Court File No.: CV-15-535019-00CP

ONTARIO
SUPERIOR COURT OF JUSTICE

B E T W E E N :

BILL BENNETT

Plaintiff

- and -

HYDRO ONE INC., HYDRO ONE BRAMPTON NETWORKS INC., HYDRO ONE REMOTE COMMUNITIES INC., NORFOLK POWER DISTRIBUTION INC., and HYDRO ONE NETWORKS INC.

Defendants

Proceeding under the *Class Proceedings Act, 1992*

CERTIFICATION MOTION RECORD
(Returnable May 9-11, 2017)

VOLUME 2 OF 4

April 14, 2016

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CERTIFICATION MOTION RECORD

Table of Contents

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AFFIDAVIT OF M. LILLY IANNACITO
(sworn April 13, 2016)

I, M. Lilly Iannacito, of the Town of Richmond Hill, in the Regional Municipality of York, MAKE OATH AND SAY:

1. I am a Law Clerk with the law firm of LAX O'SULLIVAN LISUS GOTTLIEB LLP, co-counsel for the Plaintiff and, as such, have knowledge of the matters contained in this affidavit.

2. Attached to this affidavit and marked as Exhibit "A" is a copy of the "Hydro One Cornerstone: Case Study", dated 2008, which I have accessed online.

3. Attached to this affidavit and marked as Exhibit "B" is a copy of the "Shared Services – Cornerstone Capital", filed on July 13, 2009, which I have accessed online.

4. Attached to this affidavit and marked as Exhibit "C" is a copy of the "Shared Services Capital – Cornerstone", filed on May 19, 2010, which I have accessed online.

5. Attached to this affidavit and marked as Exhibit "D" is a copy of "Hydro One Inc. Submissions to the Board of Directors", dated May 12, 2011 and filed on June 15, 2012, which I have accessed online.

6. Attached to this affidavit and marked as Exhibit "E" is a bundle of documents filed on June 15, 2012, including: "Hydro One Cornerstone Phase 4 CIS Replacement Stakeholder Session", dated June 29, 2011; "Hydro One Stakeholder Consultation Notes", dated October 19, 2011; and "Hydro One Stakeholder Consultation Notes", dated June 5, 2012. I have accessed these documents online.

7. Attached to this affidavit and marked as Exhibit "F" is a copy of "Hydro One Customer Information System Replacement, Project Update, Cornerstone Phase 4 Update for Stakeholders", dated October 19, 2011, which I have accessed online.

8. Attached to this affidavit and marked as Exhibit "G" is a copy of "Hydro One Annual Report 2012", which I have accessed online.

9. Attached to this affidavit and marked as Exhibit "H" is a copy of the "Shared Services Capital – Cornerstone", filed on May 28, 2012, which I have accessed online.

10. Attached to this affidavit and marked as Exhibit "I" is a copy of the "Non-Typical Capital - Customer Information System", filed on June 15, 2012, which I have accessed online.

11. Attached to this affidavit and marked as Exhibit "J" is a copy of a number of interrogatories, along with Hydro One's responses thereto, filed on October 11, 2012 regarding Ontario Energy Board file number EB-2012-0136, which I have accessed online.

12. Attached to this affidavit and marked as Exhibit "K" is a copy of "Hydro One Annual Report 2013", which I have accessed online.

13. Attached to this affidavit and marked as Exhibit "L" is a copy of "Hydro One Inc. Management's Discussion and Analysis for the three and six months ended June 30, 2013 and 2012", which I have accessed online.

14. Attached to this affidavit and marked as Exhibit "M" is a copy of a Hydro One News Release headed "Hydro One Releases 2013 Third Quarter Financial Results", dated November 14, 2013, which I have accessed online.

15. Attached to this affidavit and marked as Exhibit "N" is a copy of "Hydro One Annual Report 2014", which I have accessed online.

16. Attached to this affidavit and marked as Exhibit "O " is a copy of the excerpt from Chapter 3 of the "2014 Annual Report of the Office of the Auditor General of Ontario", Section 3.11 entitled "Smart Metering Initiative", which I have accessed online.

17. Attached to this affidavit and marked as Exhibit "P" is a copy of a Hydro One News Release headed "Hydro One Releases 2013 Year-End Financial Results", dated February 13, 2014, which I have accessed online.

18. Attached to this affidavit and marked as Exhibit "Q" is a copy of a Hydro One News Release headed "Hydro One Releases 2014 Year-End Financial Results", dated May 7, 2014, which I have accessed online.

19. Attached to this affidavit and marked as Exhibit "R" is a copy of "Hydro One Inc. Management's Discussion and Analysis for the years ended December 31, 2014 and 2013", which I have accessed online.

20. Attached to this affidavit and marked as Exhibit "S" is a copy of a report prepared by PwC entitled "Hydro One Customer Service and Billing Issues – Lessons Learned", dated December 2014, which I have accessed online.

21. Attached to this affidavit and marked as Exhibit "T" is a copy of the Ontario Ombudsman Report entitled "In the Dark", dated May 2015, which I have accessed online.

22. Attached to this affidavit and marked as Exhibit "U" is a copy of "Scorecard - Hydro One Networks Inc." dated September 28, 2015 with attached "Appendix A – 2014 Scorecard Management Discussion and Analysis Template" dated May 22, 2015, which I have accessed online.

23. Attached to this affidavit and marked as Exhibit "V" is a copy of the Ontario Energy Board "Retail Settlement Code", revised on October 8, 2015, which I have accessed online.

24. Attached to this affidavit and marked as Exhibit "W" is a copy of the Huffington Post media report dated December 4, 2015 entitled "Hydro One Billing Complaints Probe Ends, Because Company Is Being Privatized", which I have accessed online.

SWORN BEFORE ME at the City of Toronto,
in the Province of Ontario on April 13, 2016

Lisa Lutwak
Commissioner for Taking Affidavits

LISA S. LUTWAK

M. LILLY IANNACITO

BILL BENNETT
Plaintiff

-and-

HYDRO ONE INC., et al
Defendants

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AFFIDAVIT OF M. LILLY IANNACITO
(sworn April 13, 2016)

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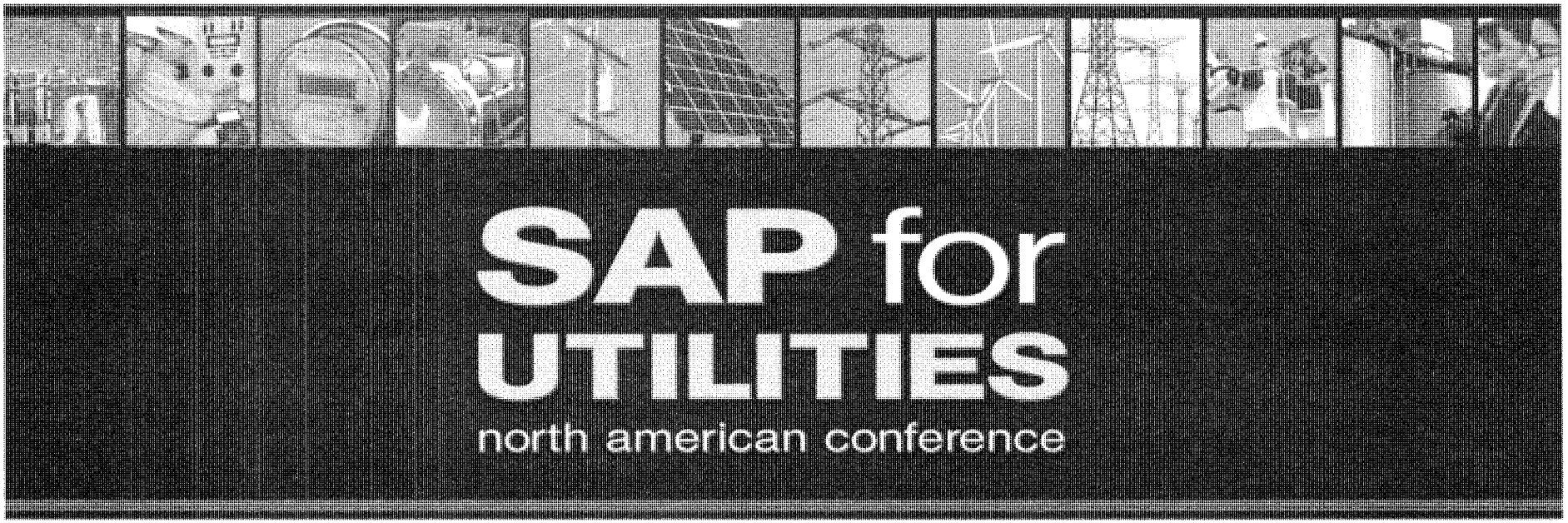
Lawyers for the Plaintiff

This is Exhibit "A" referred to in the Affidavit of M. Lilly Iannacito sworn April 13, 2016

Lisa Lutwak

Commissioner for Taking Affidavits (or as may be)

