad guidelines and policies. May make recommendations concerning selection, training, discipline and remuneration of staff. May also responsible for construction.
14	510.780.310	Engineer F	Incumbent is considered an authority in an engineering field of specialization and acts as a technical consultant to the organization. This level is a dual-stream first level managerial position. Incumbents may be responsible for directing a staff of professional and support employees or act as a technical specialist. Responsible for planning and directing large engineering programs/projects; sets priorities and allocates resources; makes necessary decisions on all day-to-day operating matters within constraints of company policy. Receives work in terms of broad objectives.
15	210.100.130	Financial Director	Responsible for providing overall direction for tax, insurance, budget, credit and treasury functions for the organization. Provide short to medium term direction for all corporate financial functions so that financial transactions, policies, and procedures meet the organization's short and medium-term business objectives and are conducted in accordance with regulations, and standards. Activities may include: credit control; cash flow; investment management; tax; insurance; treasury; internal audit; budgeting and forecasting; and foreign exchange. Lead, direct, evaluate, and develop a team of senior managers to ensure that the organization's financial strategy is implemented effectively, consistently and according to established guidelines.
16	999.999.011	Fleet Mechanic	Be responsible for the inspection, repair and maintenance, as well emergency repair of vehicles (e.g. bucket truck, all terrain vehicles, go track, digger truck, ladder truck forklift, backhoe, manlift, vans/pickup trucks and the hydraulic equipment of the vehicles e.g. booms, buckets. Maintain inspection schedules and coordinate scheduling repairs to be contracted out. Work is performed in a garage or on site.
17	700.792.431	General Labourer/ Roustabout	This is the level at which individuals with no previous experience enter into the company. Acts as a general labourer. Works under close supervision within well defined procedures. Duties involve general field/plant maintenance or clean-up work. Minimum qualifications include a high school diploma with minimal related experience.
18	120.100.220	Human Resource Manager / Consultant	This position plans, designs, develops, implements and administers policies and programs through functional supervision in all or some of the following areas: employee relations, executive compensation, wage and salary administration, job evaluation, performance management, recruitment and selection and employment equity/ human rights.
19	920.788.410	Lineman - Journeyman	Responsible for the installation, maintenance, removal, and inspection of transmission/distribution power lines. Typically requires 4 years of experience and certification as a Power Line Technician (or equivalent).
20	999.999.113	Lines Apprentice	A four year apprenticeship leading to a Power Line Technician position.
21	920.680.430	Meter Reader	Responsible for reading electric, gas, or water meters and keeping track of their average use by recording information. Other duties would include inspecting meters for damages and defects. Entry level position which typically requires a high school education.
22	220.778.413	Production Field Administrator III	Works independently. Works closely with field operations. Assists in all areas of production and general accounting duties, clerical and office administration functions. Provides analysis and input of operational accounting information and codes and inputs all payables and production volumes. May assist in preparing special production reports. Requires broad knowledge of department procedures. Orders all stationery/supplies and runs office. Monitors, troubleshoots and co-ordinates with head office maintenance of existing computer systems. May check work of junior staff and provide guidance. Working with a Supervisor, assists in preparing field accruals and analyzes actual performance versus budget. Possesses a solid understanding of basic accounting principles. Requires advanced PC and database management knowledge. An accounting background or diploma with 8 years' office experience is typically required.
23	999.999.004	Protection and Control Technician	Perform initial inspections, conduct trouble-shooting and preventative maintenance, carry out modifications and repairs as required, on all types of protection, telecommunications, metering and control equipment which comes under Protection and Control (P&C) jurisdiction. Discuss and review results with supervisor, if the equipment is highly critical from the standpoint of system operation, before putting the equipment into service.
24	999.999.006	Regional Maintainer	Construct and maintain transmission and distribution lines and associated apparatus. Maintain power service to electrical customers. Understands and is able to operate the tools of his/her trade, and is familiar with the various instruments, i.e. voltmeters, ammeters and hometers. Must be familiar with hydraulically-operated articulated or telescopic aerial devices. Must provide at own expense any tools listed for the classification if required in his/her work in accordance with the attached tool list. This classification also includes the requirement to hold a Power Line Technician certification (or equivalent).

(#)	Survey Code	Generic Position	Generic Description
25	999.999.007	Regional Maintainer - Electrical	Responsible for the general maintenance and repair work on electrical systems and equipment at various geographical locations. Requires overhauling, maintaining and inspecting equipment such as conductors & insulators i.e. batteries, station bus, cable, compressed air systems, fire protection equipment switchgear i.e. circuit breakers, load interrupters metalclad switchgear, oil circuit breakers, SF6 breakers, air blast breakers, transformers, rotating machines, distribution stations & equipment. Has the necessary knowledge of the trade theory, operating principles, charts, tables, testing equipment and other reference works, to test, dismantle, repair, clean and assemble station electrical equipment within the required specifications. Requires certification as a construction and maintenance electrician.Also performs mechanical and protection and control work
26	999.999.005	Regional Maintainer - Forestry	Perform line clearing adjacent to power lines and associated apparatus. Carries out all phases of vegetation management including the application of pesticides. Understands and operates tools associated with the trade, various types of vehicles and aerial equipment, hand or power-operated pesticide application equipment. Must provide at own expense, any tools listed for this classification if required in his/her work, in accordance with the attached tool list. In addition to the above, may have the following skills: • Lead Hand Skills (including documentation, job planning and knowledge of work management systems as required) • Work Protection Code Skills (including establishing, and holding) • Contract Monitoring Skills • Environment Skills (such as PCB management, WHMIS, waste management, etc).
27	999.999.008	Regional Maintainer - Lines (Supervisor)	This position is responsible for the safety, quality and quantity of the work performed by his/her crew. They plan work including staffing requirements, assigning work, co-ordinate work with other work groups, ensure proper work practices are followed, report on work performed and engage in good public relations. He/she performs the following physical work activities. Construct and maintain transmission and distribution lines and associated apparatus. Maintain power service to electrical customers. Also responsible for contract monitoring and lead hand responsibilities.
28	115.100.340	Senior Legal Counsel	Responsible for providing management and employees with advice on a broad range of moderately complex conflicting legal principles. The applicable laws and regulations are numerous and varied, and present difficult problems of interpretation. Applies independent judgement in recommending a course of action for a client department, providing input as to the ramifications of a course of action, a legal decision, or a new piece of legislation. Usual qualifications include a law degree, membership in a law society/bar assocation and/or other relevant jurisdiction with a minimum of 8 year's related experience.
29	430.612.340	Service Dispatcher	Responsible for handling incoming consumer calls to schedule and dispatch service technicians to problem areas (including high voltage switching). Maintains documentation of crew activities for continuous knowledge of line and substation work. Key coordinator during power failures provides notification to internal and external customers regarding restoration of power services.
30	999.999.009	Stock keeper	Receives, receipts, stores, issues and ships materiel used in operations. Manages materiel, in accordance with established practices and regulations. Is responsible for materiel under his/her control. Performs maintenance, not requiring formal trades qualifications, and assists in tasks where unskilled or semi-skilled ability is required.
31	999.999.010	System Operator (Controller)	Monitor and operate the transmission/distribution system assets on a 24-hour basis. Determine condition and recommend on availability of equipment. Carry out Manual Block and Rotational Load Shedding Schedules procedures. Monitor, approve and report LV - load transfers. Direct / monitor personnel on a 24 hour basis (i.e. - switching agents, field crews) in the operation of the Transmission / Distribution network system assets. Troubleshoot & sectionalize for low voltage feeder faults.
32	110.200.130	Top Rates and Regulatory Affairs Executive	Executive with primary responsibility for preparing, managing, and leading company's testimony in utilities rate cases before local, regional or federal agencies. Responsibilities include development of all research associated with regulatory activities including activity across other regulatory entities and maintaining relationship with all regulators. Develops cost factors in association with utilities rate cases, may or may not, be involved in delivery of testimony. Typically reports to a Top Legal Executive, Chief Operations Officer or a Top Utilities Executive.

APPENDIX C

Detailed Compensation Benchmarking Methodology

Summarized in this appendix is supporting descriptions of how we determined values for each of the major components of compensation. Specifically:

Base Salary – Annual base salary at April 1, 2011. If an hourly rate was reported, we annualized the value by multiplying the standard number of hours per week by 52 weeks per year. If a weekly rate was reported, we annualized the value by multiplying by 52 weeks per year.

Total Cash Compensation - Base salary ***plus*** most recent short-term incentive or bonus paid.

Benefits and Pensions – To value benefit and pension programs, we applied a relative value process to a set of standard employer paid cost factors, plus actuarial and demographic assumptions to measure all financially significant features of benefit and pension programs based on open and closed plans. See detailed methodology below.

Total Compensation - Total cash compensation ***plus*** estimated annual value of most recent long-term incentive grant (i.e., expected value of stock options or share awards) and pensions and benefits.

Detailed Benefits and Pension Methodology – Total remuneration includes the following values for benefits and pensions:

- Mercer's relative value process applies a broad set of standard cost factors, plus actuarial and demographic assumptions to measure all of the financially significant features of benefit programs on a benefit line basis.

- Effectively, this process isolates the plan design and removes variable factors such as historical experience, demographics, and utilization trends specific to each participant in the study. For example, if two survey participants have an identical benefit offering, the values will be equal regardless of the actual plan costs to each of the employers.

Aligning Values with Hydro One's Actual Costs

- For the purpose of this Total Compensation study, we adjusted the manual rates within our relative value tools so that the results by line of benefit more closely reflect Hydro One's actual benefit costs and liability figures.

Participation & Anti-Selection:

Active Flex Benefits:

- Participation: We use a standardized set of participation assumptions for all participants that vary only by the number of options that are offered under the plan. Therefore, two identical flex programs will produce similar relative Total Values.

- Anti-Selection: A unique feature of flex plans is that employees who choose richer options are likely to be higher claimers than those choosing poorer options. This is reflected within our methodology by increasing the value of the richer options and reducing the value of the poorer options. The final relative values of the flex plan are a weighted average of the values of each of the options.

- Optional plans that are fully employee-paid (such as optional life) are excluded from the review.

- Low value core plans / catastrophic core plans and spousal top-up plans are excluded from the valuation.

Projection Methodology for Pension Plans

Defined Benefit Plans

- For defined benefit plans, annual service costs were estimated for each company's plan design at various earnings levels using a common sample employee demographic (age and years of service). The annual service costs were converted into company provided values by deducting any required employee contributions under each plan. The resulting company provided values were converted into earnings based formulas and applied to the individual membership data for each company.

Defined Contribution Plans

- For defined contribution benefit plans, the company provided value was set equal to the company contributions.

- Where employees are entitled to choose the level of their contributions, employees were assumed to contribute at the level that would maximize company contributions.

Projection Methodology for Post Retirement Non-Pension (PRNP)

Employee-specific factors including earnings and service are projected to each of the assumed retirement ages at which point the benefit payable is determined, actuarially valued and discounted with interest to the current age of the employee. The resulting values are split pro-rata on service into the benefit in respect of past service and the benefit in respect of future service, and the future service benefit value is converted to a level percentage of future pensionable earnings.

- The results are weighted by the assumed retirement rates and combined to produce a single value of future benefit accruals, as a percentage of future earnings, per member.
- Benefits are projected both before and after retirement based on benefit-specific (e.g. medical, dental) inflation assumptions.
- Benefits are coordinated with provincial medical and drug plans.
- Lifetime maximums are reflected where applicable.

Flex Premium Cost Sharing & Credit Allocation:

- Cost sharing is determined using each participant's actual price tag and credit formula.
- Assumptions are made as to where credits would commonly be used, unless they are allocated to specific benefits. These assumptions coordinate with the standardized participation assumptions outlined earlier.

Standard Demographic Assumptions:

- A common population reflecting the general demographics of a Canadian workforce group and adjusted to more closely mirror Hydro One's workforce is used in the analysis.
  - This population reflects a group of employees with an average age of 45, average service of 15 years, and average annual earnings of $90,000 (average earnings used for benefit purposes).
- For Pension and Post Retirement Non-Pension benefits, the above population is assumed to retiree approximately as follows:
  - 25% of the group retire at age 55
  - 60% of the group retire at age 60
  - 15% of the group retire at age 65
  - 70% of the active members are assumed to be married over their career while 90% of members are assumed to be married at the time of their retirement

Other Actuarial Assumptions:

- The following assumptions were used in the review:
  - Discount rate: 5.75% per annum
  - Inflation: 2.00% per annum
  - Salary Increase: 4.00% per annum
  - Post Retirement mortality UP 1994 generational mortality (80% male)
  - Termination rates of 2% each year prior to age 55 (for pension values)
  - Medical and Dental inflation/utilization increases

MERCER

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OEB Expert Evidence Requirements

The OEB revised their Rules of Practice and Procedure on January 9, 2012 to include a new Rule 13A for 'Expert Evidence'. The revised Practice and Procedure requires that a party that engages an expert shall ensure that the expert is made aware of and has agreed to accept the responsibilities imposed by the new Rule 13A. As the sponsor of a special study being prepared by an external expert on behalf of Hydro One, you have the accountability to ensure that these OEB requirements regarding expert evidence are met.

The following is a check list to ensure that the Expert is aware of and has agreed to Rule 13A; this is a direct excerpt from 13A.03 and 13A.06 of the Rule.

Expert Evidence Check List		Yes or No
Does the expert's evidence include:		
(a)	the experts name, business name and address, and general area of expertise;	Y
(b)	the experts qualifications, including the expert's relevant educational and professional experience in respect of each issue in the proceeding to which the expert's evidence relates;	Y
(c)	the instructions provided to the expert in relation to the proceeding and, where applicable, to each issue in the proceeding to which the expert's evidence relates;	Y
(d)	the specific information upon which the expert's evidence is based, including a description of any factual assumptions made and research conducted, and a list of the documents relied on by the expert in preparing the evidence; and	Y
(e)	in the case of evidence that is provided in response to another expert's evidence, a summary of the points of agreement and disagreement with the other expert's evidence.	NA
Has the expert been made aware of and agreed to accept the responsibilities that are or may be imposed on the expert as set out in Rule 13A.		Y

It is suggested that the report submitted by the expert should include a summary of the above information, signed off and dated by the expert, in the front end of the special study report. Otherwise, a separate summary document containing this information should be signed and dated by the expert and provided to Hydro One. This separate summary document will be submitted with the special study report in the pre-filed evidence.

A template for the separate stand alone summary document is provided as Attachment 1. The complete Rule 13A for 'Expert Evidence' from the OEB's Rules of Practice and Procedure, dated January 9, 2012, is provided as Attachment 2. Both must be provided by you to your external expert.

ATTACHMENT 1
Template for External Expert Rule 13A Sign Off Document

Title of Report:
Compensation Cost Benchmarking Study

Consultant:
Iain Morris
Partner, Human Capital Business Leader - Canada
Mercer (Canada) Limited
161 Bay Street
Toronto, Ontario M5J 2S5

- Human Resource consultant to major Canadian and multi-national employers
- Extensive experience on total reward strategy, rewards program design, benchmarking and cost analyses

Qualifications:
Education: Bachelor of Arts Queen's University 1980

Experience: Mr. Morris consults to many of Canada's leading organizations with a focus on reward strategy design and implementation. This includes business needs driven rewards strategy development and the design and implementation of performance-linked compensation systems. Iain has worked with organizations in a number of industries including: mining, utilities, financial services, retail, and manufacturing. Recent projects include:

- Leading a comprehensive total reward benchmarking and cost analysis for a major gas distribution company

- Developing and implementing a total reward strategy for a major engineering consulting firm

- Assessing the effectiveness of the total reward strategy and program design for a leading retailer

Iain has more than 30 years of rewards consulting experience with Mercer and another global H.R. consulting firm.

Instructions Provided:
The primary sources of instructions were the RFP, (RFP #SCO-1000152789, March 2nd 2011) that Hydro One issued for this project and various conversations with Hydro One in verifying scope and progress.

The following are excerpts from the RFP:
"in its December 23, 2010 Decision approving Transmission Revenue Requirements for 2011 and 2012, the Ontario Energy Board provided direction and the other expectations for further information on compensation and efficiency comparisons".

The Board directed "Hydro One to revisit compensation cost benchmarking study [the Mercer study] in an effort to more appropriately compare compensation costs to those of other regulated transmission and/or distribution utilities in North America." Towards that end, the Board directed "Hydro One to consult with stakeholders about how the Mercer study should be updated and expanded to produce such analyses".

Mercer met with Stakeholders and with Hydro One during the course of conducting the study to receive feedback on the project methodology and progress.

Basis of Evidence:
1) 2008 Compensation Cost Benchmarking Study, Mercer (Canada) Limited
2) 2011 Total Compensation Survey conducted on behalf of Hydro One
3) Total Compensation data and program design information for Hydro One provided by the Company Human Resources Department
4) Mercer and industry standard analytical methods and assumptions

Context of Evidence:
NA

Confirmation:
The expert has been made aware of and agrees to accept the responsibilities that are or may be imposed on the expert as set out in Rule 13A.

Signature:

Name of Expert: Iain Morris

Date: 09 April 2012

ATTACHMENT 2
OEB Rule 13A for 'Expert Evidence'

The following is an excerpt in its entirety of Rule 13A from the Ontario Energy Board "Rules of Practice and Procedure" (Revised January 9, 2012), pages 13 &14. A direct link to the entire document is provided here:
OEB Rules of Practice and Procedure

13A. Expert Evidence

13A.01 A party may engage, and two or more parties may jointly engage, one or more experts to give evidence in a proceeding on issues that are relevant to the expert's area of expertise.

13A.02 An expert shall assist the Board impartially by giving evidence that is fair and objective.

13A.03 An expert's evidence shall, at a minimum, include the following:
- (a) the expert's name, business name and address, and general area of expertise;
- (b) the expert's qualifications, including the expert's relevant educational and professional experience in respect of each issue in the proceeding to which the expert's evidence relates;
- (c) the instructions provided to the expert in relation to the proceeding and, where applicable, to each issue in the proceeding to which the expert's evidence relates;
- (d) the specific information upon which the expert's evidence is based, including a description of any factual assumptions made and research conducted, and a list of the documents relied on by the expert in preparing the evidence; and
- (e) in the case of evidence that is provided in response to another expert's evidence, a summary of the points of agreement and disagreement with the other expert's evidence.

13A.04 In a proceeding where two or more parties have engaged experts, the Board may require two or more of the experts to:
- (a) in advance of the hearing, confer with each other for the purposes of, among others, narrowing issues, identifying the points on which their views differ and are in agreement, and preparing a joint written statement to be admissible as evidence at the hearing; and
- (b) at the hearing, appear together as a concurrent expert panel for the purposes of, among others, answering questions from the Board and others as permitted by the Board, and providing comments on the views of another expert on the same panel.

13A.05 The activities referred to in **Rule 13A.04** shall be conducted in accordance with such directions as may be given by the Board, including as to:

(a) scope and timing;
(b) the involvement of any expert engaged by the Board;
(c) the costs associated with the conduct of the activities;
(d) the attendance or non-attendance of counsel for the parties, or of other persons, in respect of the activities referred to in paragraph (a) of **Rule 13A.04**; and
(e) any issues in relation to confidentiality.

13A.06 A party that engages an expert shall ensure that the expert is made aware of, and has agreed to accept, the responsibilities that are or may be imposed on the expert as set out in this **Rule 13A**.

Year End Hydro One Networks Inc Payroll* (M$) (Tx and DX)

2009

REPRESENTATION	TOTAL NO. EMPLOYEES	TOTAL WAGES	Base Pay	Overtime(Incl Premium)	Incentive	Other**	Average Base Pay
PWU Reg	3,307	$ 313,506,371	$ 241,758,749	$ 50,934,813		$ 20,807,309	$ 73,105
SOCIETY Reg	1,170	$ 107,796,452	$ 97,475,843	$ 4,518,060		$ 5,879,745	$ 83,313
MCP Reg	609	$ 83,331,393	$ 69,012,110		$ 9,191,373	$ 5,065,505	$ 113,320
Total Reg	**5,086**	**$ 504,634,217**	**$ 408,246,702**	**$ 55,452,872**	**$ 9,191,373**	**$ 31,752,559**	**$ 80,269**
PWU Temp	234	$ 6,805,803	$ 6,385,536	$ 150,661		$ 269,606	$ 27,289
Society Temp	85	$ 4,307,445	$ 4,128,414	$ 39,998		$ 139,032	$ 48,570
MCP Temp	14	$ 1,016,300	$ 997,022			$ 9,988	$ 71,216
Total Temp	**333**	**$ 12,129,548**	**$ 11,510,972**	**$ 190,659**		**$ 418,627**	**$ 34,567**
CASUAL	1711	$ 106,586,619	$ 84,775,588	$ 12,542,881		$ 9,268,151	$ 49,547
TOTAL	**7130**	**$ 623,350,384**	**$ 504,533,262**	**$ 68,186,412**	**$ 9,191,373**	**$ 41,439,337**	**$ 70,762**

2010

REPRESENTATION	TOTAL NO. EMPLOYEES	TOTAL WAGES	Base Pay	Overtime(Incl Premium)	Incentive	Other**	Average Base Pay
PWU Reg	3,397	$ 327,600,666	$ 260,915,303	$ 51,809,932	$ 6,528	$ 14,868,904	$ 76,808
SOCIETY Reg	1,315	$ 125,599,454	$ 117,961,991	$ 4,326,114	$ 22,859	$ 3,288,489	$ 89,705
MCP Reg	651	$ 88,150,303	$ 74,337,104	$ 403,461	$ 8,568,152	$ 4,841,586	$ 114,189
Total Reg	**5,363**	**$ 541,350,422**	**$ 453,214,398**	**$ 56,539,507**	**$ 8,597,538**	**$ 22,998,979**	**$ 84,508**
PWU Temp	185	$ 5,762,822	$ 5,627,702	$ 62,451		$ 72,670	$ 30,420
Society Temp	80	$ 5,097,027	$ 4,793,945	$ 112,596		$ 190,486	$ 59,924
MCP Temp	21	$ 1,366,870	$ 1,315,636			$ 51,234	$ 62,649
Total Temp	**286**	**$ 12,226,719**	**$ 11,737,283**	**$ 175,047**		**$ 314,389**	**$ 41,039**
CASUAL	1707	$ 109,976,920	$ 84,735,113	$ 12,740,012		$ 12,501,795	$ 49,640
Total	**7356**	**$ 663,554,061**	**$ 549,686,793**	**$ 69,454,566**	**$ 8,597,538**	**$ 35,815,164**	**$ 74,726**

*This payroll reflects compensation costs associated with year-end headcounts for all EPSCA, PWU, Society and MCP Transmission and Distribution staff.

**“Other” includes travel time, vacation bonus, unused vacation days paid out, standby allowance, shift allowance, vacation pay on termination and a variable to address data restrictions.

Year End Hydro One Networks Inc Payroll* (M$) (Tx and DX)

2011

REPRESENTATION	TOTAL NO. EMPLOYEES	TOTAL WAGES	Base Pay	Overtime(Incl Premium)	Incentive	Other**	Average Base Pay
PWU Reg	3,456	$ 353,770,142	$ 275,254,552	$ 63,197,265		$ 15,318,324	$ 79,645
SOCIETY Reg	1,330	$ 134,279,772	$ 126,051,768	$ 4,947,039	$ 2,250	$ 3,278,715	$ 94,776
MCP Reg	644	$ 88,234,049	$ 73,880,625	$ 69,859	$ 9,414,079	$ 4,869,486	$ 114,721
Total Reg	**5,430**	**$ 576,283,963**	**$ 475,186,946**	**$ 68,214,163**	**$ 9,416,329**	**$ 23,466,525**	**$ 87,511**
PWU Temp	211	$ 5,508,958	$ 5,331,454	$ 85,668		$ 91,836	$ 25,268
Society Temp	79	$ 5,234,552	$ 4,983,808	$ 26,116		$ 224,627	$ 63,086
MCP Temp	22	$ 1,660,391	$ 1,612,601	$ 1,331		$ 46,460	$ 73,300
Total Temp	**312**	**$ 12,403,901**	**$ 11,927,862**	**$ 113,115**		**$ 362,923**	**$ 38,230**
CASUAL	1488	$ 106,663,199	$ 80,054,576	$ 14,588,897		$ 12,019,727	$ 53,800
TOTAL	**7,230**	**$ 695,351,063**	**$ 567,169,384**	**$ 82,916,175**	**$ 9,416,329**	**$ 35,849,175**	**$ 78,447**

2012

REPRESENTATION	TOTAL NO. EMPLOYEES	TOTAL WAGES	Base Pay	Overtime(Incl Premium)	Incentive	Other**	
PWU Reg	3,512	$ 366,737,424	$ 285,742,261	$ 65,093,183		$ 15,901,981	$ 81,357
SOCIETY Reg	1,371	$ 139,579,280	$ 131,098,578	$ 5,070,715		$ 3,409,987	$ 95,603
MCP Reg	659	$ 91,074,470	$ 76,345,990		$ 9,696,502	$ 5,031,978	$ 115,764
Total Reg	**5,543**	**$ 597,391,174**	**$ 493,186,828**	**$ 70,163,898**	**$ 9,696,502**	**$ 24,343,946**	**$ 88,975**
PWU Temp	232	$ 5,674,226	$ 5,491,397	$ 88,238		$ 94,591	$ 23,660
Society Temp	87	$ 5,365,416	$ 5,108,403	$ 26,769		$ 230,243	$ 58,785
MCP Temp	24	$ 1,708,832	$ 1,660,979			$ 47,853	$ 68,635
Total Temp	**343**	**$ 12,748,474**	**$ 12,260,779**	**$ 115,007**		**$ 372,688**	**$ 35,725**
CASUAL	1516	$ 112,013,563	$ 84,070,216	$ 15,320,695		$ 12,622,652	$ 55,455
TOTAL	**7,402**	**$ 722,153,211**	**$ 589,517,824**	**$ 85,599,600**	**$ 9,696,502**	**$ 37,339,286**	**$ 79,641**

Year End Hydro One Networks Inc Payroll* (M$) (Tx and DX)

2013

REPRESENTATION	TOTAL NO. EMPLOYEES	TOTAL WAGES	Base Pay	Overtime(Incl Premium)	Incentive	Other**	
PWU Reg	3,511	$ 377,658,190	$ 294,233,172	$ 67,045,979		$ 16,379,040	$ 83,803
SOCIETY Reg	1,373	$ 143,957,864	$ 135,222,741	$ 5,222,837		$ 3,512,286	$ 98,487
MCP Reg	656	$ 93,459,412	$ 78,289,077		$ 9,987,397	$ 5,182,938	$ 119,343
Total Reg	**5,540**	**$ 615,075,466**	**$ 507,744,990**	**$ 72,268,815**	**$ 9,987,397**	**$ 25,074,264**	**$ 91,651**
PWU Temp	255	$ 6,104,709	$ 5,916,395	$ 90,885		$ 97,429	$ 23,173
Society Temp	96	$ 5,820,302	$ 5,555,580	$ 27,572		$ 237,150	$ 58,119
MCP Temp	27	$ 1,897,368	$ 1,848,079			$ 49,289	$ 69,424
Total Temp	**378**	**$ 13,822,379**	**$ 13,320,053**	**$ 118,457**		**$ 383,868**	**$ 35,283**
CASUAL	1595	$ 117,592,181	$ 88,810,534	$ 15,780,315		$ 13,001,332	$ 55,681
TOTAL	**7,513**	**$ 746,490,026**	**$ 609,875,578**	**$ 88,167,588**	**$ 9,987,397**	**$ 38,459,464**	**$ 81,181**

2014

REPRESENTATION	TOTAL NO. EMPLOYEES	TOTAL WAGES	Base Pay	Overtime(Incl Premium)	Incentive	Other**	
PWU Reg	3,511	$ 388,987,936	$ 303,060,167	$ 69,057,358		$ 16,870,411	$ 86,317
SOCIETY Reg	1,371	$ 148,276,600	$ 139,279,423	$ 5,379,522		$ 3,617,655	$ 101,590
MCP Reg	655	$ 96,263,194	$ 80,637,749	$ -	$ 10,287,019	$ 5,338,426	$ 123,018
Total Reg	**5,537**	**$ 633,527,730**	**$ 522,977,339**	**$ 74,436,880**	**$ 10,287,019**	**$ 25,826,492**	**$ 94,443**
PWU Temp	281	$ 6,589,104	$ 6,395,141	$ 93,611		$ 100,352	$ 22,771
Society Temp	105	$ 6,285,506	$ 6,012,841	$ 28,400		$ 244,265	$ 57,184
MCP Temp	29	$ 2,005,057	$ 1,954,289			$ 50,768	$ 66,740
Total Temp	**415**	**$ 14,879,666**	**$ 14,362,271**	**$ 122,011**		**$ 395,385**	**$ 34,585**
CASUAL	1617	$ 121,732,433	$ 92,087,337	$ 16,253,725		$ 13,391,372	$ 56,949
TOTAL	**7,570**	**$ 770,139,829**	**$ 629,426,947**	**$ 90,812,615**	**$ 10,287,019**	**$ 39,613,248**	**$ 83,150**

PENSION COSTS

1.0 PENSION COSTS

Hydro One Networks is a participant in the Hydro One Pension Plan ("the Plan"). The Plan is a contributory, defined-benefit pension plan whose members comprise represented employees of the Power Workers Union ("PWU"), the Society of Energy Professionals ("Society"), MCP employees, pensioners who were employees, and pensioners who are beneficiaries of employees or pensioners.

The Plan covers Hydro One and its subsidiaries, except Hydro One Brampton Inc. The Plan does not segregate assets in a separate account for individual subsidiaries, nor is the accrual cost of the benefit plans allocated to, or funded separately by, entities within the consolidated group. Accordingly, for Hydro One Networks, the Plan is accounted for as a defined contribution plan and no deferred pension asset or liability is recorded on Hydro One Network's financial statements.

The Board has previously allowed cash payments related to pension obligations to be recorded in rates (RP-1998-0001). As well, in April 2006, the OEB in its Decision with Reasons, approved full recovery of Distribution pension costs included in OM&A (RP-2005-0020/EB-2005-0378). Pension costs were similarly approved for Transmission pension costs (EB-2006-0501, EB-2008-0272, and EB-2010-0002); this treatment was continued in Hydro One Distribution's last cost of service application as well (EB-2009-0096).

The Hydro One pension cost allocated to Hydro One Networks is based on the ratio of base pensionable earnings for Hydro One Networks' staff, as compared to the total base pensionable earnings for all of Hydro One employees. The method of allocation of the pension cost and the Inergi annual pension charge is consistent among all shared services costs, for operating and capital costs, and is consistent with the methodology reviewed during RP-2005-0020/EB-2005-0378, EB-2006-0501, EB-2007-0681 and EB-2008-0272, EB-2009-0096, and EB-2010-0002.

For the Transmission business, the annual charge to be recovered through rates is estimated as follows:

Annual cash pension cost (millions)
(*may not add due to rounding*)

2013

Corporate Pension Costs	Transmission		Distribution		Other		Total	
OM&A	$	32	$	39	$	4	$	75
Capital	$	38	$	41	$	-	$	79
	$	**70**	**$**	**80**	**$**	**4**	**$**	**154**

2014

Corporate Pension Costs	Transmission		Distribution		Other		Total	
OM&A	$	33	$	42	$	4	$	79
Capital	$	42	$	37	$	-	$	79
	$	**75**	**$**	**79**	**$**	**4**	**$**	**158**

2.0 ACTUARIAL CALCULATION

The most recent actuarial valuation for the Plan was as at December 31, 2009. In September 2010, Hydro One filed this actuarial valuation with the Financial Services Commission of Ontario (FSCO). The valuation showed that the Plan had a deficit of $434 million, on a going-concern basis. The required contribution for the Hydro One companies was initially set at $139 million starting in 2010, variable based on the level of base pensionable earnings. Of this amount, about $91 million represented annual current service costs, and the remaining portion represented special payments over 15 years required toward the going-concern deficiency.

In accordance with applicable regulations, Hydro One makes all required contributions on a monthly basis.

Hydro One's next actuarial valuation is required by December 31, 2012. The valuation will depend on investment returns, changes in benefits, and actuarial assumptions.

The staff growth reflected in the increase in current service cost supports the requirements of the work program.

During 2010 and 2011, actual contributions were about $191 million and $153 million, respectively. The Company made an additional payment of $48 million in December 2010 as a result of a one-time special funding contribution by Hydro One Inc. which is included in the $191 million. The payment was over and above the minimum required by the actuarial valuation governing its contribution requirements for the period 2010 - 2012. Actual contribution requirements in 2013 and 2014 may differ depending on the level of base pension earnings used to compute the monthly contribution. As well, actual contribution requirements in 2013 and 2014 may materially differ from the estimates provided depending on the results of the next actuarial funding valuation as at December 31, 2012 which will be filed with FSCO in September 2013. The difference between the estimated and actual pension costs will be tracked in a variance account (see Exhibit F1, Tab 1, Schedule 2).

3.0 PENSION PLAN GOVERNANCE AND PERFORMANCE

Hydro One is the Plan sponsor and administers the pension assets and obligations of the Plan. As of December 31, 2011, the Plan had a reported net asset value of $4,682 million and about 12,967 members. About 43% of the Plan's members are active. The remaining Plan members are inactive, either retired, beneficiaries of retirees, former employees eligible for a deferred pension or members on long-term disability. The Plan governance was reviewed during RP-2005-0020/EB-2005-0378.

The Fund has consistently outperformed the benchmark made up of passive market indices. In the period from June 29, 2001 (the Fund's inception) to December 31, 2011, the Fund returned 5.30% annualized while the Fund's target benchmark is 5.12%, thus outperforming its target benchmark return by 0.18%. The fund's investments are divided into asset classes and each asset class has a corresponding market index (i.e. Canadian Equities market index is the S&P/TSX). The actual performance of each asset class is then measured against this market index (policy benchmark). The Fund's policy benchmark is a calculated weighted average benchmark based on the Fund's strategic asset mix.

COSTING OF WORK

1.0 OVERVIEW

Hydro One Transmission's work program is bundled into packages of work identified as programs or projects. Program and project costs are comprised primarily of activities associated with labour, equipment and material acquisition. This Exhibit details the breakdown of each of these three cost activities, and how the costs are applied to programs and projects. This costing approach is consistent with the requirements of US Generally Accepted Accounting Principles ("USGAAP").

Hydro One Transmission categorizes its costs into two major classifications - common and direct. Common costs, both OM&A and capital expenditures, are allocated to Transmission and Hydro One's other lines of business. Direct costs charged to work orders include labour (comprising salaries, benefits and pension costs), material, fleet and supply chain. Labour costs are calculated as a product of actual time multiplied by the standard labour rate. Material costs are charged directly to the work program. Fleet costs are charged using a fleet rate, and supply chain costs are charged via a material surcharge. All of these elements are described in detail in this Exhibit.

2.0 PROJECT AND PROGRAM MAJOR COST CATEGORIES

2.1 Labour Rate

Trade labour and equipment hours are distributed directly to benefiting programs and projects by using timesheets, consistent with common industry practice. Standard hourly labour and equipment rates are then used to convert the reported hours into costs. Both labour and equipment rates are "fully loaded" to ensure that all associated support costs required to deploy resources and equipment are accurately and cost effectively distributed to the benefiting work.

On an annual basis, the standard labour rates are derived based on information gathered through the annual budgeting process. Resource budgets for each major resource category are calculated and categorized into three basic cost components: forecast billable (direct charged) hours, forecast non-billable hours and forecast non-billable expenses. Total payroll and expense costs along with an assignment of support activity costs, divided by the forecast billable hours, create the standard labour rate. Table 1, below, shows an <u>example</u> of the composition of standard labour rate for <u>one category</u>, the Regional Electrical Maintainer – Regular Staff, over the period 2009 to 2014.

Table 1
Standard Labour Rate Composition
Regional Maintainer – Electrical
($ per Hour)

	Historic			**Bridge**	**Test**	
	2009	**2010**	**2011**	**2012**	**2013**	**2014**
Payroll Obligations	68.88	71.46	73.62	77.56	79.89	82.28
Contractual time away from work	8.72	9.45	9.73	9.10	9.41	9.74
Time not directly benefiting a specific Program or Project	5.64	5.70	5.87	8.30	8.55	8.81
Field Supervision and Technical Support	19.54	16.08	17.31	17.24	18.75	18.35
Support Activities	15.22	16.31	16.47	16.80	17.30	17.82
Labour Rate	**118.00**	**119.00**	**123.00**	**129.00**	**133.00**	**137.00**

The cost elements embedded in the standard rate as illustrated in Table 1 are explained in the pages following, using the example of the position, Regional Maintainer – Electrical for the 2011 cost composition.

2.1.1 Payroll Obligations ($77.56)

A brief description of the cost elements included in this category is provided below. Compensation, wages and benefits are more fully explained in Exhibit C1, Tab 5, Schedule 2.

Base Labour and Payroll Allowances (54% of Payroll Obligations)

- Base Pay: Contractually negotiated and reflected in wage schedules.
- Payroll Allowances: Allowances are also contractually negotiated and stated in collective agreements. Regular staff (PWU) are entitled to travel, footwear and on-call allowances. Casual trades are entitled to board and travel allowances where circumstances require it.

Company Benefits (39% of Payroll Obligations)

- Regular Staff: Comprising pension (29.5% base pensionable earnings) and current and post employment benefits; health, dental, etc. (28.2% of base pensionable earnings).
- Non-Regular Staff (for example, casual trades): Pension and welfare contributions made on behalf of the regular employee. These contributions are significantly lower in comparison to the Company benefit contributions made on behalf of the regular employee.

Government Obligations (5% of Payroll Obligations)

- Consists primarily of Canada Pension Plan (CPP), Employment Insurance (EI), Employee Health Tax (EHT) and Workplace Safety and Insurance Board (WSIB) contributions.

2.1.2. Contractual Time Away from Work ($9.10)

This category consists primarily of employee vacation and statutory holidays, all established and identified in the Company's collective agreements. Sickness and accident costs are also included and are based on historical trends and consider current Company initiatives.

2.1.3. Time Not Directly Benefiting a Specific Program or Project ($8.30)

This category includes time for attendance of safety meetings, housekeeping and downtime often created due to inclement weather. These estimates are based primarily on historical trends.

2.1.4 Field Supervision and Technical Support ($17.24)

This category includes the costs associated with field trades supervision and other management and technical staff providing support services to manage and monitor the status of the assigned programs and projects.

2.1.5. Support Activities ($16.80)

Administrative Expenses and Centralized Support (56% of Support Activities)

- These costs include administrative expenses such as travel costs, cell-phones and other miscellaneous expenses that cannot be specifically attributed to a particular program or project. Also included is an assignment of costs for centralized clerical support activities to facilitate work management system requirements.

Health Safety and Environment (34% of Support Activities)

- Costs to design, develop and deliver safety and environmental practices and work methods and training programs primarily for staff working in field locations. Costs are assigned based on the forecast consumption of these services as agreed to by the Health Safety and Environment function and service recipient.

2.2 Fleet Rate

Hydro One controls and manages approximately 6,700 vehicles and other work equipment to support its work programs used for both Transmission and Distribution work. The Fleet complement is directly related to the Hydro One Lines of Business work program requirements and staff levels. Fleet Management is described in Section 3.0 of this Exhibit.

Fleet assets are categorized into 59 classes of equipment. For each equipment class, a standard equipment rate is calculated by dividing the annual forecast cost to maintain each class of equipment by the annual forecast hours that the class of equipment is required to work (utilization hours). Utilization hours are derived based on a review of historical trends and an annual review of the upcoming work program. Utilization hours are defined as the hours the equipment is being used "on the job". Table 2 below, shows the hourly fleet rate, as an example, for one of the commonly used classes of equipment in the Transmission business (a line maintenance truck) for historical, bridge and test years, illustrating that the rate includes all costs attributable to the benefiting work.

Table 2
Fleet Rate – Line Maintenance Truck
($ per Hour)

	Historic			**Bridge**	**Test**	
	2009	**2010**	**2011**	**2012**	**2013**	**2014**
Operations & Repairs	25.26	34.36	35.28	35.62	36.42	37.74
Fuel Costs	6.52	7.85	6.28	9.14	9.34	9.68
Depreciation	18.22	17.70	18.44	19.24	20.24	21.58
Hourly Rate	**50.00**	**60.00**	**60.00**	**64.00**	**66.00**	**69.00**

The cost elements embedded in the fleet standard rate as illustrated in Table 2 are explained in the pages following, using the example of the Line Maintenance Truck for the 2012 cost composition.

Operations & Repair Costs (56% of Fleet Rate)

- This cost category consists primarily of repair costs (labour and parts) which are derived based on a forecast of the annual maintenance schedules for each piece of equipment. The age and the history of the vehicles are considered in the calculation. Throughout the year, all repair costs are charged directly to individual pieces of equipment. Operations cost include administration staff and their allocated share of central service support costs (for example, work methods and safety training activities).