LISA S. LUTWAK



Hydro One Cornerstone: Case Study

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Brian Martin

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eventure

Hydro One: At A Glance

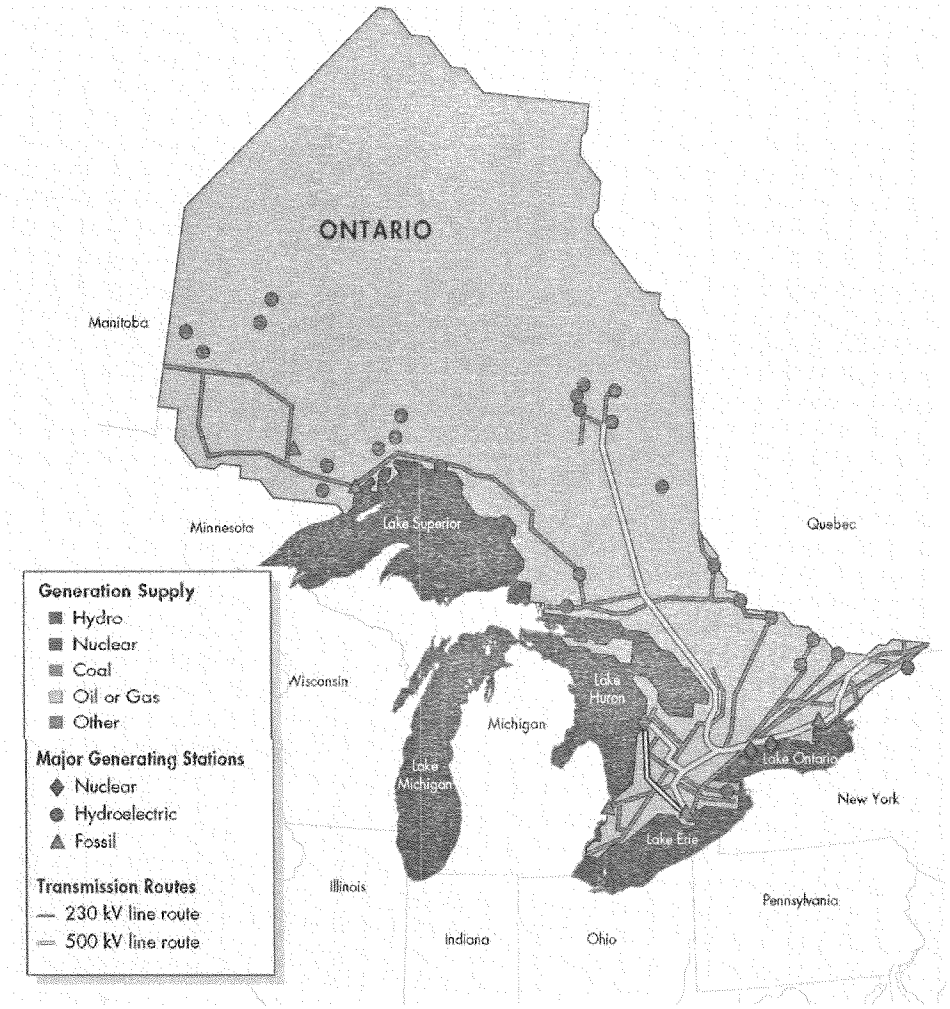
One of the largest electricity delivery Systems in the World

Wholly owned by the Province of Ontario

Ontario Energy Board regulates Transmission and Distribution separately

Transmission	Distribution
• $7.3 Billion in assets • 28,900 KM network – over 96% of capacity in Ontario • 51 LDCs, 61 large industrials • 26 Interconnection facilities • 273 Transmission stations	• $5.4Billion in assets • 123,000 KM system – spans 75% of Ontario • 1.3 Million rural and urban customers incl. 32 LDCs, 50 Large industrials

Hydro One: Ontario Footprint



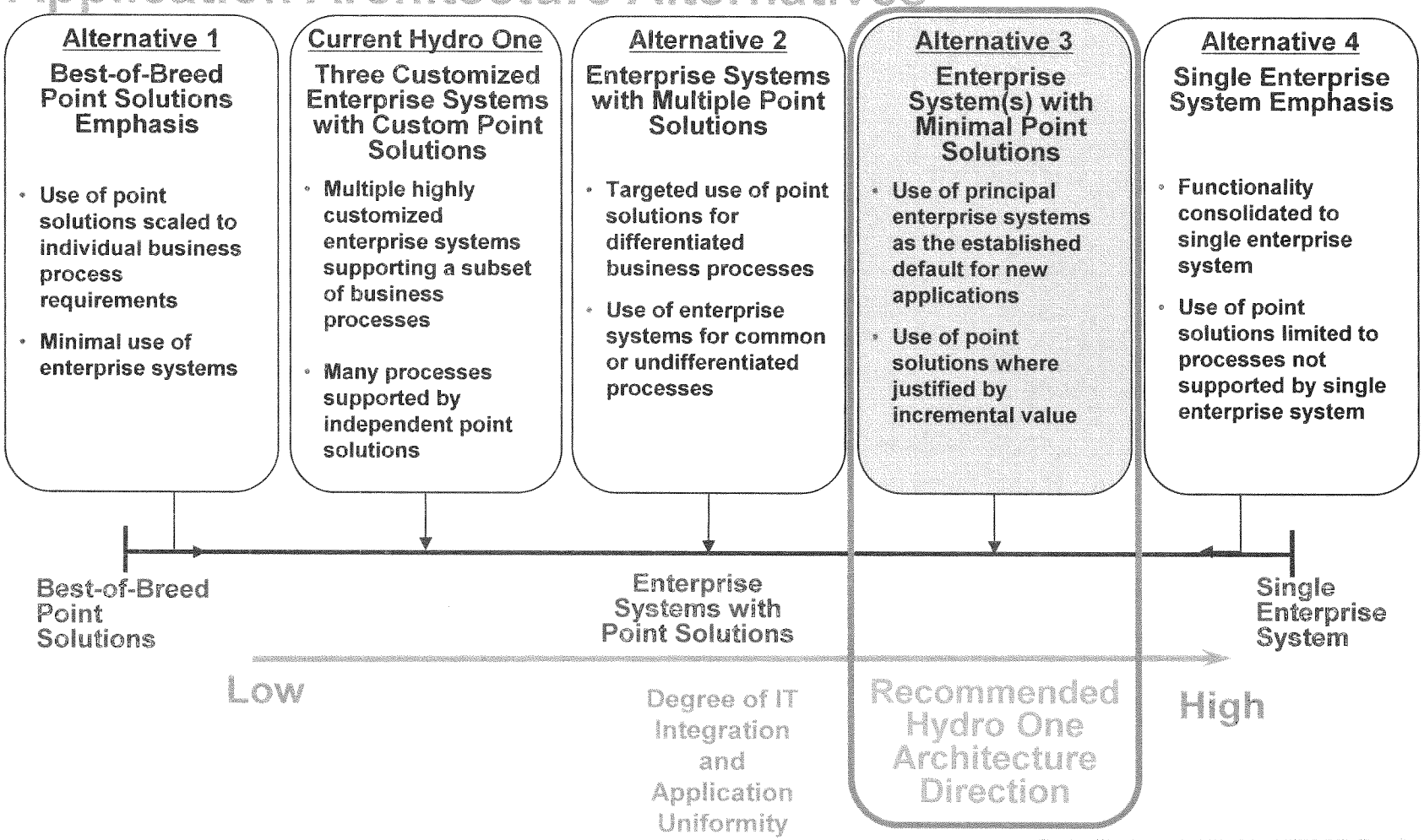
Our mission is to be an efficient and dynamic electricity transmission and distribution company that is best in North America in the areas of safety, customer service and reliability, while focusing on our people and creating shareholder value

Hydro One:
Strategic Five Year Vision

- Ensure public confidence as stewards of provincial assets
- Best safety record in the world
- Top quartile reliability
- Customer satisfaction: 90% across all segments
- Skills development and retention
- Shareholder returns: Productivity/ “A” category Rating

IT Strategy: Catalyst for Change

Application Architecture Alternatives



Beyond IT:
Business Driven Program takes Shape

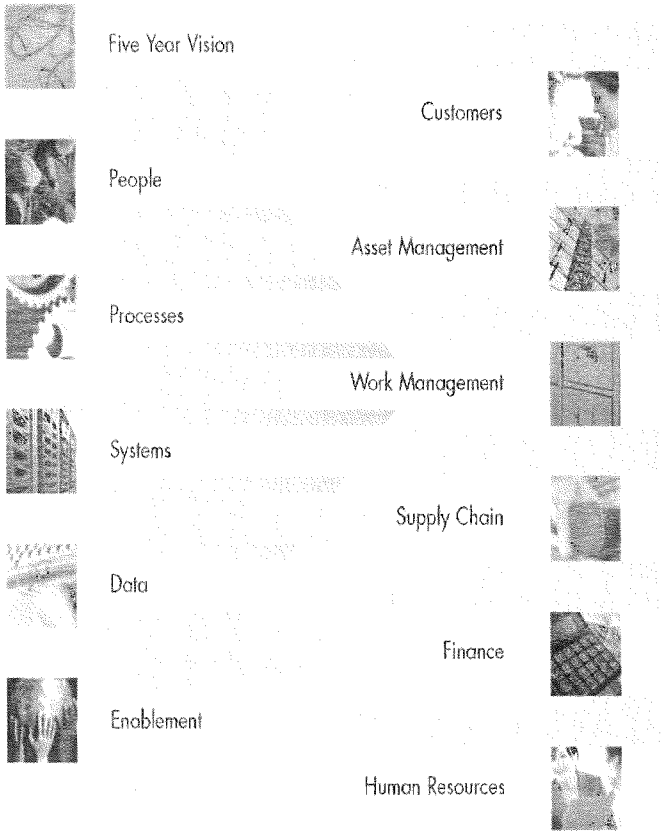
Business and IT Challenges make opportunity right for a more transformational program. "This is not an IT project"