Fuel Cost (14% of Fleet Rate)

- Fuel consumption cost is calculated based on past history (including distance driven), future fuel price projections and the composition of the class. Fuel consumption rate remains relatively stable between 2009 to 2011. This has resulted from the recent acquisitions of newer vehicles and equipment over the period with improved fuel efficiency, as well as our environmental initiatives e.g. reduced idling. The fuel cost increase in 2012 is due to the recent rise in fuel prices.

Depreciation (30% of Fleet Rate)

- The depreciation for each class is calculated based on Hydro One's current depreciation policies, the current composition of other fleet and the annual forecast additions and deletions.

External Fleet Rentals

Due to the seasonal and fluctuating nature of the work program, Hydro One Transmission requires externally owned equipment to meet work program peaks. Similar to the process used to cost its own fleet, Hydro One Transmission calculates and uses standard rates to distribute these costs to programs and projects.

2.3 Material Surcharge Rate

A standard material surcharge rate, which captures supply chain procurement costs benefiting a particular program or project, is applied to material costs. (A detailed description of Hydro One's approach to supply chain management is found in Section 4.0 of this Exhibit.)

Material costs charged to a project or program are based on the issue cost from Inventory, which is the Average Unit Price (AUP) or the direct-shipped purchase order price. On a monthly basis, total monthly material charges are surcharged with a fixed percentage cost to recover costs associated with purchasing, transportation and inventory management. The percentages range from 11% to 20%, depending on work program service requirements. The percentages are derived by assigning the costs of these activities to the work programs based on an annual assessment of the consumption of these services divided by the annual forecast of purchased material.

The costs recovered in the surcharge are as follows:

- Hydro One Costs: Management, demand planning, warehousing and transportation of material (comprising approximately 54% of the total costs).
- Inergi Contract Costs: Procurement and investment recovery (comprising approximately 46% of the total costs).

2.4 Other Program and Project Costs

Depending on the nature of the work, Hydro One Transmission's program or project costs also include additional costs beyond the major contributors identified above. These additional costs may include the costs of external contractors and/or miscellaneous job specific consumables such as travel expenses or the purchase of low value material.

In terms of estimating and costing of capital work, there may be circumstances when removal costs or customer contributions need to be separately identified. In these cases, the cost of removal work is accounted for as depreciation, and customer contributions are netted against gross capital costs.

Capital work also receives a monthly charge for its share of corporate interest and overhead costs. The composition of these two cost categories and the annual calculation are explained in Exhibit D1, Tab 2, Schedule 1, Allowances for Funds Used During Construction and Exhibit C1, Tab 7, Schedule 2, Overhead Capitalization.

2.5 Standard Rates

When using standard rates, residual costs naturally arise when actual costs incurred differ from the standards. These variances are accounted for on a monthly basis and assigned to both capital and maintenance programs. The monthly assignments of residual costs are made to OM&A and Capital based on the program and project cost activities responsible for generating the year-to-date variances.

3.0 FLEET MANAGEMENT SERVICES

Fleet Management Services provides centralized and turnkey services that include maintenance, administration, vehicle replacement and disposal. Vehicles are maintained to an optimum level to ensure public and employee safety and compliance with laws and Ministry regulations, including, but not limited to, CSA225, the Highway Traffic Act and the Commercial Vehicle Operator's Registration regulations. Fleet Management Services also ensures that environmental impacts are minimized, and line-of-business productivity is optimized by minimizing downtime, and travel time, and by optimizing technology and continuous improvement opportunities.

Fleet Management Services has adapted to the changing needs of its business by:

- Revising the Company's model for responding to internal customers from fixed zone service to a mobile and fire hall model, with maintenance garages strategically placed throughout the Province to facilitate a more rapid turnaround for vehicle servicing;
- Rationalizing the Company's fleet and facilities (that is, optimizing the number of garages and geographical locations served);
- Reducing equipment downtime and improving our equipment utilization;
- Providing more competitive and cost efficient fleet support;

- Adopting a flexible service delivery model that matches the nomadic and variable work program needs of Hydro One’s lines of business with service delivery options that mirror private sector practices. Such options include shift work, extended hours of service and mobile service delivery;
- Developing more timely, strategic and cost-efficient processes for equipment procurement and disposal;
- Developing a long-range capital replacement program; and
- Adopting data collection and information management systems that match the nomadic requirements of the Company’s business units.

3.1 Maintenance Model

Fleet Management Services has developed a balanced maintenance model for mobile service delivery and centralized facilities. This model provides for 29 Motor Vehicle Inspection Stations (MVIS) and balances geographical customer requirements, travel time, third party vendor support and response time. Mobile/satellite repair units minimize costs by providing timely on-site field support for various nomadic work programs, such as vegetation control, new construction and off-road tower maintenance. Services provided to the lines of business meet the rigorous requirements of Fleet Management Services’ agreements and are structured as a mobile and fire hall operating model to meet customer requirements.

3.2 Managed Systems

Fleet Management System

The strategic alliance to implement a fleet management system (“FMS”), developed with Automotive Resources International (“ARI”) in 2003, was renewed in 2008. The implementation of the FMS created an automated web-based system that uses a single credit card for each vehicle to capture all operating costs including fuel, parts and repairs. The FMS also prescribes spending guidelines and negotiated discounts. The system measures a variety of targets that reconcile approved purchase orders, estimates versus actuals, and vendor-related expenditures, discounts and complaints.

The benefits of the FMS include:

- Improved scheduling of preventative maintenance, reduced repair times, travel time and reduced equipment downtime;
- Increased access to a number of vendors for fuel, repairs and parts, thus minimizing cost and downtime;
- Improved cost and efficiency, through carefully-considered procurement strategies and economies of scale, including improved volume discounts for fuel, parts and service;
- A 1-800 number for repairs, roadside assistance and towing and improved reporting and data collection.

The FMS uses a variety of linked programs to manage the data and information for all facets of the business, including internal and external repairs. This system and associated programs are operated in partnership with ARI, and take advantage of internal and external intelligence and technology.

The maintenance program minimizes avoidable and expensive repairs and minimizes equipment downtime, which results in improved equipment utilization. Both internal and external service providers have access to the appropriate information through state-of-the-art automated management systems, allowing for quality decision-making at all levels of the maintenance program. Examples of the information provided include:

- Real time vehicle history;
- Warranty criteria and warranty recovery;
- A work and resources scheduling tool;
- A pending and overdue work information alert system;
- Product information, including vendor-specific information;
- Repair and safe practices manuals;
- Process and policy information;
- Invoice and cost-management details;
- Monthly and ad-hoc reports;
- Work order management; and
- A decision making tool on potential repairs to vehicles nearing end of life.

GPS / Telematics

In collaboration with ARI (Automotive Resources International), Hydro One Fleet Services introduced GPS (Global Positioning System) on 500 units as part of the Hydro One Environmental Plan. This initiative provides data in the categories listed below in order to better evaluate patterns and habits of drivers with real-time information:

- Reducing engine idle time
- Decreasing miles driven
- Minimizing speed acceleration
- Reducing emissions
- Providing acceptable data for Fuel Tax Credits
- Reducing fuel costs

3.3 Fleet Complement and Utilization

Fleet Management Services controls and manages approximately 6,700 vehicles and other equipment primarily for Transmission and Distribution work. Inventory levels are controlled and set by the Hydro One Transmission lines of business and Fleet Management Services within the guidelines set for staffing versus fleet ratio, type and volume of work programs, geographic locations and utilization targets. The increase in the fleet complement, therefore, is directly related to the increase in the Company's work on system infrastructure and corresponding staffing levels. Fleet Management Services maintains 29 Motor Vehicle Inspection Stations (MVIS) to support 25 transmission stations and 70 Forestry/Provincial Lines distribution locations.

As capital and OM&A investments have been increasing, the options to meet increased equipment demand include the purchase, lease or rental of additional equipment, or increased utilization of existing equipment. The optimum option is to increase utilization, which minimizes capital investment compared to the option of additional purchases. Simultaneously, it maximizes the advantage of owned core equipment versus the additional cost of external rentals, which is 30 percent higher than owned equipment rates. This assessment is based on an internal comparison of the actual costs of equipment rentals versus those of owned core equipment.

The benefits of improving utilization include:

- Decreased long term capital requirements;
- Improved ability to respond to fluctuations in work programs; and
- Reduced rental costs, with a correspondingly lower impact on the Company's OM&A budget.

Equipment utilization averages have increased from approximately 65 percent in 2001 to approximately 80 percent in 2011. The 2011 average equipment rate is $21.11; this is established by dividing the total actual recovery by the total actual utilization hours.

3.4 Fleet Management Services Budget

Fleet Management Services' annual budget is developed and managed based on the all-in costs of operating the fleet and the following criteria:

- Historical and forecast fixed and variable costs including fuel, depreciation, maintenance and repair, labour/staffing, external rentals and corporate allocations;
- Historical cost and mechanical fitness evaluations;
- Work program forecasts provided by the lines of business;
- Estimates provided by internal and external providers;
- The requirements of the capital/vehicle replacement program; and
- Projected escalators.

Table 3, below, provides total expenditures on the components comprising the fleet rate for historic, bridge and test years. These expenditures are distributed among each of the 59 classes of vehicles.

Table 3
Fleet Management Services Budget Expenditures
($ Million)

	Historic			Bridge	Test	
	2009	**2010**	**2011**	**2012**	**2013**	**2014**
Operations & Repairs	55.3	53.6	59.0	58.9	60.7	62.5
Depreciation	32.7	34.4	38.2	36.2	38.4	40.7
Fuel	20.0	22.0	25.2	30.5	31.4	32.3
Subtotal	**108.0**	**110.0**	**122.4**	**125.6**	**130.5**	**135.5**
Rentals	6.0	5.0	5.0	3.0	4.0	4.0
Total	**114.0**	**115.0**	**127.4**	**128.6**	**134.5**	**139.5**

3.4.1 Operations and Repairs

This cost category primarily consists of repair costs (external and internal labour and parts), the budget for which is based on a forecast of the annual maintenance schedules for each piece of equipment. The age and the history of the vehicles are considered in the calculations. Throughout the year, all repair costs are charged directly to each piece of equipment. Operations cost include administration staff and their allocated share of central service support costs (for example, work methods and safety training activities).

3.4.2 Depreciation

The depreciation for each class within the fleet is calculated based on the current depreciation policies in Hydro One, and considers the current composition of the fleet, and annual forecast additions and deletions.

3.4.3 Fuel Cost

Fuel cost per class of equipment is calculated based on past history and current market projections as well as the current composition of the class. Throughout the year, fuel costs are charged directly to the particular piece of equipment consuming the fuel.

3.4.4 External Fleet Rentals

Due to the seasonal and fluctuating nature of the Company's work program, Hydro One Transmission requires the use of externally-owned equipment to meet the peaks in its programs. Using a process similar to that used to cost Hydro One Transmission's own fleet, standard rates are calculated and costs are distributed to the Company's programs and projects.

4.0 SUPPLY CHAIN MANAGEMENT

Hydro One delivers end-to-end supply chain services for the Transmission, Distribution and Remotes businesses. The focus is on the right product with the right quality, at the right place, right time and at the right cost.

The proposed 2013 costs for Supply Chain Services are expected to be $45.1 million, with a slight decrease to $45.0 million in 2014. These services include strategic sourcing (purchase) of materials and services, storage and distribution of materials; demand planning, inspection services, transportation, inventory management, and investment recovery of disposed assets.

Supply Chain Services costs are allocated to work programs and projects through the material surcharge rate.

This section describes the budgeted cost levels, followed by a description of the components of Supply Chain Management.

Table 4
Supply Chain
($ Million)

	Historic			Bridge	Test	
	2009	**2010**	**2011**	**2012**	**2013**	**2014**
Total	37.6	38.2	42.9	44.8	45.1	45.0

The increase in supply chain costs between 2009 and 2012 reflects the increase in transaction volumes supporting the growth in Hydro One's work programs, as well as cost increases related to transportation and warehousing, demand planning and expediting requirements.

Hydro One Transmission's supply chain is a non-core service which has been out-sourced to Inergi L.P. The components of supply chain management performed by Inergi include sourcing (purchase) of materials and services, transportation, contract management, expediting and inspection services.

This agreement was contracted for the same service levels at a declining price over the term of the contract.

4.1 Supply Chain Policies and Procedures

Hydro One Transmission operates a fair and transparent procurement process that gives all companies equal opportunity to do business consistent with its Procurement Policy and Principles.

Tenders and proposals are evaluated based on predefined evaluation criteria by cross-functional teams. The outcome of the evaluation is the foundation for awarding procurement contracts.

4.2 Sourcing of Materials and Services

The sourcing of materials and services, primarily carried out within Inergi, includes the following:

- Demand Management and Procurement – Market intelligence with respect to commodities, processing purchase transactions and inspecting and expediting services to ensure delivery to contract commitments.

- Sourcing and Vendor Management – Services to support sourcing all commodities and services which include managing the size and composition of the vendor base, resolving issues, and negotiating stocking arrangements.

Hydro One Transmission manages its procurement and supply base by using strategic sourcing in the acquisition of goods and services. Strategic sourcing is a disciplined business process for purchasing goods and services on a Company-wide basis using cross-functional teams to manage the supply base as a valued resource. The methodology's five-step process includes spending analysis, market analysis, development of a sourcing strategy, negotiation and award and contract management.

4.3 Inspection Services

Inergi LP is engaged to provide timely inspection services to assure that products are manufactured in accordance to specifications established by Hydro One Transmission, and tracks costs and schedules on a product and project basis. For example, Hydro One has undertaken a replacement program for a wide range of its transformers that are near their end-of-life, requiring inspection during their manufacturing and testing.

4.4 Storage and Distribution of Materials - Warehousing

Hydro One Transmission's central warehouse operation in Barrie is responsible for the storage and distribution of materials for the service centres and station locations. This warehouse services two primary customers, Customer Operations and Grid Operations. Customer Operations is further serviced through 78 field service centres and Grid Operations through 28 station locations. The field staff are responsible for receiving shipments and for storing and ordering material. Deliveries to the service centres are contracted to a third party transportation carrier.

4.5 Transportation

Hydro One Transmission manages its inbound and outbound transportation of materials through contracts with third party companies. In 2007, Hydro One Transmission entered into such a contract for material flowing in and out of the central warehouse. The strategy is to actively manage the cost of such traffic and reduce transportation cost year over year. For example transportation costs for wood poles were reduced as the new vendor provides the majority of their poles from Guelph compared to Kirkland Lake as with the previous vendor. It was determined an average of approximately 350 kms less per truckload.

4.6 Investment Recovery

The final step of the supply chain is the disposal and investment recovery of end-of-life assets. This recovery is typically in the range of $1.9 million to $3.6 million per year, and primarily involves vehicle and scrap metal sales. Hydro One Transmission continues to focus on extracting the maximum value possible from the sale of these assets.

A breakdown of the sale of assets is noted in Table 5.

Table 5
Breakdown of Sales of Assets through Investment Recovery Program
($ Million)

Type of Sale	Recovery 2009	Recovery 2010	Recovery 2011
Vehicle Sales	1.1	1.1	1.9
Scrap Metal	1.2	0.8	1.7
Tools	0.0	0.0	0
Total	**2.3**	**1.9**	**3.6**

4.7 Cost Savings from Strategic Sourcing

Through its strategic sourcing initiative, Hydro One Networks will extract savings in the purchase of major equipment, commodities and services such as power transformers, circuit breakers, wood poles, distribution transformers, wire and cable, and pole and line hardware. Strategic sourcing results vary from commodity to commodity or from one service to another.

The main benefits of sourcing strategies are described below:

- Active involvement of internal stakeholders to communicate their business needs for the products and services;
- Cost reduction by increased leverage of Company-wide expenditures – purchases are consolidated by commodity and/or service to ensure that the business receives maximum value. This eliminates the need to tender and purchase as requirements surface -- an added benefit of this approach;
- Reduced total life cycle cost for materials and services – when purchasing equipment, all aspects are identified to ensure that Hydro One Transmission acquires maximum value for the life cycle of the equipment. For example, specifications, maintenance requirements, installation services and warranty services are defined and reviewed to ensure that business needs will be met, and order and invoice processes, lead time and inventory requirements, etc. are evaluated to determine where greater efficiencies may be realized;
- Improved security of supply through longer-term agreements. To maximize value, longer-term agreements are established with fixed prices, or formula pricing is considered to ensure that Hydro One Transmission achieves best value;
- Improved and/or consistent quality of material and services.

Strategic sourcing will continue to be a major focus, as the Company emphasizes cost control and security of supply during a volatile commodity market, while demand in the global utility sector increases.

4.8 Recent Productivity Improvements in Supply Chain Management

Hydro One Transmission is focused on continuous improvement, and supply chain management is one example. This section details some work in progress to provide effectiveness and efficiency gains.

Hydro One has implemented a new sourcing model which categorizes spend across materials and services. This allows us to go to market on a more consolidated spend basis to realize increased sourcing savings, and to lower costs through dealing with a fewer number of suppliers. Supply Chain is also implementing electronic invoicing, allowing Hydro One to increase the value of available discounts captured, and to reduce paper flow and transaction costs. Hydro One is also identifying and taking advantage of opportunities to leverage the Province of Ontario's commodity contracts.

Hydro One Transmission has also developed "Outline Agreements" with vendors to establish a standing order or relationship for critical materials, such as cable and power transformers. In addition, the Company involves some suppliers in its planning activities, and studies historical buying patterns to assist in planning purchases.

In 2009, warehousing implemented a cross docking initiative to ensure receipting is done in a timely and compliant fashion. In 2011, warehousing implemented a bar coding system to further improve its effectiveness.

Streamlining standards is another way in which Hydro One Transmission is improving the strategic sourcing process. For switches, for example, the Company previously had approximately 37 standards, which were reduced to 17. In addition to simplifying procurement, this also increases both the likelihood that spares will be available for use, and the ease of maintaining a lower inventory.

COMMON CORPORATE COSTS,
COST ALLOCATION METHODOLOGY

Allocation of common costs to Hydro One's Transmission and Distribution businesses and to each Hydro One affiliate is based on clearly articulated shared services and an established cost allocation approach based on cost causality principles.

The Common Corporate Costs OM&A programs include the provision of Corporate Common Functions and Services ("CCF&S"), Asset Management, Information Management Services, and Operating programs to support Hydro One Networks' Distribution and Transmission businesses.

CCF&S include corporate management activities, finance, human resources, communications, legal, regulatory, security, internal audit and risk management, strategic planning. Asset Management programs include developing asset strategies, policies and standards; identifying, planning and prioritizing specific OM&A and Capital work on distribution and transmission systems and monitoring the execution of the annual work program and real estate facility services.

A description of the Common Corporate Costs has been provided at Exhibit C1, Tab 4, Schedule 2.

In 2010, the Company commissioned a study by Black and Veatch (B&V) to update the methodology to allocate common costs among the business entities, the results of which were accepted in the Board's EB-2010-0002 Decision with Reasons, dated December 23, 2010. The methodology developed represents the industry's best practices, identifying appropriate cost drivers to reflect cost causality and benefits received.

In 2012, B&V conducted a further review of the common costs allocation methodology that is used in this current filing. The report on this study is provided as Attachment 1 to this exhibit.

As part of the new study, the cost drivers used in EB-2010-0002 were updated to incorporate current information. Updating the driver inputs resulted in a shift in allocation from Distribution ($6.0 million or 1.3%) and Telecom ($0.3 million or 0.1%) to Transmission ($6.3 million or 1.4%).

For the four week period ending July 15, 2011, Hydro One employees representing $111 million of labour costs participated in the Asset Management Time Study. Incorporating the results of the 2011 time study resulted in a shift from Distribution to Transmission ($4.7 million or 1.1%).

Updating the time allocations of the functions and activities included in Shared Services resulted in a shift from Transmission ($8.5 million or 1.9%), Telecom ($0.6 million or 0.2%), Brampton ($0.2 million or 0.1%) and Remotes ($0.2 million or 0.1%) to Distribution ($9.5 million or 2.3%).

Hydro One accepted the results of the B&V study as providing a reasonable and equitable approach to the assignment of common costs among the business entities using the common services. This methodology was based on the R. J. Rudden Associates (Rudden) Study that the Board accepted in the Distribution rate decision RP-2005-0020/EB-2005-0378.

The following Tables 1 and 2 provide the allocation of 2013 and 2014 CCF&S costs, respectively, to all business units.

Table 1
Allocation of 2013 CCF&S Costs ($ Millions)

Description	Total	Transmission	Distribution	Hydro One Telecom	Hydro One Brampton	Hydro One Remotes	Hydro One Inc.
Corporate Management	5.3	2.7	2.3	0.1	0.1	0.1	0.1
Finance	34.0	19.5	13.6	0.5	0.2	0.2	0.1
Human Resources	10.9	6.4	4.3	0.2	0.0	0.1	0.0
Corporate Communications & Services	11.4	5.3	6.1	0.0	0.0	0.1	0.0
General Counsel & Secretariat	8.9	4.7	3.6	0.1	0.2	0.2	0.1
Regulatory Affairs	23.6	11.5	12.0	0.0	0.0	0.1	0.0
Corporate Security	3.8	1.8	2.0	0.0	0.0	0.0	0.0
Internal Audit	4.3	2.5	1.3	0.1	0.2	0.1	0.0
Real Estate & Facilities	62.5	31.8	30.7	0.0	0.0	0.0	0.0
Total CCF&S Costs	**164.8**	**86.1**	**75.9**	**1.0**	**0.7**	**0.9**	**0.2**

Table 2
Allocation of 2014 CCF&S Costs ($ Millions)

Description	Total	Transmission	Distribution	Hydro One Telecom	Hydro One Brampton	Hydro One Remotes	Hydro One Inc.
Corporate Management	5.4	2.8	2.4	0.1	0.1	0.1	0.1
Finance	34.0	19.5	13.6	0.5	0.2	0.2	0.1
Human Resources	11.2	6.5	4.4	0.2	0.0	0.1	0.0
Corporate Communications & Services	12.6	5.7	6.8	0.0	0.0	0.1	0.0
General Counsel & Secretariat	9.1	4.8	3.7	0.1	0.2	0.2	0.1
Regulatory Affairs	23.0	9.7	13.2	0.0	0.0	0.1	0.0
Corporate Security	3.9	1.8	2.1	0.0	0.0	0.0	0.0
Internal Audit	4.4	2.6	1.4	0.1	0.2	0.1	0.0
Real Estate & Facilities	64.3	32.7	31.6	0.0	0.0	0.0	0.0
Total CCF&S Costs	**167.9**	**86.1**	**79.1**	**1.0**	**0.7**	**0.9**	**0.2**

REVIEW OF SHARED SERVICES COST ALLOCATION (TRANSMISSION) – 2012

PREPARED FOR

Hydro One Networks Inc.

1 FEBRUARY 2012

BLACK & VEATCH
Building a world of difference.

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I. Summary

A. BACKGROUND

Black & Veatch Corporation ("B&V" or "we") is pleased to submit this Report on our Review of Shared Services Cost Allocation (Transmission) – 2012 ("2012 Review") to Hydro One Networks Inc. ("Hydro One").

In 2004, B&V was engaged by Hydro One to recommend a best practice methodology to distribute the costs of providing Shared Services, including costs under its outsourcing contract with Inergi LP, to Hydro One and its subsidiaries ("2005 Review"). B&V recommended, Hydro One adopted and the Ontario Energy Board ("OEB") accepted a methodology to distribute those costs, as described in our *Report on Common Corporate Costs Methodology Review* dated May 20, 2005 ("2005 Common Costs Report").

The OEB-accepted methodology has been applied to Hydro One's Business Plans, and reviewed by B&V with reports issued, as follows:

B&V REVIEW	BUSINESS PLAN	B&V REPORT
2006 Review	BP 2007-2011	*Report on Implementation of Common Corporate Costs Methodology* dated May 31, 2006
2008 Review	BP 2009-2013	*Report on Implementation of Common Corporate Costs Methodology* dated September 10, 2008
2009 Review	BP 2010-2014	*Report on Shared Services Costs Methodology* dated June 29, 2009
2010 Review	Updated BP 2010-2014	*Report on Shared Services Costs Methodology – 2011* dated February 26, 2010

The OEB-accepted methodology has been applied by Hydro One to its Business Plan for 2012-16 ("BP 2012-2016") data for its 2013/2014 Transmission Rates filing. This Report describes the "2012 Review" that B&V performed, at Hydro One's request, of Hydro One's application of the methodology to its BP 2012-16, and presents B&V's conclusions.

B. HYDRO ONE ORGANIZATION

Hydro One Inc. is wholly owned by the Province of Ontario. It operates through the following wholly owned subsidiaries, each of which is a business unit: Hydro One Networks Inc., which includes the Transmission business and the Distribution business; Hydro One Brampton Inc. ("Brampton"); Hydro One Remote Communities Inc. ("Remotes"); and Hydro One Telecom Inc. ("Telecom"). Table 1 provides information about the business units.

Table 1 - Business Units

BUSINESS UNIT	DESCRIPTION
Transmission	Owns and operates substantially all of Ontario's electricity transmission system.
Distribution	Owns and operates a distribution system which spans approximately 75% of Ontario and serves approximately 1.1 million customers.
Brampton	Owns, operates and manages electricity distribution systems and facilities in Brampton, Ontario.
Remotes	Owns, operates, maintains and constructs generation and distribution assets used to supply of electricity to remote communities in northern Ontario.
Telecom	Sells high bandwidth telecommunication services to carriers, Internet service providers, and large public and private sector organizations.
Hydro One Inc.	Represents activities performed exclusively for the benefit of the shareholder of Hydro One Inc. Most of the costs incurred by Hydro One, Inc, are for the benefit of the other businesses, and are allocated to the other businesses.

The OEB regulates, separately, each of the following: Hydro One Distribution, Hydro One Transmission, Hydro One Brampton, and Hydro One Remotes. Each business is required to account separately for its assets, revenues and costs, for both regulatory and financial accounting purposes.

C. SHARED SERVICES AND COST OF SHARED SERVICES

Shared Services comprises the functions and services identified in Table 2; Exhibit A further describes the functions and services.

The BP 2012-16 includes 2013 planned costs totaling approximately C$396.8 million incurred to provide the Shared Services. The Shared Services are provided, and costs are incurred, for the benefit of the businesses listed in Section B.

Approximately 33% of the Shared Services costs are incurred under an outsourcing arrangement with Inergi LP ("Inergi"). In this Report, Shared Services includes the portions of Inergi services identified in BP 2012-16 as "sustainment."

In addition, previous studies included costs which were assigned to the Materials Surcharge; these costs are not included in Shared Services because Hydro One now charges these costs outside the Shared Services cost process.

Table 2 lists all of the functions and activities included in Shared Services for as described in this report.

Table 2 - Functions and Activities in Shared Services

Hydro One Inc. Corporate Office	
Operations ■ EVP Office - Operations ■ Facilities & Real Estate ■ Contract Management ■ Conservation and Demand Management ■ Network Operating ■ Customer Care ■ Distributed Generation ■ Customer Business Relations	**Strategy** ■ EVP Office – Strategy ■ First Nations & Metis Relations ■ Corporate Affairs ■ Infrastructure and Systems Development (ISD) ● Business Information Technology ● Power Systems Information Technology ● Business Architecture ● Security Operations ■ Asset Management ● Asset Strategy ● Business Performance ● Strategy Alignment ● Sustainment Investment Planning ● Distribution Business Development ● Transmission Development ● AM VP Office
Corporate Services ■ Treasury ■ Corporate Controller ■ Taxation ■ Human Resources ■ Labour Relations ■ Regulatory Affairs ■ Business Planning / Regulatory Finance	
Law / Corporate Secretariat	**Internal Audit**
Telecom Services	**Finance and Accounting Services**
Customer Support Operations	**Settlements**
ETS- Applications Support and Infrastructure Support	

D. B&V'S ASSIGNMENT

For the 2012 Review, our assignment was to:

a. Evaluate whether the existing Cost Allocation Methodology continues to be appropriate for Hydro One, and identify changes that are necessary or desirable.

b. Review Hydro One's application of the OEB-accepted Cost Allocation Methodology to the BP 2012-16.

Concurrently with this 2012 Review, B&V reviewed and issued reports on Hydro One's Overhead Capitalization Rate methodology and Common Assets allocation.

E. OVERVIEW OF METHODOLOGY

The B&V methodology for allocating the costs of Hydro One's Shared Services was designed to address the following considerations:

- Compliance with OEB precedent including Docket RP-2002-0133 (*In The Matter Of The Ontario Energy Board Act, 1998)*, S.O. 1998, c.15
- Compliance with relevant provisions of the Affiliate Relationships Code for Electricity Distributors and Transmitters ("Code")
- Cost incurrence- Are the costs needed to perform services required by the business units?
- Cost allocation- Are costs appropriately allocated among business units?
- Cost / benefit- Do benefits received equal or exceed the cost?

An overview of the B&V cost allocation methodology is described below:

- Identify the functions and services included in Shared Services
- Identify activities that are performed in order to provide the Shared Services
- Distribute the annual departmental costs in the BP 2012-16 among the activities performed by each department, based on time and/or cost studies
- Distribute the cost of each activity among the business units based on direct assignment when possible, and based on cost drivers when not possible

A cost driver is a formula for sharing the cost of an activity among those who cause the cost to be incurred. The direct assignment of costs when possible, and the use of cost drivers to allocate costs when direct assignment is not possible, is consistent with OEB precedent, including Docket RP-2002-0133. The guiding principle used by the B&V methodology to assign cost drivers is cost causation.

Cost drivers are discussed in Section II-D. The different types of cost drivers are described in Exhibit B.

F. SCOPE OF WORK

Consistent with B&V's standard practice for consulting assignments, we relied on the genuineness and completeness of all documents presented to us by Hydro One, and we accepted factual statements made to us by Hydro One (e.g., counts of workstations, headcount, budgeted amounts) subject only to their overall reasonableness and any actual contrary knowledge, but without our independent confirmation. All dollar amounts in this Report are stated in Canadian dollars.

G. RESULTS AND CONCLUSIONS

B&V believes that the current cost allocation methodology continues to be appropriate for Hydro One because it achieves the purposes for which it was designed (to distribute costs in a manner that is consistent with OEB precedent and regulatory practice) and promotes transparency and efficiency.

Table 3 presents the results of Hydro One's distribution of the 2013 and 2014 costs of providing the Shared Services included in BP 2012-16.

Table 3 - Distribution of 2013 and 2014 Shared Services Costs

BUSINESS	2013		2014	
	$ Millions	% of Total	$ Millions	% of Total
Transmission	$185.6	46.8%	$187.2	47.0%
Distribution	205.7	51.8%	205.9	51.7%
Other	5.5	1.4%	5.5	1.3%
Total Shared Services Costs	**$396.8**	**100.0%**	**$398.6**	**100.0%**

Based on our review, Black & Veatch believes that the results of Hydro One's application of the B&V Shared Services cost allocation methodology to its BP 2012-16 data (the results for years 2013 and 2014 are shown in Table 3) reflects a cost causation-based distribution of the costs of providing the Shared Services and conforms to the OEB-accepted methodology.

B&V also notes that Hydro One management believes that the existing methodology is appropriate for the company, the cost allocation process receives strong support from Hydro One management and is well integrated into the budgeting process and the Shared Services Model is updated periodically to reflect current information.

II. Statement of Approach

This section presents the approaches used by B&V to evaluate whether the existing Shared Cost Allocation Methodology continues to be appropriate for Hydro One, and to review Hydro One's application of the methodology to BP 2012-16 costs of providing the Shared Services.

A. EVALUATE CURRENT COST ALLOCATION METHODOLOGY

The current Shared Cost Allocation Methodology was first applied to Hydro One's Business Plan 2006-10. Hydro One has asked B&V to evaluate whether the methodology is still appropriate, and what changes if any could be considered. B&V's approach is discussed in detail in Section III.

B. REVIEW APPLICATION OF CURRENT METHODOLOGY TO BP 2012-16

In preparing the 2012 Review, B&V performed the following tasks:

Task 1. Reviewed Hydro One's organizational structure and identified functions and services included in Shared Services.

Task 2. Identified the activities performed by each department in order to provide each of the Shared Services identified in Task 1.

Task 3. Determined BP 2012-16 budgeted costs for Shared Services in Task 1.

Task 4. Identified the business units (service recipients or beneficiaries) that use the Shared Services.

Task 5. Distributed total BP 2012-16 resources (time for labour resources and cost for non-labour and Inergi resources) for each of the Shared Services identified in Task 1, among the activities identified in Task 2.

Task 6. Directly assigned activity costs to business units where a direct relationship exists.

Task 7. For activities where less than all of the BP 2012-16 resources were directly assigned to business units in Task 6, assigned a cost driver that reflects cost causation.

Task 8. Populated the cost drivers.

Task 9. Reviewed the 2011 Time Study

Task 10. Computed total cost of Shared Services for each business unit.

Task 11. Performed analytical review of results.

Task 12. Reviewed the Shared Services Model used to perform the computations.

C. PRINCIPLES OF COST DISTRIBUTION

There are two methods to distribute shared costs among business units – Direct Assignment and Allocation. *Direct Assignment* is used when the portion of an activity used by a business unit can be reasonably established. Approximately 59% of Shared Services costs in the BP 2012-16 were assigned directly to one or more of Hydro One's business units.

Allocation is used when more than one business unit uses an activity, but the portions of the activity that each uses cannot be directly established. In this case, a cost driver must be assigned to distribute the costs of the activity. A cost driver is a formula for sharing the cost of an activity among those who cause the cost to be incurred. The principles used by B&V to assign cost drivers are discussed in Section II.D below.

Direct assignment is preferable to Allocation because it is based on a more direct relationship between activities and costs.

D. COST DRIVERS

As stated above, a cost driver is a formula for sharing the cost of an activity among those who cause the cost to be incurred. The guiding principle that B&V uses in assigning cost drivers is cost causation. Cost causation means that there is a causal relationship between the cost driver and the costs incurred in performing the activity. In some cases, cost causation cannot be easily implemented or established, in which cases selecting cost drivers based on benefits received is a fair treatment.

Other factors considered in assigning cost drivers include:

- Practicality – The cost driver should be understandable, obtainable at reasonable cost, and objectively verifiable in the initial year as well as in subsequent years.
- Stability – Cost driver values should be reasonably stable from year to year. When estimates are used, the cost driver should be able to be estimated with reasonable accuracy, and estimates should be unbiased.
- Materiality – When choosing between cost drivers, small differences can often be ignored in favor of Practicality and Stability (see above).

E. TYPES OF COST DRIVERS

Cost drivers can be classified as External or Internal. External drivers are based on data that are external to the cost allocation process, such as physical units or financial amounts.

Internal drivers are based on values computed as part of the allocation process. For example, the cost of a supervisor's salary might be allocated in the same proportion as the salaries of the people being supervised, and the cost of general departmental expenses might be allocated in the same proportion as the specifically assigned departmental activities. Exhibit B further describes different types of cost drivers.

III. Evaluate Current Cost Allocation Methodology

The current Cost Allocation methodology was first applied to Hydro One's Business Plan 2006-10. B&V also has reviewed the application of the methodology, as listed in Section I.A. Background**.** The purpose of this portion of the assignment was to evaluate whether the methodology is still appropriate, and what changes if any would be recommended.

This task was accomplished by meeting with Hydro One finance personnel, senior managers, managers in the Shared Services departments and business units/users, during the course of our review of the application of the methodology.

B&V established the following framework for this evaluation:

1. Does the current cost allocation methodology achieve the purposes for which it was designed?

The current cost allocation methodology meets the purposes for which it was designed. It has been accepted by the OEB, and its use of direct assignments and cost drivers conforms to best practices.

2. Does the current methodology promote efficient use of resources?

The current methodology has the support of Hydro One management. It is understood by the business units to which costs are distributed, and accepted as being fair and reasonable. The Telecom, Brampton and Remotes business units confirm that the services are provided to them at a cost that reflects economies of scale.

The current methodology allows the business units to determine precisely what amount they are charged by department and by activity within the department. This transparency provides a basis for understanding the charges and the value of the services received.

In addition, the current methodology is well-integrated with Hydro One's annual Business Planning process and produces reasonably stable results over time.

3. What trade-offs have been made in implementing the current methodology? What improvements can be made?

Following are changes that have been considered by Hydro One and B&V:

Units-of-service billing

The current methodology uses direct assignments for approximately 59% of costs. The remaining portions of the costs are distributed using cost drivers. An alternative method would be to implement a units-of-service billing mechanism. While that would create a seemingly more precise distribution of costs, it would be constrained by lack of a basis for charging time for many activities (e.g., human resources, IT infrastructure) and would have adverse consequences including greater complexity and cost.

More automated Shared Services Model

The Shared Services Model could be made more automated, in order to add departments and reflect change to the organizational structure more easily. This would require an investment of IT time to make the model truly automatic and error-proof. We do not believe the annual savings of several hours would be worth this investment. In addition, some tasks, such as determining direct assignments or selecting allocators, cannot be automated.

Greater use of concurrent time studies

In the current application of the methodology, direct assignments are used for approximately 59% of costs. Direct assignments include concurrent time studies (where personnel record their time each day or week for a test period, such as the 2011 Time Study- see Section V) and distributions of time by managers (see Section Task 5- Distributed Total Budgeted Resources for Each of the Shared Services Among Activities).

Hydro One considered expanding the use of concurrent time studies to other departments (beyond the 2011 Time Study). The departments in the 2011 Time Study are able to determine with reasonable accuracy the time they spend on various projects because the projects are clearly defined, and their work is not seasonal. However, for other departments, the projects are not clearly defined, and their work may be largely seasonal. Therefore, using concurrent time studies for these other departments would not be representative.

In addition, the option for all employees to record their time over the course of the year would add significantly to costs and complexity.

Therefore, B&V considers 100% concurrent time recording to be a more costly and less effective approach than is presently used.

B&V believes that the current cost allocation methodology continues to be appropriate for Hydro One, because it achieves the purposes for which it was designed (to distribute costs in a manner that is consistent with OEB precedent and regulatory practice), and promotes transparency and efficiency.

IV. Review Application of Current Methodology to BP 2012-16

In this Section we will discuss each of the Tasks performed in the Scope of Work, as stated in Section II-B. This includes the purpose of the Task, the detailed steps performed, the source of the information and the results.

Task 1. Reviewed Hydro One's organizational structure and identify functions and services in Shared Services.

The purpose of this task was to describe Hydro One's organizational structure for providing corporate functions and services, and to identify the Shared Services; evaluating the allocation of the cost of the Shared Services is the purpose of this Review.

The organization of Hydro One Inc. is described in Section I.B- Hydro One Organization. The Shared Services support the Transmission business unit and the Distribution business unit, as well as support Remotes, Brampton and Telecom.

Shared Services comprise the functions and services identified in Exhibit A in Section I.C- Shared Services And Cost Of Shared Services. Exhibit A further describes the functions and services. This information was provided by Hydro One in discussions and documents.

Task 2. Identified Activities Performed to Provide Each of the Shared Services

The purpose of this task was to identify the activities that are performed in order to provide each of the Shared Services.

Functions and services (identified in Task 1) are performed for the benefit of the business units. Activities (discussed in this Task 2) are the tasks performed in order to render the functions and services. Activities are measured in the amount of resources used.

To distribute the resources required to provide the Shared Services among the business units on the basis of cost causation, the activities performed were identified by the appropriate Hydro One department manager. The activities identified accounted for over 97% of the total 2013 cost of the resources included in BP 2012-16 (time for labour resources, costs for non-labour and Inergi resources) to provide the Shared Services. The remaining activities are identified as General Departmental Activities and Other Departmental Expenses and included activities such as training and development.

Task 3. Determined BP 2012-16 Cost for Each of the Shared Services

The purpose of this task was to obtain the BP 2012-16 costs for each of the Shared Services. As part of this task, Hydro One provided to B&V the labour and non-labour portions of the BP 2012-16 for each of the Shared Services, as well as descriptions of major non-labour cost items.

Task 4. Identified Business Units

The purpose of this task was to identify the business units that use the Shared Services. The business units are listed in Table 1. The information was provided by Hydro One. In addition, B&V interviewed management personnel from the business units to confirm that they use the Shared Services for which they are assigned costs.

Task 5. Distributed Total Budgeted Resources for Each of the Shared Services Among Activities

The purpose of this task was to distribute the resources (time for labour and costs for non-labour and Inergi) required for each of the Shared Services identified in Task 1, among the activities identified in Task 2. In subsequent tasks, the cost of each activity was either directly assigned to one or more business units or allocated using cost drivers.

Labour costs

To distribute budgeted labour costs, the Hydro One manager responsible for each Shared Services determined the portion of annual time spent by the personnel under his or her supervision on each of the activities identified in Task 2. Some managers based their estimates on concurrent time records that they maintain, some conducted interviews with their personnel, and some used their informed judgment. The information provided by the managers was reviewed by Hydro One Inc. and B&V, and was found to be reasonable and consistent with prior distributions of resources.

Approximately $111 million of labour costs (for the departments in the study), representing approximately 27% of the annual total Shared Services costs (and approximately 53% of annual labour costs), were directly assigned based on the 2011 Time Study, discussed in Section V.

Non-labour costs

To distribute the budgeted non-labour costs, $40.8M, or 80%, of the total of $51.0M, were examined and distributed based on direct assignment or allocation. This included OEB invoices, communications programs, insurance costs and claims, human resources programs, labour relations programs, Bill 198 consultant, actuarial consultants and audit fee. The balance of non-labour costs includes items such as training and development, non-specific expenses and general expenses (such as travel).

Inergi costs

The costs of the Shared Services provided by Inergi were distributed among the activities, based on information provided by Hydro One Inc., assignments and allocations by Hydro One and B&V, and the application of judgment by Hydro

One and B&V. The approach for each of the Shared Services provided by Inergi is described below. Exhibit A describes these services in greater detail.

- **Customer Support Operations–** Costs were assigned among activities based on the estimated portion of total amounts paid to Inergi to perform the function. All of the activities are related directly to the Distribution business.
- **Settlement –** Only one activity, no distribution of costs among activities required. The resources used in the activity were directly assigned between Transmission and Distribution based on estimated effort.
- **Finance –** Costs were assigned among activities based on estimated portion of total amount paid to Inergi to perform the function.
- **Human Resources –** Costs were assigned among activities based on estimated effort by Inergi. All activities were allocated among the business units based on headcount.
- **Enterprise Technology Services –** ETS includes the cost of sustainment activities for baseline infrastructure and for support of major application groups (i.e., customer service; finance; human resources; Passport / Cornerstone; Market Ready; and telecom). The cost of baseline infrastructure services was based on contract amounts. The balance of costs were distributed among the applications groups based on the relative costs of Inergi support, the number of applications supported and judgment as to the complexity of the applications.

Task 6. Assigned Activity Costs to Business Units

The purpose of this task was to assign, among the business units identified in Task 4, the resources (time for labour resources and costs for non-labour and Inergi resources) for each activity identified in Task 2. In Task 10, these assignments were used to distribute the cost of each activity among the business units. This task was performed concurrently with Task 5 – Distributed Total Budgeted Resources for Each of the Shared Services Among Activities.

For each activity identified in Task 2, the Hydro One manager responsible for each of the Shared Services divided the resources among one or more business units, based on the business units that caused the costs to be incurred. When possible, all or a portion of costs were assigned directly.

Any portion of an activity that was not directly assigned, was allocated among business units using cost drivers, as described in Task 7. Each activity was determined to be:

- Caused by Transmission and Distribution only, and the split cannot be determined, or
- Caused by Transmission and / or Distribution and at least one other business unit, and the split cannot be determined.

Task 7. Assigned Cost Drivers

As discussed above, the costs of activities were directly assigned to business units when possible. The purpose of this task was to select cost drivers for the portion of costs which were not directly assigned in Task 6. In Task 10, the cost drivers were used to distribute the activity costs among the business units.

The principles that B&V used to assign cost drivers are discussed in Section II.D-Cost Drivers. B&V selected cost drivers based on applying the principles discussed above, its experience in performing cost allocation studies, consultations with Hydro One as to the nature of each activity, and industry practices and regulatory requirements.

Section II.E Types Of Cost Drivers describes the types of cost drivers.

Table 4 summarizes the direct assignments and types of costs drivers used to distribute the Shared Services costs among the business units. Amounts include the Inergi charges.

Table 4 - Direct Assignments and Cost Drivers for 2013 Shared Services Costs

TYPE	2013 $ ASSIGNED ($ MILLIONS)	% OF TOTAL
Direct Assignment	$235.8	59.4%
Physical	34.4	8.7%
Financial	52.9	13.3%
Internal	73.7	18.6%
Total Shared Services Costs	**$396.8**	**100.0%**

Task 8. Populated Cost Drivers

The purpose of this task was to determine the values of each cost driver that are attributable to each business unit, in order to distribute the costs of each activity among the business units. The supporting information was provided by Hydro One.

Task 9. Reviewed 2011 Time Study

This Task is discussed in Section V.

Task 10. Computed Total Shared Services Costs For Each Business Unit

The purpose of this task was to distribute the total cost of each activity among the business units. The amount distributed was the sum of the amounts directly assigned in Task 6 and allocations based on the cost drivers identified in Task 7.

For allocations based on the cost drivers, the amount allocated to each business unit was computed by multiplying the activity cost to be allocated, by the cost driver portion value for the business unit.

Task 11. Performed Analytical Review

The purpose of this task was to compare the results of the distribution of the BP 2012-16 Shared Services Costs among the business units to the results in the 2010 Review, 2009 Review, 2008 Review and 2006 Review, and to understand the differences.

The proportions of the total cost distributed to each business unit have been reasonably similar over time and differences are explained by additions and removal of departments from the Shared Services (i.e., the 2012 Review includes Asset Management departments and Operating group departments, and excludes Materials Surcharge, for the first time), changes in allocations of time, changes in allocator values and changes in departmental functions and activities.

Task 12. Reviewed Shared Services Model

The purpose of this task was to review the Shared Services Model that Hydro One has developed for allocating the cost of Shared Services, to determine if it properly reflects and models the OEB-accepted cost allocation methodology for the Shared Services costs in the BP 2012-16.

B&V first reviewed Shared Services Model in connection with our 2008 Review, and has reviewed the model for the 2009 Review, 2010 Review and this 2012 Review. The model is updated periodically to reflect organizational changes; Business Plan costs; additions to and deletions of departmental activities; time and cost distributions among activities; assignments of allocators; and cost driver values.

The Shared Services Model distributes departmental costs among activities (Task 6), then distributes the cost of each activity based on direct assignment or cost drivers (Task 10).

Based on our review, the Shared Services Model properly implements the OEB-accepted methodology for distributing the costs of corporate functions and services in the BP 2012-16, and continues to produce a cause-based allocation of costs.

V. 2011 Time Study

Hydro One employees representing approximately $111 million of labour costs participated in a time study for the four-week period ending July 15, 2011 (referred to as the "2011 Time Study").

The departments that participated in the 2011 Time Study were the Asset Management departments identified in Table 2, and the following departments in the Operations group: Conservation and Demand Management; Customer Care; Distributed Generation; Customer Business Relations; and Network Operating.

The responsibilities of each of the departments that participated in the 2011 Time Study are included in Exhibit A.

The personnel in these departments are able to determine with reasonable accuracy, on a current basis, the time they spend on Distribution Operations and Maintenance, Distribution Capital Projects, Transmission Operations and Maintenance and Transmission Capital Projects because the projects on which they work are clearly defined.

A properly performed time study measures cost causation and is widely accepted as a basis for allocating costs. B&V designed, administered and supervised the 2011 Time Study and found it to be appropriate. It was not practical to perform a full-year study, but the results for a four-week period are believed to be representative of the full-year. To support this judgment, B&V reviewed the previous Hydro One Asset Management time studies and found that the results were reasonably similar to the 2011 Time Study results, with differences explained by changes in the departments included in the studies.

Therefore, B&V found the 2011 Time Study to be a proper basis for directly assigning the costs of the departments included in the study between the Distribution and Transmission and business units.

Exhibit A: Shared Services

FUNCTIONS AND SERVICES	DESCRIPTION
Hydro One Inc. Corporate Office (HOI)	
President and CEO	Leadership of the staff of the Corporation to ensure that their culture and behaviours lead to achievement of its strategic objectives. Develop and update strategy and establishes performance targets to assess progress towards the goals and objectives defined by the strategy.
Chair	Strategic direction, implementation and results for Hydro One Inc. and for each subsidiary.
CFO's Office	Provide Hydro One and subsidiaries with strategic review and approval for all financial and investment decisions. Review of policies and procedures, treasury operations and tax planning, financial control and reporting.
Treasurer's Office	Debt and equity issuance, Capital structure management and oversight of Finance- Treasury function.
Pension	Pension fund contributions.
Board of Directors	Strategic direction, implementation and results for Hydro One Inc. and for each subsidiary.
Corporate Secretariat	Provide direction and analysis in areas of: 1) Board and Committee(s); 2) Office of Chair and Board members; 3) Code of Business Conduct; 4) Community Citizenship; 5) Freedom of Information and Privacy, 6) Corporate Archives, 7) Corporate Records, 8) Corporate Secretariat.
Vice President	Oversee and support Law, Regulatory and Corporate Secretariat General Counsel functions.
Donations	Includes donations to support injury prevention, corporate donations (e.g. Salvation Army), energy education, United Way and local community causes.
Shared Operations	
EVP- Operations	Oversight of Operations group.
Real Estate	Manage and acquire rights of way and easements; manage property taxes; manage SLU revenue programs; manage Employee Relocation Program.
Contract Management	Manage overall business relationship between Hydro One and Inergi LP.
Conservation and Demand Management	Design and deliver energy CDM incentive based programs for all customer segments; Leverage Smart Grid investments to provide customer enablement of new technologies for energy management; Co-ordinate Greener Choices program to improve energy efficiency of Hydro One's assets and develop a culture of conservation among employees; Provide input to Corporate Strategic Plan and develop recommendations on emerging strategic opportunities.
Network Operating	Operates the largest electricity delivery system in Ontario and one of the largest in North America for the needs of the Province of Ontario. Hydro One has a highly skilled and experienced workforce using first-class operating systems located in a state-of-the-art Control Centre. Hydro One is a team working

FUNCTIONS AND SERVICES	DESCRIPTION
	together and safely to ensure Ontario has a safe, reliable supply of electricity.
Customer Care	Service the approximately 1.1 million distribution customers. Improve customer satisfaction through strategic system and process enhancements, effective services contracting, proactive communications and quality programs. Service programs include meter reading, billing, settlements, customer contact handling and collections. Project work includes regulatory compliance initiatives and service enhancements.
Distributed Generation	Develop, manage, and look for operational efficiencies in the process (application to connection) for generators connecting to Hydro One's distribution system. Coordinate status meetings with internal stakeholder groups. Manage relationship of generators pre and post connection process through Account Executives, Customer Advisory Board, DG Consultation Forum. Perform capacity screenings. Provide operating maps. Perform pre-FIT consultations. Manage Connection Cost Agreement and Distribution Connection Agreement.
Customer Business Relations	Manage relationships with Hydro One's large customers including over 90 Transmission-connected Industrials, 79 LDCs and 33 Transmission-connected Generators, representing almost 70% of Hydro One's revenues. Includes Operating Support; Account Executives; Contract Management; and Customer Programs.
Coporate Support	
Treasury	Risk management including insurance purchasing; insurance claims settlement; financial risk management; cash & banking operations; debt management-prospectus, debt issuance, borrowing, maintain relationship with shareholders; funds management; investor relations- shareholders, creditors, equity analysts & rating agencies; support business activities; project management.
Corporate Controller	Corporate Accounting & Reporting; Revenue Management; Financial Modeling & Analysis; Accounting Policy; Internal Control; IFRS / US GAAP; Inergi Finance; Bill 198; Corporate Compliance.
Taxation	Meet internal and external tax compliance requirements and reduce overall corporate tax liability through tax planning for current and new businesses, acquisitions and dispositions, special projects, tax compliance (including income tax, HST, and DRC returns for all entities), tax accounting, lobbying for legislative tax changes and government tax audits.
Human Resources	Primarily employee-related services.
Labour Relations	Provide full-scale service pertaining to bargaining, Ontario Labour Relations Board hearings, grievance and arbitration hearings, advice and guidance, plus training to all levels of Hydro One management. Involves interaction with 21 unions and 24 collective agreements.
Regulatory Affairs	Coordinate applications filings with OEB; compliance with OEB orders; design and implement regulatory policy; manage relationship with OEB. Specific tasks include: cost allocation and rate design for regulated Tx and Dx, especially rate

FUNCTIONS AND SERVICES	DESCRIPTION
	structures and rates for Tx and Dx tariffs; Assist implementation of approved Tx and Dx rates; support transmitters' representative on IESO Technical Panel; provide load forecasts for all Hydro One business units and IESO; manage MV Star to support wholesale and retail settlement; provide strategic and analytical support to load research and CDM initiatives.
Regulatory Affairs- OEB Cost	Direct billed OEB costs for Transmission and Distribution businesses.
Regulatory Affairs- NEB Cost	Direct billed NEB costs for Transmission business.
Regulatory Affairs- Rate Hearings	Costs of Rate Hearings before the OEB for Transmission and Distribution businesses.
Business Planning and Regulatory Finance	Financial modeling & analysis; corporate planning & reporting; regulatory finance; decision support to the lines of business
Strategy	
EVP- Strategy	Oversight of Strategy group.
First Nations and Metis Relations	Provide First Nations and Métis consultation advice and support; Provide advice re First Nations and Métis HR strategies; Provide strategic advice to Remotes with respect to First Nations and Métis issues.
Corporate Affairs	Support all external and internal communications initiatives. Interact with most other Hydro One departments; special focus on Customer Service. Support major projects including: development of partnership activities; coordinate with external energy agencies (e.g. OPA, IESO), Ministries in Ontario Public Service and internal Hydro One resources. Participate in pre-public consultations with municipalities and First Nations. Support customer strategy, rate strategy, distribution generation strategy; develop working relationships with customers, regulators, shareholder, lenders; labour relations; corporate culture.
Transmission Development	Transmission capital projects and programs to expand, enhance, upgrade and improve the transmission system. Focus on area supply, network transfer capability, transformer station upgrades, load customer connections, transmission connected generation, protection and control development and special studies.
Business Architecture	Application support and training; Business systems architecture; Reporting & analytics; Manage key asset customer database; provide integrated systems support; support Cornerstone.
PSIT (Power Systems Information Technology)	Applications; Compliance security; Data services; Information services; IT operations; System architecture.
Business Information Technology	Information technology security; Enterprise IT architecture; Service delivery; Technology services; Governance of IT architecture, Business analysis and information management, Project management; Inergi & Telecom services management.
Security Operations	Incident reporting and security awareness; Threat intelligence gathering; Physical security and asset threat and risk assessments; Investigations; Theft of electricity consultation and detection; Workplace violence prevention and

FUNCTIONS AND SERVICES	DESCRIPTION
	response; Contract security procurement assistance; Overall security and asset protection advice; Security infrastructure Capital and OM&A investment planning and project management.
Asset Strategy	Align corporate strategy with Asset Management, and investment plans with business plan; 10-year Tx and Dx plans; apply Risk Methodology in asset planning; asset analytics PIP; rate case filings; NERC/NPCC reliability standards and compliance; strategic AM policies and processes; plan emergency / disaster response.
Business Performance	Release work to LOBs; Business Planning; Produce AM Annual Budget; Scorecard Report and Analysis; Compliance Reporting.
Strategy Alignment	Ensure business plans and assumptions are aligned with corporate strategy; evaluate emerging and approved strategies for alignment and facilitate corrective action.
Sustainment Investment Planning	Long term Tx and Dx sustainment plans including multi year programs; 5 year Investment Plan; timely release of work on Field Business Unit efficiency initiatives and multi-year plans; rate filings; support Customer Business Relations; prepare functional requirements for standards; provide requirements and expectations; manage Tx and Dx reliability through investments and initiatives.
Distribution Business Development	Review, design and manage connection of distributed generation to distribution system; manage joint services arrangements with external parties; plan and oversee required upgrades/additions; plan and implement the Advanced Distribution System; manage smart meter project; manage distribution sector rationalization; leverage smart meter and other distribution assets for additional activities/services.
Asset Management VP	Oversight of Asset Management group
General Counsel	
Law	Provides legal advice to all business units, acting as an internal “law firm” for the Corporation on most aspects of law affecting it, and is also well acquainted with day- to-day requirements of the Corporation.
Network Executive	
Internal Audit & Risk Management	Provides assurance that internal controls continue to operate effectively, identification and recommendations for areas where controls can break down or need improvement to meet corporate objectives.
Telecom Services	
Telecom Services	Provides telecommunications infrastructure across the Province, including both voice and data. Links staff and business applications at Trinity, Richview TS, Markham and London Call Centers, Mill Creek data centre, 125 field offices (400 total sites including stations) and customers via Call Centres and Web sites.
Inergi Functions	
Customer Support Operations	Inbound call handling; bill production; collections; data services.

FUNCTIONS AND SERVICES	DESCRIPTION
Settlements	Provide settlement and reconciliation services for wholesale and retail markets.
Finance and Accounting Services	Accounts Payable; Accounts Receivable (non-energy); Fixed asset and project cost accounting; general accounting and planning, budgeting and reporting
Human Resources	Payroll and related services
Accounts Payable	Invoice processing and payment
Inergi ETS	
Applications Support	Supports IT applications: Customer Support Operations, Finance, Human Resources / Cornerstone, Passport / Cornerstone, Market Ready, Telecomm Services.
Infrastructure Support	Support IT infrastructure including platforms, servers, printers, workstations, IT communications, Help Desk.

Exhibit B: Types of Cost Drivers

TYPE	DESCRIPTION	EXAMPLES
External Cost Drivers		
Physical	Physical units; usually objectively determinate but often require estimates	Headcount (of employees), number of workstations, invoices to vendors
Financial	Financial information from accounting or management reports, budgets or projections	Capital expenditures, Net utility plant, Program Project Costs, Total capital, Total revenue
Blended	Weighted combinations of other drivers, used when one or more drives are applicable and none is clearly preferable; weights determined by judgment	Non-energy Rev_Assets Blend = 50% weight for Non-Energy Revenue and 50% weight for Assets
Driver xBusiness Unit	Any driver may be modified by excluding one or more business units to which the activity does not apply	Cost driver for Inergi Finance Fixed Asset Accounting is Gross Utility Plant, but Brampton business unit performs its own fixed asset accounting and does not use the shared service, therefore activity cost driver is called Gross Utility PlantxB (i.e., Gross Utility Plant excluding Brampton)
Internal Cost Drivers		
All Internal Cost Drivers	Use the result of previous allocations as the basis for further allocations	Cost of general departmental expenses might be allocated in the same proportion as the specifically assigned departmental activities

OVERHEAD CAPITALIZATION RATE

This evidence will discuss the methodology used to allocate Common Corporate Functions and Services ("CCF&S") and Asset Management costs to capital projects.

Hydro One capitalizes costs that are directly attributable to capital projects and also capitalizes overheads supporting capital projects. The overhead capitalization rate is a calculated percentage representing the amount of overhead costs that are required to support capital projects in a given year.

In its August 16, 2007, Decision on the Company's 2007 and 2008 Transmission rates (EB-2006-0501), the Board accepted the methodology, recommendations and the allocation of costs from a study by RJ Rudden Associates (Rudden). This study had been commissioned to derive an overhead capitalization rate for Hydro One Transmission's CCF&S and Asset Management costs. The accepted methodology was reviewed by Black & Veatch (B&V), formerly RJ Rudden Associates, and used in the Transmission rate filing EB-2010-0002 and Distribution rate filing EB-2009-0096.

In 2012 the Company commissioned B&V to review and update the capital overhead methodology. The methodology was again based on the previously accepted Rudden Study. The 2013-2014 overhead capitalization rates have been calculated consistent with the revised B&V study methodology. The consistency in the use of this approach for the 2013 and 2014 test years was reviewed by B&V in 2012, and is provided as Attachment 1 to this Exhibit.

Hydro One Networks in 2007 began reviewing the overhead capitalization rate on a quarterly basis to determine if the rate needed to be changed to reflect in-year changes in capital spending and associated support costs. At year-end, capitalized overheads are trued-up to reflect actual results. This results in a better alignment of overhead costs with the capital projects that they support and removes the need for an e-factor adjustment.

Hydro One proposes that the resulting overhead capitalization rate as calculated in the B&V study in 2012, continues to be a reasonable method of distributing CCF&S and Asset Management costs to capital projects. Hydro One's submissions in this Application reflect the overhead capitalization rate as developed.

Table 1 summarizes the overhead capitalization rates as reviewed by B&V.

Table 1
Overhead Capitalized
2013 and 2014 Test Years

Overhead Cost Category	**2013**		**2014**	
	Capitalization Rate (%)	**Amount Capitalized ($M)**	**Capitalization Rate (%)**	**Amount Capitalized ($M)**
Corporate Functions and Services	7%	$92.5	7%	$92.7
Asset Management and Operators	2%	21.4	2%	21.6
Total	**9%**	**$113.8**	**9%**	**$114.3**

In its EB-2011-0268 decision, the Board granted Hydro One Transmission approval to adopt United States Generally Accepted Accounting Principles (US GAAP) in place of modified International Financial Reporting Standards (IFRS) as its approved basis for regulatory accounting and reporting. In its decision, the Board considered it appropriate to require Hydro One Transmission "to conduct a critical review of its current and proposed capitalization practices. This review shall not be a benchmarking study per se, but should include information with respect to what other US transmitters typically capitalize and the capitalization methodologies used by other transmitters with a view to comparing these to Hydro One's capitalization policies."

As documented in the report which is provided as Attachment 2 to this exhibit, as directed by the OEB, Hydro One Transmission critically reviewed its cost capitalization policy with a particular focus on overhead and indirect costs. In its review, Hydro One Transmission found that its treatment of overheads capitalized is not inconsistent with other major US and Canadian industry participants. The Company's overhead capitalization rate, when expressed as a percentage of gross operating costs, is within the observed range and essentially consistent with the median found in Hydro One Transmission's industry research of other Canadian and US utilities. The Company also concluded that its methodology, as reviewed by Black and Veatch and previously approved by the Board, is consistent with legacy Canadian and existing US GAAP. In addition, and more importantly, Hydro One Transmission's methodology is consistent with regulatory principles including the key goals of achieving intergenerational equity and avoiding cross subsidization.

REVIEW OF OVERHEAD CAPITALIZATION RATES (TRANSMISSION)– 2013-2014

PREPARED FOR

Hydro One Networks Inc.

1 FEBRUARY 2012

BLACK & VEATCH
Building a world of difference.

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I. Overview

A. INTRODUCTION

Black & Veatch ("B&V" or "we") is pleased to provide this Report to Hydro One on our *Review of Overhead Capitalization Rates (Transmission)– 2013-2014*. The Overhead Capitalization Rates ("OH Cap Rates") developed by Hydro One are percentages that are applied to the cost of Transmission and Distribution capital expenditures; the results are the amounts of Shared Services costs that are capitalized to those capital expenditures for the year.

The methodology was developed for Hydro One by B&V, first presented in our report *Distribution Overhead Capitalization Rate Method* report dated May 20, 2005 and accepted by the Ontario Energy Board ("OEB").

The OEB-accepted methodology for development of the OH Cap Rates has been applied to Hydro One's Business Plans, and reviewed by B&V with reports issued, as follows:

B&V REVIEW	BUSINESS PLAN	B&V REPORT
2006 Review (Transmission)	2007-2011	*Transmission Overhead Capitalization Rate Method* dated April 30, 2006
2008 Review (Transmission)	2009-2013	*Implementation of Transmission Overhead Rate Capitalization Methodology – 2009 / 2010* dated September 10, 2008
2009 Review (Distribution)	2010-2014	*Review of Overhead Capitalization Rates* dated June 29, 2009
2010 Review (Transmission)	2010-2014	*Review of Overhead Capitalization Rates (Transmission) – 2011/2012* dated February 26, 2010

Hydro One computed the **Transmission OH Cap Rate to be 9% for 2013 and 9% for 2014** (*Appendix A, row 83*). The calculation of Transmission OH Cap Rates for 2012-2016 is shown in Appendix A.

Based on the work we performed, B&V believes that Hydro One's implementation of the Overhead Capitalization Rate methodology for 2013-2014 and its computation of the 2013-2014 Transmission OH Cap Rates are appropriate and conform to the OEB-accepted methodology.

B. BACKGROUND

Hydro One's capital spending program is a major focus for the utility in terms of time and cost. Transmission Capital spending is budgeted to be $1,070M in 2013 and $1,089M in 2014, each representing approximately 11% of Transmission Net utility plant.

Most of Hydro One's capital program is performed by Hydro One employees, and not contracted out. Hydro One's capital program requires significant support from all areas of the utility, including engineering, management, administration and infrastructure resources. These resources support Transmission Operations and Maintenance ("Tx OMA") and Transmission Capital Expenditures work.

C. CRITERIA FOR COST ALLOCATION METHODS

The portion of Shared Services costs attributed to Transmission was determined based on the OEB-accepted methodology, as described in the B&V's *Review of Shared Services Cost Allocation (Transmission)– 2012* dated February 1, 2012**.** The Transmission OH Cap Rate is used to distribute the Transmission portion of Shared Services costs, between Transmission OMA and Transmission Capital Expenditures. Following are the criteria that B&V used in selecting and evaluating methods to develop the OH Cap Rates methodology:

- The method should be based on *cost causation*. Cost causation means that there is a causal relationship between the basis used to allocate a cost, and the costs that has been incurred.
- If cost causation cannot be used or is determined to be inappropriate in the circumstances, the method usually considered next is *benefits received* (i.e., allocated to the business that received the benefits).
- The method should be based on data that can be obtained at reasonable cost and are objectively verifiable, in the initial year as well as in subsequent years.
- If the method uses estimates, results should be unbiased and reasonably consistent with the results that would be obtained from using actual data.

D. DESCRIPTION OF OH CAP RATE METHOD

Ideally, the amount of Shared Services costs to be capitalized would be based entirely on time studies for labor costs, and additional analyses for other costs, for each Shared Services activity.

Approximately $111 million of labour costs (for the departments in the study), representing approximately 27% of the annual total Shared Services costs (and approximately 53% of annual labour costs), were directly assigned between OMA and capital based on a time study performed for the four-weeks ending July 15, 2011 ("2011 Time Study"). The departments included in the 2011 Time Study are Asset Management (which comprises the following departments: Asset Strategy, Business Performance, Strategy Alignment, Sustainment Investment Planning, Distribution Business Development, Asset Management VP Office, and Transmission Development); Network Operating department (in the Operations group); and other departments in the Operations group (Conservation and Demand Management, Customer Care, Distributed Generation, Customer Business Relations).

A properly performed time study measures cost causation, and is widely accepted as a basis for allocating costs. B&V designed, administered and supervised the Hydro One 2011 Time Study methodology and supervised the study, and found it was properly conducted, and therefore is a proper basis to determine the portion of the costs of the participating departments to be capitalized to Transmission capital expenditures.

While the remaining Shared Services departments can determine with reasonable accuracy the portions of time spent on Transmission, Distribution and the other business units, they are unable to determine with reasonable accuracy the time spent on OMA versus capital projects. Therefore, the amount of costs to be capitalized must be computed using allocators based on cost causation or benefits received.

In traditional utility cost allocation studies, administrative and general costs are allocated based on one or more factors such as Labor costs, OMA, Investment in Plant or a weighted combination of two or more. B&V considered the following two bases for allocating Shared Services costs between OMA and capital projects:

- **Labor Content Method-** Labor Content of Transmission / Distribution OMA versus Transmission / Distribution capital expenditures
- **Total Spending Method-** Total Spending on Transmission / Distribution OMA versus Transmission / Distribution capital expenditures

The Shared Services costs to be allocated are causally related to both Labor content and Total spending. Therefore the OH Cap Rate method for Shared Services costs recommended by B&V uses a weighting of 50% Labor Content and 50% Total Spending, as there is no evidence that either the Labor Content method or the Total Spending method is meaningfully more appropriate.

- The formula for Transmission (Tx) Labor Content is:

Tx Labor Content = Tx Labor $ in Tx Capital Expenditures / (Labor $ in Tx Capital Expenditures + Labor $ in Tx OMA)

- The formula for Tx Total Spending is:

Tx Total Spending = Tx Capital Expenditures / (Tx Capital Expenditures + Tx OMA)

The table below shows the results of the computations for 2013 and 2014.

PORTION OF SHARED SERVICES CAPITALIZED	TRANSMISSION-2013	TRANSMISSION-2014
Labor Content- Capital	60.3%	60.5%
Total Spending- Capital	77.0%	77.0%
50/50 Average	68.7%	68.8%

Sensitivity Analysis

As a sensitivity analysis, B&V analyzed two sensitivity cases- the highest Labor Content weight considered (75%) and the lowest Labor Content weight considered (25%). The results, shown below, indicate the total OH Cap Rates would not change materially.

CASES	LABOR CONTENT / TOTAL SPENDING	TRANSMISSION-2013		TRANSMISSION-2014	
		% Shared Services Costs Capitalized	2013 OH Cap Rate	% Shared Services Costs Capitalized	2014 OH Cap Rate
Recommended	50%/50%	68.7%	9.4%	68.8%	9.3%
High Labor Case	75%/25%	64.5%	8.9%	64.6%	8.8%
Low Labor Case	25%/75%	72.9%	9.9%	72.9%	9.7%

Note- In all cases Tx Labor Content-Capital was 60.3% and Tx Total Spending-Capital was 77.0% in 2013, and Tx Labor Content-Capital was 60.5% and Tx Total Spending-Capital was 77.0% in 2014.

B&V also considered the following:

1. The same rate is applied to capitalized assets regardless of their actual usage of Shared Services. For example, a transformer that is purchased for use in a capital project from a pre-approved vendor requires very little Shared Services, but receives the same rate of overhead capitalization as a project requiring substantial Shared Services support. In applying the OH Cap Rates, there will be differences compared to performing a specific analysis for each project. However, the B&V method is appropriate because:

- B&V's recommended Labor / Total Content method correctly computes the total Shared Services dollars to be capitalized, and the amount charged to specific expenditures has virtually no effect on the financial statements or on ratepayers.
- Most assets purchased for stand-alone use are Minor Fixed Assets and the OH Cap Rates are computed without them, and not applied to them. Other assets (i.e., non-Minor Fixed Assets) purchased are usually parts of larger projects, therefore the use of average OH Cap Rates is appropriate, because larger expenditures are more likely to have an average usage of Shared Services.
- It is impractical to perform an analysis for each project.

2. The OH Cap Rates are developed based on the weighted Labor Content and Total Spending, but are applied to Total Capital Cost.

It is appropriate to compute the total costs to be capitalized based on the weighted Labor Content / Total Spending. Once the amount to be capitalized is computed, it can be applied based on either Total Cost or Labor Content. B&V

recommends stating the capitalization rate based on Total cost, and applying it to Total cost dollars, as Hydro One has done, because it is easier to plan and implement based on Total cost than Labor content.

B&V believes that allocating Shared Services costs to capital expenditures based on 50% Labor Content / 50% Total Spending is the most appropriate method for Hydro One, and is consistent with industry practice and with the nature of the Shared Services costs being capitalized.

E. USE OF BUDGETED NUMBERS

The OH Cap Rates are developed based on Business Plan numbers and other estimates. Hydro One reviews and adjusts the OH Cap Rates quarterly to reflect changes in capital spending and associated support costs. At year-end, capitalized overheads are trued-up (in-year) to reflect actual results. Therefore, no adjustment is needed in subsequent years.

II. Computation of Transmission OH Cap Rate

This Section presents, as an example, the computation of the Transmission OH Cap Rate for 2013. The calculation of the Transmission OH Cap Rate uses the same method for all years in BP 2012-16.

A. FORMULA

The following formula is used to compute the 2013 and 2014 Transmission OH Cap Rates:

Transmission OH Cap Rate= (Transmission CCF&S Cap + Transmission AM, NO, OP Cap) / Transmission Capital

Where

Applicable Transmission CCF&S costs = Transmission Common Corporate Functions & Services costs subject to capitalization, excluding costs of AM, NO, OP groups

Transmission AM, NO, OP Cap= Portion of the following departments capitalized to Transmission capital projects:

- All departments within the Asset Management group (AM), plus
- Network Operating department (NO) (which is part of the Operations group), plus
- Additional departments in the Operations group: Conservation and Demand Management, Customer Care, Distributed Generation and Customer Business Relations (OP).

Transmission Capital = Cost of Transmission capital expenditures supported by Shared Services (i.e., CCF&S plus AM, NO, OP); also, total cost of Transmission capital expenditures to which the Transmission OH Cap Rate is applied

Transmission CCF&S Cap = Transmission CCF&S costs capitalized = (Transmission Labor Content X 50% + Transmission Total Spending X 50%) X Applicable Transmission CCF&S Costs

Transmission Labor Content = Transmission Labor $ in Transmission Capital Expenditures / (Labor $ in Transmission Capital Expenditures + Labor $ in Transmission OMA)

Transmission Total Spending = Transmission Capital Expenditures / (Transmission Capital Expenditures + Transmission OMA)

These terms are further discussed below.

B. RECOMMENDED METHOD

This section discusses the method recommended by B&V to compute the Transmission OH Cap Rate. References below are to Appendix A, and the amounts and percentages cited are for 2013 and 2014. The calculations use projected data. Because the methodology includes a true-up at the end of the year (Section I.E), the amounts recorded by Hydro One reflect actual data.

1. TRANSMISSION CAPITAL

(Appendix A, rows 1-8)

Transmission Capital represents the cost of Transmission business Capital Expenditures that are supported by Transmission business CCF&S activities and AM, NO, OP activities, and is the total cost of Transmission business Capital Expenditures to which the Transmission OH Cap Rate is applied. Transmission Capital equals total spending for Transmission Capital Expenditures reported for financial accounting, adjusted as follows:

- Minor Fixed Assets (such as vehicles) and Interest Capitalized are removed because they require little CCF&S or AM, NO, OP support.
- Capitalized Overhead is removed to avoid redundancy.
- Capital Contributions by Customers are added because the CCF&S or AM, NO, OP effort required is related to gross capital cost, not net capital cost.
- Removal Costs are added because removal of capital assets requires CCF&S or AM, NO, OP effort.

2. TRANSMISSION SPENDING FOR OMA

(Appendix A, rows 10-16)

Transmission Spending for OMA is used in computing the portion of Total Spending (capital plus OMA) related to capital (rows 42-46). The amounts are based on the Updated BP 2012-16, with adjustments to remove those costs which are included in Applicable CCF&S Costs (row 34).

3. APPLICABLE TRANSMISSION CCF&S COSTS

(Appendix A, rows 18-34)

Applicable Transmission CCF&S (row 34) represents the Transmission CCF&S costs that are subject to capitalization, and equals the total Shared Services costs distributed to the Transmission Business in the Shared Services Model, adjusted as follows:

- The Transmission portion of AM, NO, OP costs are deducted, because the capitalization ratios are determined in the 2011 Time Study.
- The Transmission Facilities costs that are removed from the CCF&S costs, relating to Operations facilities, are added back, because they are used to support activities that support Capital Expenditures.
- Transmission CCF&S costs for departments that do not support capital expenditures are removed. These activities are Inergi- Customer Support Operations (CSO), Inergi- Settlements, Inergi-ETS costs to support CSO Applications and Inergi-ETS costs to support market transition costs.

4. TRANSMISSION LABOR CONTENT- CAPITAL

(Appendix A, rows 36-40)

Transmission Labor Content-Capital is the portion of total Transmission labor costs included in Transmission Capital Expenditures. The computation uses the formula:

Transmission Labor Content = Transmission Labor $ in Transmission Capital Expenditures / (Labor $ in Transmission Capital Expenditures + Labor $ in Transmission Operations and Maintenance)

The Labor $ on Rows 37-38 were developed by Hydro One. The Labor $ are fully burdened labor costs (salary plus benefits).

5. TRANSMISSION TOTAL SPENDING- CAPITAL

(Appendix A, rows 37-41)

Transmission Total Spending-Capital is the portion of Transmission total spending included in Transmission Capital Expenditures, using the formula:

Transmission Total Spending = Transmission Capital Expenditures / (Transmission Capital Expenditures + Transmission Operations and Maintenance)

Transmission spending for OMA (row 43) is from row 16. Transmission spending for capital expenditures (row 44) is from row 8.

6. TRANSMISSION CCF&S CAP

The average of Transmission Labor Content-Capital (from row 40) and Total Spending- Capital (from row 46), using the appropriate weights (rows 49-50), is the capitalized portion of CCF&S costs (row 52). This portion is multiplied by the Applicable CCF&S costs (row 54 from row 34) to compute Capitalized CCF&S costs (row 56).

7. TRANSMISSION AM, NO, OP CAP

(Appendix A, rows 58-74)

Transmission AM, NO, OP Cap represents the amount of AM, NO, OP costs capitalized to Transmission Capital Expenditures. The 2011 Time Study showed that 24.3% of Asset Management group time, 11.6% of Network Operating group time and 4.3% of Customer Care group time, are related to Transmission Capital Expenditures. These percentages are applied to the Updated BP 2012-16 annual budgeted amounts for those groups, and the results are the amounts of AM, NO, OP costs to be capitalized (rows 70-74).

8. TRANSMISSION OH CAP RATE

(Appendix A, rows 76-83)

The Transmission OH Cap Rate equals A) the sum of items 6 and 7 above, divided by B) Capital spending. The Transmission OH Cap Rate for 2013 is 9**%** and for 2014 is 9**%** (row 83).

		TRANSMISSION OVERHEAD CAPITALIZATION RATES				
	($ millions)	**2012**	**2013**	**2014**	**2015**	**2016**
1	**Capital Expenditures**					
2	Total capexp	974.2	1,070.4	1,088.5	985.9	1,067.6
3	Less: Minor fixed assets	(31.4)	(26.0)	(27.3)	(25.4)	(25.9)
4	Less: Capitalized overhead	(115.2)	(116.5)	(117.0)	(109.9)	(111.2)
5	Less: Capitalized interest	(48.9)	(43.7)	(56.4)	(59.9)	(57.6)
6	Add: Capital contributions	198.2	291.0	310.2	67.1	16.2
7	Add: Removal costs	23.9	35.9	36.2	41.9	35.8
8		1,000.9	1,211.1	1,234.3	899.8	924.7
9						
10	**OM&A**					
11	Total OM&A	430.6	452.0	459.8	485.2	499.7
12	Less: CCF&S costs	(113.5)	(113.2)	(112.6)	(113.2)	(113.2)
13	Less: Facility costs	(22.2)	(22.7)	(23.5)	(24.0)	(24.5)
14	Less: Asset Management \1	(71.7)	(71.6)	(73.0)	(74.3)	(75.2)
15	Add: Capitalized overheads	115.2	116.5	117.0	109.9	111.2
16		338.3	360.9	367.8	383.6	398.0
17						
18	**Capitalized CCF&S Costs**					
19	Total Costs per Model	184.4	185.5	187.2	189.1	189.9
20	Less: AM	(35.3)	(35.8)	(37.0)	(37.4)	(37.2)
21	Less: Operations	(0.6)	(0.6)	(0.7)	(0.7)	(0.7)
22	Less: Network Operations	(31.4)	(32.2)	(33.2)	(33.9)	(34.9)
23	Less: CBR	(3.6)	(3.6)	(3.7)	(3.8)	(3.9)
24	Net CCF&S Costs	113.5	113.2	112.6	113.2	113.2
25	Add: Facility costs	22.2	22.7	23.5	24.0	24.5
26						
27	Less operating-type CCF&S costs:					
28	Inergi - CSO	-	-	-	-	-
29	Inergi - ETS CSO Apps	-	-	-	-	-
30	Inergi - ETS Market Ready	(1.1)	(1.1)	(1.1)	(1.0)	(1.0)
31	Inergi - Settlements	(0.2)	(0.2)	(0.2)	(0.3)	(0.3)
32		(1.3)	(1.3)	(1.3)	(1.3)	(1.2)
33						
34	Applicable CCF&S costs	134.4	134.6	134.7	135.9	136.5
35						
36	Portion capitalized based on labour content:					
37	Labour in OM&A	154.3	172.3	175.5	196.0	204.2
38	Labour in capexp	237.5	262.1	269.0	244.1	267.9
39		391.8	434.4	444.5	440.1	472.1
40	% capexp	60.6%	60.3%	60.5%	55.5%	56.7%
41						
42	Portion capitalized based on total spending:					
43	OM&A	338.3	360.9	367.8	383.6	398.0
44	Capexp	1,000.9	1,211.1	1,234.3	899.8	924.7
45		1,339.2	1,572.0	1,602.1	1,283.4	1,322.8
46	% capexp	74.7%	77.0%	77.0%	70.1%	69.9%
47						
48	Weighting:					
49	Labour content	50.0%	50.0%	50.0%	50.0%	50.0%
50	Total spending	50.0%	50.0%	50.0%	50.0%	50.0%
51						
52	Portion capitalized based on weighting of two methods	67.7%	68.7%	68.8%	62.8%	63.3%
53						
54	Applicable CCF&S costs	134.4	134.6	134.7	135.9	136.5
55						
56	Capitalized CCF&S costs	91.0	92.5	92.7	85.3	86.4
57						

		TRANSMISSION OVERHEAD CAPITALIZATION RATES				
	($ millions)	**2012**	**2013**	**2014**	**2015**	**2016**
58	**Capitalized AM, NO, OP Costs**					
59	Network AM, NO, OP (Tx + Dx):					
60	Asset Management group	64.2	62.5	62.7	63.4	63.4
61	Network Operating department	45.7	47.0	48.3	49.4	50.8
62	Operations group (certain departments, see Report)	17.3	17.4	18.9	19.8	19.5
63		127.3	126.8	129.9	132.5	133.7
64						
65	Portion capitalized (per time study):					
66	Asset Management group	24.3%	24.3%	24.3%	24.3%	24.3%
67	Network Operating department	11.6%	11.6%	11.6%	11.6%	11.6%
68	Operations group (certain departments, see Report)	4.3%	4.3%	4.3%	4.3%	4.3%
69						
70	Capitalized AM, NO, OP costs:					
71	Asset Management group	15.6	15.2	15.2	15.4	15.4
72	Network Operating department	5.3	5.4	5.6	5.7	5.9
73	Operations group (certain departments, see Report)	0.7	0.8	0.8	0.9	0.8
74		21.6	21.4	21.6	22.0	22.1
75						
76	**Overhead Capitalization Rate**					
77	Capitalized CCF&S costs	91.0	92.5	92.7	85.3	86.4
78	Capitalized AM, NO, OP costs	21.6	21.4	21.6	22.0	22.1
79	**TOTAL SHARED COSTS CAPITALIZED**	112.6	113.8	114.3	107.3	108.5
80						
81	Capexp	1,000.9	1,211.1	1,234.3	899.8	924.7
82						
83	**Overhead capitalization rate**	**11.0%**	**9.0%**	**9.0%**	**12.0%**	**12.0%**
84						
85	\1 Asset Management excludes facility costs					

Hydro One Networks Inc.