Our Business Challenges		EAM Opportunities
Patchwork of highly customized, unsupported legacy systems		*A consolidated and integrated platform…*
have led to		*will enable*
Siloed and complex processes	***EAM***	*Simplified and standardized end-to-end processes…*
and created		*and support*
Barriers to achieving integration cost savings		*Sustained integration cost savings*

Cornerstone: The Program

How SAP supports Hydro One's Transformation

CORNERSTONE



Cornerstone:
The Program Mission

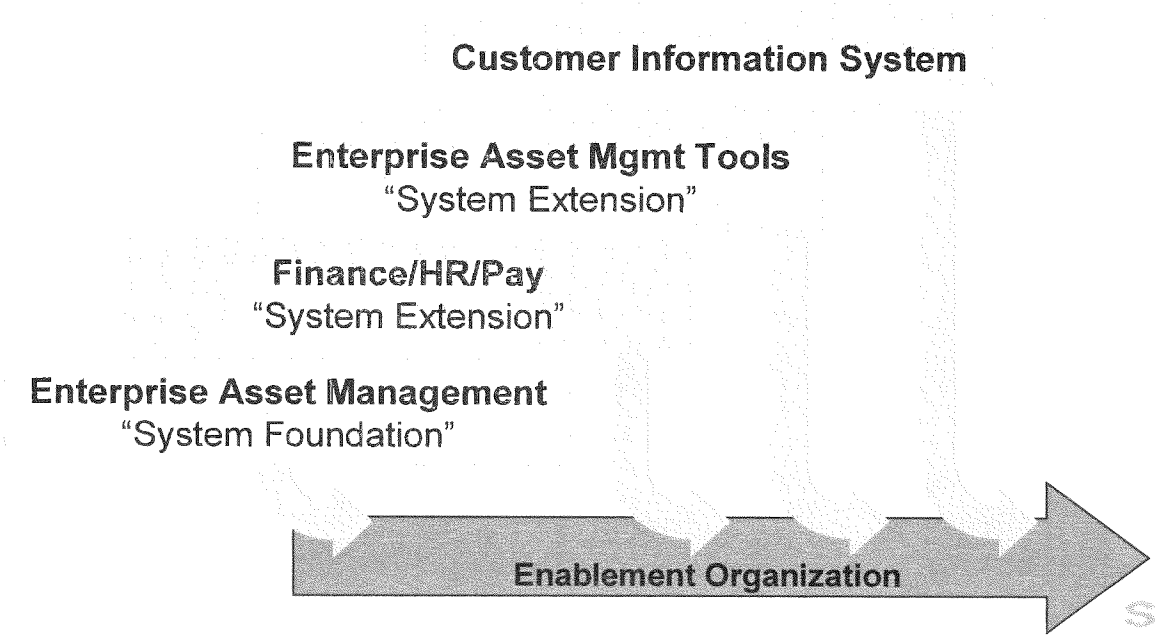
Support the Corporate Mission

Provide renewing and sustaining support for Hydro One's Internal Controls

Create more effective and efficient business operations

Enable achievement of corporate regulatory objective

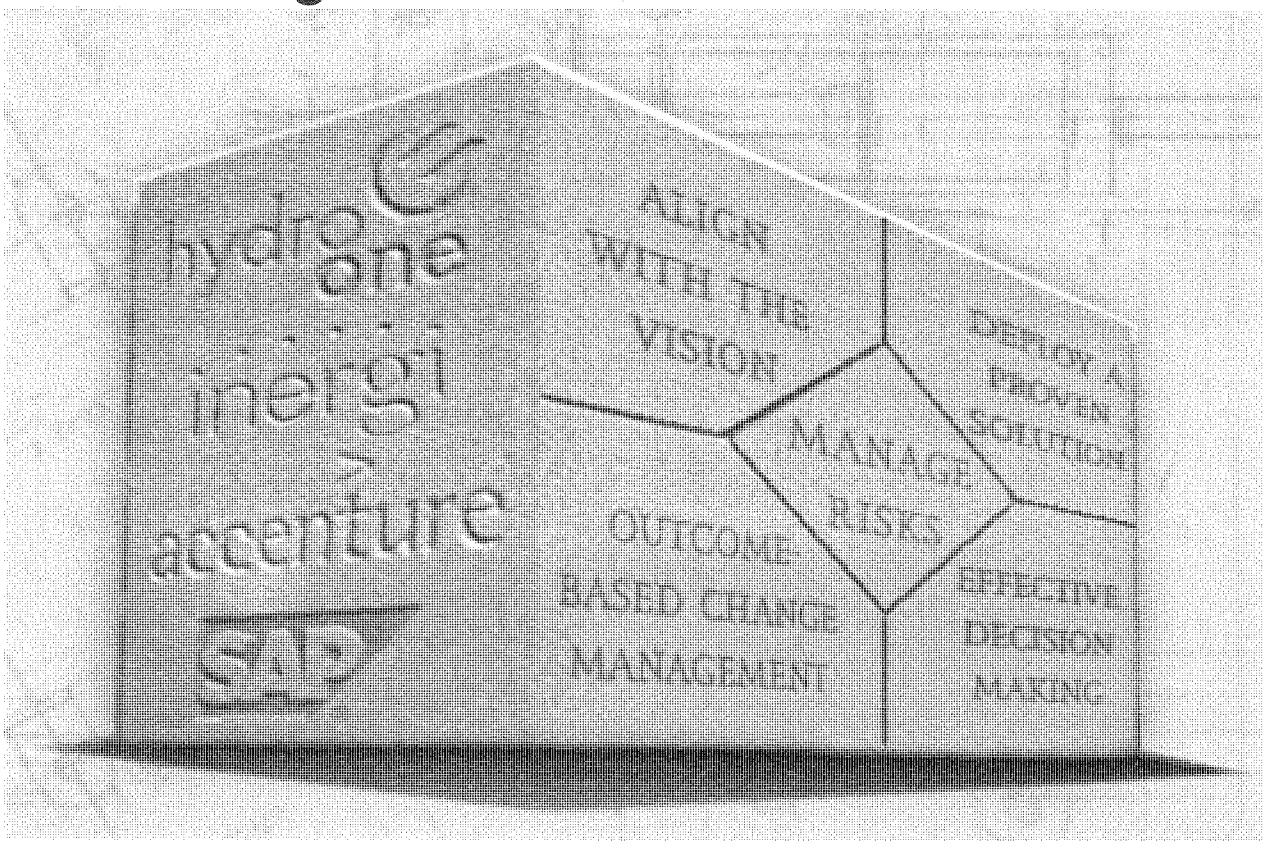
Drive Employee Engagement



Cornerstone:
Phase One – The Project Team

"The power of Four"

"Vanilla tastes great!"