Transmission Business – Review of Overhead Capitalization Policy

April 14, 2012

Executive Summary

In its EB-2011-0268 decision, the Ontario Energy Board (OEB or Board) granted Hydro One Networks Inc. (Hydro One, Networks or the Company) approval to adopt United States (US) generally accepted accounting principles (GAAP) in place of modified International Financial Reporting Standards (IFRS) as its approved basis for regulatory accounting and reporting.

In its decision, the Board considered it appropriate to require Networks "to conduct a critical review of its current and proposed capitalization practices. This review shall not be a benchmarking study per se, but should include information with respect to what other U.S. transmitters typically capitalize and the capitalization methodologies used by other transmitters with a view to comparing these to Hydro One's capitalization policies."

The following report has been developed to document the results of Hydro One's review of the appropriateness of its capitalization accounting policy for overhead and indirect costs. The Company's review incorporated a study of accounting theory under the various GAAP frameworks, a review of regulatory guidance in North America and a comparison between Hydro One's practices and those of other North American utilities.

The study approach incorporated the following steps:

1. A review of Hydro One's legacy accounting policy and the rationale for it;
2. A review of the GAAP environment governing overhead/indirect cost capitalization;
3. A review of North American regulatory principles and related guidance;
4. An assessment of the of Hydro One's approach in light of steps 2 and 3 above;
5. Conducting industry research; and
6. Conclusion

Hydro One's overhead capitalization rate, when expressed as a percentage of gross operating costs, is within the observed range and essentially consistent with the median found in the Company's industry research of other Canadian and US utilities.

This information is summarized in the following table.

Overhead Capitalization Rate (as a percentage of gross operating costs*)			
Hydro One	**Canadian Utilities****	**U.S. Utilities****	**Analysis**
Transmission (2013) - 20%	Industry Median*** - 19%	Industry Median**** - 19%	• The range of overhead capitalization rates varies across the utilities in Canada and US. For Canadian utilities it ranges from 5% to 35.6% with an observed median of 19%. For U.S. utilities, it ranges from 7.33% to >50% with an observed median of 19%. • The rates are based on legacy Canadian GAAP for Canadian utilities and US GAAP for US utilities. However, both accounting frameworks are substantively the same in this area.

* *Gross operating costs include capitalized overheads added back.*
** *Refer Appendix A for a list of the Canadian and U.S. utilities researched and summary of findings.*
*** *Median represents middle value of the range of overhead capitalization rates for those utilities selected for research and where rate information was available.*
**** *The US median is based on a concentration of three results in the 19% range, with one individual outlier at ~7% and another >50%.*

In addition to the rate findings, industry research clearly shows that the capitalization of general and administrative overhead costs is accepted practice.

The key findings of the Company's policy review were:

1. In prior years, Hydro One has capitalized an appropriate proportion of overhead and indirect corporate support expenditures based on a consistently applied, rational and systematic model based on causality. No changes in Hydro One's methodology are proposed with the adoption of US GAAP.

2. Legacy Canadian and US GAAP both allow for the capitalization of attributable indirect costs and overheads, while IFRS specifically prohibits the capitalization of several categories of such expenditures.

3. Canadian, and more particularly US regulatory guidance, supports the capitalization of attributable overheads based on a cost causality model.

4. Hydro One capitalizes an appropriate proportion of its indirect and overhead support expenditures, consistent with GAAP and regulatory guidance.

5. Hydro One's practice, both in terms of the types and proportion of overhead and indirect expenditures capitalized, is generally consistent with the practices of many other large North American transmitters and other rate regulated utilities.

6. Hydro One's cost capitalization policy with respect to overheads and indirect costs is an appropriate one for use in a US GAAP regulatory environment.

Introduction - Overview of the Study

In its EB-2011-0268 decision, the Board granted Networks approval to adopt US GAAP instead of modified IFRS for regulatory accounting and reporting purposes. The OEB generally accepted Hydro One's position that adopting US GAAP would result in benefits both to its customers and to its shareholder. In addition, in response to intervenor assertions that Hydro One's capitalization practices had been "aggressive" under legacy Canadian GAAP, the OEB also considered "it appropriate to require Hydro One to conduct a critical review of its current and proposed capitalization practices. This review shall not be a benchmarking study per se, but should include information with respect to what other U.S. transmitters typically capitalize and the capitalization methodologies used by other transmitters with a view to comparing these to Hydro One's capitalization policies."

In its decision with reasons on EB-2011-0268, the OEB noted that the reduction in revenue requirement, and intervenor support for it, was a significant argument in favour of retaining the Company's legacy cost capitalization policy for Networks' Transmission Business. Hydro One's cost capitalization policy was developed under legacy Canadian GAAP, where it has been subjected to external audit since inception of the company. The Company believes that It continues to be an appropriate policy under US GAAP. Such a policy was not allowable under the constraining cost capitalization rules found within IFRS, most particularly in IAS 16 "Property, Plant and Equipment."

Specifically, significant differences in accounting exist between US and legacy Canadian GAAP on one side, and IFRS on the other, with respect to the indirect and general and administrative overhead expenditures that qualify for capitalization. A measure of the magnitude of the revenue requirement impact of the different accounting frameworks can be seen in the $200 million adjustment required to reflect the Board's EB-2011-0268 Transmission decision that authorized the Company's use of US GAAP for regulatory purposes.

In response to the Board's direction, Hydro One has performed a critical review of the theoretical appropriateness of its accounting policies governing the capitalization of overhead and indirect costs. This review focused on: a review of the conformance of its legacy Canadian and continuing US GAAP capitalization policy with GAAP; consistency with regulatory principles and guidance; and a comparison with the practices of other major US and Canadian utilities. These comparable utilities include both transmitters and large distributors, including some within Ontario. The latter were included as it was determined early on in the study that the Board would likely require an extension of the scope of the transmission analysis to distributors given that Networks had also requested an exception to adopt US GAAP for its Distribution Business as well. On March 23, 2012, the Board approved Networks' request in respect of its Distribution Business (EB-2011-0399) as well. A similar request was made in that decision to conduct a Distribution Business cost capitalization study. However, given the requirement to compare to other Ontario local distribution companies that are using modified IFRS as a basis for their external reporting and rate setting, the scope of that report is likely to be somewhat different than this one.

The Company determined that it was appropriate to extend of the scope of its research to include large Canadian distributors as finding detailed information on US practice was quite difficult. Inclusion of other Canadian entities expands the pool of comparable utilities. In addition, a recent surge in the numbers of Canadian utilities seeking approval to adopt US GAAP in place of IFRS has led to increased informal information sharing and greater availability of information in Canada.

The critical review requested by the Board has been conducted in two main parts. The first part was a review of the origin and continued appropriateness of Hydro One's cost capitalization accounting policies under GAAP and under regulatory principles and guidance. The second element of the study was a comparison to the practices of other major North American rate regulated utilities. As noted in the Board's request, this was not intended to be a comprehensive benchmarking study. Instead, it was treated as an intelligence gathering activity aimed at gathering useful information on what types and amounts of indirect and overhead costs other utilities capitalize.

The general approach adopted to fulfill the Board's request is described below:

1. Review Hydro One's Legacy Accounting

Hydro One's existing cost capitalization policies and the underlying rationale for them were evaluated and are summarized herein.

2. Summarize GAAP

The indirect and overhead cost capitalization requirements of competing GAAP frameworks were evaluated and are summarized herein.

3. Summarize Regulatory Guidance

Specific regulatory guidance was gathered and summarized and underlying regulatory principles governing cost capitalization were identified and are discussed herein.

4. Assess Theoretical Appropriateness of Hydro One's Approach

Hydro One assessed the degree of conformity between its cost capitalization practices and the requirements of GAAP and objectives of regulatory principles.

5. Conduct Industry Research

Hydro One gathered information on the overhead capitalization practices of selected major North American utilities. The objective of this research was to determine to what extent Hydro One's indirect cost and overhead capitalization approach conforms to generally accepted utilities practice and to what extent it can be deemed "aggressive" compared to its peers.

6. Conclusion

Hydro One reviewed the conclusions from step 4 above and the comparable information from step 5 to conclude on the reasonableness of continuing to apply its legacy Canadian GAAP approach to its US GAAP rate setting.

1. Review Hydro One's Legacy Accounting

Key findings: Hydro One has capitalized an appropriate proportion of overhead and indirect corporate support expenditures based on a consistently applied rational and systematic cost causality model.

Hydro One has two primary accounting policies that govern the capitalization of expenditures for each of its legal subsidiaries and regulated businesses. The policy that governs the classification of expenditures between capital and operation, maintenance and administration (OM&A) is SP 0775 R0 "Classification of Expenditures." This policy has not been significantly adjusted since demerger from Ontario Hydro in 1999 and the guidance included within it has been applied consistently in determining the rate base and revenue requirement for each of Hydro One's regulated subsidiaries and businesses. The policy has also been consistently reflected in developing Hydro One Transmission's audited financial statements.

The second applicable policy is SP 0804 R0 "Shared Corporate Services Cost Allocation and Transfer Pricing Policy," which outlines the principles to be used in allocating shared corporate functions and services costs. This policy provides guidance on the allocation of shared services costs, requiring that they be assigned to affiliates based on the principle of cost-causation.

General capitalization approach

Hydro One provides detailed policy guidance on whether expenditures incurred in a given accounting period should be recorded in the Statement of Operations as an expense of that period, or included as an asset on the Balance Sheet. For regulatory purposes, the consequence of this decision is either inclusion in current period revenue requirement or in the rate base. The overriding criteria applied in determining the appropriate accounting treatment of an expenditure is whether or not it meets the definition of an asset under GAAP. In almost all cases, the regulatory treatment parallels the GAAP classification.

To determine whether an expenditure represents and an expense of the period or an asset with future economic benefit, the GAAP principle of "matching" is applied. The definition of an asset under US GAAP is found in Financial Accounting Standards Board (FASB) Statement of Financial Accounting Concepts (SFAS) No. 6 "Elements of Financial Statements." Under this concepts standard, an asset consists of "probable future economic benefits obtained or controlled by a particular entity as a result of past transactions or events." In addition, "an asset has three essential characteristics: (a) it embodies a probable future benefit that involves a capacity, singly or in combination with other assets, to contribute directly or indirectly to future net cash inflows, (b) a particular entity can obtain the benefit and control others' access to it, and (c) the transaction or other event giving rise to the entity's right to or control of the benefit has already occurred." This definition is virtually identical to that found in the parallel accounting standard in legacy Canadian GAAP. This is found in section 1000 "Financial Statement Concepts" in Part V of the Handbook of the Canadian Institute of Chartered Accountants.

Asset recognition of those expenditures that will probably result in future economic benefits is a foundational concept in accrual accounting. Accrual accounting requires that the relationship between an expense and a revenue item be evaluated and, where there is a direct relationship, that the timing of expense recognition be matched to the recognition of that future related revenue. This assessment requires that the strength and nature of the relationship between expenditures and resultant future benefits be evaluated. This is accomplished by using professional judgment to determine whether a causality and/or beneficial relationship exists between them. In a rate regulated environment, any assessment of future benefits resulting from expenditures will also include in an assessment of whether the expenditure provides operational or service benefits to future customers. This also requires some assessment of whether the expenditure is caused by, or benefits future customer generations.

Hydro One's Classification of Expenditures Policy

Hydro One's Classification of Expenditures Policy is one of the company's most important and often referenced accounting policies. In general, it provides general and specific guidance on the types of expenditures that qualify as assets, defines capitalization terms, provides dollar capitalization thresholds for projects and provides specific decision rules for certain types of transactions.

Under the policy, expenditures incurred for the following general purposes are eligible for capitalization, when above established materiality limits:

- purchase, construction and commissioning of specific assets;
- design and development of specific assets;
- additions of new or replacement components for existing assets; and
- betterments that result in increases in: productive capacity or output; efficiency; useful life span over original specification; or economy of operation.

The Classification of Expenditures Policy requires that the following types of expenditures qualify for capitalization: direct labour; direct materials and supplies; transportation costs; directly attributable external costs; fees; permits; indirect expenditures (including financing costs and attributable shared functions and services costs including general engineering, administrative salaries and expenses), and attributable indirect depreciation of equipment, tools and transport and work equipment.

While the policy does not specifically determine which overhead and indirect costs may be capitalized, it does provide the overall framework for the definition of an asset.

Hydro One’s Shared Corporate Services Cost Allocation and Transfer Pricing Policy

This policy governs the allocation of shared asset and corporate functions and services costs between Hydro One’s various subsidiaries and regulated businesses. For Networks, the policy also governs the allocation of shared asset management costs between the Transmission and Distribution businesses. The policy is important to ensure that the risk of cross subsidization between regulated and unregulated entities, and between different regulated businesses, is minimized. The policy also provides guidance on the acceptable basis of transfer pricing between entities, essentially reflecting the guidance found within the Board’s Affiliate Relationships Code.

Shared corporate services include the provision of shared strategic management, policy and functional support to the subsidiaries and businesses of the parent entity. The rationale for sharing such costs is that it is economically more efficient to locate them centrally and share them based on causality and benefit than to replicate them within each affiliate. Shared costs relate to the provision of such shared services as: legal; regulatory; procurement; building and real estate support; information management and technology; corporate administration, finance, tax, treasury, pension, risk management, audit, planning, human resources, health and safety, communications, investor relations, trustee, and public affairs.

The same causality and benefit principles that are used to drive the allocation of shared corporate support expenditures and shared asset costs are also used to determine the appropriate classification of indirect and overhead expenditures between capital and OM&A.

The corporate cost allocation methodology requires that expenditures that can reasonably be specifically identified with a specific affiliate (i.e. subsidiary or regulated business) be allocated to that affiliate on a direct cost basis. However, most shared corporate functions and services costs cannot be directly associated with a specific affiliate and are therefore not treated as a direct charge. Shared corporate services costs that are not directly attributed must be allocated to the receiving affiliate using a rational and systematic mechanism. In general, cost drivers are used to achieve this goal. The driver to be used in allocating each shared cost should be the most appropriate based on the principle of cost causality. Causality exists when the incurrence of the shared cost is due to the business requirements of the affiliate. The Company must evaluate whether the cost would have been incurred had the affiliate’s requirements not caused it? In cases where a causal relationship cannot be identified, but where the affiliate benefits from the shared service, a cost driver is selected that instead reflects the principle of cost benefit. In this case, the objective is to determine the proportion of total benefits provided by the shared service is enjoyed by the affiliate. Where a shared staff time study is deemed to be the most appropriate cost driver, such a time study is periodically updated to provide relevant information and evidence of causality and benefit.

Hydro One’s methodology is reviewed internally on an annual basis and is independently reviewed periodically by an expert consultant for continued appropriateness of assumptions such as drivers. A full description of the cost allocation methodology as reviewed by Black and Veatch can be found in their report. Specific cost drivers and allocation rates are updated by Hydro One on an annual basis. All changes in direct and indirect costs, the allocation methodology, or cost drivers/allocators are appropriately documented.

Accurate allocation is necessary to ensure that, to the extent possible, customers of specific regulated utilities are paying for the cost of providing that utility's service. In addition, accurate and principle-based allocation ensures that the risk of cross subsidization between regulated and unregulated affiliates is minimized. Use of fully-allocated cost-based pricing ensures that inter-affiliate transfers comply with both the letter and the spirit of the Board's Affiliate Relationships Code. This code requires that affiliate transfers generally occur at fair value or, where such a value cannot reasonably be ascertained, at fully allocated cost taken as a proxy for fair value. Under Hydro One's accounting policy for cost allocation and transfer pricing, the inter-affiliate transfer of shared corporate services occurs at a fully allocated transfer price that retains the fair value proxy concept. This is because it incorporates the same general cost components that would be charged by an external service provider or vendor.

Summary of Hydro One's Overhead Capitalization Methodology

Hydro One uses the same general methodology and principles that it uses to allocate shared costs to affiliate entities when it classifies expenditures between current period expense and capital. The rationale for this is that the principles of causality and benefit are equally relevant for developing a robust and defensible assignment of cost responsibility between current and future customer generation. The objective of avoiding cross subsidization is the same as faced in allocating costs between entities. However, in the case of accounting classification the issue is avoiding having different generations (i.e. years) of customers cross subsidize each other. Customers should generally pay the costs that they cause or receive benefits from. Hydro One's accounting policies and practices have aimed at maintaining this objective to the extent possible while still adhering to the requirements of GAAP.

Hydro One's overhead capitalization methodology, similar to its allocation methodology, is subject to periodic external review by an independent consultant (currently Black and Veatch). The overhead capitalization methodology currently proposed for use by Hydro One Transmission develops separate capitalization rates within each affiliate, after shared costs have been fully allocated. To ensure that only those costs that benefit future customer generations get capitalized as part of the acquisition cost of fixed and intangible assets, Hydro One's methodology first screens allocated costs for whether or not they contribute to such assets. Certain expenditure types that are clearly not causally or beneficially linked to the acquisition of assets are removed from the overhead capitalization pool and disqualified from potential capitalization. This occurs as a first step in developing the capitalization rate. Secondly, if allocated shared costs can be associated with capital programs or projects, such costs are directly assigned to the pool of capitalizable expenditures even if they are not directly charged. Thirdly, a causality and benefit-based model is used to develop the capitalization rate. This rate is revisited through the year and adjusted as required to ensure that in-year variances are trued-up appropriately as underlying factors change.

Hydro One's methodology is based on the following principles:

- Regulatory Precedent – The shared service allocation methodology was initially developed with the assistance of Black and Veatch (then Rudden Associates) and was first documented in their 2005 "Report on Common Corporate Costs Methodology Review," which was accepted by the Board. Prior to the introduction of this independent review, Hydro One had carried out its own causality-based overhead allocation for its transitional rate orders for 1999 and 2000 rate years. The Black and Veatch report explicitly shows that the allocation and capitalization methodologies in use are based on cost causality and benefit principles. The current cost allocation methodology is consistent with that sued in prior years under legacy Canadian GAAP and is appropriate for use in a US GAAP environment. The use of direct assignments and cost drivers conforms to best practice.

- Cost Causation - The allocation methodology is reflective of the cost required to provide the shared services to affiliates. Shared service costs are allocated to each affiliate based on direct assignment where possible or based on activity cost drivers or time studies when not. The use of cost drivers conforms with the principle of direct attribution found in GAAP, as well as the regulatory principle of intergenerational equity.

- Supportive Methodology - The approach is supported by a defined and documented methodology that is subject to constant update. In addition, the approach is reviewed by, and reported on by an independent external consultant (Black and Veatch) on a recurring basis. In general, Black and Veatch reviews and reports on Hydro One's methodology in advance of major cost of service rate applications. Cost allocations and capitalization rates are updated annually by Hydro One as part of the business planning process. The current methodology is well understood by the subsidiaries and business units to which costs are distributed as well as estimators and project managers who are accountable for determining the cost of capital projects and programs. In addition, the current methodology is integrated with Hydro One's annual business planning process, thus producing reasonable and stable results over time.

2. Summarize GAAP

Key findings: Legacy Canadian and US GAAP both allow for the capitalization of attributable overheads while IFRS provide specific prohibitions that restrict the capitalization of several categories of such expenditures.

To evaluate the appropriateness of Hydro One's cost capitalization policy for indirect and overhead costs, it is useful to review the specific guidance found in the applicable accounting standards under each of the three relevant accounting frameworks: legacy Canadian GAAP; US GAAP and IFRS. More specifically, these are:

1. Legacy Canadian GAAP as defined by Part V of the Handbook of the Canadian Institute of Chartered Accountants;

2. US GAAP as defined by the Accounting Standards Codification (ASC) of the FASB; and
3. Current Canadian GAAP or IFRS as defined by Part I of the Handbook of the Canadian Institute of Chartered Accountants (CICA).

With respect to overhead accounting, it is necessary to understand that the concept of developing and applying overhead rates is a management accounting tool rather than a financial accounting activity. As a result, there is very limited explicit guidance in the financial accounting pronouncements of the three major accounting bodies.

1. Legacy Canadian GAAP

Financial Accounting

Guidance on the capitalization of expenditures under legacy Canadian GAAP is primarily found in section 3061 "Property, Plant and Equipment." Section 3061.16 indicates that property plant and equipment assets should be recorded at cost and provides guidance on the types of costs that qualify for capitalization. Section 3061.05 states that the cost of asset is " the amount of consideration given up to acquire, construct, develop or better an item of property, plant and equipment and includes all costs directly attributable to the acquisition, construction, development or betterment of the asset."

A major difference between section 3061 and the comparable IFRS standard (discussed in further detail below), is that the Canadian standard does not specifically bar the capitalization of indirect cost categories such as "general and administrative overheads" or "training costs."

Per paragraph 20 of the CICA standard, "the cost of an item of property, plant and equipment includes direct construction or development costs (such as materials and labour), and overhead costs directly attributable to the construction or development activity." No definition of the term "directly attributable" is provided in the standard, resulting in the need for management to exercise its professional judgement in assessing the degree of direct attribution that exists.

For rate regulated entities, paragraph 10 of the section provides criteria for assessing whether or not an entity's assets qualify as rate-regulated property, plant and equipment. Each of Hydro One's rate regulated subsidiaries, including Hydro One Networks' Transmission Business, meets these criteria. Meeting the rate regulated definition is important as it allows for a different method of capitalizing financing costs than that that would be used by an unregulated entity. Specifically, a qualifying enterprise may capitalize the rate regulator's allowance for funds used during construction, even if it includes a cost of equity component. In addition, assets that meet these criteria may be costed in accordance with regulatory guidance from a qualifying rate regulator, which may differ from the generally accepted basis of costing in use by non-rate regulated enterprises.

Management Accounting

Certified Management Accountants of Canada has developed and released guidance on certain general management accounting practices (MAPs), including overhead accounting. The applicable document is MAP-2400 "Indirect Costs." The relevant overhead accounting document discusses the issues related to designing costing systems for indirect costs. However, it is important to note that this MAP does not represent a primary source of financial accounting guidance within the formal legacy Canadian GAAP hierarchy. The purpose of this MAP is to discuss the issues related to designing management costing systems for indirect costs. Indirect costs are of all functional types, including administrative, manufacturing, logistical, and marketing. The issues related to handling indirect costs are general and independent of the functional nature of the cost. Hydro One's capitalization model complies with the indirect cost pool design recommended by MAP-2400. Since cost allocation forms an integral part of Hydro One's financial accounting capitalization model, it is appropriate that it is consistent with the approach for indirect cost allocation described below.

The MAP notes that when costs are used in contractual settings, such as in cost reimbursement contracts, insurance settlements, or transfer pricing where the price is based on cost, the criterion used to judge the adequacy of the costing system is whether its design could be reasonably expected to avoid material cost distortions in handling indirect costs. When various cost centers provide a significant level of services to themselves and to each other, the design of the costing system should reflect these interactions.

In general, the approach for designing the system of indirect cost pools should have the following steps:

- Classify the cost as direct or indirect;
- Determine if the cost is directly attributable to the cost object and assign it to the object to which it belongs if it is;
- Assign the cost to an appropriate indirect cost pool if it is indirect; and
- Choose an appropriate allocation basis for each indirect cost pool to assign the indirect costs in that pool to the final cost object.

MAP 2800 "Cost Allocation Rates" describes issues in the development and application of cost allocation bases or objects. The allocation of indirect costs to cost objects represents one of the most challenging tasks facing management accountants. This MAP identifies circumstances where care in allocating indirect costs is particularly important and it notes that ultimately the appropriate cost allocation should reflect the nature and purpose of the exercise.

An indirect cost that is allocated to a cost object should reflect that cost object's use of the capacity resource to which the cost relates (effectively cost causality). As all cost allocations are by their nature subject to some degree of arbitrariness, the key is to develop a cost allocation which reasonably reflects the cause and effect relationship between resource use and resource cost.

MAP 6120 “Transfer Pricing in Regulated Environments” focuses on the pricing of transfers of goods or services in a regulated environment where goods or services are transferred between affiliates. Consistent with the requirements of the Board’s Affiliate Relationships Code and Hydro One’s relevant transfer pricing accounting policy described above, this MAP refers to full cost as an appropriate pricing method for such affiliate transactions in absence of market based pricing.

In general, the MAPs provide technical guidance to ensure some theoretical consistency between entities and consistent professional standards in management accounting and pricing. In general, management accounting concepts are common to various jurisdictions irrespective of which financial accounting framework applies. While management accounting is an internally focused activity, management accounting decisions and practices have real impacts on an entity’s financial accounting and financial statements.

2. US GAAP

As approved by the Board in its EB-2011-0268 decision, Hydro One Transmission has adopted US GAAP for rate-setting purposes effective January 1, 2012. Also, as noted by Hydro One in its application to adopt US GAAP as its basis for regulatory accounting and reporting, there are very few differences between legacy Canadian GAAP and existing US GAAP. Most of these differences relate to Balance sheet disclosure and presentation.

There is no formal standard within the body of documentation that represents US GAAP that provides comprehensive accounting guidance on the topic of property, plant and equipment. FASB’s ASC 360 “Property, Plant and Equipment” would appear to provide this but on closer inspection it is an aggregation of pre-codification standards dealing with specific capital accounting issues such as the capitalization of financing costs, business combinations, leases and industry-specific issues. It does not provide a complete accounting framework for fixed assets.

ASC 360 does define the cost of acquiring an asset. The historical cost of acquiring an asset includes the costs necessarily incurred to bring it to the condition and location necessary for its intended use. The term “activities” necessary to bring an asset to the condition and location necessary for its intended use is to be construed broadly, encompassing physical construction of the asset, as well as all the steps required to prepare the asset for its intended use. For example, cost includes administrative and technical activities during the preconstruction stage, such as the development of plans or the process of obtaining permits from governmental authorities. It also includes activities undertaken after construction has begun in order to overcome unforeseen obstacles, such as technical problems, labour disputes, or litigation. The standard does not provide specific guidance that limits the types of expenditures or costs that qualify for capitalization.

In 2003, the American Institute of Certified Professional Accountants (AICPA) exposed a draft Statement of Position (SOP) on “Accounting for Certain Costs and Activities Related to Property, Plant, and Equipment.” This was a proposed comprehensive standard intended to be issued before all standard setting accountability was later assigned to the FASB. The objective of the draft SOP was to replace the set of traditions and conventions that then made up US GAAP for property, plant, and equipment. The SOP proposed one consistent set of rules covering which costs that could be capitalized, either as part of the initial acquisition or construction of an asset, or during the asset's useful life. This resulted in a draft standard that was very close in content to the current IFRS accounting standard for property, plant and equipment.

The draft proposed to limit the categories of costs that could be capitalized to those that were "directly related." However, for the purposes of the proposed standard, "directly related" costs were interpreted as incremental direct costs, thus excluding indirect costs such as general and administrative overheads from capitalization. It specifically listed costs like executive management, corporate accounting, corporate legal, office management, human resource and marketing as indirect costs that would be ineligible for capitalization acquisition costs of capital assets. Respondents from capital intensive industries, including rate regulated utilities, were strongly opposed to the incremental cost capitalization principle include in the proposed SOP. Respondents found that a more appropriate method of costing capital assets was a full cost basis that includes direct costs and a reasonable attribution of indirect costs including general and administrative overheads. The incremental costing proposal was the primary reason why the exposure draft did not receive wide enough support to be adopted. As a result, the project was abandoned by the AICPA and not picked up as part of the FASB's go-forward work agenda. The abandonment of this project, based on a rejection of the incremental costing model, provides solid evidence that US users were not willing to accept the loss of their ability to capitalize general and administrative overheads. The practice of capitalizing such expenditures remains GAAP in the US to this day.

ASC 980 "Regulated Operations" provides the detailed guidance on accounting for rate regulated operations and the recognition of regulatory assets and liabilities that previously resided in SFAS 71 "Accounting for the Effects of Certain Types of regulation." SFAS 71 was the primary source of guidance under both US and legacy Canadian GAAP for guidance on rate regulated accounting matters. The effect is identical to that described above under Canadian GAAP, which is not surprising given that Canadian entities that were applying legacy Canadian GAAP looked to SFAS 71 in their application of regulatory accounting.

3. IFRS

Unlike US GAAP, IFRS provides very detailed and directive accounting guidance for property, plant and equipment in statement IAS 16. In addition, the IFRS framework has certain differences from those that underlay legacy CGAAP and US GAAP. For example, IFRS does not include a matching principle. Moreover, IFRS does not include any accounting recognition of the effects of rate regulation.

IAS 16 generally restricts capitalization of expenditures to those that are directly attributable to the construction or development of an asset. However, similar to the abandoned AICPA proposal in US GAAP, IAS 16 specifically prohibits the capitalization of certain expenditure categories like general and administrative overheads and training costs, even if a directly attributable argument can be made. A strong causal relationship is not sufficient to support capitalization given these prohibitions.

IFRS does not just have the effect of prohibiting the capitalization of general and administrative overheads. It also restricts the capitalization of other indirect expenditures where a “directly attributable” relationship cannot be demonstrated sufficiently to conform to international practice. For example, many indirect management and supervisory expenditures are not eligible for capitalization because they cannot be associated with a specific asset, not because they are unrelated to a capital work program. In Hydro One’s EB-2010-0002 application, the adoption of IFRS had the impact of reclassifying, from capital to OM&A, about $200 million per annum of various categories of overhead and indirect expenditures.

It is well known that IFRS does not deal with the generic issue of rate regulated accounting. The IASB has struggled to finalize its rate regulated accounting project over the last few years and has yet to produce a useful accounting standard to deal with the rate regulated accounting issue. This topic is still on its work plan. In addition, it is clear that the specific IFRS standards that have been issued were not designed to achieve regulatory objectives.

3. Summarize Regulatory Guidance

Key findings: Canadian, and more particularly US regulatory guidance, supports the capitalization of attributable corporate support costs based on a cost causality model.

Canadian Regulatory Guidance

The Board has very recently revised its Accounting Procedures Handbook (APH) for Electricity Distribution Utilities to provide guidance to Ontario local distribution companies using modified IFRS as their approved basis for rate setting. The previous version of the APH provided guidance to utilities that had their rates set under legacy Canadian GAAP. In general, that APH required that regulatory accounting and reporting was based on legacy Canadian GAAP as is currently found in Part V of the CICA Handbook.

Article 410 provided that “property, plant and equipment should be recorded at cost, which includes the purchase price and other acquisition costs such as: option costs when an option is exercised, brokers’ commissions, installation costs including architectural, design and engineering fees, legal fees, survey costs, site preparation costs, freight charges, transportation insurance costs, duties, testing and preparation charges.”

Article 230 defined the components of construction cost. Specifically, “the cost of construction properly included in the electric plant accounts shall include where applicable, the cost of labour; materials and supplies; transportation; work done by others for the utility; injuries and damages incurred in construction work; privileges and permits; special machinery services; allowance for funds used during construction; and such portion of general engineering, administrative salaries and expenses, insurance, taxes, and other similar items as may be properly included in construction costs."

The previous legacy Canadian GAAP APH provided recognition that many of the categories of expenditures included in Hydro One's capital overhead rate do potentially qualify for capitalization, consistent with the general guidance found in legacy Canadian GAAP.

US Regulatory Guidance

The US Federal Energy Regulatory Commission (FERC) provides guidance that ensures consistency in accounting and reporting among US utilities. The FERC Uniform System of Accounts (USoA) is a key part of this accounting and reporting structure. The FERC provides guidelines for use by utilities in the US, including guidance on "overhead construction costs." The FERC's USoA guidance is provided under the overall framework of US GAAP.

- All overhead construction costs, such as engineering, supervision, general office salaries and expenses, construction engineering and supervision by others than the accounting utility, law expenses, insurance, injuries and damages, relief and pensions, taxes and interest, shall be charged to particular jobs or units on the basis of the amounts of such overheads reasonably applicable thereto, to the end that each job or unit shall bear its equitable proportion of such costs and that the entire cost of the unit, both direct and overhead, shall be deducted from the plant accounts at the time the property is retired.

- As far as practicable, the determination of payroll charges included in construction overheads shall be based on time card distributions thereof. Where this procedure is impractical, special studies shall be made periodically of the time of supervisory employees devoted to construction activities to the end that only such overhead costs as have a definite relation to construction shall be capitalized. The addition to direct construction costs of arbitrary percentages or amounts to cover assumed overhead costs is not permitted.

- For Major utilities, the records supporting the entries for overhead construction costs shall be so kept as to show the total amount of each overhead for each year, the nature and amount of overhead expenditure charged to each construction work order and to each electric plant account, and the bases of distribution of such costs.

In addition, per FERC guidelines, allowable components of construction costs also include:

- Engineering and supervision - This includes the portion of the pay and expenses of engineers, surveyors, draftsmen, inspectors, superintendents and their assistants applicable to construction work.

- General administration - This includes the portion of the pay and expenses of the general officers and administrative and general expenses applicable to construction work.

- Engineering services – This includes the amounts paid to other companies, firms, or individuals engaged by the utility to plan, design, prepare estimates, supervise, inspect, or give general advice and assistance in connection with construction work.

While these cost elements are generally consistent with cost components included as capital by Hydro One under both legacy CGAAP and US GAAP, it is useful to note that many of these types of costs do not qualify for capitalization under IFRS IAS 16.

4. Assess Theoretical Appropriateness of Hydro One's Approach

Key findings: Hydro One capitalizes an appropriate proportion of its indirect and overhead support expenditures consistent with GAAP and formal regulatory guidance.

Overheads and indirect expenditures that relate to capital projects are those that are not directly charged to a capital program or project. While the expenditures may be causally or beneficially attributable to the capital project in aggregate, they may not be so easily assignable to a specific asset or capital project without the incurrence of significant additional expenditures that would have very limited benefit to either the shareholder or the rate payer.

Many regulated entities concentrate their corporate services within holding companies for efficiency in servicing the needs of regulated and unregulated subsidiaries. Hydro One Networks owns and operates two separately regulated transmission and distribution businesses. As such, it is able to provide many of their services on a shared basis rather than replicating them within each business. This results in lower costs and a more efficient delivery of electrical service to end customers. This model also results in a need for comparatively more cost allocation than seen in entities that do not share services. Under Hydro One's model, the costs of shared services are allocated to the serviced affiliates using the Black and Veatch reviewed methodology. Within each regulated business or subsidiary, allocated shared service costs are then classified as either current expense (i.e. OM&A) or capital. As previously stated, both cost allocation and cost classification are based on the same high level criteria – causality or benefit.

For companies that do not share common corporate support expenditures, such amounts are directly charged to capital, or more likely included in capital through the application of standard labour and non-labour rates. The organizational location of departments offering supporting services may influence whether the amount is charged to capital as an indirect cost (e.g. embedded in standard rates) or as an overhead through application of an overhead rate. Thus, a lower overhead capitalization rate compared to another utility may not necessarily be indicative of lower absolute capitalization of indirect support costs. Nor does a lower overhead rate indicate greater productivity or efficiency.

The absence of publicly available information on the organization structure, types and amounts of supporting functions' costs, standard cost structures and overhead allocation methodologies and rates make it very difficult to compare data between entities without conducting very extensive benchmarking studies, likely with the full cooperation of the other entity. However, while a precise peer-to-peer comparison on rates may not be achievable because of general lack of detailed comparative data, Hydro One Transmission's comparison work does indicate the use of a generally consistent practice of using cost causation principles to capitalize corporate support costs and other genera and administrative overheads.

Both legacy Canadian GAAP and US GAAP allow for the capitalization of directly attributable overheads costs under the general accounting principle of matching. This practice is supported by FERC guidance that incorporates the concept of intergenerational equity. Neither GAAP nor FERC provide explicit guidance on specific expenditures that may be capitalized or on cost allocation methods. The GAAP concept of matching and the regulatory principle of intergenerational equity both require the application of causality and benefit assessment to determine which expenditures should be capitalized. As documented in Black and Veatch's independent report, these are the same criteria used to allocate Hydro One's shared service costs to target subsidiaries and regulated businesses. These same criteria are used to determine the proportion of allocated expenditure that should be capitalized.

In its EB-2008-0408 Report, "Transition to International Financial Reporting Standards," under Issue 3.3, the Board commented on intervenor concerns that the adoption of IFRS, entailing a significant reduction in the types of expenditures that qualify for capitalization, could result in significant intergenerational inequities. Interestingly, in its report, the Board expressed an opinion that "the capitalization principles as they now appear in IFRS recognize the nature of indirect costs and whether they are truly attributable to capital projects. The ability of the Board to set just and reasonable rates is enhanced by clarity in capitalization principles that emphasize cost causality." Hydro One agrees with the view expressed in the last sentence and recognizes that the strict application of IFRS rules could result in significant shifts from rate base to revenue requirement for certain utilities. In section 3.3 of its report, the Board also noted that "It will be important for the Board to have a clear understanding of utility capitalization practices, and the effects, if any, of a shift to IFRS capitalization principles. The Board therefore supports the requirement for utilities to file their capitalization policies in their first cost of service filing after the transition to IFRS, and will also require that the revenue requirement impacts of any change in capitalization be specifically and separately quantified." The $200 million quantification of the impact of an IFRS capitalization policy was made clear in EB-2010-0002.

Hydro One Transmission undertakes large capital investments for network upgrades, local supply development projects and replacement and refurbishment of aging infrastructure. These capital projects are constructed and managed internally by the Transmission Business. Significant shared corporate support costs are directly caused by this capital construction program. If the internal construction program did not exist, many of these expenditures would not be required or could be reduced.

In addition, if such projects were outsourced to a turnkey engineering firm, many of these indirect costs and general and administrative overheads would be embedded in the construction costs charged by the turnkey contractor and would be capitalized without question, even under the constraints of IFRS. To comply with the regulatory principle of intergenerational equity, it is logical that the same classification as OM&A or capital should occur irrespective of whether the capital work is self-constructed or turn-keyed.

5. Conduct Industry Research

Key findings: Hydro One's practice, both in terms of the type and proportion of overhead and indirect expenditures capitalized, is consistent with the practices of other North American rate regulated utilities.

Methodology

As requested, Hydro One included a review of the practice of other rate regulated entities in other North American jurisdictions as part of the critical review of its cost capitalization policy. Hydro One notes that the Board asked the Company to gather comparative data but that this exercise was explicitly not intended to constitute a formal benchmarking exercise. This industry research included an examination of the financial statements and regulatory filings of some of the largest utilities in Canada and the US to obtain information on the nature of their overhead and indirect cost capitalization practices and rates. A summary of the research findings can be found in Appendix A.

During the course of its research, Hydro One found that publicly available information on the types of expenditures capitalized as overhead was very difficult to gather from available sources such as financial statements, securities filings and regulatory applications costs and the capitalization percentages. In addition, it was also very difficult to access comparable information on overhead percentages and rates. The Company expects this difficulty results from the fact that detailed disclosure of an entity's indirect cost and overhead accounting practices is not required disclosure under either US or legacy Canadian GAAP. In addition, there is no requirement for entities to disclose detailed information on which overheads or indirect costs are capitalized in their summary of significant accounting policies disclosed within their financial statements. Finally, risk and liability issues applicable to public securities filers have the effect of discouraging voluntary disclosure of information and make approaching another company for information difficult. As there is no offsetting incentive for companies to publicly disclose such information, virtually none do so.

In its review of the practices of other major transmission utilities, Hydro One started its review with major US transmission utilities. In recognition of the difficulty encountered in accessing detailed information on the overhead capitalization practices of these entities, the scope of the comparison was expanded to capture other major Canadian utilities and even large Ontario local distributors. Given the similarities between US and legacy Canadian GAAP, as well as similarities in the cost of service regulatory model in the Canadian and US jurisdictions, this was deemed to be appropriate.

Observation Summary

A detailed summary of Hydro One's findings from reviewing nine Canadian and nine US companies is included as Appendix A. Several other major US companies were also investigated but no useable information was derived from their publicly available financial or regulatory information.

The following table provides a high level summary of the findings with respect to overhead capitalization rate:

Overhead Capitalization Rate (as a percentage of gross operating costs*)			
Hydro One	**Canadian Utilities****	**U.S. Utilities****	**Analysis**
Transmission (2013) – 20%	Industry Median*** - 19%	Industry Median**** - 19%	• The range of overhead capitalization rates varies across the utilities in Canada and US. For Canadian utilities it ranges from 5% to 35.6% with an observed median of 19%. For U.S. utilities, it ranges from 7.33% to >50% with an observed median of 19%. • The rates are based on legacy Canadian GAAP for Canadian utilities and US GAAP for US utilities. However, both accounting frameworks are substantively the same in this area.

* *Gross operating costs include capitalized overheads added back.*
** *Refer Appendix A for a list of the Canadian and U.S. utilities researched and summary of findings.*
*** *Median represents middle value of the range of overhead capitalization rates for those utilities selected for research and where rate information was available.*
**** *The US median is based on a concentration of three results in the 19% range, with one individual outlier at ~7% and another >50%.*

The comparative analysis performed for this report resulted in the identification of a range of acceptable accounting practices and capitalization rates prevalent in the industry. For example, an organization with a shared services structure where broad corporate management and administrative functions are centralized could be characterized by larger overhead allocations from the central indirect costs pool to business units. A more decentralized operation would have the majority of management and administrative costs directly attributed to the target activities, capital and operations.

The key observations made for the Canadian and US utilities researched were as follows:

- The majority of utilities capitalized general and administrative expenditures by including these costs in their overhead capitalization methodology. Some of the more common types of support expenditures within this category include finance, corporate communications, human resources, law, treasury, strategy, information technology, regulatory affairs and other corporate support costs.

- The most common capitalization methods in use appear to be a mix of direct allocation, cost drivers and time studies. In addition, there is evidence that external capitalization studies, such as the one Black and Veatch does for Hydro One, are performed from time to time by some entities.

- The majority of utilities capitalized corporate services expenditures under their capitalization approach. There are variations in the proportions that service expenditures are charged and capitalized as indirect costs (for example those included in the standard labour rates) or charged as overhead costs through the application of an overhead rate. Hydro One's comparison shows that most of corporate services costs appear to be charged to capital through overhead rates rather than being included in standard labour rates.

- All of the US utilities referenced compliance with FERC guidelines as the basis for their overhead capitalization practice.

6. Conclusion

Key findings: Hydro One's cost capitalization policy with respect to overhead and indirects expenditures is consistent with GAAP, regulatory guidance and regulatory practice. Hydro One's cost capitalization policy is appropriate.

As directed by the OEB, Hydro One critically reviewed its cost capitalization policy with a particular focus on overhead and indirect costs. Hydro One found that its treatment is not inconsistent with other major US and Canadian industry participants. In addition, Hydro One concluded that its methodology, as reviewed by Black and Veatch and previously approved by the Board, is consistent with legacy Canadian and existing US GAAP. In addition, and more importantly, Hydro One's methodology is consistent with regulatory principles including the key goals of achieving intergenerational equity and avoiding cross subsidization.

Summary of Findings - Canadian Utilities

	Utility Name, Regulator	Analysis	Overhead Cost Components	Overhead Capitalization Rates CGAAP *(as a % of gross operating costs)*	Reference
1.	BC Hydro, British Columbia Utilities Commission.	• Capitalized Overhead of $278M for 2011 is approximately 21% of operating costs. • Capitalized Overhead would be reduced to a $100 million under IFRS (9%). BC Hydro proposing to use a regulatory account to phase in the resulting increase over a 10 year period. • More recently they have proposed to use US GAAP.	• **Corporate Costs** – (Finance, Information Technology, Human Resource, Communications, Law, Internal Audit, Regulatory Support, Senior Management and Board, Indirect Supervision and General Engineering, Fleet and Procurement)	• 21% *(percentage is derived from capitalized overhead value and operating costs values extracted from reference documents)*	• Amended F2012 to F2014 Revenue Requirements Application.
2.	Toronto Hydro Electric System (THES), Ontario Energy Board(OEB).	• Overheads allocated based on cost drivers/time study and include cost of corporate functions and services and employee future benefits. • Proposing to use US GAAP from 2012 with no material impact on overhead rates.	• **Corporate Costs** – (Finance, Information Technology, Human Resource, Communications, Law, Internal Audit, Regulatory Support, Senior Management and Board) • Fleet indirects and procurement indirects are recovered through standard labour rates.	• *~ 22%* *(percentage is derived)*	• Exhibit C1, Tab 3, schedule 4(EB-2011-0144).

	Utility Name, Regulator	Analysis	Overhead Cost Components	Overhead Capitalization Rates-CGAAP *(as a % of gross operating costs)*	Reference
3.	Hydro Ottawa, Ontario Energy Board (OEB).	• Overheads allocated based on cost drivers/time study and include cost of corporate functions and services and employee future benefits. • Overhead rates will reduce to 10.3% on adopting IFRS based capitalization approach. Allocation to capital reduced by $10.5 million.	• Corporate Costs – Chief Regulatory officer, General Council, Hold Co Corporate Costs, COOs office, Finance, Supply Chain, Human Resource, IT, Supervision, Operations Engineering.	• 15.4% *(Percentage extracted from referenced document)*	• 2012 EDR Application.
4.	Fortis BC, British Columbia Utilities Commission.	• Fortis BC (Electricity) requested approval of US GAAP for rate setting. As part of its 2012-2013 application Fortis BC updated its methodology for calculating Capitalized Overhead resulting in a 23.9% capitalization rate. Fortis BC proposes to continue using the 20% for 2012-2013. • Fortis BC (Electricity) derives their corporate overhead rate through a 3 step process. First a driver is identified for each corporate department. Next the department costs are allocated to the operating business units (Generation, Network Services, Customer Service) using the drivers. Finally the relative proportion of capital related work in the operating business units are determined based on relative labour hours charge to O&M versus capital in 2010. : Generation 75%, Networks Service Customer Service 13 %.	• Fortis BC (electricity) Corporate Costs – (Finance, Information Technology, Human Resource, Communications, Law, Internal Audit, Regulatory Support, Senior Management and Board, Health and Safety, Environmental. • No detailed component information available for Fortis BC (Gas)	• Electricity-20% (increased to 23.9% beyond 2012-2013) • Gas - 14% *(Percentage extracted from referenced document)*	• 2012-2013 Revenue Requirement Application.

	Utility Name, Regulator	Analysis	Overhead Cost Components	Overhead Capitalization Rates-CGAAP *(as a % of gross operating costs)*	Reference
5.	Enmax Power Corporation, Alberta Utilities Commission.	• The Alberta Utilities Corporation (AUC) approved a 7 year Formula Based Ratemaking for the period 2007 to 2014 for Transmission and Distribution. Included was approval for a 19% overhead capitalization rate for the term of the plan with a 3% escalation per year. • A mix of time study, cost-drivers and direct attribution is used for allocation of overhead costs.	• **Corporate Costs** – (Finance, Information Technology, Human Resources, Communications, Law, Internal Audit, Regulatory Support, Senior Management and Board, Indirect Supervision and General Engineering, Fleet and Procurement)	• 19% *(Percentage extracted from referenced document)*	• 2007-2016 Formula Based Ratemaking Decision issued in March 25, 2009.
6.	Union Gas, Ontario Energy Board.	• Union Gas forecasts capital overhead as 14.9% of total utility operating and maintenance costs in 2013. This is consistent with the 2007 Board-approved levels of 15%. • A mix of direct attribution, time studies and cost drivers is used for allocation of overhead costs.	• **Corporate Costs** – (Executive, Asset Operations, Regulatory and Business Services, Finance, Human Resources, Corporate Services, Legal, Strategic Development, Information Technology.	• 14.9% *(Percentage extracted from referenced document)*	• EB-2011-0210, Exhibit D1, Tab 2.

	Utility Name, Regulator	Analysis	Overhead Cost Components	Overhead Capitalization Rates-CGAAP *(as a % of gross operating costs)*	Reference
7.	Enbridge Gas Distribution.	• Administrative and general overheads are capitalized based on cost drivers/time study and approved by Enbridge's Board.	• Detailed information on cost components not available.	• 6.8% *(Percentage extracted from referenced document)*	• EB-2011-0008, Exhibit B, Tab 4, Schedule 2.
8.	Newfoundland Power, Board of Commissioners of Public Utilities.	• Certain general expenses related, either directly or indirectly, to the Company's capital program are capitalized based on approval from the regulator. • For 2012 General Expenses Capitalized is $2.8 million Compared to Operating Costs of $52.7 million.	• Detailed information on cost components not available.	• 5% *(percentage is derived from capitalized overhead value and operating costs values extracted from reference documents)*	• 2012 Capital Budget Application and 2010 General Rate Application.
9.	Powerstream, Ontario Energy Board (OEB).	• Overheads allocated based on payroll burden study and include management, engineering, stores and vehicle burdens loaded to standard labour rates.	• Detailed information on cost components not available.	• Management Burden - 6% • Engineering Burden - 60% *(Percentage extracted from referenced document)*	• EB-2008-0244, Exhibit B1, Tab 3, Schedule 1.

Summary of Findings - U.S. Utilities

	Utility Name, Regulator	Analysis	Overhead Cost Components	Overhead Capitalization Rates-U.S.GAAP ***(as a % of gross operating costs)***	Reference
1.	Southern California Edison, California Public Utilities Commission (CPUC).	• Administrative and General ("A&G") overhead costs are based on study approved by the regulator. • Overheads allocated based on cost drivers/time study and include cost of corporate functions and services like human resource, IT, corporate finance and risk assessment and strategy. Pensions and benefits are capitalized at 37.7%.	• Corporate Cost – Audit, Controllers, Corporate Communications, Customer Service, Human Resources, Law, Treasurer. • Strategy – General Functions and Information Technology. • Operations Support – Training, Environmental, Health and Safety.	• 19.4% *(Percentage extracted from referenced document)*	• 2012 General Rate Case Exhibit No. SCE-07, Vol.01 Chapter I, X and XI and work papers • 2009-General Rate Case proceeding s with CPUC.
2.	San Diego Gas & Electric Company (SDG&E), California Public Utilities Commission (CPUC).	• A percentage of certain A&G direct costs, including A&G Salaries, shared service costs, outside services employed, are reassigned to construction each year. The transfer rate to construction projects is determined by an A&G effort study last conducted in 2009 and approved by CPUC. Other costs capitalized include fleet, purchasing, warehousing and pension benefits.	• A&G costs represent corporate services and include A&G salaries, shared services, office supplies and expenses and outside services employed.	• Labour overheads to capital-33.9%. • A&G costs to capital - 18.1% *(Percentage extracted from referenced document)*	• 2012 Gen. Rate Case Exhibit SDG&E-43 Segmentatio n & Re-Assignment Rates and work papers

	Utility Name, Regulator	Analysis	Overhead Cost Components	Overhead Capitalization Rates-U.S.GAAP *(as a % of gross operating costs)*	Reference
3.	Pacific Gas & Electric Company (PG&E), California Public Utilities Commission (CPUC).	• Overhead allocation is based on detailed review by Corporate Service departments to calculate the appropriate administrative and general (A&G) capital allocation. Pensions and benefits are also capitalized. • No information available on non-labour related overhead allocation rates.	• Detailed component information on corporate services was not available. • A significant portion comprised of A&G labour costs.	• 7.33% of A&G labour costs allocated to capital. *(Percentage extracted from referenced document)*	• Decision on Test Year 2011 A.09-12-020, I.10-07-027 • Ex PGE-006: 2011 GRC Prepared Testimony: Exhibit 6 – Admin & General Expenses.
4.	Kansas City Power and Light Company, Missouri Public Service Commission	• Indirect A&G costs include corporate services costs, executive salaries and indirect labour. • The Uniform System of Accounts addresses the indirect allocation of A&G payroll to construction activity.	• A&G costs include corporate services - (Audit, Controllers, Corporate Communications, Customer Service, Human Resources, Law, and Treasurer).	• The labour allocation to construction at 19.33% was based on a study filed with the regulator in 2006. *(Percentage extracted from referenced document)*	• Missouri PSC, Utility Services Division, Direct Testimony of Kimberly K. Bolin, Staff, Case No. ER-2006-0314.

	Utility Name, Regulator	Analysis	Overhead Cost Components	Overhead Capitalization Rates-U.S.GAAP *(as a % of gross operating costs)*	Reference
5.	Commonwealth Edison Illinois Public Utilities Commission	• An Administrative and General Overheads ("A&G") study was done by Commonwealth Edison, (ComED) to justify its overhead allocation between capital and OM&A to the regulator for the year 2001 to 2004. • The study was done by an external consultant Alliance Consulting Group ("ACG"). • The study showed that since about 1999 ComEd began incurring increased levels of capital expenditures compared to prior years primarily reflecting ComEd's increased investment programs to improve the reliability of its distribution system. In addition, during the period, ComEd implemented accounting changes and made operational decisions that reflect a systematic plan to shift costs from O&M expense to capital.	• Indirect cost components include – Labour, Employee Benefits, Supervision, General and Administrative, Contracting, Affiliate Services, Indirect Materials, Vehicle Fleet and Corporate and Other Support.	• A&G distributed to capital- ▪ 2001-57.2% ▪ 2002-60% ▪ 2003-70.9% ▪ 2004-71.4% • Capitalization rate information is not available. *(Percentage extracted from referenced document)*	• A&G Effort Study, Chapter VI Analytical and Other Review, Page A-305.

	Utility Name, Regulator	Analysis	Overhead Cost Components	Overhead Capitalization Rates-U.S.GAAP *(as a % of gross operating costs)*	Reference
6.	Bonneville Power Administration (BPA).	• Capitalized costs include direct labour and materials, payments to contractors, indirect charges for engineering supervision and similar overhead items.	• Detailed information not available. • Includes indirect costs for engineering and supervision**.**	• Capitalization rate information is not available.	• Bonneville Power, 2011 Annual Report, Audited FS
7.	UNS Electric (Arizona), Arizona Corporation Commission	• It appears that they capitalize A&G expenses according to Decision of Arizona Corporation Commission on rates for 2008. Expenses are related to shared service group and administrative costs associated with installation of equipment to serve customers, even though such costs can not be traced directly to individualized capital projects	• Capitalized A&G includes shared services cost which represent general and administrative overheads and corporate services**.**	• Capitalization rate information is not available	• Decision 70360, Docket No. E-04204A-06-0783, Appln. of UNS Electric Inc. before Arizona Corporat-ion Comm.

	Utility Name, Regulator	Analysis	Overhead Cost Components	Overhead Capitalization Rates-U.S.GAAP *(as a % of gross operating costs)*	Reference
8.	Seattle City Light (Seattle City Council)	• A&G capitalized is assumed in financial forecast but no rates given.	• Detailed information not available.	• Capitalization rate information is not available	• Revenue Require-ments Presentation, RAC Meeting 2, Sept 22, 2009.
9.	Illinois Public Utilities Commission	The Uniform System of Accounts for Electric Utilities Operating in Illinois talks about overhead allocation: • Overhead construction costs to be charged on the basis of the amounts of such overheads reasonably applicable. • Determination of payroll charges included in const. overheads to be based on time cards. Where impractical, special studies shall be made periodically.		• Capitalization rate information is not available but the Illinois utilities USofA support capitalization of indirect costs and general and administrative overheads.	• Working Copy of the USoA for Electric Utilities Operating in Illinois, Illinois Commerce Comm. Accounting Department August 1, 2007.

COMMON ASSET ALLOCATION

1.0 INTRODUCTION

This evidence will discuss the nature of Common Fixed Assets ("Shared Assets") and the method by which the costs of these assets are assigned to the Transmission and Distribution business units.

Similar to the common corporate costs discussed in Exhibit C1, Tab 7, Schedule 1, Hydro One has been able to maximize efficiencies through the centralization of the maintenance, management and purchase of shared assets at the corporate level. These assets include shared land and buildings, telecommunication equipment, computer equipment, applications software, tools and transportation and work equipment ("T&WE").

2.0 SHARED ASSETS AND FACILITIES COSTS

Most fixed assets are directly assigned to the appropriate business unit. The remaining assets (5% of total assets) are considered shared assets, and are allocated to Transmission and Distribution as described later in this exhibit. Table 1, below, summarizes the total gross fixed assets and identifies the proportion of allocated shared assets.

Table 1
Summary of Gross Fixed Assets
as at December 31, 2010 ($ Million)

	Transmission	Distribution	Total
Total Fixed Assets	11,666.3	7,397.0	19,063.3
Shared Assets (in Total)	461.2	600.1	1,061.3
Shared Asset %	43.5%	56.5%	100%

Shared assets are sub-divided into two categories. Major Fixed Assets consist of land, buildings, applications software, and telecommunications equipment. Minor Fixed Assets include office furniture, computer equipment, tools and T&WE. Table 2, below, shows the proportion of major and minor shared fixed assets, accumulated depreciation and net book value as of December 31, 2010.

Table 2
Details of Shared Net Fixed Assets
as at December 31, 2010 ($ Million)

Asset	**Gross Asset Value**	**Accumulated Depreciation**	**Net Book Value**
Shared Major Assets	473.1	87.7	385.4
Shared Minor Assets	588.2	362.0	226.2
Total Shared Assets	**1,061.3**	**449.7**	**611.6**

3.0 ALLOCATION OF SHARED ASSETS IN SERVICE

Due to the nature of Hydro One's business, shared assets are not directly attributable to either the Transmission or Distribution business units. In addition, from year to year, the use of these shared assets may change, based upon changes in the underlying Transmission and Distribution work programs. Consequently, the methodology by which shared assets are allocated to the Transmission and Distribution business units is subject to periodic review. The intent of such a review is to ensure that the assignment of assets is reflective of their use and that the costs are apportioned appropriately amongst the business units.

In 2008, the Company commissioned a study by Black & Veatch (B&V) (Formerly R.J. Rudden Associates) to determine a methodology to allocate the assets which are not directly attributable to Transmission or Distribution. The methodology developed represents industry best practices, identifying appropriate cost drivers to reflect cost causality and benefits received. The B&V study resulted in the allocation of shared assets based on the relative usage by Transmission and Distribution or by cost drivers, similar to those used for the common corporate functions and services.

The Company has accepted the approach of the B&V study as a reasonable representation of the use of shared assets amongst the business units. This methodology was utilized and subsequently accepted by the Board in its EB-2008-0272, EB-2009-0096, and EB-2010-0002 Decision with Reasons.

The appropriate use of the common asset allocation methodology for the 2013 and 2014 test years has been reviewed and confirmed by B&V in 2012, and is provided as Attachment 1 to this Exhibit.

Due to the significance of Cornerstone as a Shared Asset, Hydro One has developed transfer price charge rates to allocate a portion of the revenue requirement related to certain Shared Assets to the Telecom and Remotes businesses. In the past, no Shared Assets were assigned to Telecom or Remotes because the amounts would have been very small. The methodology and impact of the transfer price charges are described in more detail in Attachment 1 to this Exhibit.

Hydro One has used the approved B&V Asset Allocation methodology in this application and Table 3 below shows the Hydro One Common Asset allocation as at December 31, 2010.

Table 3
Hydro One Common Asset Allocation
as at December 31, 2010 ($ Million)

Total Gross Value All Hydro One Transmission & Distribution Assets $19,063 million			
Transmission (Total)	$11,666	Distribution (Total)	$7,397
Transmission (Direct)	$11,205	Distribution (Direct)	$6,797
Transmission (Common)	$461	Distribution (Common)	$600

REVIEW OF SHARED ASSETS ALLOCATION (TRANSMISSION) – 2012

PREPARED FOR

Hydro One Networks Inc.

1 FEBRUARY 2012

BLACK & VEATCH
Building a world of difference.

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LIST OF TABLES

I. Summary

A. BACKGROUND AND PURPOSE

Black & Veatch ("B&V" or "we") is pleased to submit this Report on our Review of Shared Assets Allocation (Transmission) – 2012 to Hydro One Networks Inc. ("HONI") This Report describes the review that B&V performed, at the request of Hydro One, of Hydro One's allocation of the costs of Shared Assets in its 2013/2014 Transmission Rates filing before the Ontario Energy Board ("OEB"). In this Report, "cost" is original cost (i.e., gross book value) as derived of December 31, 2010.

In 2005, B&V recommended, Hydro One adopted, and the OEB accepted a methodology for Hydro One to allocate the costs of Shared Assets between its Transmission business and Distribution business, and issued our *Report on Shared Assets Methodology Review* dated June 15, 2005 ("2005 Assets Report"). B&V's objective in allocating the Shared Assets was to ensure that the allocation was reasonable, reflected best practices and was consistent with the allocation of the costs of the common corporate functions and services, as discussed in our *Review of Shared Services Costs Allocation (Transmission)– 2012* dated February 1, 2012 ("2012 Shared Costs Report)".

The OEB-accepted methodology has been applied to Hydro One's Business Plans, and reviewed by B&V with reports issued, as follows:

B&V REVIEW	ASSET VALUES	B&V REPORT
2006 Review	12/31/2005	*Report on Common Assets Methodology 2006* dated May 31, 2006
2008 Review	12/31/2007	*Report on Common Assets Methodology 2008* dated September 10, 2008
2009 Review (Distribution)	12/31/2008	*Report on Common Assets Allocation- 2009* dated June 29, 2009
2010 Review (Transmission)	12/31/2008	*Report on Common Assets Allocation (Transmission) - 2010* dated February 26, 2010

The OEB-accepted methodology has been applied by Hydro One to its Business Plan 2012-16 ("BP 2012-2016") data for its 2013/2014 Transmission Rates filing. This Report describes the "2012 Shared Assets Allocation Review (Transmission)" that B&V performed, at Hydro One's request, of Hydro One's application of the methodology to its BP 2012-16, and presents B&V's conclusions.

In its 2013/2014 Transmission Rates filing, Hydro One has allocated 43.5% of the cost of the Shared Assets to its Transmission business, and 56.5% to its Distribution business. These are approximately the same as in its 2010/2011 Distribution Rates filing and its 2011/2012 Transmission Rates filing.

In addition, Hydro One has developed transfer price charge rates for the Telecom and Remotes businesses, to be used in allocating to those businesses a portion of the revenue requirement related to the Shared Assets (e.g., depreciation expense and return). In the past, before Cornerstone assets had been placed in service, no Shared Assets were assigned to Telecom or Remotes because the amounts would have been very small.

No Shared Assets are allocated to Brampton, because it does not use the assets.

B. TYPES OF SHARED ASSETS

Hydro One provided B&V with a list of the Shared Assets, by Asset Group and Asset Subgroup, as shown in Table 1.

Table 1 - Types of Shared Assets

ASSET GROUP	ASSET SUBGROUPS
Major Assets	▪ Software ▪ Buildings and Telecommunications equipment
Minor Fixed Assets ("MFA")	▪ Aircraft ▪ Computer Hardware ▪ Office equipment ▪ Service equipment- Miscellaneous ▪ Service equipment- Measurement and Testing ▪ Service equipment- Storage ▪ Tools ▪ Transportation Work Equipment ▪ Transportation Work Equipment- Power equipment

If an asset was estimated to be used at least 95% in either Transmission or Distribution, the cost of that asset was removed from Shared Assets and directly assigned to that business.

C. SUMMARY OF APPROACH

Allocation of Asset Costs to Transmission and Distribution

A cost driver was assigned to each asset (i.e., a building within Major Assets), asset type (i.e, Pickup Trucks within TWE) or Asset Subgroup, based on discussions with Hydro One personnel to ascertain what cost driver was most closely related to the usage of the asset or the Asset Subgroup. The cost drivers used to allocate the Shared Assets were selected from among, or derived from, the cost drivers used to allocate the costs of the common corporate functions and services. The specific steps used for each Asset Group and Subgroup are discussed below. The amounts allocated to Transmission and Distribution are summarized in Table 2.

Development of Transfer Price Charge Rates for Telecom and Remotes

The transfer price charge rates represent the usage of the Shared Assets by the Telecom and Remotes businesses. Our approach to developing the transfer price charge rates was as follows:

- The portion of each asset that should be allocated to Telecom and Remotes based on the appropriate cost driver was determined.
- The total dollar amount allocated to Telecom, representing Shared Asset cost, was computed for each asset by multiplying the Telecom share of usage by the asset cost; these dollar amounts were summed and divided by the category total cost to determine the Telecom share for the category. The same was done for Remotes. Table 3 presents the Telecom and remotes shares.
- The percentages should be applied to each component of the revenue requirement related to the Shared Assets (e.g., depreciation expense and return), to compute the dollar amount charged to Telecom and Remotes. The amounts charged to Telecom and Remotes should be applied to reduce the revenue requirement recovered from rate payers of the Transmission and Distribution businesses.

  For example, the study determined that Telecom uses 0.38% (Table 3) of the shared Major Assets owned by HONI. As such, 0.38% of the revenue requirement associated with major assets is charged to Telecom. The revenue requirement calculated for HONI will include 100% of the assets, however, the other revenues received from the Hydro One Inc. subsidiaries will reduce the revenue requirement which is used to derive the tariff rates.

II. Descriptions of Asset Groups

A. MAJOR ASSETS

Software

Most of the software included in Shared Assets was for Hydro One's Cornerstone project, an enterprise-wide system to support work management, asset management, human resources, financial and other functions. Cornerstone Phase 1, Phase 2 and parts of Phase 3 have been placed in service as of December 31, 2010. These costs were allocated using a cost driver that reflects the activities supported. Infrastructure costs related to Cornerstone Phase 1 and Phase 2 were allocated based on the activities those phases support.

Buildings and Telecommunications Equipment

Each asset included in Buildings and Telecommunications Shared Assets was discussed with Hydro One personnel, and allocated using one of the following methods:

- **Specific estimation for a building.** For example, Sudbury Service Centre has estimated usage of Transmission-20% / Distribution-80%.
- **Direct assignment based on type of usage**. For example, Hydro One summarized Fleet time charges (which are recorded to time sheets concurrently with usage) for years 2009 and 2010 and determined that Fleet usage is Transmission- 26.09% and Distribution- 73.91%; therefore the costs for buildings used for Fleet were allocated using these percentages.

  Buildings used for Training were allocated using the cost driver Headcount.
- **Cost drivers based on usage.** For example, Buildings used to manage both Transmission and Distribution projects are allocated using the cost driver *ProgramProjectCosts*, developed in Hydro One's Shared Services Cost study.

B. MINOR FIXED ASSETS

Each component of Minor Fixed Assets includes many individual items. B&V reviewed the lists of individual items and determined that the following allocations are appropriate:

- **Aircraft –** Helicopter and supporting components. Usage was based on an analysis of time charges (which are recorded to time sheets concurrently with usage) for years 2009 to 2010.
- **Computer Hardware –** Includes Laptops, Desktops, Network Equipment, Printers, etc. Allocated using a cost driver based on the number of *Workstations* (50% weight) and the cost driver *Headcount* (50% weight).
- **Office equipment –** Includes office furniture and other office equipment. Allocated using the cost driver *Headcount*.

- **Service equipment - Miscellaneous** – Includes miscellaneous equipment. Allocated using *Total Shared Services* cost driver, developed in Hydro One's Shared Services Cost study.
- **Service equipment- Measurement and Testing** – Includes Meters, Splicers etc. used for Distribution. Directly assigned to *Distribution*.
- **Service equipment- Storage** – Includes Waste Storage and Other Storage equipment. Allocated using the cost driver based on spending for *Operating and Maintenance costs and Capital spending*.
- **Tools** – Includes Rental tools. Allocated Transmission-80% / Distribution-20% reflecting estimated usage based on information as to which business units are renting the tools.
- **Transportation & Work Equipment** – Includes primarily Vehicles. Allocated using the cost driver "Fleet", which represents Fleet time charges (which are recorded to time sheets concurrently with usage) for years 2009 and 2010. Except for items representing less than 0.5% of cost, the usage for all of the Transportation & Work Equipment Shared Assets were recorded on time sheets and included in the computation of the Fleet cost driver.

The results are summarized in Table 2.

III. Summary of Results

Table 2 presents the allocation of Shared Assets to Transmission and Distribution.

Table 2 - Summary of Shared Assets Allocation

YEAR - END 2010 $ MILLIONS COST	TOTAL	TRANSMISSION	DISTRIBUTION	TRANSMISSION %	DISTRIBUTION %
Major Assets					
Software	$379.5	$220.2	$159.3	58.0%	42.0%
Building / Telecom	93.6	48.1	45.5	51.4%	48.6%
Total	**473.1**	**268.3**	**204.8**	**56.7%**	**43.3%**
Minor Fixed Assets					
Aircraft	19.6	14.0	5.6	71.4%	28.6%
Computer Hardware	71.0	42.6	28.4	60.0%	40.0%
Office Equipment	7.0	4.2	2.8	60.0%	40.0%
Service- Misc.	7.3	3.4	3.9	46.6%	53.4%
Service- Measure/Test	8.7	-	8.7	0.0%	100.0%
Service- Storage	6.9	3.7	3.2	53.6%	46.4%
Tools	5.5	4.4	1.1	80.0%	20.0%
Transportation & Work Equipment	462.2	120.6	341.6	26.1%	73.9%
Total	**588.2**	**192.9**	**395.3**	**32.8%**	**67.2%**
Total - All Shared Assets	**$1,061.3**	**$461.2**	**$600.1**	**43.5%**	**56.5%**

Table 3 presents the Shared Assets transfer price charges for Telecom and Remotes.

Table 3 - Transfer Price Charges for Other Businesses

ASSET GROUP	TELECOM	REMOTES
Major Assets	0.38%	0.18%
Minor Fixed Assets	0.22%	0.10%
Total - All Shared Assets	**0.26%**	**0.12%**

DEPRECIATION AND AMORTIZATION EXPENSES

1.0 INTRODUCTION

The purpose of this evidence is to summarize the method and amount of Hydro One Transmission's depreciation and amortization expense for the 2013 and 2014 test years.

The depreciation and amortization expense for Hydro One's submission for 2007 and 2008 Electricity Transmission revenue requirements (EB-2006-0501) was supported by an independent study conducted by Foster Associates Inc. (Foster), completed in June, 2006. In EB-2008-0272, Hydro One submitted a 2008 Technical Update conducted by Foster completed in August 2008 that supported the 2009 and 2010 depreciation and amortization expense. No Depreciation Study or Technical Update was carried out for 2011 or 2012 rates and depreciation rates were not changed from those previously approved. The Board accepted the costs flowing from the previous Depreciation Study and Technical Updates for the purpose of supporting Transmission rates in those years. Foster Associates has completed a new Depreciation Study for Hydro One Transmission in support of its 2013 and 2014 application. The new study can be found at Exhibit C1, Tab 8, Schedule 1, Attachment 1.

The depreciation and amortization expense for 2013 is $346.7 million and for 2014 is $374.7 million.

2.0 DEPRECIATION EXPENSE

In accordance with the Board's Decision (EB-2006-0501), Hydro One Transmission used the Foster methodology, updated to reflect the results from the new Depreciation Study completed in 2012, for determining the depreciation rates proposed to be used in the calculation of depreciation expenses for 2013 and 2014.

The depreciation expense for 2013 is $340.4 million and for 2014 is $367.7 million.

Detailed depreciation schedules are filed at Exhibit C2, Tab 4, Schedule 1.

Table 1
Transmission Depreciation Expense
$ Million

Description	**Historic**			**Bridge**	**Test**	
	2009	**2010**	**2011**	**2012**	**2013**	**2014**
Depreciation On Fixed Assets	243.3	265.4	282.3	316.3	314.9	335.6
Less Capitalized Depreciation	(12.2)	(8.4)	(9.6)	(9.5)	(9.8)	(9.8)
Asset Removal Costs	10.1	13.8	19.7	23.7	35.3	41.9
Losses/(Gains) On Asset Disposition	(2.3)	(4.8)	(0.1)	0.0	0.0	0.0
Total	**239.0**	**265.9**	**292.3**	**330.5**	**340.4**	**367.7**

3.0 AMORTIZATION EXPENSE

Amortization expense addresses the recovery of amounts that the Board has required Hydro One Transmission to defer to a future date. The Board has, in past decisions, approved the deferred balance and prescribed the method and time period over which the balance in each regulatory deferral or variance account may be disposed.

Amortization schedules for test, bridge and historical years are filed at Exhibit C2, Tab 4, Schedule 1. Table 2, below, reproduces this summary.

Table 2

Transmission Amortization Expense ($ Million)

Description	Historic			Bridge	Test	
	2009	2010	2011	2012	2013	2014
Environmental Assets and Other	2.5	6.5	8.9	6.4	8.5	9.3

3.1 Environmental Assets and Other

Hydro One Transmission provides for estimated future expenditures required to remediate past environmental contamination and to comply with current environmental legislation. Since these future expenditures are expected to be recovered in future rates, Hydro One Transmission has recognized the net present value of these estimated future expenditures as a regulatory asset on its Balance Sheet. This regulatory asset balance is amortized on a basis consistent with the pattern of current expenditures expected to be incurred up to the year 2018. Hydro One Distribution received concurrence from the Board for this accounting treatment as part of the RP-2000-0023 Decision. Hydro One Transmission's treatment of these costs in its Application for 2007-2008 Transmission Rates (EB-2006-0501) was consistent with that Decision and was accepted by the Board. The treatment of these costs in this Submission is consistent with both of these prior proceedings.

2011 Depreciation Rate Review

Hydro One Networks Inc.

— Transmission Operations
— Common Operations

foster associates

CONTENTS

EXECUTIVE SUMMARY

INTRODUCTION

This report presents a 2011 review and update of depreciation rates and parameters for Transmission and Common plant owned and operated by Hydro One Networks Inc. (Company or Hydro One Networks). The review requested by Hydro One Networks was conducted under the direction and supervision of Dr. Ronald E. White whose professional qualifications are provided in Section V.

Foster Associates is a public utility economic consulting firm headquartered in Rockville, Maryland offering economic research and consulting services on issues and problems arising from governmental regulation of business. Areas of specialization supported by the firm's Fort Myers office include property life forecasting, technological forecasting, depreciation estimation, and valuation of industrial property.

Foster Associates has undertaken numerous depreciation engagements for both public and privately owned business entities, including detailed statistical life studies, analyses of required net salvage rates, and the selection of depreciation systems that will most nearly achieve the goals of depreciation accounting under the constraints of either government regulation or competitive market pricing. Foster Associates is widely recognized for industry leadership in the development of depreciation systems, life analysis techniques and computer applications for conducting depreciation and valuation studies.

PLANT ACCOUNT STRUCTURE

The hierarchical structure of plant accounting records maintained by Hydro One Networks for major asset categories provides: a) Uniform System of Account (USoA) categories; b) cost of asset components (Profile ID); c) vintage identification (Asset ID); and d) property unit identification within vintages (CAT ID).

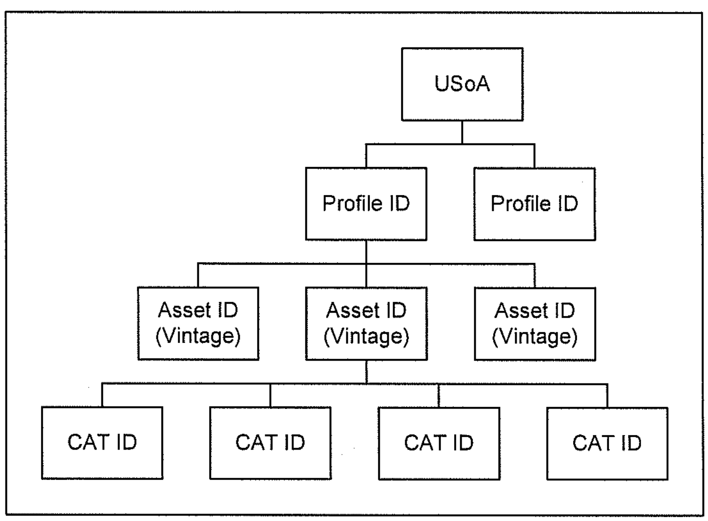


Fig. 1 Account Structure

The lowest level at which the installed cost of a property unit (*e.g.*, a single pole or transformer) can be estimated is by vintage year of placement within a Profile ID. (The cost of a property unit within a vintage can be estimated by dividing the vintage cost by the recorded number of installed property units). A Profile ID is an aggregation of vintage costs sharing common physical or functional attributes. All vintages of power transformers larger than 230 kV, for example, or all vintages of underground cable are classified in unique Profile IDs. It is neither practical nor feasible, however, to estimate service lives and maintain accumulated depreciation reserves for each property unit.

CURRENT DEPRECIATION RATES

Depreciation rates currently used by Hydro One Networks for Transmission operations were developed in a 2006 depreciation review conducted by Foster Associates. In EB–2006–0501 (Decision dated August 16, 2007), the Ontario Energy Board (OEB) accepted the depreciation expense flowing from the depreciation review for purposes of setting rates in the test year.[1]

Life tables were constructed in the 2006 review for each USoA plant account for which retirements were recorded over the period 2000–2005. Life tables constructed over this limited historical period exhibited uniformly high degrees of censoring and indeterminate measurements of service life. These results were directly attributable to insufficient retirement experience over the available band of activity years.

Absent the availability of sufficient retirement activity to conduct statistical service life studies, depreciation rates developed in the 2006 review were derived from a composite of parameters *(i.e.*, projection lives and projection curves) recommended by the former Ontario Hydro internal Depreciation Review Committee (DRC) for asset profiles contained in a USoA category. The dominant projection curve and dollar–weighted average projection life (rounded to the nearest integer) of the constituent asset profiles were selected to describe the forces of retirement acting upon a USoA plant account.[2]

2011 DEPRECIATION RATE REVIEW

The principal findings and recommendations of the Hydro One Networks 2011 Depreciation Rate Review are summarized in the Statements section of this re-

[1]Depreciation rates currently used by Hydro One Networks for Common operations were developed in a 2005 depreciation review conducted by Foster Associates. In RP–2005–0020/EB–2005–0378 (Decision dated April 12, 2006), the Ontario Energy Board (OEB) accepted the depreciation expense flowing from the depreciation review for purposes of setting rates in the test year. In EB–2008–0272, Hydro One Networks submitted a 2008 Technical Update conducted by Foster Associates completed in August 2008 that supported the 2009 and 2010 depreciation and amortization expense. The Board accepted the costs flowing from the Depreciation Study for the purpose of supporting Transmission rates in those years.

port. Statement A provides a comparative summary of current and proposed annual depreciation rates for each rate category. Statement B provides a comparison of current and proposed annual depreciation accruals. Statement C provides a comparison of computed, recorded and redistributed depreciation reserves for each rate category. Statement D provides a comparative summary of current and proposed parameters including projection life, projection curve, average service life, and average remaining life. Statement E displays the computation of proposed USoA projection lives derived from recommended IFRS profile lives. A set of statements is included in this report for both Transmission (BU 210) and Common (BU 300) Operations.

SCOPE OF REVIEW

Principal activities undertaken in the 2011 review included:

- Collection of plant and reserve data;
- Reconciliation of assembled database to Company records;
- Discussions with Hydro One Networks plant accounting and operations personnel;
- Estimation of projection lives and retirement dispersion patterns;
- Analysis and redistribution of recorded depreciation reserves; and
- Development of recommended accrual rates for each rate category.

DEPRECIATION SYSTEM

A depreciation rate is formed by combining the elements of a depreciation system. A depreciation system is composed of a method, a procedure and a technique. A depreciation method (*e.g.*, straight–line) describes the component of the system that determines the acceleration or deceleration of depreciation accruals in relation to either time or use. A depreciation procedure (*e.g.*, vintage group) identifies the level of grouping or sub–grouping of assets within a plant category. The level of grouping specifies the weighting used to obtain composite life statistics

[2]In 1954, by joint agreement of the Engineering, Operations and Comptroller's Division of Ontario Hydro, average service lives were estimated for each of the Company's various plant accounts. The estimated lives were based on engineering/financial judgment and information gathered regarding service lives used by other utilities. Statistical studies based on survivor curves were introduced in 1959 to further improve the estimation of life expectancies. The DRC was established in 1973 to provide formal engineering review for various classes of assets. The role of the committee was expanded in 1975 to include responsibility for recommending service lives and service costs (*i.e.*, provisions for fixed asset removal costs) of all assets. The DRC annually reviewed the service lives of all major facilities and a selection of plant components, with the objective of reviewing all plant components at least once every five years. DRC recommendations were based on factors such as operating experience, retirement history, engineering judgment, expected regular maintenance and system requirements. The DRC review process was discontinued by Hydro One Networks in 1998.

for an account. A depreciation technique (*e.g.*, remaining–life) describes the life statistic used in the system.