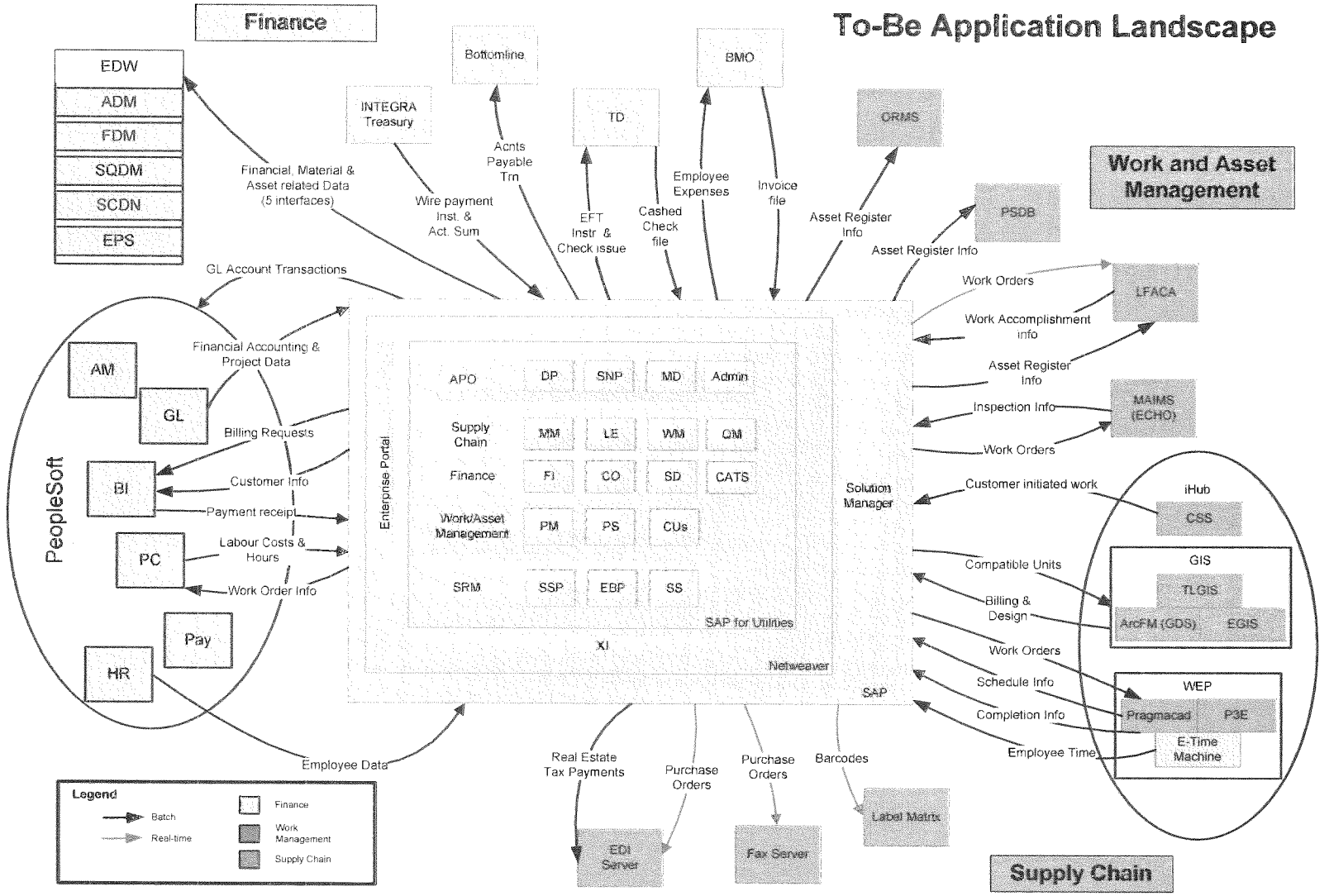


Cornerstone:
Phase One - Scope

Phase One will replace current Passport functionality in supply chain, work management, asset management, and accounts payable, with SAP functionality.

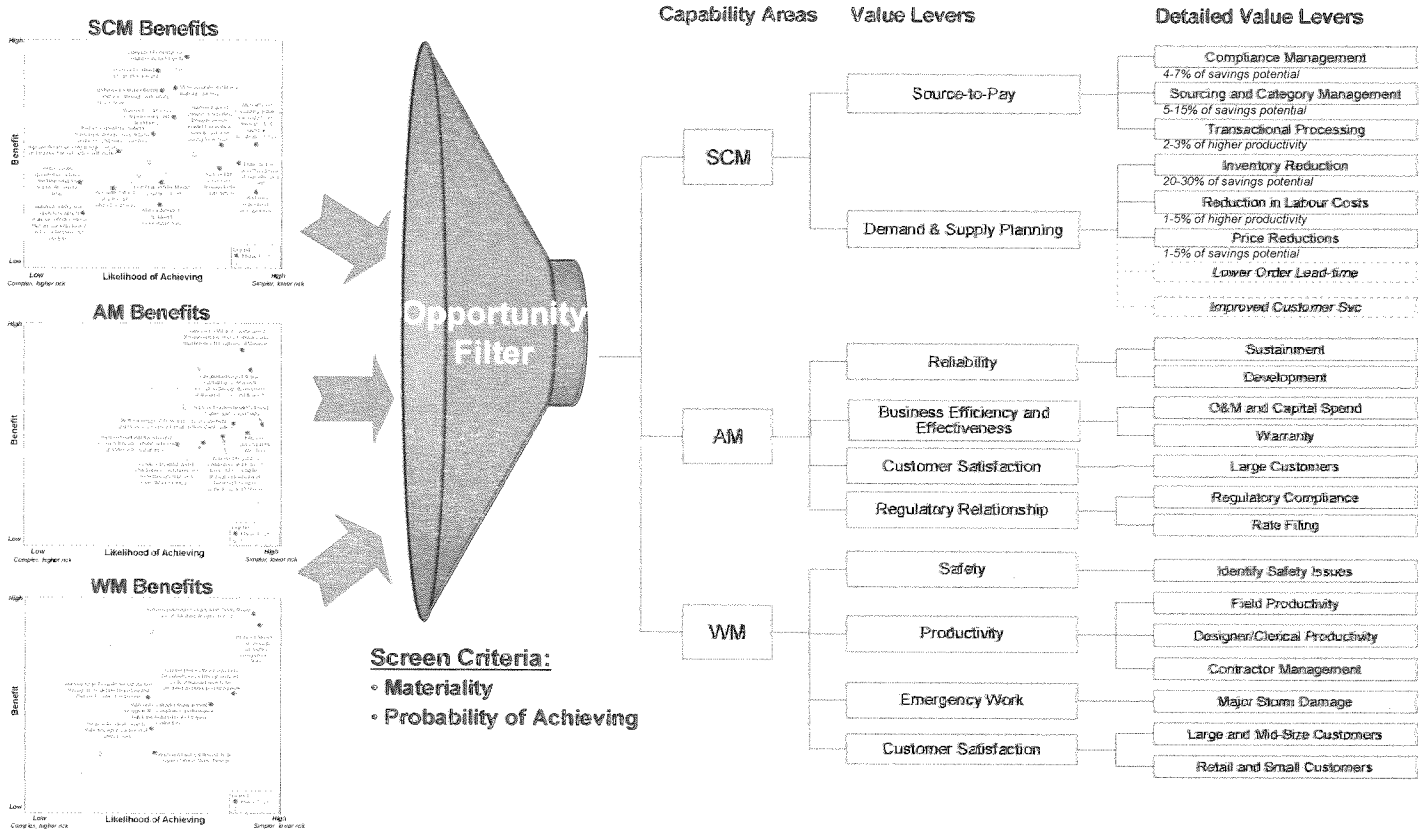
Functional Area	SAP Modules
Supply Chain	*ECC 6.0* *-MM, SD, PM, PS* *-WM, HR** *-FI (G/L, AR, AP)*
Accounts Payable	*SRM (APO)*
Work Initiation	*SCM*
Preventative Maintenance	*PI*
	EP

Cornerstone:
Phase One – Scope/Landscape



Cornerstone:
Phase One – Value Streams

Business benefits were identified, prioritized and driven down to detailed value levers. KPI creation is underway.



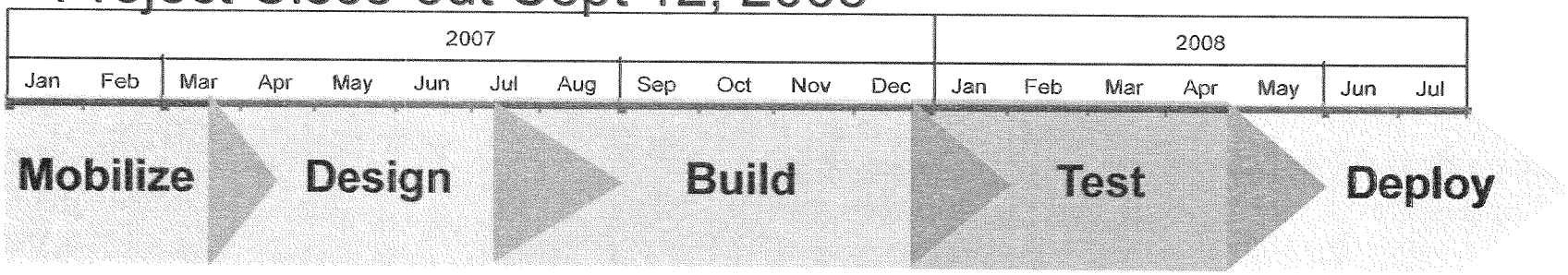
Cornerstone:
Phase One – Project Timeline

Project Mobilization January 2007

Go-Live of June 2nd 2008

Project Post Go-Live suspended July 31st 2008

Project Close-out Sept 12, 2008



 # Person days/# People on the project: 43,265/468

 # Deliverables produced: 861

 # Issues raised/addressed: 721

 # Change Requests addressed: 436

 # Test Scenarios executed/Total SIRs: 868/1097

 # Tasks on Cutover Plan: 1287

 # People Classroom Trained prior to go-Live: 2221

Cornerstone:
Phase One – Transition to Enablement

The 'Project' Phase of the Project may be over – but the "real" work is just beginning.