With the exception of selected general support asset categories for which amortization accounting has been adopted, Hydro One Networks is currently using a depreciation system composed of the straight–line method, vintage group procedure, remaining–life technique. Amortization accounting is used for general plant categories in which the unit cost of plant items is small in relation to the number of units classified in the account. Plant is retired (*i.e.,* credited to plant and charged to the reserve) as each vintage achieves an age equal to the amortization period.

The matching and expense recognition principles of accounting provide that the cost of an asset (or group of assets) should be allocated to operations over an estimate of the economic life of the asset in proportion to the consumption of service potential. It is the opinion of Foster Associates that the objectives of depreciation accounting are being achieved using the currently approved vintage–group procedure, which distinguishes service lives among vintages, and the remaining–life technique, which provides cost apportionment over the estimated weighted–average remaining life of a rate category. It is also the opinion of Foster Associates that amortization accounting remains appropriate for the intangible and general plant categories summarized in Table 1 below.

Account Number	Description	Amortization Period
A	B	C
1610	Computer Software	10 yrs.
1610S	Computer Software - SAP	10 yrs.
1915	Office Furniture and Equipment	7 yrs.
1920	Computer Hardware - Minor	5 yrs.
1925	Computer Software - Major	10 yrs.
1925S	Computer Software - SAP	10 yrs.
1935	Stores Equipment	8 yrs.
1940	Tools, Shop and Garage Equipment	6 yrs.
1945	Measuring and Testing Equipment	5 yrs.
1960	Miscellaneous Equipment	5 yrs.

Table 1. Amortization Accounts

RECOMMENDED DEPRECIATION RATES

Table 2 provides a summary of the changes in annual rates and accruals resulting from adoption of the parameters and depreciation system recommended for the Company's Transmission Operations.

Function	Accrual Rate			2011 Annualized Accrual		
	Current	Proposed	Difference	Current	Proposed	Difference
A	B	C	D=C-B	E	F	G=F-E
Intangible	10.87%	10.00%	-0.87%	$1,530,877	$1,408,350	($122,527)
Transmission	1.85%	1.75%	-0.10%	191,408,677	180,784,223	(10,624,454)
General Plant	4.30%	4.53%	0.23%	34,478,695	36,278,878	1,800,183
Total	2.04%	1.96%	-0.08%	$227,418,249	$218,471,451	($8,946,798)

Table 2. Transmission Operations

The composite accrual rate recommended for Transmission Operations is 1.96 percent. The current equivalent rate is 2.04 percent. The recommended change in the composite rate is a reduction of 0.08 percentage points.

A continued application of current rates would provide annualized depreciation expense of $227,418,249 compared with an annualized expense of $218,471,451 using the proposed rates. The resulting 2011 expense reduction is $8,946,798.

Table 3 provides a summary of the changes in annual depreciation rates and accruals derived for the Company's Common Operations.

Function	Accrual Rate			2011 Annualized Accrual		
	Current	Proposed	Difference	Current	Proposed	Difference
A	B	C	D=C-B	E	F	G=F-E
Intangible	11.07%	9.53%	-1.54%	$34,827,298	$29,987,881	($4,839,417)
General	11.04%	6.22%	-4.82%	28,531,685	16,084,353	(12,447,332)
Total	11.06%	8.04%	-3.02%	$63,358,983	$46,072,234	($17,286,749)

Table 3. Common Operations

Adjustments developed in the 2011 review produce a composite depreciation rate of 8.04 percent. Depreciation expense is currently accrued at an equivalent composite rate of 11.06 percent. The proposed change in the composite depreciation rate is, therefore, a reduction of 3.02 percentage points.

A continued application of current rates would provide annualized depreciation expense of $63,358,983 compared with an annualized expense of $46,072,234 using the rates developed in the review. The reduction for Common Operations proposed in the 2011 review is $17,286,749.

Study Procedure

Introduction

The purpose of a depreciation study is to analyze the mortality characteristics, net salvage rates and adequacy of the depreciation accrual and recorded depreciation reserve for each rate category. This review provides the foundation and documentation for recommended changes in the depreciation accrual rates used by Hydro One Networks for Transmission and Common Operations. The proposed rates are subject to approval by the Ontario Energy Board.

Scope

The steps involved in conducting the 2011 depreciation review can be grouped into four major tasks:

- Data Collection;
- Life Analysis and Estimation;
- Depreciation Reserve Analysis; and
- Development of Accrual Rates.

The scope of the 2011 review for Hydro One Networks included a consideration of each of these tasks as described below.

Data Collection

The minimum database required to conduct a statistical life study consists of a history of vintage year additions and unaged activity–year retirements, transfers and adjustments. These data must be appropriately adjusted for transfers, sales and other plant activity that would otherwise bias the measured service life of normal retirements. The age distribution of surviving plant for unaged data can be estimated by distributing plant in service at the beginning of the study year to prior vintages in proportion to the theoretical amount surviving from a projection or survivor curve identified in the life study. The statistical methods of life analysis used to examine unaged plant data are known as *semi–actuarial techniques*.

A far more extensive database is required to apply statistical methods of life analysis known as *actuarial techniques*. Plant data used in an actuarial life study most often include age distributions of surviving plant at the beginning of a study year and the vintage year, activity year, and dollar amounts associated with normal retirements, reimbursed retirements, sales, abnormal retirements, transfers, corrections, and extraordinary adjustments over a series of prior activity years. An actuarial database may include age distributions of surviving plant at the beginning of the earliest activity year, rather than at the beginning of the study year. Plant additions, however, must be included in a database containing an opening age distribution to derive aged survivors at the beginning of the study year. All activity year transactions with vintage year identification are coded and stored in a database. These data are processed by a computer program and transaction summary reports are created in a format reconcilable to official plant records. The availability of such detailed information is dependent upon an accounting system that supports aged property records. The Continuing Property Record (CPR) system used by Hydro One Networks provides aged transactions for all plant accounts.

Prior to 1998, plant accounting records were maintained in a legacy Fixed Asset Management System (FAMS) developed by Ontario Hydro. FAMS was replaced with an SAP system in 1998. The SAP system was replaced with a PeopleSoft asset accounting system in 2000. The PeopleSoft system was configured with the asset profiles maintained in the SAP system and uploaded with age distributions of surviving plant at December 31, 1999.[3] The PeopleSoft system was replaced in August 2009 by an updated version of the SAP system.

Plant and reserve data used in conducting the 2011 depreciation review was assembled by Hydro One Networks personnel and coded by Foster Associates. Plant accounting transactions recorded between January 1, 2008 and July 31, 2009 were extracted from the PeopleSoft system, coded and appended to the database used in conducting the 2008 update. Transactions recorded between August 1, 2009 and December 31, 2010 were extracted from the SAP system. An additional dataset of profile plant and reserve balances at December 31, 2010 was assembled and reconciled to aggregate USoA balances. (See Statement E).

Age distributions of surviving plant (*i.e.*, plant surviving by vintage year of placement) at December 31, 2010 were derived by Foster Associates from the vintaged plant transactions and reconciled to age distributions provided by Hydro One Networks. The complexity of the process through which the database was compiled and mapped to USoA plant categories prevented Foster Associates from reconciling the database to any public reports of Hydro One Networks. The integrity of the assembled database, however, was verified by the Company.

LIFE ANALYSIS AND ESTIMATION

Life analysis and life estimation are terms used to describe a two–step procedure for estimating the mortality characteristics of a plant category. The first step (*i.e.*, life analysis) is largely mechanical and primarily concerned with history. Statistical techniques are used in this step to obtain a mathematical description of the forces of retirement acting upon a plant category and an estimate of the *projection life* of the account. The mathematical expressions used to describe these life characteristics are known as *survival functions* or *survivor curves*.

[3]In 2003, Hydro One undertook a two–phase project to a) map asset profiles maintained in PeopleSoft to USoA plant account classifications; and b) align quantities maintained in a Power System Data Base (PSDB) to the re–mapped USoA account classifications. The PSDB provides property unit identification and quantities associated with investments maintained in PeopleSoft. Asset profiles maintained in SAP were not mapped to USoA plant account classifications. This limitation prohibited using pre–2000 plant accounting activity in the 2006 depreciation review.

The second step (*i.e.*, life estimation) is concerned with predicting the expected remaining life of property units still exposed to forces of retirement. It is a process of blending the results of a life analysis with informed judgment (including expectations about the future) to obtain an appropriate projection life and curve descriptive of the parent population from which a plant account is viewed as a random sample. The amount of weight given to a life analysis will depend upon the extent to which past retirement experience is considered descriptive of the future.

The analytical methods used in a life analysis are broadly classified as actuarial and semi–actuarial techniques. Actuarial techniques can be applied to plant accounting records that reveal the age of a plant asset at the time of its retirement from service. Stated differently, each property unit must be identifiable by date of installation and age at retirement. Semi–actuarial techniques can be used to derive service life and dispersion estimates when age identification of retirements is not maintained or readily available.

An actuarial life analysis program designed and developed by Foster Associates was employed in this review. The first step in an actuarial analysis involves a systematic treatment of the available data for the purpose of constructing an observed life table. A complete life table contains the life history of a group of property units installed during the same accounting period and various probability relationships derived from the data. A life table is arranged by age–intervals (usually defined as one year) and shows the number of units (or dollars) entering and leaving each age–interval and probability relationships associated with this activity. A life table minimally shows the age of each survivor and the age of each retirement from a group of units installed in a given accounting year.

A life table can be constructed in any one of at least five methods. The annual–rate or retirement–rate method was used in this review. The mechanics of the annual–rate method require the calculation of a series of ratios obtained by dividing the number of units (or dollars) surviving at the beginning of an age interval into the number of units (or dollars) retired during the same interval. This so–called "retirement ratio" (or set of ratios) is an estimator of the hazard rate or conditional probability of retirement during an age interval. The cumulative proportion surviving is obtained by multiplying the retirement ratio for each age interval by the proportion of the original group surviving at the beginning of that age interval and subtracting this product from the proportion surviving at the beginning of the same interval. The annual–rate method is applied to multiple groups or vintages by combining the retirements and/or survivors of like ages for each vintage included in the analysis.

The second step in an actuarial analysis involves graduating or smoothing the observed life table and fitting the smoothed series to a family of survival functions. The functions used in this study are the Iowa–type curves which are mathematically described in terms of the Pearson frequency curve family. The observed life table was smoothed by a weighted least–squares procedure in which first, second and third degree orthogonal polynomials were fitted to the observed retirement ratios. The resulting function can be expressed as a survivorship function which is numerically integrated to obtain an estimate of the projection life. The smoothed survivorship function is then fitted by a weighted least–squares procedure to the Iowa–curve family to obtain a mathematical description or classification of the dispersion characteristics of the data.

The set of computer programs used in this analysis provides multiple rolling–band, shrinking–band and progressive–band analyses of an account. Observation bands are defined in terms of a "retirement era" that restricts the analysis to the retirement activity of all vintages represented by survivors at the beginning of a selected era. In a rolling–band analysis, a year of retirement experience is added to each successive retirement band and the earliest year from the preceding band is dropped. A shrinking–band analysis begins with the total retirement experience available and the earliest year from the preceding band is dropped for each successive band. A progressive–band analysis adds a year of retirement activity to a previous band without dropping earlier years from the analysis. Rolling, shrinking and progressive band analyses are used to detect the emergence of trends in the behavior of the dispersion and projection life.

Options available in the Foster Associates actuarial life analysis program include: the width and location of both placement and observation bands; the interval of years included in a selected band analysis; the estimator of the hazard rate (actuarial, conditional proportion retired, or maximum likelihood); the elements to include on the diagonal of a weight matrix (exposures, inverse of age, inverse of variance, or unweighted); and the age at which an observed life table is truncated. The program also provides tabular and graphics output as an aid in the analysis.

As noted above, the database for Hydro One Networks contains plant accounting transactions for activity years 2000–2010. While it is theoretically possible to obtain life indications from an actuarial analysis of a single activity year, retirements during the year must be widely distributed over the beginning–of–year surviving vintages of a nearly mature plant account.[3] A similar limitation applies to the database of Hydro One Networks which contains minimal retirement activity during the available activity years. Retirements must be sufficiently distributed across vintages within these years in order to obtain meaningful service life indications from a statistical analysis.

Life tables were constructed for each USoA plant account for which retirements were recorded over the period 2000–2010. Without exception, life tables

[3]Plant maturity is achieved when the age distribution of surviving plant resembles a complete survivor curve descriptive of the forces of retirement acting upon the plant category.

constructed over this limited historical period exhibited uniformly high degrees of censoring and indeterminate measurements of service life. These results were directly attributable to insufficient retirement experience over the available band of activity years.

As was noted in the 2006 review, limitations in conducting life analyses were also imposed by vintage years "banded" by the Company in 1992 and again in 1998 when age distributions from a Fixed Asset Management System (FAMS) were uploaded to SAP. All pre–1950 vintages were assigned a vintage year of 1950. Plant installed between 1951 and 1955 was assigned a vintage year of 1955. Similarly, plant installed during the intervals 1956–1960, 1961–1965 and 1966–1970 were assigned vintage years 1960, 1965 and 1970, respectively. Although discontinued in 1971, the banding of pre–1970 vintages will continue to produce unreliable life indications until most of the earlier vintages have been retired from service.

Pending the availability of sufficient retirement activity to conduct service life studies, it is the opinion of Foster Associates that a composite of the parameters estimated for the asset profiles contained in a USoA account provides the best available estimate of service life statistics for the current depreciation review.

Class/Category Service Lives

Confronted with an inability to obtain meaningful service life indications from statistical analyses, attention was shifted in the 2011 review to the profile lives derived in preparing for the implementation of International Financial Reporting Standards (IFRS) in 2008. The motivation for estimating USoA service lives from asset profile service lives (now termed class/category in SAP) has been strengthened by a requirement that Canadian rate–regulated entities transition to IFRS no later than January 1, 2013. This requirement carries with it a set of accounting rules (IAS 16) that changes depreciation accounting for long–lived assets. For example, IAS 16 requires that property, plant and equipment assets be componentized into items of property; that depreciation be calculated at the item level; and the carrying amount (*i.e.* cost less accumulated depreciation) be "derecognized" on disposal or when no further economic benefits are expected from its use.[4]

The *Recognition Principle* of IAS 16 prescribes that the cost of an *item* of property, plant and equipment shall be recognized as an asset if, and only if: a) it is probable that future economic benefits associated with the item will flow to the

[4]Group depreciation accounting neither reports nor recognizes gains or losses resulting from the retirement of property units before or after the expiration of an estimated service life. Under–depreciation of property units retired earlier than predicted is offset by over–depreciation of property units remaining in service beyond the estimated average service life of a group. This treatment is consistent with the regulatory principle that opportunities should be preserved for the recovery of capital devoted to public service.

entity; and b) the cost of the item can be measured reliably. Importantly, IAS 16 does not prescribe the unit of measure for recognition, *i.e.*, what constitutes an item of property plant and equipment. Individually insignificant items may be aggregated and the Recognition Principle applied to the aggregated value.

Based on these principles and recognizing that a USoA category may include a greater diversity of plant items than contemplated under an item procedure, a Profile ID (or class/category) is considered to be an appropriate and practical aggregation of plant items under IAS 16. This level of aggregation means that service lives will be estimated by Profile ID and gains or losses will be computed for plant items retired prior to achieving an age equal to an applied service life.

The requirement to estimate item service lives at the class/category level for IFRS reporting strongly suggests that USoA lives used for US GAAP reporting should mirror Profile ID lives estimated for assets aggregated into USoA categories. This functional relationship was preserved in the 2011 review by adopting composited Profile ID lives estimated for each class/category as a surrogate for a USoA projection life (P–Life). Profile lives used in the computation of proposed depreciation rates were estimated by an internal project team assigned to review and update estimates previously developed by the DRC. Members of the review team included engineers, accountants and other subject matter experts having managerial responsibilities for the assets under review. Meetings of the project team were facilitated by Foster Associates.

Unlike the item accounting procedure prescribed under IAS 16, group depreciations rates developed under US GAAP are formulated with recognition of retirement dispersion. This requirement was satisfied in the 2011 review by selecting an Iowa survivor curve considered descriptive of the forces of retirement acting upon each USoA category. Recommended survivor curves were selected by Foster Associates based on experience and an understanding of the parametric form of the associated probability density functions. Proposed projection lives derived from harmonic weighting of the profile lives recommended by the project team are summarized in Statement E.

Depreciation Reserve Analysis

The purpose of a depreciation reserve analysis is to compare the current level of recorded reserves with the level required to achieve the goals or objectives of depreciation accounting if the amount and timing of future retirements and net salvage are realized as predicted. The difference between a required (or theoretical) depreciation reserve and a recorded reserve provides a measurement of the expected excess or shortfall that will remain in the depreciation reserve if corrective action is not taken to eliminate the reserve imbalance.

Unlike a recorded reserve which represents the net amount of depreciation expense charged to previous periods of operations, a theoretical reserve is a measure of the implied reserve requirement at the beginning of a study year if the timing of future retirements and net salvage is in exact conformance with a survivor curve chosen to predict the probable life of property still exposed to the forces of retirement. Stated differently, a theoretical depreciation reserve is the difference between the recorded cost of plant presently in service and the sum of depreciation expense and net salvage that will be charged in the future if retirements are distributed over time according to a specified retirement frequency distribution.

The survivor curve used in the calculation of a theoretical depreciation reserve is intended to describe forces of retirement that will be operative in the future. However, retirements caused by forces such as accidents, physical deterioration and changing technology seldom, if ever, remain stable over time. It is unlikely, therefore, that a probability or retirement frequency distribution can be identified that will accurately describe the age of plant retirements over the complete life cycle of a vintage. It is for this reason that depreciation rates should be reviewed periodically and adjusted for observed or expected changes in the parameters chosen to describe the underlying forces of mortality.

Although reserve records are commonly maintained by various account classifications, the sum of all reserves is the most important measure of the status of a company's depreciation practices. If statistical life studies have not been conducted or retirement dispersion has been ignored in setting depreciation rates, it is likely that some accounts will be over–depreciated and other accounts will be under–depreciated relative to a calculated theoretical reserve. Differences between a theoretical reserve and a recorded reserve also will arise as a normal occurrence when service lives, dispersion patterns and net salvage estimates are adjusted in the course of depreciation reviews. It is appropriate, therefore, and consistent with group depreciation theory to periodically redistribute or rebalance recorded reserves among the various primary accounts based upon the most recent estimates of retirement dispersion and net salvage rates.

It is the opinion of Foster Associates that a redistribution of recorded reserves is appropriate for Hydro One Networks at this time. Offsetting reserve imbalances (attributable to both the passage of time and parameter adjustments recommended in the current review) should be realigned among primary accounts to reduce offsetting imbalances and increase depreciation rate stability.

With the exception of amortizable categories in which theoretical or computed reserves replace recorded reserves, all remaining reserves were redistributed by multiplying the calculated reserve for each USoA primary account by the ratio of the sum of recorded reserves to the sum of calculated reserves. The sum of redistributed reserves is, therefore, equal to the sum of recorded depreciation reserves before the redistribution.

Statement C provides a comparison of recorded, computed and rebalanced reserves for Transmission Operations (BU 210) on December 31, 2010. The recorded reserve was $4,114,915,718 or 36.9 percent of the depreciable plant investment. The corresponding computed reserve is $3,597,646,814 or 32.3 percent of the depreciable plant investment. A proportionate amount of the measured reserve imbalance of $517,268,904 will be amortized over the composite weighted–average remaining life of each rate category using the remaining life depreciation rates proposed in this review.

Statement C also provides a comparison of recorded, computed and rebalanced reserves for Common Operations (BU 300) on December 31, 2010. The recorded reserve was $245,380,112, or 42.8 percent of the depreciable plant investment. The corresponding computed reserve is $204,850,535 or 35.8 percent of the depreciable plant investment. A proportionate amount of the measured reserve imbalance of $40,529,577 will be amortized over the composite weighted–average remaining life of each rate category using the remaining life depreciation rates proposed in this review.

DEVELOPMENT OF ACCRUAL RATES

The goal or objective of depreciation accounting is cost allocation over the economic life of an asset in proportion to the consumption of service potential. Ideally, the cost of an asset—which represents the cost of obtaining a bundle of service units—should be allocated to future periods of operation in proportion to the amount of service potential expended during an accounting interval. The service potential of an asset is the present value of future net revenue (*i.e.*, revenue less expenses exclusive of depreciation and other non–cash expenses) or cash inflows attributable to the use of that asset alone.

Cost allocation in proportion to the consumption of service potential is often approximated by the use of depreciation methods employing time rather than net revenue as the apportionment base. Examples of time–based methods include sinking–fund, straight–line, declining balance, and sum–of–the–years' digits. The advantage of using a time–based method is that it does not require an estimate of the remaining amount of service capacity an asset will provide or the amount of capacity actually consumed during an accounting interval. Using a time–based allocation method, however, does not change the goal of depreciation accounting. If it is reasonable to predict that the net revenue pattern of an asset will either decrease or increase over time, then an accelerated or decelerated time–based method should be used to approximate the rate at which service potential is actually consumed.

The time period over which the cost of an asset will be allocated to operations is determined by the combination of a procedure and a technique. A depreciation procedure describes the level of grouping or sub–grouping of assets within a plant category. Broad group, vintage group, equal–life group, and item (or unit) are a few of the more widely used procedures. A depreciation technique describes the life statistic used in a depreciation system. Whole life and remaining life (or expectancy) are the most common techniques.

Depreciation rates recommended in the 2011 review were developed using a system composed of the straight–line method, vintage group procedure, remaining–life technique. It is the opinion of Foster Associates that this system will remain appropriate for Hydro One Networks, provided depreciation studies are conducted periodically and parameters are routinely adjusted to reflect changing operating conditions.

It is also the opinion of Foster Associates that amortization accounting currently approved for selected intangible and general support asset accounts is consistent with the goals and objectives of depreciation accounting derived from the matching and expense recognition principles of accounting. Amortization accounting for these rate categories relieves Hydro One Networks of the burden to maintain detailed plant records for numerous plant items in which the unit cost is small in relation to the cost of tracking the disposition of the assets.

STATEMENTS

INTRODUCTION

This section provides a comparative summary of depreciation rates, annual depreciation accruals, recorded and computed depreciation reserves, and current and proposed service life statistics recommended for Hydro One Networks Inc. Transmission and Common Operations. The content of these statements is briefly described below.

- Statement A provides a comparative summary of current and proposed annual depreciation rates using the vintage group procedure, remaining–life technique.
- Statement B provides a comparison of current and proposed annualized 2011 depreciation accruals derived from the depreciation rates contained in Statement A.
- Statement C provides a comparison of recorded, computed and redistributed reserves for each rate category at December 31, 2010.
- Statement D provides a comparative summary of current and proposed parameters and statistics including projection life, projection curve, average service life, and average remaining life.
- Statement E displays the computation of proposed USoA projection lives derived from recommended IFRS profile lives.

Current depreciation accruals shown on Statements B are the product of the plant investment (Column B) and current depreciation rates shown on Statement A. These are the effective rates used by Hydro One Networks for the mix of investments recorded on December 31, 2010. Similarly, proposed depreciation accruals shown on Statements B are the product of the plant investment and proposed depreciation rates shown on Statement A. Proposed remaining life accrual rates (Statement A) are given by:

$$\text{Accrual Rate} = \frac{1.0 - \text{Reserve Ratio}}{\text{Remaining Life}}.$$

Statements A through E

HYDRO ONE NETWORKS INC. - Transmission Operations (BU 210) Statement A

Comparison of Current and Proposed Accrual Rates
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

	Current			Proposed			
Account Description	Rem. Life	Net Salvage	Accrual Rate	Rem. Life	Net Salvage	Reserve Ratio	Accrual Rate
A	B	C	D	E	F	G	H
INTANGIBLE PLANT							
1610 Computer Software	3.76		10.87%	← 10 Year Amortization →			10.00%
Total Intangible Plant			10.87%	2.36		76.38%	10.00%
TRANSMISSION PLANT							
1705D Land - Depreciable	74.03		1.27%	77.60		25.63%	0.96%
1706 Land Rights	54.68		1.27%	75.03		28.57%	0.95%
1708 Buildings and Fixtures	32.93		1.88%	30.04		46.04%	1.80%
1715 Station Equipment	27.41		2.19%	30.62		37.52%	2.04%
1720 Towers and Fixtures	70.56		1.09%	55.55		29.86%	1.26%
1730 Overhead Conductors and Devices	37.85		1.64%	43.67		37.70%	1.43%
1735 Underground Conduit	27.84		2.03%	47.95		36.26%	1.33%
1740 Underground Conductors and Devices	40.06		2.19%	55.98		7.67%	1.65%
1745 Roads and Trails	75.63		0.99%	33.79		45.19%	1.62%
Total Transmission Plant			1.85%	36.45		36.09%	1.75%
GENERAL PLANT							
Depreciable							
1905D Land - Depreciable				73.47		30.34%	0.95%
1908 Buildings and Fixtures	30.68		1.99%	28.20		43.07%	2.02%
1910 Leasehold Improvements	1.00		-17.81%	1.00		108.03%	-8.03%
1922 Computer Hardware - Major	5.00		10.42%	3.61		76.36%	6.55%
1955 Communication Equipment	12.36		4.48%	12.78		42.71%	4.48%
1980 System Supervisory Equipment	9.76		4.67%	9.01		52.69%	5.25%
Total Depreciable			4.22%	11.82		46.94%	4.46%
Amortizable							
1925 Computer Software - Major	3.76		10.87%	← 10 Year Amortization →			10.00%
Total Amortizable			10.87%	7.01		29.86%	10.00%
Total General Plant			4.30%	11.71		46.74%	4.53%
TOTAL TRANSMISSION OPERATIONS			2.04%	32.00		36.91%	1.96%

HYDRO ONE NETWORKS INC. - Transmission Operations (BU 210) Statement B

Comparison of Current and Proposed Accruals
Current: VG Procedure / RL Technique
Proposed: VG Procedure / RL Technique

Account Description	12/31/10 Plant Investment	2011 Annualized Accrual Current	Proposed	Difference
A	B	C	D	E=D-C
INTANGIBLE PLANT				
1610 Computer Software	$ 14,083,503	$ 1,530,877	$ 1,408,350	$ (122,527)
Total Intangible Plant	$ 14,083,503	$ 1,530,877	$ 1,408,350	$ (122,527)
TRANSMISSION PLANT				
1705D Land - Depreciable	$ 971,630	$ 12,340	$ 9,328	$ (3,012)
1706 Land Rights	225,253,672	2,860,722	2,139,910	(720,812)
1708 Buildings and Fixtures	364,262,198	6,848,129	6,556,720	(291,409)
1715 Station Equipment	5,852,569,462	128,171,271	119,392,417	(8,778,854)
1720 Towers and Fixtures	1,914,825,775	20,871,601	24,126,805	3,255,204
1730 Overhead Conductors and Devices	1,421,375,170	23,310,553	20,325,665	(2,984,888)
1735 Underground Conduit	267,321,213	5,426,621	3,555,372	(1,871,249)
1740 Underground Conductors and Devices	88,744,071	1,943,495	1,464,277	(479,218)
1745 Roads and Trails	198,378,327	1,963,945	3,213,729	1,249,784
Total Transmission Plant	$ 10,333,701,518	$ 191,408,677	$ 180,784,223	$ (10,624,454)
GENERAL PLANT				
Depreciable				
1905D Land - Depreciable	$ 3,229,785	$ -	$ 30,683	$ 30,683
1908 Buildings and Fixtures	105,270,832	2,094,890	2,126,471	31,581
1910 Leasehold Improvements	100,228	(17,851)	(8,048)	9,803
1922 Computer Hardware - Major	2,318,969	241,637	151,892	(89,745)
1955 Communication Equipment	354,291,451	15,872,257	15,872,257	
1980 System Supervisory Equipment	327,277,589	15,283,863	17,182,073	1,898,210
Total Depreciable	$ 792,488,854	$ 33,474,796	$ 35,355,328	$ 1,880,532
Amortizable				
1925 Computer Software - Major	$ 9,235,499	$ 1,003,899	$ 923,550	$ (80,349)
Total Amortizable	$ 9,235,499	$ 1,003,899	$ 923,550	$ (80,349)
Total General Plant	$ 801,724,353	$ 34,478,695	$ 36,278,878	$ 1,800,183
TOTAL TRANSMISSION OPERATIONS	$ 11,149,509,374	$ 227,418,249	$ 218,471,451	$ (8,946,798)

HYDRO ONE NETWORKS INC. - Transmission Operations (BU 210)

Depreciation Reserve Summary
Vintage Group Procedure
December 31, 2010

Statement C

Account Description	Plant Investment	Recorded Reserve Amount	Recorded Reserve Ratio	Computed Reserve Amount	Computed Reserve Ratio	Redistributed Reserve Amount	Redistributed Reserve Ratio
A	B	C	D=C/B	E	F=E/B	G	H=G/B
INTANGIBLE PLANT							
1610 Computer Software	$ 14,083,503	$ 15,024,094	106.68%	$ 10,756,603	76.38%	$ 10,756,603	76.38%
Total Intangible Plant	$ 14,083,503	$ 15,024,094	106.68%	$ 10,756,603	76.38%	$ 10,756,603	76.38%
TRANSMISSION PLANT							
1705D Land - Depreciable	$ 971,630	$ 310,406	31.95%	$ 217,645	22.40%	$ 249,056	25.63%
1706 Land Rights	225,253,672	81,655,027	36.25%	56,228,939	24.96%	64,344,008	28.57%
1708 Buildings and Fixtures	364,262,198	151,625,752	41.63%	146,545,596	40.23%	167,695,337	46.04%
1715 Station Equipment	5,852,569,462	2,242,800,808	38.32%	1,919,170,056	32.79%	2,196,148,358	37.52%
1720 Towers and Fixtures	1,914,825,775	465,387,302	24.30%	499,597,305	26.09%	571,700,146	29.86%
1730 Overhead Conductors and Devices	1,421,375,170	573,494,362	40.35%	468,335,808	32.95%	535,926,929	37.70%
1735 Underground Conduit	267,321,213	138,076,476	51.65%	84,701,863	31.69%	96,926,198	36.26%
1740 Underground Conductors and Devices	88,744,071	8,156,296	9.19%	5,945,853	6.70%	6,803,970	7.67%
1745 Roads and Trails	198,378,327	52,335,156	26.38%	78,335,281	39.49%	89,640,779	45.19%
Total Transmission Plant	$ 10,333,701,518	$ 3,713,841,585	35.94%	$ 3,259,078,346	31.54%	$ 3,729,434,781	36.09%
GENERAL PLANT							
Depreciable							
1905D Land - Depreciable	$ 3,229,785	$ 951,626	29.46%	$ 856,387	26.52%	$ 979,983	30.34%
1908 Buildings and Fixtures	105,270,832	48,355,939	45.93%	39,622,060	37.64%	45,340,392	43.07%
1910 Leasehold Improvements	100,228	28,826	28.76%	94,622	94.41%	108,278	108.03%
1922 Computer Hardware - Major	2,318,969	1,965,003	84.74%	1,547,404	66.73%	1,770,729	76.36%
1955 Communication Equipment	354,291,451	163,823,800	46.24%	132,229,423	37.32%	151,313,027	42.71%
1980 System Supervisory Equipment	327,277,589	167,024,606	51.03%	150,704,471	46.05%	172,454,429	52.69%
Total Depreciable	$ 792,488,854	$ 382,149,800	48.22%	$ 325,054,368	41.02%	$ 371,966,838	46.94%
Amortizable							
1925 Computer Software - Major	$ 9,235,499	$ 3,900,239	42.23%	$ 2,757,496	29.86%	$ 2,757,496	29.86%
Total Amortizable	$ 9,235,499	$ 3,900,239	42.23%	$ 2,757,496	29.86%	$ 2,757,496	29.86%
Total General Plant	$ 801,724,353	$ 386,050,039	48.15%	$ 327,811,864	40.89%	$ 374,724,334	46.74%
TOTAL TRANSMISSION OPERATIONS	$ 11,149,509,374	$ 4,114,915,718	36.91%	$ 3,597,646,814	32.27%	$ 4,114,915,718	36.91%

HYDRO ONE NETWORKS INC. - Transmission Operations (BU 210)

Statement D

Current and Proposed Parameters
Vintage Group Procedure

	Current Parameters						Proposed Parameters					
Account Description	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
INTANGIBLE PLANT												
1610 Computer Software	7.00	SQ	7.00	3.76			10.00	SQ	10.00	2.36		
Total Intangible Plant									10.00	2.36		
TRANSMISSION PLANT												
1705D Land - Depreciable	78.00	SQ	78.00	74.03			100.00	S6	100.00	77.60		
1706 Land Rights	75.00	SQ	75.00	54.68			100.00	S6	99.99	75.03		
1708 Buildings and Fixtures	50.00	SQ	50.00	32.93			50.00	S6	50.26	30.04		
1715 Station Equipment	42.00	S2	42.59	27.41			45.00	S2	45.56	30.62		
1720 Towers and Fixtures	89.00	S2	89.06	70.56			75.00	S2	75.16	55.55		
1730 Overhead Conductors and Devices	57.00	S3	57.20	37.85			65.00	S3	65.13	43.67		
1735 Underground Conduit	45.00	S2	45.53	27.84			70.00	S2	70.19	47.95		
1740 Underground Conductors and Devices	45.00	S2	45.00	40.06			60.00	S2	60.00	55.98		
1745 Roads and Trails	97.00	S2	97.08	75.63			55.00	S2	55.84	33.79		
Total Transmission Plant									53.24	36.45		
GENERAL PLANT												
Depreciable												
1905D Land - Depreciable							100.00	S6	99.98	73.47		
1908 Buildings and Fixtures	44.00	S4	44.12	30.68			45.00	S4	45.22	28.20		
1910 Leasehold Improvements	10.00	SQ	12.88	1.00			10.00	S6	17.88	1.00		
1922 Computer Hardware - Major	8.00	SQ	8.00	5.00			10.00	S6	10.85	3.61		
1955 Communication Equipment	19.00	SQ	19.00	12.36			20.00	L2	20.39	12.78		
1980 System Supervisory Equipment	17.00	SQ	17.00	9.76			15.00	L2	16.70	9.01		
Total Depreciable									20.04	11.82		
Amortizable												
1925 Computer Software - Major	7.00	SQ	7.00	3.76			10.00	SQ	10.00	7.01		
Total Amortizable									10.00	7.01		
Total General Plant									19.81	11.71		
TOTAL TRANSMISSION OPERATIONS									47.24	32.00		

HYDRO ONE NETWORKS INC.
Asset Category Summary - Transmission (BU 210)
December 31, 2010
Harmonic Weighting

Statement E

Description	Current P-Life		Proposed P-Life		Plant		Depreciation Reserve	
	USoA	IFRS	USoA	IFRS	USoA	IFRS	USoA	IFRS
A	B	C	D	E	F	G	H	I
1706 Land Rights								
RIGHTS & EASMNTS <LANDSCAPING>		100		100		3,158,528		150,452
EASMNTS & RIGHTS, PURCH& ACQUI		100		100		222,095,144		82,069,700
Total 1706	75-SQ	100	100-S6	100	225,253,672	225,253,672	81,655,027	82,220,153
1708 Buildings and Fixtures								
STN BUILDINGS COMPONENTS		50		50		316,653,949		150,262,350
CRANES&HOISTS IN BLDGS		50		50		1,238,837		121,583
BLDG W U/G CABLE		50		50		20,819,205		2,433,664
SERV STRUCTURES		50		50		25,550,207		8,548,561
Total 1708	50-SQ	50	50-S6	50	364,262,198	364,262,198	151,625,752	161,366,158
1715 Station Equipment								
RIGHTS & EASMNTS <LANDSCAPING>		20		50		312		28
LANDSCAPING		50		50		17,149,807		1,288,294
SITE IMPRV-EXCL FENCE,RD,EASMT		50		50		308,189,278		115,134,575
COST EQUIP FOUNDATIONS, EXCAV		65		65		421,220,113		170,452,561
STEEL/PIPE STRUC FOR SWITCH EQ		65		65		320,283,055		136,453,442
FENCES,GATES, BLDG		30		30		82,441,585		19,448,780
ROT ELEC EQP(NO WIND'G)		65		65		15,387,219		10,451,261
ROT ELEC EQP(WIND'GS)		65		65		301,966		65,971
CAPACITORS		40		30		119,105,800		34,622,638
REGULATORS INCL INSTAL COST		40		40		4,024,017		2,665,053
MOBILE SUB-STATIONS		30		30		126,618		11,256
MISC STN EQP-TRSF/VOLT TRSF		40		40		242,949,327		63,621,203
SERV SWG-AC/DC-LIGHT TRSF		60		55		143,139,242		39,370,319
CONTROL CABLE&CONDUIT		60		60		271,468,976		108,953,668
GROUNDING SYSTEMS		60		60		141,039,506		49,615,073
METERING UNITS		15		15		45,820,777		31,345,619
SWITCHBOARDS		60		60		520,673,181		215,872,642
SUP CNTRL- PRIM H/WARE & SYS		20		20		248,561,871		56,290,185
SUP CNTRL - PRIM APPL S/WARE		20		20		10,834,344		1,374,349
SERVICE SYSTEMS		50		50		152,682,388		73,087,378
TRANSF<=50KV OR <5MVA		60		40		34,293,868		13,111,179
TRNSF<=115KV OR >5MVA		60		50		244,052,352		110,366,550
TRANSF <=230KV		60		50		317,027,488		129,883,907
TRANSF >230KV		60		50		203,253,874		69,863,505
TRANSF INSTAL COST		60		50		167,076,423		49,186,036
SWITCHING >=34.5KV		45		45		188,480,485		87,132,109
SWITCHING >=115KV		45		45		114,303,047		57,777,332
SWITCHING >=230KV		45		45		94,725,862		26,907,618
SF6 SWITCHGEAR		45		45		365,796,578		132,700,619
RECLOSERS		45		45		597,215		101,413
MISC SWITCHING		45		45		185,333,976		96,154,911
BUS (RIGID & STRAIN)		45		45		209,574,266		82,564,300
CABLE		45		45		66,062,438		26,369,547
CCT BREAKERS >=230KV		45		45		238,357,298		99,030,985
CCT BREAKERS >=115KV		45		45		74,357,994		29,140,484
CCT BREAKERS <115KV		45		45		118,307,100		44,979,168
CCT BREAKERS INSTALL		45		45		110,424,579		27,879,057
ENCLD SWGR (ALL COMPNT)		45		45		55,145,236		15,516,430
Total 1715	42-S2	51	45-S2	49	5,852,569,462	5,852,569,462	2,242,800,808	2,228,789,446
1720 Towers and Fixtures								
STEEL TWR, SUP&FTNG		80		90		1,416,505,078		398,744,729
POLES INCL XARM,GUY,ANCHR		60		50		448,149,187		67,790,855
STEEL POLES		60		90		50,171,509		2,706,725
Total 1720	89-S2	75	75-S2	81	1,914,825,775	1,914,825,775	465,387,302	469,242,310
1730 Overhead Conductors and Devices								
INSULATORS		60		60		244,637,054		74,618,464
GROUNDING SYSTEM		50		50		129,323,510		49,717,238
OPT GRND WIRE		25		25		22,572,757		4,779,005
OVERHD CONDUCTOR ALL		75		75		967,113,315		423,474,936
SWITCHES&DEVCE		60		60		18,163,499		5,125,229
RETENSION COSTS		60		60		39,565,035		20,499,504
Total 1730	57-S3	69	65-S3	69	1,421,375,170	1,421,375,170	573,494,362	578,214,376
1735 Underground Conduit								
INSULATORS		70		70		140,166		5,125
UGRD CONDUIT		70		70		267,181,047		135,035,674
Total 1735	45-S2	70	70-S2	70	267,321,213	267,321,213	138,076,476	135,040,799

HYDRO ONE NETWORKS INC. Statement E

Asset Category Summary - Transmission (BU 210)
December 31, 2010
Harmonic Weighting