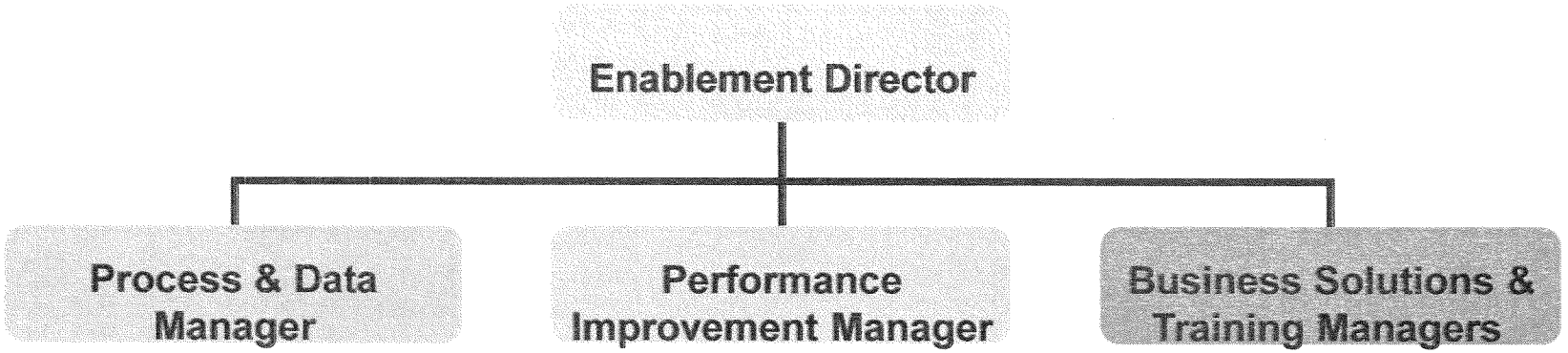
Hydro One has set up an Enablement organization to continue to drive value from Cornerstone long-term

VISION

The Enablement Organization will drive productivity through enterprise process improvements and ensure we leverage the Cornerstone Assets to their full potential

Cornerstone:
Phase One – Transition to Enablement

Enablement Structure and Guiding Principles

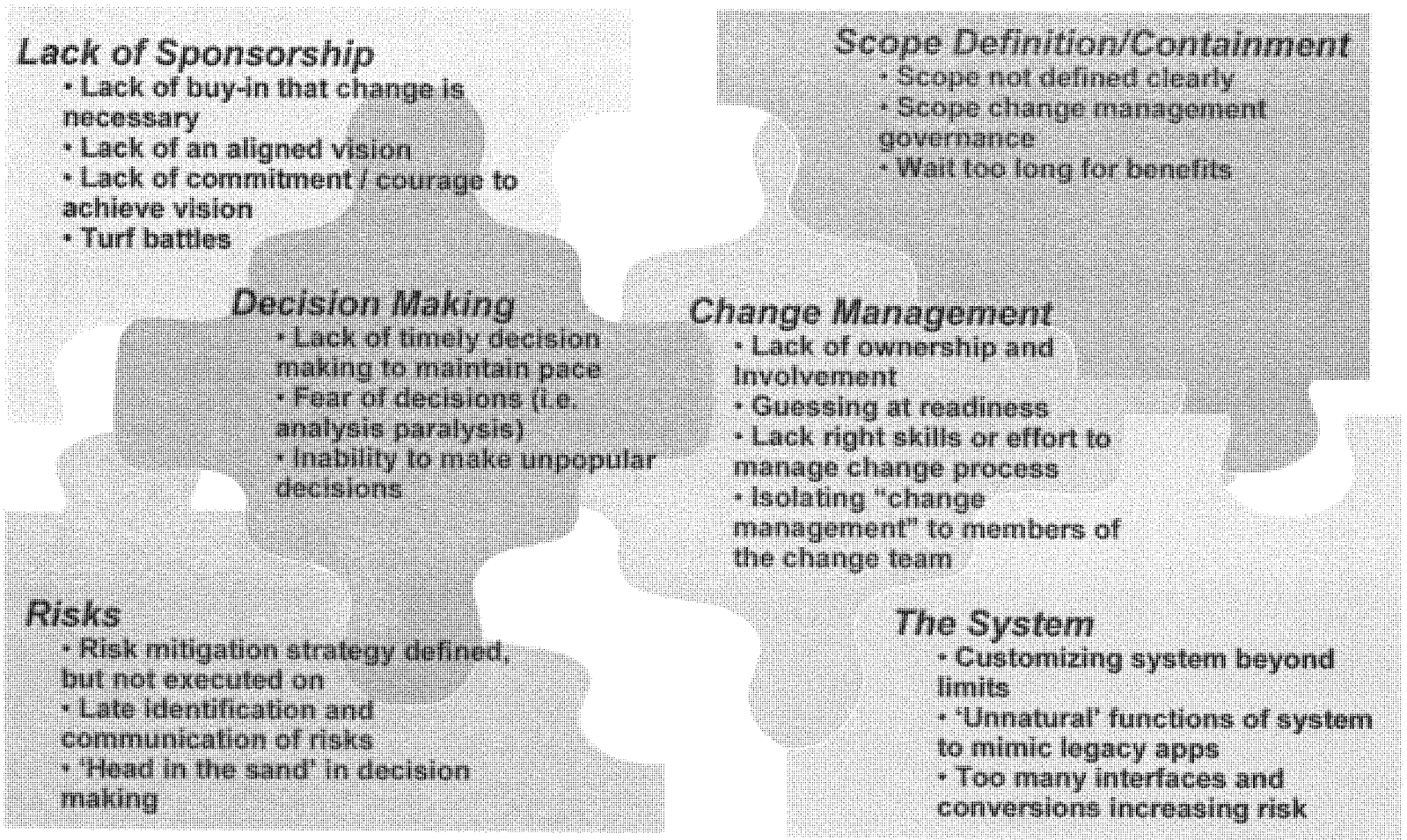


Enablement Guiding Principles

- Continuously leverage the Cornerstone investment
- Improve impacted business processes on an ongoing basis
- Identify and prioritize business improvements based on measurable and verifiable value
- Govern data as an asset to drive better analysis and decision making
- Increase end user productivity and quality of work

Cornerstone: Project/Program Success

Cornerstone "Why Projects Fail" Placemat

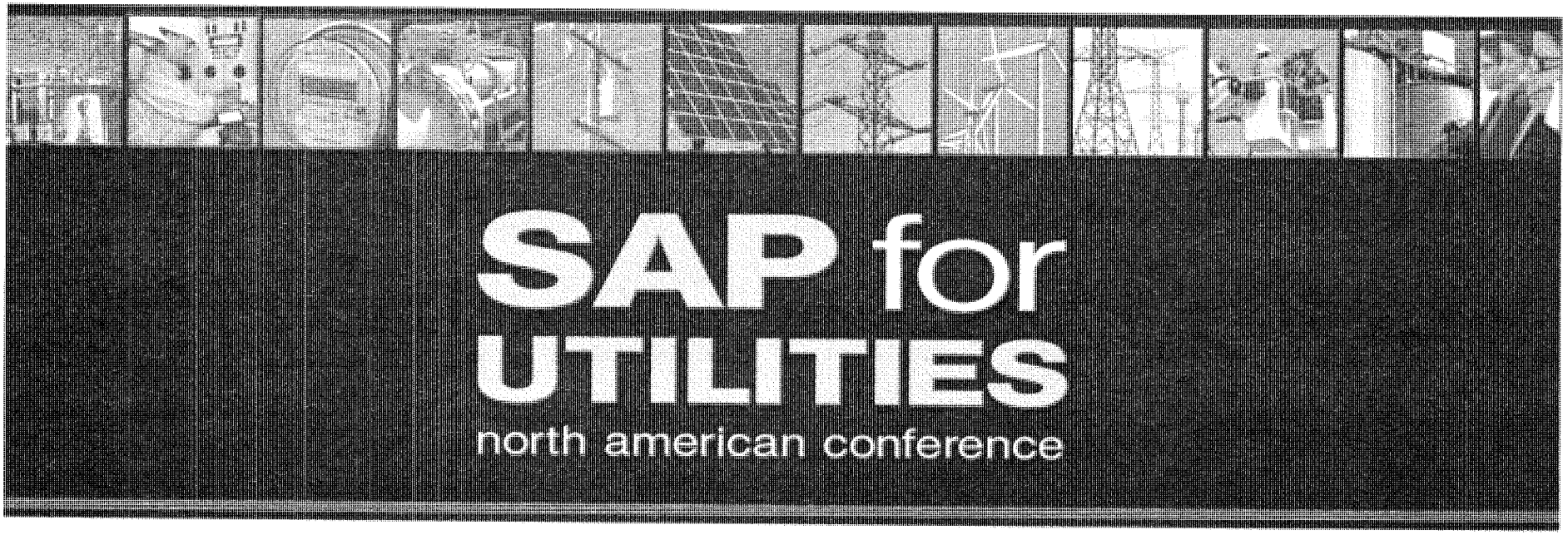


Cornerstone: Project/Program Success

Cornerstone Program Values

- Collaborative relationships
- Respect and trust for one another
- Badgeless
- Client focused
- Transparency
- Sponsor support
- Empowered teams

Questions?



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Brian Martin

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This is Exhibit "B" referred to in the Affidavit of M. Lilly Iannacito sworn April 13, 2016

Commissioner for Taking Affidavits (or as may be)

LISA S. LUTWAK

SHARED SERVICES - CORNERSTONE CAPITAL

1.0 OVERVIEW

The Cornerstone Project is part of the overall information technology ("IT") strategy to replace several of Hydro One's key enterprise information systems as they reach their 'end of life'. The Cornerstone Project is also a major business process transformation initiative that provides a platform for further effectiveness and efficiency gains at Hydro One. The Cornerstone Project is to be carried out in four phases as summarized below:

Phase 1 (Completed June 2008): Replace end of life Passport application and functionality associated with work management, supply chain, procurement, accounts payable and asset registry with a modern Enterprise Asset Management ("EAM") solution using SAP. This phase was completed successfully in June 2008.