Description	Current P-Life		Proposed P-Life		Plant		Depreciation Reserve	
	USoA	IFRS	USoA	IFRS	USoA	IFRS	USoA	IFRS
A	B	C	D	E	F	G	H	I
1740 Underground Conductors and Devices								
60 UGRD CONDUCTOR		60		60		88,744,071		8,673,498
Total 1740	45-S2	60	60-S2	60	88,744,071	88,744,071	8,156,296	8,673,498
1745 Roads and Trails								
PERM RDS & SURFC AREA		25		25		25,896,362		1,074,903
RAILWAY TRACK		30		30		7,826,508		5,945,492
CLRNG & OVERBLDNG		70		70		159,044,307		45,083,977
ROADS & TRAILS		70		70		5,611,150		229,332
Total 1745	97-S2	63	55-S2	63	198,378,327	198,378,327	52,335,156	52,333,704
1908 Buildings and Fixtures								
GENRL-ADM&SERV-LANDSCAPING		50		50		23,920		3,910
GENRL-ADM&SERV_BLD FRAME&MTL		50		50		32,733,977		10,781,657
GENRL -ADM & SERV-RDS&SURFACES		25		25		3,903,065		653,557
GENRL-ADM & SERV-BLD FRAME		50		50		4,539,190		1,238,527
GENRL -ADM & SERV-FENCE,GATE		30		30		4,303,864		635,792
GENRL- ADM & SERV-DISTN SYS		50		50		4,869,641		859,850
GENRL -ADM & SERV_AUX EQ BLD		50		50		10,492,760		1,742,578
GENRL -COMM-LANDSCAPING		50		50		62,867		8,907
GENRL -COMM - BUILDINGS		25		25		12,731,989		9,025,098
GENRL-COMM-STR&FOOTINGS-POLES		50		50		31,609,558		15,330,893
Total 1908	44-S4	45	45-S4	45	105,270,832	105,270,832	48,355,939	40,280,769
1910 Leasehold Improvements								
GENRL -ADM & SERV-BLDGS-LEASED		10		10		100,228		100,228
Total 1910	10-SQ	10	10-S6	10	100,228	100,228	28,826	100,228
1922 Computer Hardware - Major								
GENRL-ADM &SERV-LAN ELECT DEV		10		10		658,944		632,011
GENRL-ADM & SERV- LAN CABLE		10		10		672,183		645,249
GENRL -ADM & SERV-LAN FIB OPT		10		10		987,842		573,549
Total 1922	8-SQ	10	10-S6	10	2,318,969	2,318,969	1,965,003	1,850,809
1955 Communication Equipment								
GENRL-ADM & SERV -TELCM WIRE		7		7		2,594,458		2,594,458
GENRL -ADM & SERV -TELCM EQUIP		7		7		628,577		506,255
GENRL -ADM & SERV- TELCOM SW		7		7		717,041		458,938
GENRL-COMM - RADIO EQUIPMENT		10		15		36,877,787		15,034,440
GENRL -COMM -ADMIN TELCOM EQUP		7		7		10,977,723		10,229,788
GENRL-COMM-OPTICAL WIRE 78MTH		7		7		2,208,152		78,742
GENRL -COMM -OPTICAL WIRE		25		25		85,433,984		23,135,595
GENRL -COMM - OPT WIRE TERMTN		7		20		133,615,145		80,586,819
GENRL-COMM - OPGW W FIB CABLE		25		25		68,066,238		25,451,382
GENRL -COMM -POWER SUPPLY EQUP		7		15		13,172,347		6,684,303
Total 1955	19-SQ	15	20-L2	21	354,291,451	354,291,451	163,823,800	164,760,721
1980 System Supervisory Equipment								
GENRL-COMM-DACS SYS SW 78MTH		25		25		16,112,865		418,499
GENRL -COMM-PWR LINE EQUIP		15		15		144,641,762		96,222,921
GENRL -COMM-SYS CNTRL COMP EQ		7		7		66,385,999		28,394,322
GENRL-COMM-DACS APPL S/WARE		20		20		2,486,384		1,439,714
GENRL -COMM - DACS SYS S/WARE		20		20		69,610,226		24,427,475
GENRL-COMM-POLE,COMM CAB,BTHS		25		25		28,024,143		23,199,476
GENRL -COMM - OPT WIRE TERMTN		20		20		16,209		1,263
Total 1980	17-SQ	16	15-L2	16	327,277,589	327,277,589	167,024,606	174,103,670
1705D Land - Depreciable								
LAND PURCH & ACQUI (OLD CAP)		100		100		971,630		306,039
Total 1705D	78-SQ	100	100-S6	100	971,630	971,630	310,406	306,039
TOTAL INVESTMENT					11,122,960,587	11,122,960,588	4,095,039,760	4,097,282,679
Reconciling Accounts								
1705N Land - Non Depreciable					273,833,563	273,833,563	2,882	
1905N Land - Non Depreciable					1,703,989	1,703,989	969	
1610 Computer Softwar (Amortizable)	7-SQ	7	10-SQ	10	14,083,503	14,083,503	15,024,094	12,753,177
1925 Computer Softwar - Major (Amortizable)	7-SQ	7	10-SQ	10	9,235,499	9,235,499	3,900,239	3,932,086
1905D Land - Depreciable			100-S6		3,229,785	3,229,785	951,626	951,626
Total Reconciling Accounts					302,086,339	302,086,339	19,879,810	17,636,889
TOTAL BU 210					11,425,046,926	11,425,046,927	4,114,919,569	4,114,919,568

Statements A through D

HYDRO ONE NETWORKS INC. - Common Operations (BU 300) Statement A

Comparison of Current and Proposed Accrual Rates

Current: VG Procedure / RL Technique

Proposed: VG Procedure / RL Technique

	Current			Proposed			
Account Description	Rem. Life	Net Salvage	Accrual Rate	Rem. Life	Net Salvage	Reserve Ratio	Accrual Rate
A	B	C	D	E	F	G	H
INTANGIBLE PLANT							
1610 Computer Software	2.83		11.07%	← 10 Year Amortization →			7.18%
1610S Computer Software - SAP	2.83		11.07%	← 10 Year Amortization →			10.00%
Total Intangible Plant			11.07%	7.36		27.91%	9.53%
GENERAL PLANT							
Depreciable							
1908 Buildings and Fixtures	26.40		1.98%	33.76		66.38%	1.00%
1910 Leasehold Improvements	5.35		8.67%	1.98		166.06%	-33.36%
1922 Computer Equipment - Hardware	1.13		0.89%	1.55		200.66%	-64.94%
1955 Communication Equipment	4.93		13.37%	2.39		171.74%	-30.02%
1980 System Supervisory Equipment	3.60		10.17%	1.00		186.35%	-86.35%
Total Depreciable			4.00%	16.39		91.20%	-8.96%
Amortizable							
1915 Office Furniture and Equipment	← 7 Year Amortization →		13.79%	← 7 Year Amortization →			13.79%
1920 Computer Hardware - Minor	← 5 Year Amortization →		17.54%	← 5 Year Amortization →			17.54%
1925 Computer Software - Major	2.83		11.07%	← 10 Year Amortization →			9.22%
1925S Computer Software - SAP	2.83		11.07%	← 10 Year Amortization →			10.00%
1935 Stores Equipment	← 8 Year Amortization →		11.48%	← 8 Year Amortization →			11.48%
1940 Tools, Shop and Garage Equipment	← 6 Year Amortization →		16.03%	← 6 Year Amortization →			16.03%
1945 Measurement and Testing Equipment	← 5 Year Amortization →		17.42%	← 5 Year Amortization →			17.42%
1960 Miscellaneous Equipment	← 5 Year Amortization →		17.05%	← 5 Year Amortization →			17.05%
Total Amortizable			14.62%	3.67		45.63%	13.94%
Total General Plant			11.04%	4.94		60.98%	6.22%
TOTAL COMMON OPERATIONS			11.06%	6.18		42.82%	8.04%

HYDRO ONE NETWORKS INC. - Common Operations (BU 300) Statement B

Comparison of Current and Proposed Accruals

Current: VG Procedure / RL Technique

Proposed: VG Procedure / RL Technique

Account Description	12/31/10 Plant Investment	2011 Annualized Accrual		
		Current	Proposed	Difference
A	B	C	D	E=D-C
INTANGIBLE PLANT				
1610 Computer Software	$ 52,293,388	$ 5,788,878	$ 3,756,246	$ (2,032,632)
1610S Computer Software - SAP	262,316,349	29,038,420	26,231,635	(2,806,785)
Total Intangible Plant	$ 314,609,737	$ 34,827,298	$ 29,987,881	$ (4,839,417)
GENERAL PLANT				
Depreciable				
1908 Buildings and Fixtures	$ 66,756,851	$ 1,321,786	$ 667,569	$ (654,217)
1910 Leasehold Improvements	7,752,744	672,163	(2,586,315)	(3,258,478)
1922 Computer Equipment - Hardware	618,019	5,500	(401,342)	(406,842)
1955 Communication Equipment	8,554,760	1,143,771	(2,568,139)	(3,711,910)
1980 System Supervisory Equipment	3,366,771	342,401	(2,907,207)	(3,249,608)
Total Depreciable	$ 87,049,145	$ 3,485,621	$ (7,795,434)	$ (11,281,055)
Amortizable				
1915 Office Furniture and Equipment	$ 7,075,718	$ 976,039	$ 976,039	$ -
1920 Computer Hardware - Minor	71,034,456	12,461,736	12,461,736	
1925 Computer Software - Major	60,868,798	6,738,176	5,615,082	(1,123,094)
1925S Computer Software - SAP	4,035,732	446,756	403,573	(43,183)
1935 Stores Equipment	6,882,224	790,182	790,182	
1940 Tools, Shop and Garage Equipment	5,422,008	869,010	869,010	
1945 Measurement and Testing Equipment	8,743,064	1,523,315	1,523,315	
1960 Miscellaneous Equipment	7,278,243	1,240,850	1,240,850	
Total Amortizable	$ 171,340,243	$ 25,046,064	$ 23,879,787	$ (1,166,277)
Total General Plant	$ 258,389,388	$ 28,531,685	$ 16,084,353	$ (12,447,332)
TOTAL COMMON OPERATIONS	$ 572,999,125	$ 63,358,983	$ 46,072,234	$ (17,286,749)

HYDRO ONE NETWORKS INC. - Common Operations (BU 300)

Statement C

Depreciation Reserve Summary
Vintage Group Procedure
December 31, 2010

Account Description	Plant Investment	Recorded Reserve Amount	Recorded Reserve Ratio	Computed Reserve Amount	Computed Reserve Ratio	Redistributed Reserve Amount	Redistributed Reserve Ratio
A	B	C	D=C/B	E	F=E/B	G	H=G/B
INTANGIBLE PLANT							
1610 Computer Software	$ 52,293,388	$ 37,963,197	72.60%	$ 37,850,712	72.38%	$ 37,850,712	72.38%
1610S Computer Software - SAP	262,316,349	57,170,897	21.79%	49,962,424	19.05%	49,962,424	19.05%
Total Intangible Plant	$ 314,609,737	$ 95,134,094	30.24%	$ 87,813,136	27.91%	$ 87,813,136	27.91%
GENERAL PLANT							
Depreciable							
1908 Buildings and Fixtures	$ 66,756,851	$ 26,719,865	40.03%	$ 21,691,638	32.49%	$ 44,313,251	66.38%
1910 Leasehold Improvements	7,752,744	6,824,259	88.02%	6,301,852	81.29%	12,873,881	166.06%
1922 Computer Equipment - Hardware	618,019	798,315	129.17%	607,034	98.22%	1,240,092	200.66%
1955 Communication Equipment	8,554,760	5,943,016	69.47%	7,191,702	84.07%	14,691,729	171.74%
1980 System Supervisory Equipment	3,366,771	4,431,372	131.62%	3,071,181	91.22%	6,274,031	186.35%
Total Depreciable	$ 87,049,145	$ 44,716,826	51.37%	$ 38,863,407	44.65%	$ 79,392,984	91.20%
Amortizable							
1915 Office Furniture and Equipment	$ 7,075,718	$ 3,017,849	42.65%	$ 3,023,095	42.72%	$ 3,023,095	42.72%
1920 Computer Hardware - Minor	71,034,456	44,815,041	63.09%	37,569,521	52.89%	37,569,521	52.89%
1925 Computer Software - Major	60,868,798	42,105,553	69.17%	21,982,547	36.11%	21,982,547	36.11%
1925S Computer Software - SAP	4,035,732	223,378	5.54%	201,786	5.00%	201,786	5.00%
1935 Stores Equipment	6,882,224	4,424,749	64.29%	4,424,586	64.29%	4,424,586	64.29%
1940 Tools, Shop and Garage Equipment	5,422,008	2,926,326	53.97%	2,890,219	53.31%	2,890,219	53.31%
1945 Measurement and Testing Equipment	8,743,064	4,162,726	47.61%	4,221,921	48.29%	4,221,921	48.29%
1960 Miscellaneous Equipment	7,278,243	3,853,569	52.95%	3,860,317	53.04%	3,860,317	53.04%
Total Amortizable	$ 171,340,243	$ 105,529,192	61.59%	$ 78,173,992	45.63%	$ 78,173,992	45.63%
Total General Plant	$ 258,389,388	$ 150,246,017	58.15%	$ 117,037,399	45.29%	$ 157,566,976	60.98%
TOTAL COMMON OPERATIONS	$ 572,999,125	$ 245,380,112	42.82%	$ 204,850,535	35.75%	$ 245,380,112	42.82%

HYDRO ONE NETWORKS INC. - Common Operations (BU 300)
Current and Proposed Parameters
Vintage Group Procedure

Statement D

	Current Parameters						Proposed Parameters					
Account Description	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
INTANGIBLE PLANT												
1610 Computer Software	7.00	SQ	7.00	2.83			10.00	SQ	10.00	3.63		
1610S Computer Software - SAP	7.00	SQ	7.00	2.83			10.00	SQ	10.00	8.10		
Total Intangible Plant									10.00	7.36		
GENERAL PLANT												
Depreciable												
1908 Buildings and Fixtures	45.00	S4	45.05	26.40			50.00	S4	50.01	33.76		
1910 Leasehold Improvements	10.00	SQ	10.00	5.35			10.00	S6	10.58	1.98		
1922 Computer Equipment - Hardware	8.00	SQ	8.00	1.13			10.00	S6	87.20	1.55		
1955 Communication Equipment	7.00	SQ	7.00	4.93			7.00	S6	15.00	2.39		
1980 System Supervisory Equipment	8.00	SQ	8.00	3.60			7.00	S6	11.39	1.00		
Total Depreciable									29.60	16.39		
Amortizable												
1915 Office Furniture and Equipment	7.00	SQ	7.00	2.61			7.00	SQ	7.00	4.01		
1920 Computer Hardware - Minor	5.00	SQ	5.00	1.83			5.00	SQ	5.00	2.44		
1925 Computer Software - Major	7.00	SQ	7.00	2.83			10.00	SQ	10.00	6.92		
1925S Computer Software - SAP	7.00	SQ	7.00	2.83			10.00	SQ	10.00	9.50		
1935 Stores Equipment	8.00	SQ	8.00	3.70			8.00	SQ	8.00	2.86		
1940 Tools, Shop and Garage Equipment	6.00	SQ	6.00	3.26			6.00	SQ	6.00	2.80		
1945 Measurement and Testing Equipment	5.00	SQ	5.00	2.38			5.00	SQ	5.00	2.64		
1960 Miscellaneous Equipment	5.00	SQ	5.00	2.81			5.00	SQ	5.00	2.55		
Total Amortizable									6.42	3.67		
Total General Plant									8.72	4.94		
TOTAL COMMON OPERATIONS									9.38	6.18		

HYDRO ONE NETWORKS INC. Statement E

Asset Category Summary - Common (BU 300)
December 31, 2010
Harmonic Weighting

Description	P-Life USoA	P-Life IFRS	Proposed P-Life USoA	Proposed P-Life IFRS	Plant USoA	Plant IFRS	Depreciation Reserve USoA	Depreciation Reserve IFRS
A	B	C	D	E	F	G	H	I
1908 Buildings and Fixtures								
GENRL-ADM&SERV_BLD FRAME&MTL		50		50		41,070,808		24,166,467
GENRL -ADM & SERV-RDS&SURFACES		25		25		592,733		93,501
GENRL-ADM & SERV-BLD FRAME		50		50		8,598,484		1,791,018
GENRL -ADM & SERV-FENCE,GATE		30		30		751,521		31,220
GENRL- ADM & SERV-DISTN SYS		50		50		518,576		292,975
GENRL -ADM & SERV_AUX EQ BLD		50		50		8,458,559		2,390,088
Total 1908	45-S4	50	50-S4	50	66,756,851	59,990,680	26,719,865	28,765,269
1910 Leasehold Improvements								
GENRL -ADM & SERV-BLDGS-LEASED		10		10		7,752,744		7,621,801
Total 1910	10-S6	10	10-S6	10	7,752,744	7,752,744	6,824,259	7,621,801
1922 Computer Hardware - Major								
GENRL-ADM &SERV-LAN ELECT DEV		10		10		112,663		112,663
GENRL-ADM & SERV- LAN CABLE		10		10		505,356		497,114
Total 1922	8-S6	10	10-S6	10	618,019	618,019	798,315	609,777
1955 Communication Equipment								
GENRL-ADM & SERV -TELCM WIRE		7		7		2,272,521		2,272,521
GENRL -ADM & SERV -TELCM EQUIP		7		7		1,837,766		760,533
GENRL-COMM - RADIO EQUIPMENT		10		10		11,318		11,318
GENRL -COMM -ADMIN TELCOM EQUP		7		7		4,433,155		4,147,330
Total 1955	7-S6	7	7-S6	7	8,554,760	8,554,760	5,943,016	7,191,702
1980 System Supervisory Equipment								
GENRL -COMM-PWR LINE EQUIP		15		15		389,017		66,838
GENRL -COMM-SYS CNTRL COMP EQ		7		7		2,977,754		2,977,754
Total 1980	8-S6	8	7-S6	7	3,366,771	3,366,771	4,431,372	3,044,592
TOTAL INVESTMENT					87,049,145	80,282,974	44,716,826	47,233,140
Reconciling Accounts								
1610 - Computer Software (Amortizable)	7-SQ	7	10-SQ	10	52,293,388	52,293,388	37,963,197	116,782,979
1610S - Computer Software - SAP (Amortizable)	7-SQ	7	10-SQ	10	262,316,349	262,316,349	57,170,897	
1820 - Genrl - Comm - Buildings						6,766,171		86,746
1905 - Land and Site Impbovements					6,559,892	6,559,892	24,726	
1915 - Office Furniture and Equipment	7-SQ	7	7-SQ	7	7,075,718	7,075,718	3,017,849	3,017,849
1925 - Computer Software - Major (Amortizable)	7-S6	7	10-SQ	10	60,868,798	60,868,798	42,105,553	35,870,426
1925S - Computer Software - SAP (Amortizable)	7-SQ	7	10-SQ	10	4,035,732	4,035,732	223,378	
1920 - Computer Hardware - Minor	5-SQ	5	5-SQ	5	71,034,456	71,034,456	44,815,041	37,519,455
1930 - Transportation Equipment					280,886,890	280,886,890	168,283,553	154,472,412
1935 - Stores Equipment	8-SQ	8	8-SQ	8	6,882,224	6,882,224	4,424,749	4,424,749
1940 - Tools, Shop and Garage Equipment	6-SQ	6	6-SQ	6	5,422,008	5,422,008	2,926,326	2,926,326
1945 - Measurement and Testing Equipment	5-SQ	5	5-SQ	5	8,743,064	8,743,064	4,162,726	4,100,275
1950 - Power Operated Equipment					181,285,290	181,285,290	95,222,459	98,636,378
1960 - Miscellaneous Equipment	5-SQ	5	5-SQ	5	7,278,243	7,278,243	3,853,569	3,783,189
1990 - Other Tangible Property					19,557,639	19,557,639	7,977,084	8,034,022
Total Reconciling Accounts					974,239,691	981,005,861	472,171,107	469,654,806
TOTAL BU 220					1,061,288,836	1,061,288,835	516,887,933	516,887,946

ANALYSIS

INTRODUCTION

This section provides an explanation of the supporting schedules developed in the Hydro One Networks transmission and common depreciation review to estimate appropriate projection curves, projection lives and statistics for each rate category. The form and content of the schedules developed for an account depend upon the method of analysis adopted for the category.

This section also includes an example of the supporting schedules developed for Account 1715 – Station Equipment. Documentation for all other plant accounts is contained in the review work papers. The supporting schedules developed in the Hydro One Networks review include:

Schedule A – Generation Arrangement;

Schedule B – Age Distribution;

Schedule C – Plant History;

Schedule D – Actuarial Life Analysis; and

Schedule E – Graphics Analysis.

The format and content of these schedules are briefly described below.

SCHEDULE A – GENERATION ARRANGEMENT

The purpose of this schedule is to obtain appropriate weighted–average life statistics for a rate category. The weighted–average remaining–life is the sum of Column H divided by the sum of Column I. The weighted average life is the sum of Column C divided by the sum of Column I. The following table provides a description of each column in the generation arrangement.

Column	Title	Description
A	Vintage	Vintage or placement year of surviving plant.
B	Age	Age of surviving plant at beginning of study year.
C	Surviving Plant	Actual dollar amount of surviving plant.
D	Average Life	Estimated average life of each vintage. This statistic is the sum of the realized life and the unrealized life, which is the product of the remaining life (Column E) and the theoretical proportion surviving.
E	Remaining Life	Estimated remaining life of each vintage.
F	Net Plant Ratio	Theoretical net plant ratio of each vintage.
G	Allocation Factor	A pivotal ratio which determines the amortization period of the difference between the recorded and computed reserve.
H	Computed Net Plant	Plant in service less theoretical reserve for each vintage.
I	Accrual	Ratio of computed net plant (Column H) and remaining life (Column E).

Table 4. Generation Arrangement

SCHEDULE B – AGE DISTRIBUTION

This schedule provides the age distribution and realized life of surviving plant shown in Column C of the Generation Arrangement (Schedule A). The format of the schedule depends upon the availability of either aged or unaged data. Derived additions for vintage years older than the earliest activity year in an account for unaged data are obtained from the age distribution of surviving plant at the beginning of the earliest activity year. The amount surviving from these vintages is shown in Column D. The realized life (Column G) is derived from the dollar years of service provided by a vintage over the period of years the vintage has been in service. Plant additions for vintages older than the earliest activity year in an account are represented by the opening balances shown in Column D.

The computed proportion surviving (Column D) for unaged is derived from a computed mortality analysis. The average service life displayed in the title block is the life statistic derived for the most recent activity year, given the derived age distribution at the start of the year and the specified retirement dispersion. The realized life (Column F) is obtained by finding the slope of an SC retirement dispersion, which connects the computed survivors of a vintage (Column E) to the recorded vintage addition (Column B). The realized life is the area bounded by the SC dispersion, the computed proportion surviving and the age of the vintage.

SCHEDULE C – PLANT HISTORY

An Unadjusted Plant History schedule provides a summary of recorded plant data extracted from the continuing property records maintained by the Company. Activity year total amounts shown on this schedule for aged data are obtained from a historical arrangement of the data base in which all plant accounting transactions are identified by vintage and activity year. Activity year totals for unaged data are obtained from a transaction file without vintage identification. Information displayed in the unadjusted plant history is consistent with regulated investments reported internally by the Company.

An Adjusted Plant History schedule provides a summary of recorded plant data extracted from the continuing property records maintained by the Company with sales, transfers, and adjustments appropriately aged for depreciation study purposes. Activity year total amounts shown on this schedule for aged data are obtained from a historical arrangement of the data base in which all plant accounting transactions are identified by vintage and activity year. Ageing of adjusting transactions is achieved using transaction codes that identify an adjusting year associated with the dollar amount of a transaction. Adjusting transactions processed in the adjusted plant history are not aged in the Company's records or in the unadjusted plant history.

Schedule D – Actuarial Life Analysis

These schedules provide a summary of the dispersion and life indications obtained from an actuarial life analysis for a specified placement band. The observation band (Column A) is specified to produce a rolling–band, shrinking–band, or progressive–band analysis depending upon the movement of the end points of the band. The degree of censoring (or point of truncation) of the observed life table is shown in Column B for each observation band. The estimated average service life, best fitting Iowa dispersion, and a statistical measure of the goodness of fit are shown for each degree polynomial (First, Second, and Third) fitted to the estimated hazard rates. Options available in the analysis include the width and location of both the placement and observation bands; the interval of years included in a selected rolling, shrinking, or progressive band analysis; the estimator of the hazard rate (actuarial, conditional proportion retired, or maximum likelihood); the elements to include on the diagonal of a weight matrix (exposures, inverse of age, inverse of variance, or unweighted); and the age at which an observed life table is truncated.

Estimated projection lives (Columns C, F, and I) are flagged with an asterisk if negative hazard rates are indicated by the fitted polynomial. All negative hazard rates are set equal to zero in the calculation of the graduated survivor curve. The Conformance Index (Columns E, H, and K) is the square root of the mean sum–of–squared differences between the graduated survivor curve and the best fitting Iowa curve. A Conformance Index of zero would indicate a perfect fit.

Schedule E – Graphics Analysis

This schedule provides a graphics plot of a) the observed proportion surviving for a selected placement and observation band; b) the statistically best fitting Iowa dispersion and derived average service life; and c) the projection curve and projection life selected to describe future forces of mortality.

The graphics analysis also provides a plot of the observed hazard rates and graduated hazard function for a selected placement and observation band. The estimator of the hazard rates and weighting used in fitting orthogonal polynomials to the observed data are displayed in the title block of the displayed graph.

HYDRO ONE NETWORKS INC. - TRANSMISSION

Transmission Plant
Account: 1715 Station Equipment

Dispersion: 45 - S2
Procedure: Vintage Group

Generation Arrangement

	December 31, 2010				Net			
Vintage	Age	Surviving Plant	Avg. Life	Rem. Life	Plant Ratio	Alloc. Factor	Computed Net Plant	Accrual
A	B	C	D	E	F	G	H=C*F*G	I=H/E
2010	0.5	453,124,327	45.00	44.50	0.9889	1.0000	448,089,599	10,069,430
2009	1.5	432,197,225	45.00	43.50	0.9667	1.0000	417,791,283	9,604,401
2008	2.5	186,787,540	45.00	42.50	0.9445	1.0000	176,411,886	4,150,846
2007	3.5	233,952,916	45.00	41.50	0.9222	1.0000	215,762,066	5,198,993
2006	4.5	150,304,759	45.00	40.50	0.9001	1.0000	135,283,274	3,340,124
2005	5.5	224,375,578	45.00	39.51	0.8779	1.0000	196,982,130	4,986,168
2004	6.5	188,012,028	45.00	38.51	0.8558	1.0000	160,904,185	4,178,037
2003	7.5	106,006,378	45.00	37.52	0.8338	1.0000	88,391,140	2,355,720
2002	8.5	125,005,940	45.00	36.54	0.8119	1.0000	101,494,299	2,777,859
2001	9.5	77,873,665	44.98	35.56	0.7906	1.0000	61,563,986	1,731,323
2000	10.5	146,410,141	44.99	34.59	0.7688	1.0000	112,555,992	3,254,098
1999	11.5	103,066,200	44.97	33.63	0.7477	1.0000	77,065,317	2,291,644
1998	12.5	100,435,671	45.00	32.68	0.7263	1.0000	72,945,207	2,232,135
1997	13.5	88,890,111	45.00	31.74	0.7054	1.0000	62,705,897	1,975,442
1996	14.5	96,624,522	44.98	30.82	0.6852	1.0000	66,208,543	2,148,216
1995	15.5	70,355,797	44.92	29.91	0.6660	1.0000	46,854,638	1,566,366
1994	16.5	269,289,117	44.99	29.02	0.6451	1.0000	173,706,596	5,985,430
1993	17.5	98,899,279	44.97	28.15	0.6259	1.0000	61,904,658	2,199,303
1992	18.5	373,346,511	45.05	27.29	0.6058	1.0000	226,172,216	8,287,267
1991	19.5	265,707,324	44.97	26.45	0.5882	1.0000	156,296,279	5,908,070
1990	20.5	386,601,186	45.11	25.64	0.5683	1.0000	219,699,374	8,569,534
1989	21.5	127,856,531	45.15	24.84	0.5502	1.0000	70,345,862	2,832,054
1988	22.5	105,362,640	45.15	24.06	0.5329	1.0000	56,147,955	2,333,555
1987	23.5	154,610,413	45.26	23.30	0.5149	1.0000	79,607,929	3,416,054
1986	24.5	47,969,678	45.28	22.57	0.4984	1.0000	23,906,202	1,059,334
1985	25.5	49,026,531	45.44	21.85	0.4809	1.0000	23,576,215	1,078,975
1984	26.5	46,309,930	45.53	21.15	0.4647	1.0000	21,517,912	1,017,216
1983	27.5	80,795,850	45.61	20.48	0.4490	1.0000	36,277,017	1,771,599
1982	28.5	50,311,582	45.70	19.82	0.4337	1.0000	21,820,755	1,100,920
1981	29.5	53,905,647	45.83	19.18	0.4186	1.0000	22,564,504	1,176,279
1980	30.5	158,851,259	46.00	18.56	0.4036	1.0000	64,109,709	3,453,405
1979	31.5	132,515,429	46.20	17.96	0.3889	1.0000	51,529,675	2,868,549
1978	32.5	55,505,074	46.17	17.38	0.3765	1.0000	20,897,721	1,202,271
1977	33.5	58,406,597	46.53	16.82	0.3614	1.0000	21,110,552	1,255,281
1976	34.5	44,998,605	46.65	16.27	0.3488	1.0000	15,694,619	964,658
1975	35.5	44,026,536	46.95	15.74	0.3352	1.0000	14,758,401	937,740

HYDRO ONE NETWORKS INC. - TRANSMISSION

Transmission Plant
Account: 1715 Station Equipment

Dispersion: 45 - S2
Procedure: Vintage Group

Generation Arrangement

Vintage	Age	December 31, 2010 Surviving Plant	Avg. Life	Rem. Life	Net Plant Ratio	Alloc. Factor	Computed Net Plant	Accrual
A	B	C	D	E	F	G	H=C*F*G	I=H/E
1974	36.5	47,228,158	47.22	15.22	0.3224	1.0000	15,226,596	1,000,238
1973	37.5	31,043,906	47.31	14.72	0.3112	1.0000	9,660,362	656,134
1972	38.5	33,835,924	47.82	14.24	0.2978	1.0000	10,075,167	707,624
1971	39.5	45,171,930	48.10	13.77	0.2862	1.0000	12,930,321	939,211
1970	40.5	53,979,447	48.52	13.31	0.2743	1.0000	14,807,473	1,112,510
1969	41.5	34,794,436	48.87	12.87	0.2633	1.0000	9,160,219	711,963
1968	42.5	18,853,189	49.25	12.44	0.2525	1.0000	4,760,527	382,832
1967	43.5	9,833,948	49.37	12.02	0.2434	1.0000	2,393,656	199,205
1966	44.5	12,962,370	50.04	11.61	0.2320	1.0000	3,007,179	259,046
1965	45.5	37,462,515	50.59	11.21	0.2217	1.0000	8,303,649	740,561
1963	47.5	223,846	52.04	10.45	0.2009	1.0000	44,962	4,302
1962	48.5	839,768	52.62	10.09	0.1917	1.0000	160,995	15,960
1960	50.5	49,271,134	53.40	9.38	0.1757	1.0000	8,659,187	922,670
1958	52.5	812	55.19	8.72	0.1580	1.0000	128	15
1956	54.5	52,288	56.62	8.08	0.1428	1.0000	7,464	924
1955	55.5	50,661,562	56.77	7.78	0.1370	1.0000	6,938,230	892,359
1953	57.5	33,140	58.93	7.18	0.1219	1.0000	4,039	562
1950	60.5	38,602,571	60.81	6.34	0.1043	1.0000	4,025,578	634,853
Total	16.4	$5,852,569,462	45.56	30.62	0.6720	1.0000	$3,932,819,322	$128,459,261

HYDRO ONE NETWORKS INC. - TRANSMISSION

Transmission Plant

Account: 1715 Station Equipment

Age Distribution

				Experience to 12/31/2010		
Vintage	Age as of 12/31/2010	Derived Additions	2000 Opening Balance	Amount Surviving	Proportion Surviving	Realized Life
A	B	C	D	E	F=E/(C+D)	G
2010	0.5	453,124,327		453,124,327	1.0000	0.5000
2009	1.5	432,255,844		432,197,225	0.9999	1.4999
2008	2.5	186,830,375		186,787,540	0.9998	2.4999
2007	3.5	234,101,328		233,952,916	0.9994	3.4997
2006	4.5	150,345,159		150,304,759	0.9997	4.4997
2005	5.5	224,517,398		224,375,578	0.9994	5.4995
2004	6.5	188,036,470		188,012,028	0.9999	6.4997
2003	7.5	106,083,030		106,006,378	0.9993	7.4988
2002	8.5	125,023,811		125,005,940	0.9999	8.4993
2001	9.5	78,218,149		77,873,665	0.9956	9.4765
2000	10.5	147,020,922		146,410,141	0.9958	10.4877
1999	11.5		103,897,547	103,066,200	0.9920	11.4669
1998	12.5		100,929,769	100,435,671	0.9951	12.4831
1997	13.5		89,455,447	88,890,111	0.9937	13.4793
1996	14.5		97,766,456	96,624,522	0.9883	14.4524
1995	15.5		72,405,331	70,355,797	0.9717	15.3789
1994	16.5		273,963,792	269,289,117	0.9829	16.4388
1993	17.5		101,139,555	98,899,279	0.9778	17.3981
1992	18.5		377,079,466	373,346,511	0.9901	18.4572
1991	19.5		273,336,278	265,707,324	0.9721	19.3517
1990	20.5		391,833,611	386,601,186	0.9866	20.4567
1989	21.5		129,628,082	127,856,531	0.9863	21.4474
1988	22.5		106,909,201	105,362,640	0.9855	22.4021
1987	23.5		156,298,897	154,610,413	0.9892	23.4515
1986	24.5		49,093,937	47,969,678	0.9771	24.4049
1985	25.5		49,307,586	49,026,531	0.9943	25.4794
1984	26.5		46,520,300	46,309,930	0.9955	26.4745
1983	27.5		81,454,666	80,795,850	0.9919	27.4482
1982	28.5		51,401,058	50,311,582	0.9788	28.4209
1981	29.5		54,652,911	53,905,647	0.9863	29.4123
1980	30.5		161,678,570	158,851,259	0.9825	30.4306
1979	31.5		133,753,162	132,515,429	0.9907	31.4577
1978	32.5		59,290,571	55,505,074	0.9362	32.2394
1977	33.5		60,204,825	58,406,597	0.9701	33.3925
1976	34.5		47,048,258	44,998,605	0.9564	34.2815
1975	35.5		45,409,215	44,026,536	0.9696	35.3330
1974	36.5		48,745,724	47,228,158	0.9689	36.3271

HYDRO ONE NETWORKS INC. - TRANSMISSION

Transmission Plant

Account: 1715 Station Equipment

Age Distribution

				Experience to 12/31/2010		
Vintage	Age as of 12/31/2010	Derived Additions	2000 Opening Balance	Amount Surviving	Proportion Surviving	Realized Life
A	B	C	D	E	F=E/(C+D)	G
1973	37.5		33,261,462	31,043,906	0.9333	37.1271
1972	38.5		35,373,369	33,835,924	0.9565	38.3097
1971	39.5		48,414,603	45,171,930	0.9330	39.2444
1970	40.5		55,814,011	53,979,447	0.9671	40.2995
1969	41.5		36,516,820	34,794,436	0.9528	41.2550
1968	42.5		19,907,049	18,853,189	0.9471	42.2095
1967	43.5		11,147,472	9,833,948	0.8822	42.8817
1966	44.5		14,074,170	12,962,370	0.9210	44.0810
1965	45.5		40,499,738	37,462,515	0.9250	45.1287
1963	47.5		223,846	223,846	1.0000	47.5000
1962	48.5		839,768	839,768	1.0000	48.5000
1960	50.5		53,585,685	49,271,134	0.9195	50.0494
1958	52.5		812	812	1.0000	52.5000
1956	54.5		52,288	52,288	1.0000	54.5000
1955	55.5		56,311,991	50,661,562	0.8997	54.9069
1953	57.5		33,140	33,140	1.0000	57.5000
1950	60.5		42,833,055	38,602,571	0.9012	59.8906
Total	16.4	$2,325,556,811	$3,612,093,494	$5,852,569,462	0.9857	

HYDRO ONE NETWORKS INC. - TRANSMISSION

Transmission Plant

Account: 1715 Station Equipment

Unadjusted Plant History

Year	Beginning Balance	Additions	Retirements	Sales, Transfers & Adjustments	Ending Balance
A	B	C	D	E	F=B+C-D+E
2000	3,614,235,886	118,191,442	2,555,440	22,361,942	3,752,233,829
2001	3,752,233,829	73,238,191	3,982,516	22,536,997	3,844,026,500
2002	3,844,026,500	65,399,789	7,443,045	5,958,147	3,907,941,391
2003	3,907,941,391	106,559,019	2,517,339	(1,040,636)	4,010,942,435
2004	4,010,942,435	118,022,342	14,404,097	51,979,207	4,166,539,886
2005	4,166,539,886	82,292,407	8,645,819	143,492,615	4,383,679,090
2006	4,383,679,090	119,427,072	5,174,411	8,491,077	4,506,422,828
2007	4,506,422,828	230,356,875	17,682,749	42,446,113	4,761,543,066
2008	4,761,543,066	31,412,693	7,078,185	127,829,983	4,913,707,557
2009	4,913,707,557	357,324,800	7,864,743	40,182,801	5,303,350,416
2010	5,303,350,416	557,449,189	8,126,169	(103,974)	5,852,569,462

HYDRO ONE NETWORKS INC. - TRANSMISSION

Transmission Plant

Account: 1715 Station Equipment

Adjusted Plant History

Year	Beginning Balance	Additions	Retirements	Sales, Transfers & Adjustments	Ending Balance
A	B	C	D	E	F=B+C-D+E
2000	3,637,797,428	145,565,996	2,555,440		3,780,807,984
2001	3,780,807,984	76,479,157	3,982,516	(156,246)	3,853,148,379
2002	3,853,148,379	124,910,834	7,443,045	(9,139,843)	3,961,476,325
2003	3,961,476,325	105,111,335	2,503,831	298,348	4,064,382,177
2004	4,064,382,177	187,684,587	14,023,935	(484,553)	4,237,558,277
2005	4,237,558,277	220,882,770	8,645,819	52,925	4,449,848,153
2006	4,449,848,153	149,722,321	5,174,411	(14,173,201)	4,580,222,862
2007	4,580,222,862	234,121,108	17,682,749	6,578,822	4,803,240,042
2008	4,803,240,042	186,830,375	7,078,185	(418,411)	4,982,573,820
2009	4,982,573,820	432,201,033	7,864,743	1,411,494	5,408,321,605
2010	5,408,321,605	452,478,000	8,126,169	(103,974)	5,852,569,462

HYDRO ONE NETWORKS INC. - TRANSMISSION

Transmission Plant

Account: 1715 Station Equipment

T-Cut: None
Placement Band: 1950-2010
Hazard Function: Proportion Retired
Weighting: Exposures

Rolling Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper- sion	Conf. Index	Average Life	Disper- sion	Conf. Index	Average Life	Disper- sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
2000-2004	78.4	99.3	L1.5 *	1.15	75.8	S1.5	0.45	71.8	S2	0.48
2001-2005	74.3	93.0	L1.5 *	1.42	72.5	S1.5	0.50	69.3	S2	0.55
2002-2006	74.7	95.7	L1.5 *	1.51	74.5	S1.5	0.61	70.7	S2	0.58
2003-2007	74.0	95.0	L1.5 *	1.10	77.3	S1.5	0.51	72.8	R2.5	0.50
2004-2008	74.7	98.3	L1 *	0.97	82.7	S1	0.54	74.9	R2.5	0.54
2005-2009	78.5	106.9	L1 *	0.72	92.9	S0.5	0.48	81.9	R2 *	0.44
2006-2010	80.1	112.5	L1 *	0.79	104.7	S0.5	0.68	105.8	L1.5	0.68

HYDRO ONE NETWORKS INC. - TRANSMISSION

Transmission Plant

Account: 1715 Station Equipment

T-Cut: None
Placement Band: 1950-2010
Hazard Function: Proportion Retired
Weighting: Exposures

Shrinking Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
2000-2010	77.1	104.8	L1.5*	1.16	85.9	S1	0.59	88.2	S1	0.57
2002-2010	76.4	102.4	L1.5*	1.14	84.7	S1	0.61	87.1	S1	0.60
2004-2010	77.0	103.9	L1*	0.92	88.3	S1	0.55	86.6	S1	0.56
2006-2010	80.1	112.5	L1*	0.79	104.7	S0.5	0.68	105.8	L1.5	0.68
2008-2010	85.8	120.5	S0*	0.64	110.1	S0.5	0.68	153.7	R0.5*	0.67
2010-2010	87.1	112.9	L1.5*	1.41	95.4	S1*	1.70	168.0	R1*	1.84