Phase 2 (In-Service Q3 2009): Replace end of life Peoplesoft application for Finance/Human Resources/Payroll processing with functionality provided by SAP that is integrated with the EAM solution installed in Phase 1. Also address the currently anticipated analytical and reporting business needs and requirements for International Financial Reporting Standards ("IFRS") compliance. It is expected that additional releases will be required in late 2009 or early 2010 to address any late changes in IFRS requirements.

Phase 3 (In-Service 2012): Enhance integrated planning by expanding Hydro One's SAP solution and integrating key systems/technologies and specialized packaged point solutions to drive additional business value, improve end-to-end process efficiency and improve asset lifecycle management analytics/decisions. This includes adding SAP functionality by turning on new SAP modules (including workflow for process control);

integrating specialized software applications for reliability centred maintenance optimization and scheduling/dispatch; interfacing key enterprise systems (e.g. graphical information system ("GIS"), operating, fleet, telecom, protection & control, etc); incorporating new assets into the asset registry (e.g. IT assets, real estate assets, metering assets, etc); deploying enterprise mobile strategy across the province; and consolidating end-user databases/applications.

Phase 4 (2016): Replace end of life customer service system ("CSS") or Customer-1 application.

Table 1 below identifies the capital expenditures and savings for the Cornerstone program for the period 2006 to 2011.

Table 1
Cornerstone Capital 2006 – 2011 ($ Millions)

	Historic			Bridge	Test		Allocated to Distribution	
	2006	**2007**	**2008**	**2009**	**2010**	**2011**	**2010**	**2011**
Minor Fixed Assets	**0**	**3.2**	**7.2**	5.3	1.3	1.5	0.7	0.8
Development Projects	**0**	**60.4**	**99.9**	97.2	22.7	19.3	10.0	8.5
Total Capital Cost	**0**	**63.6**	**107.1**	102.5	24.0	20.8	10.7	9.3
Savings	**0**	**0**	**0**	(8.0)	(10.5)	(19.9)	(3.1)	(6.1)
Net Capital Cost	**0**	**63.6**	**107.1**	**94.5.**	**13.5**	**0.9**	**7.6**	**3.2**

The Cornerstone capital expenditures consist of Minor Fixed Assets and Development Costs. The latter include all the costs to acquire, install and place into service the new Cornerstone systems. Cornerstone capital expenditures support the Sustainment, Development, and Operations work programs of Hydro One Networks Inc. As such they consist of assets that are largely shared by both the Transmission and Distribution

businesses. The differences in year to year expenditures are the result of the phasing of Cornerstone implementation. This table also shows the forecast capital savings arising from Cornerstone process improvements and the result of netting these savings against the total capital costs. These savings are discussed later in this schedule.

The Cornerstone Project O&M spending and the percent allocation to Distribution over the Historic, Bridge, and Test years are shown in Exhibit C1, Tab 2, Schedule 10. In Exhibit C1, Tab 5, Schedule 3 the appropriate cost allocation drivers that have been utilized to derive the Distribution allocation of the Cornerstone Project are shown.

2.0 BACKGROUND

The capital work program for Cornerstone commenced in 2007. Phase 1 of the project was successfully completed in June 2008, Phase 2 is scheduled for completion in August 2009 and work has begun on Phase 3. The four phases of the Cornerstone Project are discussed below:

Phase 1 – Enterprise Asset Management Core Functionality (Completed June 2008)

The EAM initiative replaced the existing Passport applications with a modern EAM solution in June 2008. The result is an integrated EAM application to allow for more effective information transfer within the Company and provide the basis for connectivity with other core systems as they are replaced or upgraded.

Hydro One started Phase I after obtaining Hydro One Board of Director approval in February 2007 and successfully implemented ("go-live") Phase 1 on June 30, 2008. Phase 1 delivers an EAM solution that replaces existing Passport functionality; provides additional enhancement/capability to facilitate business process improvements;

establishes data governance and data structure for ongoing data collection and management activities; addresses Bill 198 and other regulatory compliance requirements; and provides the basis for future phases of the project by turning on and utilizing additional modules within the same application suite.

The benefits from Phase 1 are based upon a complete understanding of the benefits from the SAP application. These benefits are derived from three key value levers underpinned by Cornerstone Phase 1 application, process and organizational changes. These value levers are:

- Centralizing to a single asset registry with a uniform hierarchy and selective integration to legacy databases;

- Providing greater process transparency, integration and collaboration (enabled through the application and process changes) across Hydro One's lines of business ("LOB"); and,

- Enhancing compliance to the underlying processes and data requirements.

Phase 1 savings (both Transmission and Distribution) total $200 million over a seven year period starting in 2009 to 2015. Total savings of $50.4M are expected in the test years 2010 and 2011 as shown in Table 2.

Table 2
Total Cornerstone Phase 1 Savings ($M) (Transmission & Distribution)

	2010	2011
OM&A	13.0	16.5
Capital	9.2	11.8
Total	22.2	28.3

The bulk of the total savings are through the following:

- Optimize O&M and Capital spend through enhanced asset analysis and maintenance by managing operational risks over the asset life cycle (Expected Savings $50.3M).
- Enhanced crew productivity due to better materials availability through more efficient forecasting, planning and execution. The contribution to improvement in crew productivity results from having the right materials available at the right time and the right location (Expected Savings $35.5M).
- Improve internal & supplier contract compliance through reduction in non – Purchase Order spend for direct purchase of materials and services. This benefit is derived from all users purchasing standardized materials and services off negotiated contracts at agreed prices and terms (Expected Savings $35M).

Each of the future phases build on the foundation set by Phase 1. Each of Phases 1, 2 and 3 will utilize the interconnected SAP application platform. Each phase is stand-alone to the extent that each will add its own benefits to the overall Cornerstone program.

Phase 2 – Replace PeopleSoft Finance/Human Resources/Payroll Functionality (In-Service Q3 2009)

By Q3 2009, Phase 2 will replace existing end-of-life PeopleSoft Finance, Human Resources ("HR") and Payroll processing with functionality provided by SAP that is integrated with the EAM solution installed in Phase 1. Phase 2 also addresses the current anticipated analytical and reporting business needs and the requirement to be compliant with International Financial Reporting Standards by January 1, 2011 as discussed in the project investment justification document shown in Exhibit D2, Tab 2, Schedule 3. It is expected that additional releases will be required in late 2009 or early 2010 to address any late changes in IFRS requirements.

The PeopleSoft Finance, HR and Payroll processing modules were installed in 1998 and the HR module was upgraded in 2002 and subsequently customized. These systems are core to Hydro One's financial reporting and human resource management capability.

Cornerstone Phase 2 proposes to expand Hydro One's SAP solution footprint to replace PeopleSoft; provide one integrated system of record for all finance, HR and asset data and bring a greater proportion of Hydro One's core business systems under vendor support. The scope also covers the following:

- replace the in-house application, Business, Regulatory Planning & Reporting ("BRPR"), which tracks the release of work from Asset Management to the field, with SAP business planning and investment management functionality;
- replace legacy data warehouse applications and databases with a single SAP business data warehouse and a reporting tool, to provide one source of reliable business data; and

- address currently anticipated International Financial Reporting Standards ("IFRS") requirements to accommodate IFRS compliance by January 1, 2011. A parallel IFRS Project will be carried out to review Hydro One accounting policies/practices and recommend changes to meet IFRS compliance requirements. It is expected that many of these recommendations will be incorporated into the Phase 2 SAP solution while others will be addressed in subsequent releases of SAP, to address any late changes in IFRS requirements so as to provide full IFRS compliance before the January 1, 2011 deadline. A full discussion of IFRS is provided in Exhibit A, Tab 13, Schedule 1.

Phase 2 of Cornerstone was undertaken following a competitive RFP selection and discovery process completed in 2007 and early 2008, respectively, which was used to confirm cost and scope. Hydro One started Phase 2 after obtaining Hydro One Board approval in April 2008 and after successfully completing Phase 1 in June 2008.

As in Phase 1, the main objective is not only to install an off-the-shelf solution, but also to adopt industry-standard practices. Integration of the new finance and HR application with the modules installed in Phase 1 will enhance reporting capabilities. This will be done by providing Business Intelligence / Business Warehouse capability in Phase 2. Business intelligence is the capability of collecting and analyzing internal and external data to generate knowledge and value for the organization. Business Warehouse is making information readily accessible and available for analysis.

Inergi is working closely with Hydro One, in its role as outsource business service provider and as an end user of the applications and revised business processes. Inergi and its parent company, Cap Gemini, are working with Accenture, the system integrator, to ensure the solution delivered meets Hydro One's needs. Accenture, SAP and Cap Gemini/Inergi have all committed to delivering the required solution and working in a

collaborative and open process. Governance over the project includes oversight by a sub committee of the Hydro One Board of Directors, Executive and project level reviews and an ongoing Quality Assurance /Quality Control process implemented by Accenture.

The Phase 2 benefits build on the benefits derived from three key value levers underpinned by the Cornerstone Phase I application for technology, process and organizational changes. The Phase 2 savings total approximately $50 million with expected savings of about $9.4 million in the test years 2010 and 2011 as shown in Table 3 below.

Table 3
Total Cornerstone Phase 2 Savings ($M) (Transmission & Distribution)

	2010	2011
OM&A	2.6	3.2
Capital	1.3	2.3
Total	3.9	5.5

The Phase 2 savings are based upon the following benefits identified over a seven year period starting in 2010:

1. Replacement of the core Finance / Human Resources / Payroll Functionality

Expected Benefits $20M:

- Provide efficiency improvements that are driven by having a standardized platform for business process, technology and reporting and an integrated system of record within SAP for all asset and financial data;
- Improve IT security and internal control; and

- Avoid costs associated with maintaining and reconciling two separate financial system applications and having to implement IFRS compliance requirements in both (the SAP financials implemented with Phase 1, and the legacy PeopleSoft application.).

2. Business Intelligence/Business Warehouse

Expected Benefits $30M:

- Provide field supervisors with key operational data, standard reports and analytical tools to enable further workforce productivity improvements;
- Provide the centralized Asset Management group with a common and single source for information and better analytical tools to improve asset investment decisions; and
- Provide the Company with a tool to help realize and measure progress in realizing the business benefits of Cornerstone.

Phase 3 (In-Service 2012): Enhance Integrated Planning

Phase 3 will enhance integrated planning by expanding Hydro One's SAP solution and integrating key systems/technologies and specialized packaged point solutions to drive additional business value, improve end-to-end process efficiency and improve Asset Lifecycle Management analytics/decisions. This includes adding SAP functionality by turning on new SAP modules (including workflow for process control); integrating specialized software applications for reliability centred maintenance optimization and scheduling/dispatch; interfacing key enterprise systems (e.g. GIS, operating, fleet, telecom, protection & control, etc); incorporating new assets into the asset registry (e.g.

IT assets, real estate assets, metering assets, etc); deploying enterprise mobile strategy across the province; and consolidating end-user databases.

Hydro One business information consists of many different components that reside in many different sources even after completion of Phases 1 and 2. The key is to integrate these sources to allow for asset and other business data to be captured once and used consistently throughout the Company to provide asset and asset work information from a variety of perspectives e.g. system performance, asset condition, labour, cost (historical and forecasted), work accomplishment, performance and work metrics, customer reliability, outage management, etc. This facilitates breaking down the information silos and driving enterprise integration and improvements via process, people and technology. An essential element of this vision is to provide seamless integration of data between the asset registry, work orders, scheduling/dispatch and GIS system using mobile technology. This phase enhances and streamlines end-to-end business processes by expanding and leveraging the SAP application functionality to implement workflow for process control, consolidate and eliminate duplicative and disparate end-user databases/applications to increase the assets being managed in SAP and integrating/interfacing key systems (e.g. operating, real estate, fleet, protection & control, telecom, metering, etc) to provide a centralized asset repository and single source of truth across all lines of business.

Phase 3 will also integrate SAP to the enterprise GIS system and to operating scheduling/ dispatch using standard mobile technology that is deployed to field staff across the province. It will integrate legacy historical information with current SAP data to facilitate trend analysis and performance forecasts and integrate new reliability centred maintenance optimization software to provide ongoing analysis of preventative maintenance results, validation of asset models, and facilitate strategic/scenario planning that is focused on improving asset lifecycle management decisions.

Hydro One expects savings from improved processes, elimination of duplicative data systems and improved transparency across the organization. The Phase 3 savings total approximately $130 million over a seven year period with expected savings of $14 million starting to flow in the test year 2011 as shown in table 4 which follows.

Table 4
Total Cornerstone Phase 3 Savings ($M) (Transmission & Distribution)

	2010	2011
OM&A	0	8.7
Capital	0	5.2
Total	0	14.0

Phase 4 (In-Service 2016) - Replace Customer Information System Functionality

The CSS or Customer-1 application was purchased in 1997 from Andersen Consulting (now Accenture). The application has undergone significant modifications in order to address the changes in the Ontario regulatory environment and to meet Ontario Energy Board requirements. This is an extensively customized product which is very costly to maintain and very costly to modify to meet new regulatory and business needs. Accenture no longer supports the application.

To obtain full functionality with the newer systems, and to improve workflow and improve customer satisfaction, the intent of Phase 4 is to replace the existing Customer-1 system with a more integrated application which would interface with the application suite implemented in Phases 1, 2 and 3.

This is Exhibit "C" referred to in the Affidavit of M. Lilly Iannacito sworn April 13, 2016

Lisa Lutwak

Commissioner for Taking Affidavits (or as may be)

LISA S. LUTWAK

SHARED SERVICES CAPITAL - CORNERSTONE

1.0 OVERVIEW

The Cornerstone Project is part of the overall information technology ("IT") strategy to replace several of Hydro One's key enterprise information systems as they reach their 'end of life'. The Cornerstone Project is also a major business process transformation initiative that provides a platform for further effectiveness and efficiency gains at Hydro One. The Cornerstone Project is to be carried out in four phases as summarized below:

Phase 1 (Completed June 2008): Replaced end of life Passport application and functionality associated with work management, supply chain, procurement, accounts payable and asset registry with a modern Enterprise Asset Management ("EAM") solution using SAP. This phase was completed successfully in June 2008.

Phase 2 (Majority Completed August 2009, minor items to be completed in 2010): Replaced end of life PeopleSoft application for Finance / Human Resources / Payroll processing with functionality provided by SAP that is integrated with the EAM solution installed in Phase 1. The phase 2 implementation also addressed the analytical and reporting business needs for work management, finance, investment management, HR and Pay and requirements for International Financial Reporting Standards ("IFRS") compliance. Additional releases will be required in 2010 to address the most recent requirements for IFRS and final phase 2 reporting and analytical requirements.

Phase 3 (In-Service 2010-2012): Enhance integrated planning, Enterprise Asset Management / Enterprise Resource Planning systems, tools and processes by expanding Hydro One's SAP solution and integrating key systems/technologies and specialized packaged point solutions to drive additional business value, improve end-to-end process

efficiency and improve asset lifecycle management analytics/decisions. This includes adding SAP functionality by turning on new SAP modules; integrating specialized software applications for reliability centred maintenance & optimization, scheduling & dispatch enhancements; interfacing key enterprise systems (e.g. geospatial information system ("GIS"), operating, fleet, telecom, protection & control, etc); incorporating new assets into the asset registry (e.g. IT assets, real estate assets, metering assets, etc); integration with enterprise mobile technology, enhancing functionality for HR, Finance, Work Management and Supply Chain and consolidating end-user databases/applications.

Phase 4 (2016): Replace end of life customer information system ("CIS"). Core product is Customer-1 application with numerous best of breed and custom applications fulfilling the remaining functionality of the CIS.

Table 1 below identifies the capital expenditures and savings for the Cornerstone program for the period 2007 to 2012.

Table 1
Cornerstone Capital 2007 – 2012 ($ Millions)

	Historic			Bridge	Test		TX Allocated	
	2007	**2008**	**2009**	**2010**	**2011**	**2012**	**2011**	**2012**
Minor Fixed Assets	3.2	7.2	0.2	2.0	1.5	2.1	0.6	0.9
Development Projects	60.4	99.9	90.8	32.9	19.4	27.2	10.9	15.2
Total Capital Cost	63.6	107.1	91.0	34.9	20.9	29.3	11.5	16.1
Savings	0	0	*	(10.8)	(13.9)	(22.1)	(9.5)	(15.9)
Net Capital Cost	**63.6**	**107.1**	**91.0**	**24.1**	**7.0**	**7.2**	**2.0**	**0.2**

* 8.0 million in savings realized in 2009

The Cornerstone capital expenditures consist of Minor Fixed Assets and Development Costs. The latter include all the costs to acquire, install and place into service the new Cornerstone systems. Cornerstone capital expenditures support the Sustainment, Development, and Operations work programs of Hydro One Networks Inc. As such they consist of assets that are largely shared by both the Transmission and Distribution businesses. The differences in year to year expenditures are the result of the phasing of Cornerstone implementation. This table also shows the forecast capital savings arising from Cornerstone process improvements and the result of netting these savings against the total capital costs. These savings are discussed later in this schedule.

The Cornerstone Project O&M spending and the percent allocation to Transmission over the Historic, Bridge, and Test years are shown in Exhibit C1, Tab 2, Schedule 10. In Exhibit C1, Tab 5, Schedule 3 the appropriate cost allocation drivers that have been utilized to derive the Distribution allocation of the Cornerstone Project are shown.

2.0 BACKGROUND

The capital work program for Cornerstone commenced in 2007. Phase 1 of the project was successfully completed in June 2008. The majority of Phase 2 was completed in August 2009. Work has begun on Phase 3. The four phases of the Cornerstone Project are discussed below:

Phase 1 – Enterprise Asset Management Core Functionality (Completed June 2008)

The EAM initiative replaced the existing Passport applications with a modern EAM solution in June 2008. The result is an integrated EAM application that has enabled more effective information transfer within the Company and provided the basis for connectivity with other core systems as they are replaced or upgraded.