HYDRO ONE NETWORKS INC. - TRANSMISSION

Transmission Plant

Account: 1715 Station Equipment

T-Cut: None

Placement Band: 1950-2010

Hazard Function: Proportion Retired

Weighting: Exposures

Progressing Band Life Analysis

		First Degree			Second Degree			Third Degree		
Observation Band	Censoring	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
2000-2001	92.9	131.1	S0 *	0.69	101.6	S1.5	0.85	171.3	R1.5 *	0.95
2000-2003	85.0	108.6	L1.5 *	0.67	80.2	S2	0.65	78.6	S2	0.62
2000-2005	75.8	96.6	L1.5 *	1.34	74.1	S1.5	0.45	70.2	S2	0.48
2000-2007	74.5	97.6	L1.5 *	1.29	77.9	S1.5	0.50	74.1	S2	0.55
2000-2009	76.7	103.6	L1.5 *	1.14	84.4	S1	0.51	79.8	S1.5	0.51
2000-2010	77.1	104.8	L1.5 *	1.16	85.9	S1	0.59	88.2	S1	0.57

HYDRO ONE NETWORKS INC. - TRANSMISSION

Transmission Plant

Account: 1715 Station Equipment

T-Cut: None

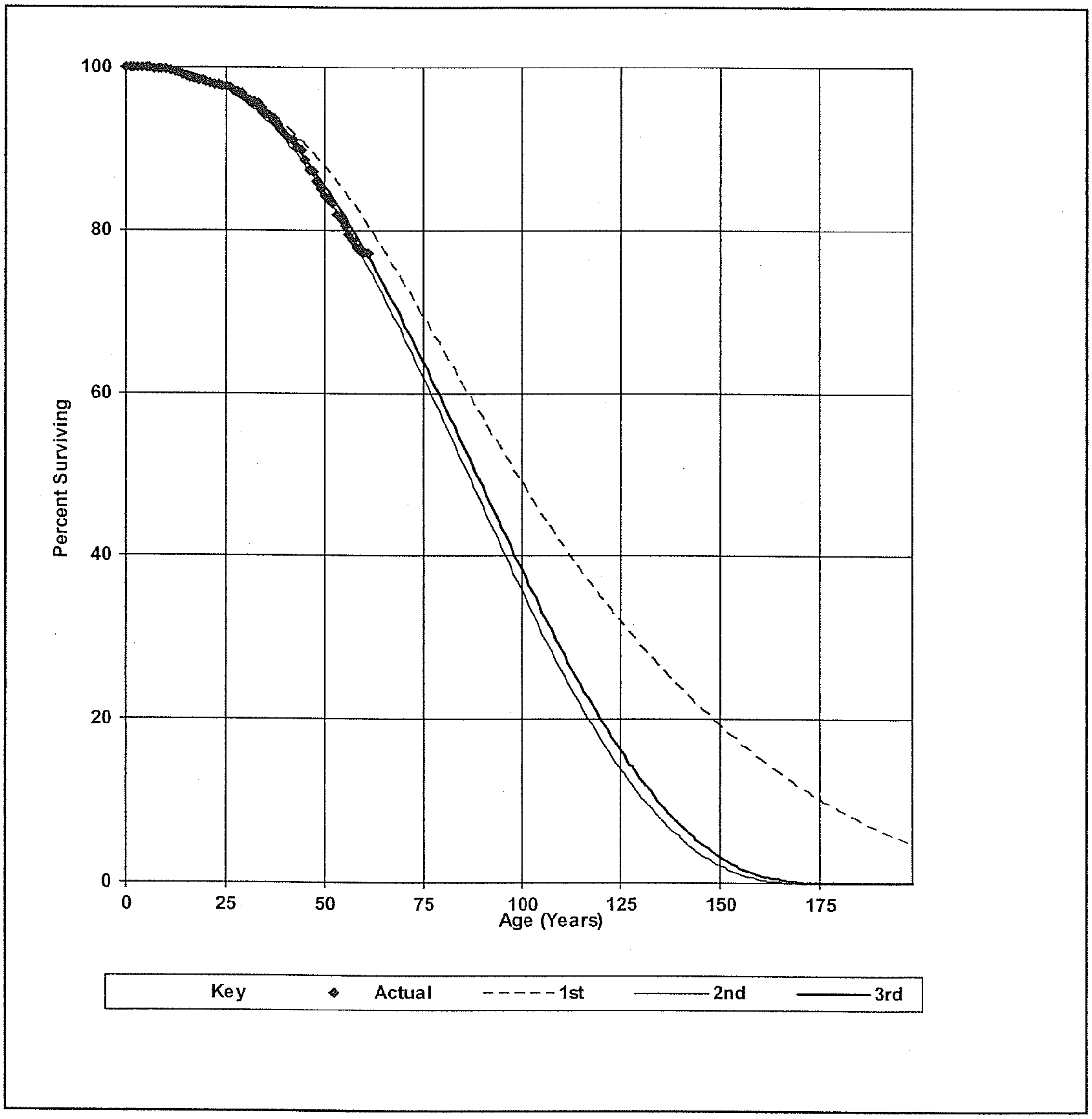
Placement Band: 1950-2010 Observation Band: 2000-2010

Hazard Function: Proportion Retired

Weighting: Exposures

Graphics Analysis

1st: 104.8-L1.5 2nd: 85.9-S1 3rd: 88.2-S1



HYDRO ONE NETWORKS INC. - TRANSMISSION

Transmission Plant

Account: 1715 Station Equipment

T-Cut: None

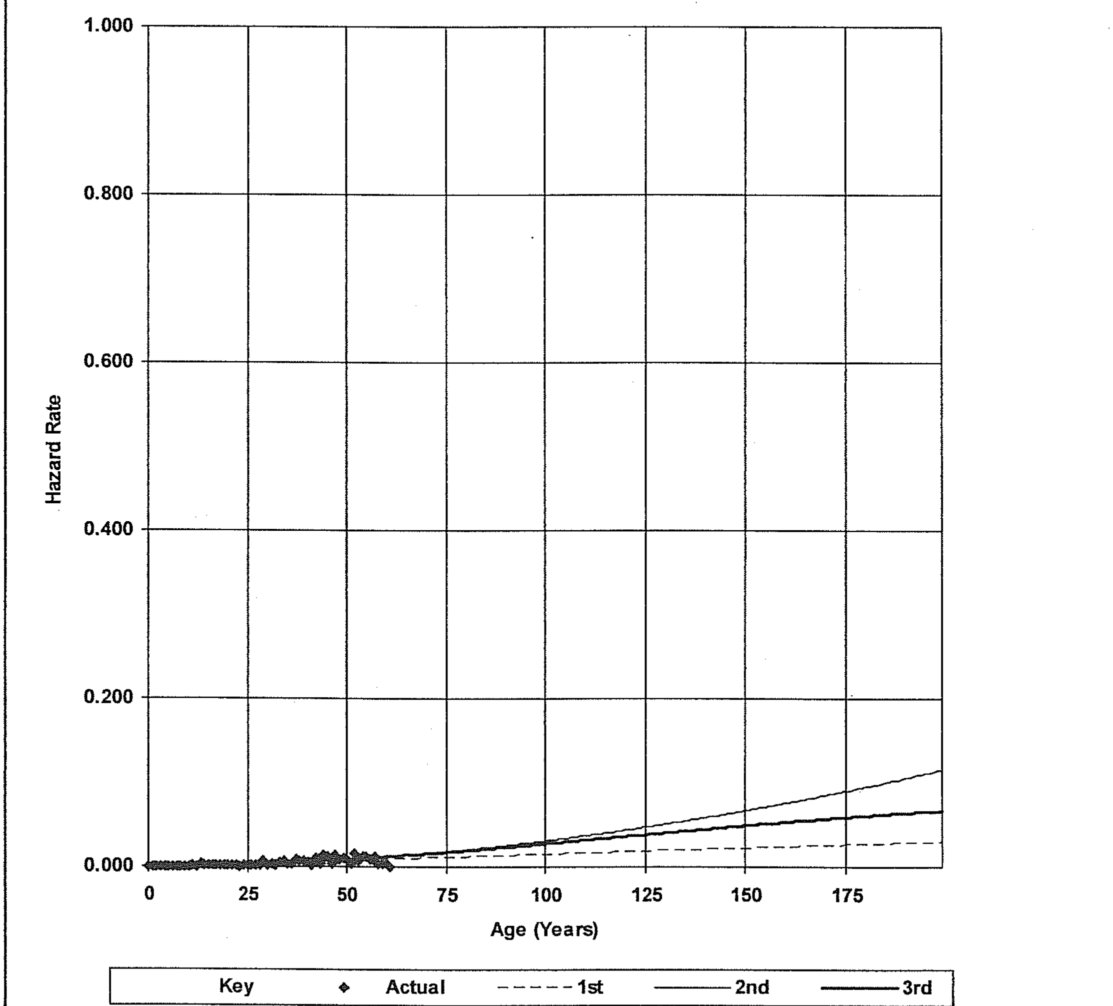
Placement Band: 1950-2010 Observation Band: 2000-2010

Hazard Function: Proportion Retired

Weighting: Exposures

Polynomial Hazard Function

1st: 104.8-L1.5 2nd: 85.9-S1 3rd: 88.2-S1



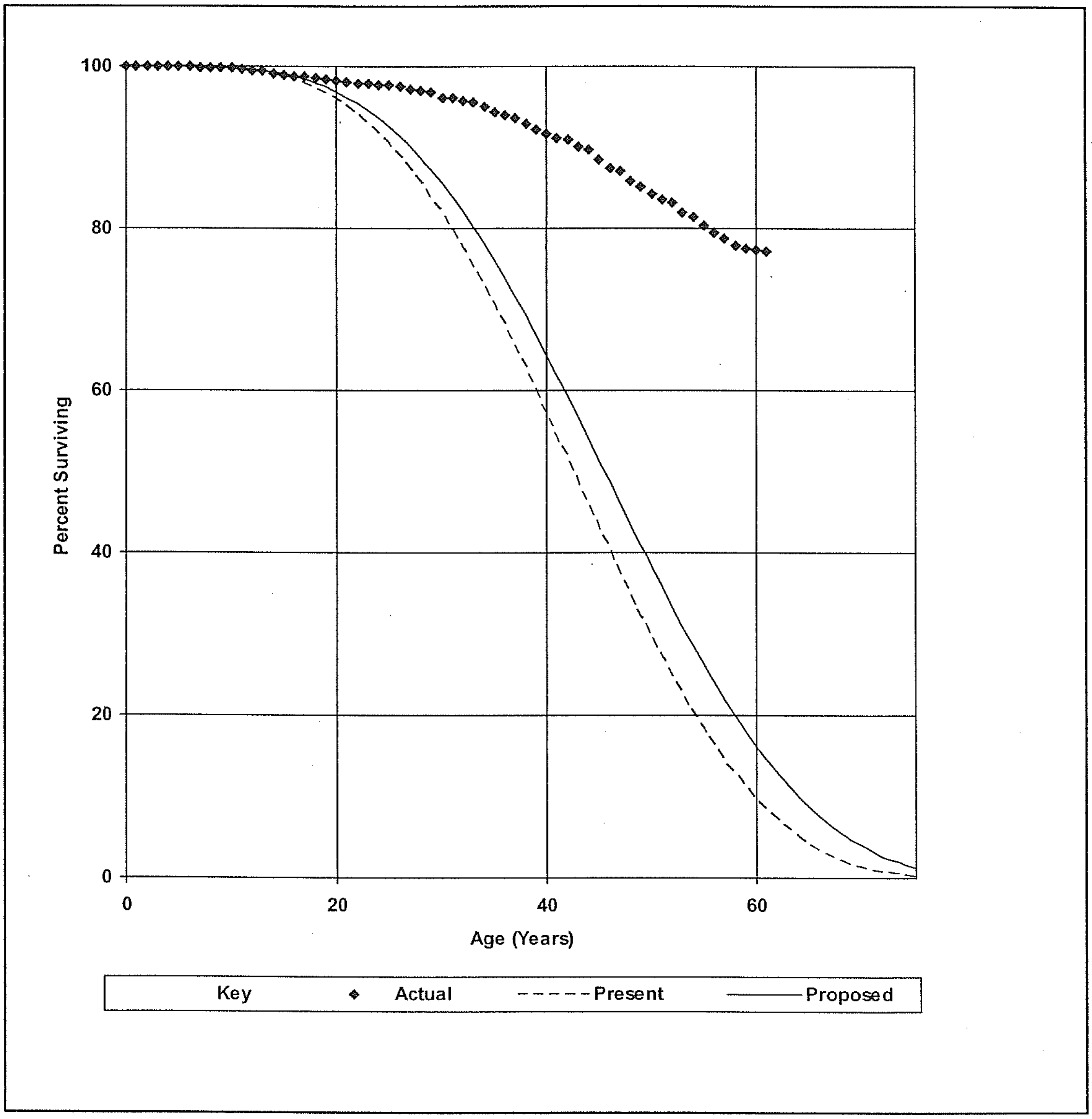
HYDRO ONE NETWORKS INC. - TRANSMISSION

Transmission Plant

Account: 1715 Station Equipment

T-Cut: None
Placement Band: 1950-2010
Observation Band: 2000-2010

Present and Proposed Projection Life Curves Present: 42.0-S2 Proposed: 45.0-S2



PROFESSIONAL QUALIFICATIONS

NAME AND ADDRESS

Ronald E. White, Ph.D.
Foster Associates, Inc.
17595 S. Tamiami Trail, Suite 212
Fort Myers, FL 33908

EDUCATION

1961 - 1964 Valparaiso University

Major: Electrical Engineering

1965 Iowa State University

B.S., Engineering Operations

1968 Iowa State University

M.S., Engineering Valuation

Thesis: The Multivariate Normal Distribution and the Simulated Plant Record Method of Life Analysis

1977 Iowa State University

Ph.D., Engineering Valuation

Minor: Economics

Dissertation: A Comparative Analysis of Various Estimates of the Hazard Rate Associated With the Service Life of Industrial Property

EMPLOYMENT

2007 - Present	Foster Associates, Inc. Chairman
1996 - 2007	Foster Associates, Inc. Executive Vice President
1988 - 1996	Foster Associates, Inc. Senior Vice President
1979 - 1988	Foster Associates, Inc. Vice President
1978 - 1979	Northern States Power Company Assistant Treasurer
1974 - 1978	Northern States Power Company Manager, Corporate Economics
1972 - 1974	Northern States Power Company Corporate Economist

1970 - 1972 Iowa State University
Graduate Student and Instructor

1968 - 1970 Northern States Power Company
Valuation Engineer

1965 - 1968 Iowa State University
Graduate Student and Teaching Assistant

PUBLICATIONS

A New Set of Generalized Survivor Tables, Journal of the Society of Depreciation Professionals, October, 1992.

The Theory and Practice of Depreciation Accounting Under Public Utility Regulation, Journal of the Society of Depreciation Professionals, December, 1989.

Standards for Depreciation Accounting Under Regulated Competition, paper presented at The Institute for Study of Regulation, Rate Symposium, February, 1985.

The Economics of Price-Level Depreciation, paper presented at the Iowa State University Regulatory Conference, May, 1981.

Depreciation and the Discount Rate for Capital Investment Decisions, paper presented at the National Communications Forum - National Electronics Conference, October 1979.

A Computerized Method for Generating a Life Table From the 'h-System' of Survival Functions, paper presented at the American Gas Association - Edison Electric Institute Depreciation Accounting Committee Meeting, December, 1975.

The Problem With AFDC is ..., paper presented at the Iowa State University Conference on Public Utility Valuation and the Rate Making Process, May, 1973.

The Simulated Plant-Record Method of Life Analysis, paper presented at the Missouri Public Service Commission Regulatory Information Systems Conference, May, 1971.

Simulated Plant-Record Survivor Analysis Program (User's Manual), special report published by Engineering Research Institute, Iowa State University, February, 1971.

A Test Procedure for the Simulated Plant-Record Method of Life Analysis, Journal of the American Statistical Association, September, 1970.

Modeling the Behavior of Property Records, paper presented at the Iowa State University Conference on Public Utility Valuation and the Rate Making Process, May, 1970.

A Technique for Simulating the Retirement Experience of Limited-Life Industrial Property, paper presented at the National Conference of Electric and Gas Utility Accountants, May, 1969.

How Dependable are Simulated Plant-Record Estimates?, paper presented at the Iowa State University Conference on Public Utility Valuation and the Rate Making Process, April, 1968.

TESTIFYING WITNESS

Alabama Public Service Commission, Docket No. 18488, General Telephone Company of the Southeast; testimony concerning engineering economy study techniques.

Alabama Public Service Commission, Docket No. 20208, General Telephone Company of the South; testimony concerning the equal-life group procedure and remaining-life technique.

Alberta Energy and Utilities Board, Application No. 1250392, Aquila Networks Canada; rebuttal testimony supporting proposed depreciation rates.

Alberta Energy and Utilities Board, Case No. RE95081, Edmonton Power Inc.; rebuttal evidence concerning appropriate depreciation rates.

Alberta Energy and Utilities Board, 1999/2000 General Tariff Application, Edmonton Power Inc.; direct and rebuttal evidence concerning appropriate depreciation rates.

Arizona Corporation Commission, Docket No. T-01051B-97-0689, U S West Communications, Inc.; testimony concerning appropriate depreciation rates.

Arizona Corporation Commission, Docket No. G-1032A-02-0598, Citizens Communications Company; testimony supporting proposed depreciation rates.

Arizona Corporation Commission, Docket No. E–01345A–08–0172, Arizona Public Service Company; testimony supporting proposed depreciation rates.

Arizona Corporation Commission, Docket No. E–0135A–03–0437, Arizona Public Service Company; rebuttal testimony supporting net salvage rates.

Arizona Corporation Commission, Docket No. E–01345A–05–0816, Arizona Public Service Company; testimony supporting proposed depreciation rates.

Arizona Corporation Commission, Docket No. E–01345A–11–0224, Arizona Public Service Company; testimony supporting proposed depreciation rates.

Arizona Corporation Commission, Docket No. G–04204A–06–0463, UNS Gas, Inc.; testimony supporting proposed depreciation rates.

Arizona Corporation Commission, Docket No. E–04204A–06–0783, UNS Electric, Inc.; testimony supporting proposed depreciation rates.

Arizona Corporation Commission, Docket No. E–04204A–09–0206, UNS Electric, Inc, testimony supporting proposed depreciation rates.

Arizona State Board of Equalization, Docket No. 6302-07-2, Arizona Public Service Company; testimony concerning valuation and assessment of contributions in aid of construction.

California Public Utilities Commission, Case Nos. A.92-06-040, 92-06-042, GTE California Incorporated; rebuttal testimony supporting depreciation study techniques.

California Public Utilities Commission. Docket No. GRC A.05–12–002, Pacific Gas and Electric Company; testimony regarding estimation of net salvage rates.

California Public Utilities Commission. Docket No. GRC A.06–12–009/A.06–12–010, San Diego Gas & Electric Company and Southern California Gas Company; testimony regarding estimation of net salvage rates.

Public Utilities Commission of the State of Colorado, Application No. 36883-Reopened. U S WEST Communications; testimony concerning equal-life group procedure.

State of Connecticut Department of Public Utility Control, Docket No. 10–12–02, Yankee Gas Services Company; testimony supporting recommended depreciation rates.

State of Connecticut Department of Public Utility Control, Docket No. 09–12–05, The Connecticut Light and Power Company; testimony supporting recommended depreciation rates.

State of Connecticut Department of Public Utility Control, Docket No. 06–12PH01, Yankee Gas Services Company; testimony supporting recommended depreciation rates.

State of Connecticut Department of Public Utility Control, Docket No. 05–03–17, The Southern Connecticut Gas Company; testimony supporting recommended depreciation rates.

Delaware Public Service Commission, Docket No. 81-8, Diamond State Telephone Company; testimony concerning the amortization of inside wiring.

Delaware Public Service Commission, Docket No. 82-32, Diamond State Telephone Company; testimony concerning the equal-life group procedure and remaining-life technique.

Public Service Commission of the District of Columbia, Formal Case No. 842, District of Columbia Natural Gas; testimony concerning depreciation rates.

Public Service Commission of the District of Columbia, Formal Case No. 1016, Washington Gas Light Company - District of Columbia; testimony supporting proposed depreciation rates.

Public Service Commission of the District of Columbia, Formal Case No. 1054, Washington Gas Light Company - District of Columbia; testimony supporting proposed depreciation rates.

Federal Communications Commission, Prescription of Revised Depreciation Rates for AT&T Communications; statement concerning depreciation, regulation and competition.

Federal Communications Commission, Petition for Modification of FCC Depreciation Prescription Practices for AT&T; statement concerning alignment of depreciation expense used for financial reporting and regulatory purposes.

Federal Communications Commission, Docket No. 99-117, Bell Atlantic; affidavit concerning revenue requirement and capital recovery implications of omitted plant retirements.

Federal Energy Regulatory Commission, Docket No. ER10-2110-000, ITC Midwest; testimony supporting proposed depreciation rates.

Federal Energy Regulatory Commission, Docket No. ER10-185-000, Michigan Electric Transmission Company; testimony supporting proposed depreciation rates.

Federal Energy Regulatory Commission, Docket No. ER09-1530-000, ITC*Transmission*; testimony supporting proposed depreciation rates.

Federal Energy Regulatory Commission, Docket No. ER95-267-000, New England Power Company; testimony supporting proposed depreciation rates.

Federal Energy Regulatory Commission, Docket No. ER11-3638-000, Arizona Public Service Company; testimony supporting proposed depreciation rates

Federal Energy Regulatory Commission, Docket No. RP89-248, Mississippi River Transmission Corporation; rebuttal testimony concerning appropriateness of net salvage component in depreciation rates.

Federal Energy Regulatory Commission, Docket No. ER91-565, New England Power Company; testimony supporting proposed depreciation rates.

Federal Energy Regulatory Commission, Docket No. ER78-291, Northern States Power Company; testimony concerning rate of return and general financial requirements.

Federal Energy Regulatory Commission, Docket Nos. RP80-97 and RP81-54, Tennessee Gas Pipeline Company; testimony concerning offshore plant depreciation rates.

Federal Power Commission, Docket No. E-8252, Northern States Power Company; testimony concerning general financial requirements and measurements of financial performance.

Federal Power Commission, Docket No. E-9148, Northern States Power Company; testimony concerning general financial requirements and measurements of financial performance.

Federal Power Commission, Docket No. ER76-818, Northern States Power Company; testimony concerning rate of return and general financial requirements.

Federal Power Commission, Docket No. RP74-80, *Northern* Natural Gas Company; testimony concerning depreciation expense.

Public Utilities Commission of the State of Hawaii, Docket No. 00-0309, The Gas Company; testimony supporting proposed depreciation rates.

Public Utilities Commission of the State of Hawaii, Docket No. 94-0298, GTE Hawaiian Telephone Company Incorporated; testimony concerning the need for shortened service lives and disclosure of asset impairment losses.

Idaho Public Utilities Commission, Case No. U-1002-59, General Telephone Company of the Northwest, Inc.; testimony concerning the remaining-life technique and the equal-life group procedure.

Illinois Commerce Commission, Case No. 04–0476, Illinois Power Company; testimony supporting proposed depreciation rates.

Illinois Commerce Commission, Docket No. 94-0481, Citizens Utilities Company of Illinois; rebuttal testimony concerning applications of the Simulated Plant-Record method of life analysis.

Iowa State Commerce Commission, Docket No. RPU 82-47, North Central Public Service Company; testimony on depreciation rates.

Iowa State Commerce Commission, Docket No. RPU 84-34, General Telephone Company of the Midwest; testimony concerning the remaining-life technique and the equal-life group procedure.

Iowa State Utilities Board, Docket No. DPU-86-2, Northwestern Bell Telephone Company; testimony concerning capital recovery in competition.

Iowa State Utilities Board, Docket No. RPU-84-7, Northwestern Bell Telephone Company; testimony concerning the deduction of a reserve deficiency from the rate base.

Iowa State Utilities Board, Docket No. DPU-88-6, U S WEST Communications; testimony concerning depreciation subject to refund.

Iowa State Utilities Board, Docket No. RPU-90-9, Central Telephone Company of Iowa; testimony concerning depreciation rates.

Iowa State Utilities Board, Docket No. RPU-93-9, U S WEST Communications; testimony concerning principles of depreciation accounting and abandonment of FASB 71.

Iowa State Utilities Board, Docket No. DPU-96-1, U S WEST Communications; testimony concerning principles of depreciation accounting and abandonment of FASB 71.

Iowa State Utilities Board, Docket No. RPU-05-2, Aquila Networks; testimony supporting recommended depreciation rates.

Kansas Corporation Commission, Docket No. 12-WSEE-112-RTS, Westar Energy, Inc.; testimony supporting proposed depreciation rates.

Kansas Corporation Commission, Docket No. 10–KCPE–415–RTS; Kansas City Power and Light; cross–answering testimony addressing the recording and treatment of third–party reimbursements in estimating net salvage rates.

Kansas Corporation Commission, Docket No. 04–AQLE–1065–RTS, Aquila Networks – WPE (Kansas); testimony supporting proposed depreciation rates.

Kansas Corporation Commission, Docket No. 03–KGSG–602–RTS, Kansas Gas Service, a Division of ONEOK, Inc.; rebuttal testimony supporting net salvage rates.

Kansas Corporation Commission, Docket No. 06–KGSG–1209–RTS, Kansas Gas Service, a Division of ONEOK, Inc.; testimony supporting proposed depreciation rates.

Kentucky Public Service Commission, Case No. 97-224, Jackson Purchase Electric Cooperative Corporation; rebuttal testimony supporting proposed depreciation rates.

Maryland Public Service Commission, Case No. 8485, Baltimore Gas and Electric Company; testimony supporting proposed depreciation rates.

Maryland Public Service Commission, Case No. 9096, Baltimore Gas and Electric Company; testimony supporting proposed depreciation rates.

Maryland Public Service Commission, Case No. 7689, Washington Gas Light Company; testimony concerning life analysis and net salvage.

Maryland Public Service Commission, Case No. 8960, Washington Gas Light Company; testimony supporting proposed depreciation rates.

Maryland Public Service Commission, Case No. 9103, Washington Gas Light Company; rebuttal testimony supporting proposed depreciation rates.

Commonwealth of Massachusetts Department of Public Utilities, D.P.U. 10–70, Western Massachusetts Electric Company; testimony supporting proposed depreciation rates.

Commonwealth of Massachusetts Department of Telecommunications and Energy, D.T.E. 06–55, Western Massachusetts Electric Company; testimony supporting proposed depreciation rates.

Massachusetts Department of Public Utilities, Case No. DPU 91-52, Massachusetts Electric Company; testimony supporting proposed depreciation rates which include a net salvage component.

Michigan Public Service Commission, Case No. U–16117, The Detroit Edison Company; testimony supporting proposed depreciation rates.

Michigan Public Service Commission, Case No. U–15699, Michigan Consolidated Gas Company; testimony supporting proposed depreciation rates.

Michigan Public Service Commission, Case No. U–13899, Michigan Consolidated Gas Company; testimony concerning service life estimates.

Michigan Public Service Commission, Case No. U-13393, Aquila Networks – MGU; testimony supporting proposed depreciation rates.

Michigan Public Service Commission, Case No. U-12395, Michigan Gas Utilities; testimony supporting proposed depreciation rates including amortization accounting and redistribution of recorded reserves.

Michigan Public Service Commission, Case No. U-6587, General Telephone Company of Michigan; testimony concerning use of a theoretical depreciation reserve with the remaining-life technique.

Michigan Public Service Commission, Case No. U-7134, General Telephone Company of Michigan; testimony concerning the equal-life group depreciation procedure.

Minnesota Public Service Commission, Docket No. E-611, Northern States Power Company; testimony concerning rate of return and general financial requirements.

Minnesota Public Service Commission, Docket No. E-1086, Northern States Power Company; testimony concerning depreciation rates.

Minnesota Public Service Commission, Docket No. G-1015, Northern States Power Company; testimony concerning rate of return and general financial requirements.

Public Service Commission of the State of Missouri, Case No. ER-2009-0090, KCP&L Greater Missouri Operations, rebuttal testimony concerning depreciation rates.

Public Service Commission of the State of Missouri, Case No. ER-2001-672, Missouri Public Service, a division of Utilicorp United Inc.; surrebuttal testimony regarding computation of income tax expense.

Public Service Commission of the State of Missouri, Case No. TO-82-3, Southwestern Bell Telephone Company; rebuttal testimony concerning the remaining-life technique and the equal-life group procedure.

Public Service Commission of the State of Missouri, Case No. GO-97-79, Laclede Gas Company; rebuttal testimony concerning adequacy of database for conducting depreciation studies.

Public Service Commission of the State of Missouri, Case No. GR-99-315, Laclede Gas Company; rebuttal testimony concerning treatment of net salvage in development of depreciation rates.

Public Service Commission of the State of Missouri, Case No. HR–2004–0024, Aquila Inc. d/b/a/ Aquila Networks–L & P; testimony supporting depreciation rates.

Public Service Commission of the State of Missouri, Case No. ER–2004–0034, Aquila Inc. d/b/a/ Aquila Networks–L & P and Aquila Networks–MPS; testimony supporting depreciation rates.

Public Service Commission of the State of Missouri, Case No. GR–2004–0072, Aquila Inc. d/b/a/ Aquila Networks–L & P and Aquila Networks–MPS; testimony supporting depreciation rates.

Public Service Commission of the State of Montana, Docket No. 88.2.5, Mountain State Telephone and Telegraph Company; rebuttal testimony concerning the equal-life group procedure and amortization of reserve imbalances.

Montana Public Service Commission, Docket No. D95.9.128, The Montana Power Company; testimony supporting proposed depreciation rates.

Nebraska Public Service Commission, Docket No. NG–0041, Aquila Networks (PNG Nebraska); testimony supporting proposed depreciation rates.

Public Service Commission of Nevada, Docket No. 92-7002, Central Telephone Company-Nevada; testimony supporting proposed depreciation rates.

Public Service Commission of Nevada, Docket No. 91-5054, Central Telephone Company-Nevada; testimony supporting proposed depreciation rates.

New Hampshire Public Utilities Commission, Docket No. DR95-169, Granite State Electric Company; testimony supporting proposed net salvage rates.

New Jersey Board of Public Utilities, Docket No. GR07110889, New Jersey Natural Gas Company; testimony supporting proposed depreciation rates.

New Jersey Board of Public Utilities, Docket No. GR 87060552, New Jersey Natural Gas Company; testimony concerning depreciation rates.

New Jersey Board of Regulatory Commissioners, Docket No. GR93040114J, New Jersey Natural Gas Company; testimony concerning depreciation rates.

New York Public Service Commission, Case No. 10–E–0050. Niagara Mohawk Power Corporation d/b/a National Grid; testimony supporting recommended depreciation rates.

North Carolina Utilities Commission, Docket No. E-7, SUB 487, Duke Power Company; rebuttal testimony concerning proposed depreciation rates.

North Carolina Utilities Commission, Docket No. P-19, SUB 207, General Telephone Company of the South; rebuttal testimony concerning the equal-life group depreciation procedure.

North Dakota Public Service Commission, Case No. 8860, Northern States Power Company; testimony concerning general financial requirements.

North Dakota Public Service Commission, Case No. 9634, Northern States Power Company; testimony concerning rate of return and general financial requirements.

North Dakota Public Service Commission, Case No. 9666, Northern States Power Company; testimony concerning rate of return and general financial requirements.

North Dakota Public Service Commission, Case No. 9741, Northern States Power Company; testimony concerning rate of return and general financial requirements.

Oklahoma Corporation Commission, Cause No. PUD 200900110, Oklahoma Natural Gas Company; testimony supporting revised depreciation rates.

Ontario Energy Board, E.B.R.O. 385, Tecumseh Gas Storage Limited; testimony concerning depreciation rates.

Ontario Energy Board, E.B.R.O. 388, Union Gas Limited; testimony concerning depreciation rates.

Ontario Energy Board, E.B.R.O. 456, Union Gas Limited; testimony concerning depreciation rates.

Ontario Energy Board, E.B.R.O. 476-03, Union Gas Limited; testimony concerning depreciation rates.

Public Utilities Commission of Ohio, Case No. 81-383-TP-AIR, General Telephone Company of Ohio; testimony in support of the remaining-life technique.

Public Utilities Commission of Ohio, Case No. 82-886-TP-AIR, General Telephone Company of Ohio; testimony concerning the remaining-life technique and the equal-life group procedure.

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Electric Utility Economics, Mid-Continent Area Power Pool, May 1974.Page 56

Moderator

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Honors and Awards

The Society of Sigma Xi.

Professional Achievement Citation in Engineering, Iowa State University, 1993.

PAYMENTS IN LIEU OF CORPORATE INCOME TAXES

1.0 INTRODUCTION

Under the *Electricity Act, 1998*, Hydro One Networks Inc. ("Networks") is required to make payments in lieu of corporate income taxes ("PILs") relating to taxable income earned by its transmission business. The Board has directed that the taxes payable method should also be used for regulatory purposes, according to its 2006 EDR Handbook, Section 7.1 "OEB 2006 Regulatory Taxes Expense Methodology".

Under the taxes payable method, no provision is made for future income taxes that result from timing differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes. Accordingly, the taxes payable method will result in the PILs income tax payable being different from the amount that would have been recorded, had the combined Canadian Federal and Ontario statutory income tax rate been applied to the regulatory net income before tax. When unrecorded future income taxes become payable, it is expected that they will be included in the rates approved by the Board and recovered from customers at that time.

PILS installments are remitted by Networks to the OEFC at the end of each month. Any balance owing at the end of the year is required to be paid by the end of February of the following year.

In the absence of an Electricity Transmission Handbook, the 2013 and 2014 Hydro One transmission regulatory tax calculations have been prepared consistent with the approach found in the 2006 EDR Handbook and the 2006 EDR Tax Model, as this approach reflects the tax payable relating to taxable income earned by the transmission business.

2.0 INCOME TAX RATE (FEDERAL AND ONTARIO)

A combined income tax rate of 26.5% has been used for the test years 2013 and 2014, comprised of a Federal rate of 15% and an Ontario rate of 11.5% as a result of the Ontario budget bill enacted on June 20, 2012. The Board's December 23, 2010 Decision (EB-2010-0002) respecting Hydro One Transmission's 2011 and 2012 Revenue Requirements approved a combined income tax rate of 28.25% for 2011 and a combined rate of 26.25% for 2012. As of June 20, 2012, the corporate income tax rate remains at 11.50% for 2012, resulting in a combined income tax rate of 26.5%. Any variance between actual taxes payable and forecast taxes, as a result of rate changes for income tax or capital cost allowance will be captured in a deferral account for tax rate changes, described further in Exhibit F1, Tab 1, Schedules 1 and 2.

3.0 RECONCILIATION BETWEEN REGULATORY NET INCOME BEFORE TAX AND TAXABLE INCOME

Reconciliation between the regulatory net income before tax ("NIBT") and taxable income for the test years 2013 and 2014 is provided in Exhibit C2, Tab 5, Schedule 1, Attachments 1 & 2. This schedule contains the income tax component of the PILs computation. It also shows how the taxable income is computed by making adjustments to the regulatory NIBT for items such as depreciation and capital cost allowance (CCA).

Reconciliation between the accounting NIBT and taxable income for the historical years 2009 and 2010 is also provided in Exhibit C2, Tab 5, Schedule 1, Attachments 3 & 4**.** This reconciliation entails adjustments to regulatory NIBT to arrive at taxable income. In order to make it easier to follow these reconciliations, Hydro One Transmission has placed these adjustments into the following five categories:

1) Recurring items that must be added (deducted) because they have been included in the OM&A expenses in arriving at the revenue requirement, or for which appropriate tax adjustments are made (for example, depreciation versus CCA);
2) Deferral accounts not included in the revenue requirement;
3) Reversal of accounting adjustments not included in the revenue requirement;
4) Recurring items not in the revenue requirement; and
5) Items whose impact is immaterial in total, and as such, have not been included in the Company's business plan (applicable to test years only).

4.0 OVERVIEW OF PROCESS TO ARRIVE AT TAXABLE INCOME

The starting point for the computation of Hydro One Transmission's taxable income is the NIBT as shown on the utility's income statement for the year. The NIBT is prepared using U.S. Generally Accepted Accounting Principles, but taxable income is computed using the relevant tax legislation, interpretations and assessing practices. Therefore, many adjustments are typically made to the NIBT to arrive at taxable income. Essentially, the NIBT is increased by amounts that are not deductible for tax purposes. This includes items such as depreciation, contingent liabilities, accounting losses, accounting provisions such as other post employment benefits ("OPEB") and revenue that has been received but not recognized for accounting purposes (for example, transmission export revenue). On the other hand, the NIBT is reduced by amounts that are deductible for tax purposes but have not been deducted in computing NIBT. This includes items such as CCA, the deductible portion of capitalized overhead, accounting gains and OPEB payments. Such reductions also include expenses incurred for which a deferral account has been set up on the balance sheet, rather than shown as a deduction through the income statement.

Consequently, it is imperative that the NIBT be adjusted for amounts that have been included (or deducted) for accounting purposes that are not income (or deductible) for tax return purposes. This is a key point in comparing the historical years tax return data to that computed for the test years, since the tax return NIBT has been increased (or reduced) by amounts that have not been added (or deducted) in computing the regulatory NIBT (e.g. contingent liabilities, accounting gains, capitalized interest). That is, for test years 2013 and 2014, adjustments for differences between the tax and accounting rules only (related to costs included in either the regulatory revenue requirement or rate base, such as CCA or capitalized overhead), are made to arrive at taxable income.

5.0 TAX TREATMENT OF DEFERRAL ACCOUNTS (REGULATORY ASSETS AND LIABILITIES)

Deferral accounts are typically recognized by utilities' balance sheets for foregone revenue or for expenses that have been incurred, for which recovery will be sought from ratepayers through future rates. Disposition of the deferral accounts is determined by the Board.

For example, as shown in Table 1, assuming that a 25% tax rate and a $100 expense is incurred, the utility will be allowed to deduct the $100 in computing taxable income for the year in which the expense has been incurred. If the Board subsequently approves recovery of this expense over a 2-year period through a rate rider, the income will be included in computing taxable income for the year in which it is billed to ratepayers. The net result is that the utility has recovered the $100 cost although the income or expense has been taxed or deducted in different years.

Table 1

	Year 1	**Year 2**	**Year 3**	**CUM**
Income (deduction)	(100)	50	50	Nil
Tax Refund (payable)	25	(12.5)	(12.5)	Nil
Cash Inflow (outflow)	(75)	37.5	37.5	Nil

Therefore, deferral accounts have not been included in computing tax payable for purposes of the revenue requirement since the tax benefit has or will be obtained through the tax system. It should be noted that this conclusion is consistent with the "2006 EDR Handbook Report of the Board" issued May 11, 2005 (page 61) that stated as follows:

> "A PILS or tax provision is not needed for the recovery of deferred regulatory asset costs, because the distributors have deducted, or will deduct, these costs in calculating taxable income in their returns. The Handbook will reflect this treatment."

6.0 CONTINGENT LIABILITIES/ACCOUNTING RESERVES

Where an accounting provision is recognized for certain contingent costs that the utility may have to incur in the future (such as obsolescence provisions, lawsuits, staff reductions), the provision will reduce the NIBT of the utility. In each subsequent year, the balance for the contingent liability/accounting reserve is reviewed by the utility for reasonableness based upon the information available at that time. The balance may be adjusted upward or downward, with NIBT either decreasing or increasing, respectively.

However, for tax purposes, a contingent liability or accounting reserve is not deductible. Rather, the amount will only be deductible (or capitalized) in computing taxable income for the taxation year in which the obligation has actually been settled. Therefore, to the extent that the current year NIBT has been increased (or decreased) by the contingent liability or accounting reserve provision, the NIBT must be adjusted to reverse the increase (or decrease) in computing taxable income.

It is not necessary to adjust the 2013 and 2014 NIBT for contingent liabilities in computing taxable income since no changes were forecasted in the contingent liability balances for 2013 and 2014. Therefore, such amounts are not included in the tax computation for purposes of the revenue requirement.

The combined (Federal and Ontario) enacted income tax rates are as follows:

	Historic			**Bridge**	**Test**	
	2009	**2010**	**2011**	**2012**	**2013**	**2014**
Federal Tax Rate (%)	19.00	18.00	16.50	15.00	15.00	15.00
Provincial Rate (%)	14.00	13.00	11.75	11.50	11.50	11.50
Total Statutory Tax Rate (%)	**33.00**	**31.00**	**28.25**	**26.50**	**26.50**	**26.50**
Capital Tax Rate (%)(1)	0.225	0.075	nil	nil	nil	nil

(1) As of July 1, 2010, the Ontario capital tax is eliminated. Therefore, there is no Ontario capital tax calculated for the 2013 and 2014 test years..