Hydro One started Phase I after obtaining Hydro One Board of Director approval in February, 2007 and successfully implemented ("go-live") Phase 1 on June 30, 2008. Phase 1 delivered an EAM solution that replaced legacy Passport functionality; provided additional enhancement/capability to facilitate business process improvements; established data governance and data structure for ongoing data collection and management activities; addressed Bill 198 and other regulatory compliance requirements; and provided the basis for future phases of the project by turning on and utilizing additional modules within the same application suite.

The benefits from Phase 1 are based upon a complete understanding of the benefits from the SAP application. These benefits are derived from three key value levers underpinned by Cornerstone Phase 1 application, process and organizational changes. These value levers are:

- Centralizing to a single asset registry with a uniform hierarchy and selective integration to legacy databases;
- Providing greater process transparency, integration and collaboration (enabled through the application and process changes) across Hydro One's lines of business ("LOB"); and,
- Enhancing compliance to the underlying processes and data requirements.

Phase 1 savings (both Transmission and Distribution) total $200 million over a seven year period starting in 2009 to 2015. Total savings of $60.4M are expected in the test years 2011 and 2012 as shown in Table 2.

Table 2
Total Cornerstone Phase 1 Savings ($M) (Transmission & Distribution)

	2011	2012
OM&A	16.5	19.0
Capital	11.6	13.3
Total	28.1	32.3

The bulk of the total savings are through the following:

- Optimize O&M and Capital spend through enhanced asset analysis and maintenance by managing operational risks over the asset life cycle (Expected Savings $50.3M).
- Enhanced crew productivity due to better materials availability through more efficient forecasting, planning and execution. The contribution to improvement in crew productivity results from having the right materials available at the right time and the right location (Expected Savings $35.5M).
- Improve internal & supplier contract compliance through reduction in non – Purchase Order spend for direct purchase of materials and services. This benefit is derived from all users purchasing standardized materials and services off negotiated contracts at agreed prices and terms (Expected Savings $35M).

Each of the future phases build on the foundation set by Phase 1. Each of Phases 1, 2 and 3 will utilize the interconnected SAP application platform. Each phase is stand-alone to the extent that each will add its own benefits to the overall Cornerstone program.

Phase 2 – Replaced PeopleSoft Finance / Human Resources / Payroll Functionality (Majority Completed August 2009, minor items to be completed in Q1-Q3 2010)

In August, 2009, Phase 2 replaced existing end-of-life PeopleSoft Finance, Human Resources ("HR") and Payroll processing with functionality provided by SAP that is integrated with the EAM solution installed in Phase 1. Phase 2 also addressed analytical and reporting business needs and helped to fulfill the requirement to be compliant with International Financial Reporting Standards by January 1, 2011 as discussed in the project investment justification document shown in Exhibit D2, Tab 2, Schedule 3. Additional releases are currently underway to address additional changes in IFRS requirements and final reporting and analytical requirements.

The PeopleSoft Finance, HR and Payroll processing modules were installed in 1998 and the HR module was upgraded in 2002 and subsequently customized. These systems were core to Hydro One's financial reporting and human resource management capability.

Cornerstone Phase 2 expanded Hydro One's SAP solution footprint by replacing PeopleSoft; providing one integrated system of record for all finance, HR and asset data and bring a greater proportion of Hydro One's core business systems under vendor support. The scope also covered the following:

- replaced the in-house application, Business, Regulatory Planning & Reporting ("BRPR"), which tracked the release of work from Asset Management to the field, with SAP investment management functionality;
- replaced legacy data warehouse applications and databases with a single SAP business data warehouse and the business objects reporting suite, to provide one source of reliable business data; and

- Addressed International Financial Reporting Standards ("IFRS") requirements to accommodate IFRS compliance by January 1, 2011. A parallel IFRS Project has been carried out to review Hydro One accounting policies/practices and recommend changes to meet IFRS compliance requirements. Many of these recommendations were incorporated into the Phase 2 SAP solution while others will be addressed in subsequent releases of SAP, to address any late changes in IFRS requirements so as to provide full IFRS compliance before the January 1, 2011 deadline. A full discussion of IFRS is provided in Exhibit A, Tab 13, Schedule 1.

Phase 2 of Cornerstone was undertaken following a competitive RFP selection in late 2007 / early 2008 and the discovery process completed in 2008, which was used to confirm cost and scope. Hydro One started Phase 2 discovery work after obtaining Hydro One Board approval in May, 2008 and continued project delivery after successfully completing Phase 1 in June 2008.

As in Phase 1, the main objective was not only to install an off-the-shelf solution, but also to adopt industry-standard practices. Integration of the new finance and HR application with the modules installed in Phase 1 has enhanced reporting capabilities. This was done by providing Business Intelligence / Business Warehouse capability in Phase 2. Business intelligence is the capability of collecting and analyzing internal and external data to generate knowledge and value for the organization. Business Warehouse is making information readily accessible and available for analysis.

Inergi worked closely with Hydro One, in its role as outsource business service provider and as an end user of the applications and revised business processes. Inergi and its parent company, Cap Gemini, worked with Accenture, the system integrator, to ensure the solution delivered met Hydro One's needs. Accenture, SAP and Cap Gemini/Inergi committed to delivering the required solution and working in a collaborative and open

process. Governance over the project included oversight by a sub committee of the Hydro One Board of Directors, Executive and project level reviews and an ongoing Quality Assurance /Quality Control process implemented by Accenture.

The Phase 2 benefits built on the benefits derived from three key value levers underpinned by the Cornerstone Phase 1 application for technology, process and organizational changes. The Phase 2 savings total approximately $50 million with expected savings of about $5.5 million in the test year 2011 and $7.0 million in 2012 as shown in Table 3 below.

Table 3
Total Cornerstone Phase 2 Savings ($M) (Transmission & Distribution)

	2011	2012
OM&A	3.2	4.1
Capital	2.3	2.9
Total	5.5	7.0

The Phase 2 savings are based upon the following benefits identified over a seven year period starting in 2010:

2.1 Replacement of the core Finance / Investment Management / Time Reporting / Human Resources / Payroll Functionality

Expected Benefits $20M:

- Provide efficiency improvements that are driven by having a standardized platform for business process, technology and reporting and an integrated system of record within SAP for all asset and financial data;
- Improve IT security and internal control; and

- Avoid costs associated with maintaining and reconciling two separate financial system applications and having to implement IFRS compliance requirements in both (the SAP financials implemented with Phase 1, and the legacy PeopleSoft application.).

2.2 Business Intelligence/Business Warehouse

Expected Benefits $30M:

- Provide field supervisors with key operational data, standard reports and analytical tools to enable further workforce productivity improvements;
- Provide the centralized Asset Management group with a common and single source for information and better analytical tools to improve asset investment decisions; and
- Provide the Company with a tool to help realize and measure progress in realizing the business benefits of Cornerstone.

Phase 3 (In-Service 2010-2012): Enhance Integrated Planning

Phase 3 will enhance integrated planning and Enterprise Asset Management / Enterprise Resource Planning systems, tools and processes by expanding Hydro One's SAP solution and integrating key systems/technologies and specialized packaged point solutions to drive additional business value, improve end-to-end process efficiency and improve asset lifecycle management analytics/decisions. This includes adding SAP functionality by turning on new SAP modules; integrating specialized software applications for reliability centred maintenance & optimization, scheduling & dispatch enhancements; interfacing key enterprise systems (e.g. geospatial information system ("GIS"), operating, fleet, telecom, protection & control, etc); incorporating new assets into the asset registry (e.g.

IT assets, real estate assets, metering assets, etc); integration with enterprise mobile technology and enhancing functionality for HR, Finance, Work Management and Supply Chain and consolidating end-user databases/applications.

Hydro One business information consists of many different components that reside in many different sources even after completion of Phases 1 and 2. The key is to integrate these sources to allow for asset and other business data to be captured once and used consistently throughout the Company to provide asset and asset work information from a variety of perspectives e.g. system performance, asset condition, labour, cost (historical and forecasted), work accomplishment, performance and work metrics, customer reliability, outage management, etc. This facilitates breaking down the information silos and driving enterprise integration and improvements via process, people and technology. An essential element of this vision is to provide seamless integration of data between the asset registry, work orders, scheduling/dispatch and GIS system with mobile integration. This phase enhances and streamlines end-to-end business processes by expanding and leveraging the SAP application functionality to implement workflow for process control, consolidate and eliminate duplicative and disparate end-user databases/applications to increase the assets being managed in SAP and integrating/interfacing key systems (e.g. operating, real estate, fleet, protection & control, telecom, metering, etc) to provide a centralized asset repository and single source of truth across all lines of business.

Phase 3 will also integrate SAP to the enterprise GIS system and to operating scheduling/ dispatch leveraging enterprise mobile technology that is deployed to field staff across the province. It will integrate legacy historical information with current SAP data to facilitate trend analysis and performance forecasts and integrate new reliability centred maintenance optimization software to provide ongoing analysis of preventative maintenance results, validation of asset models, and facilitate strategic/scenario planning that is focused on improving asset lifecycle management decisions.

Phase 3 will be completed late in 2011 and savings are not expected to be realized until 2012. Hydro One expects savings from improved processes, elimination of duplicative data systems and improved transparency across the organization. The Phase 3 expected savings total approximately $130 million over a seven year period with expected savings of $14.1 million starting in 2012 as shown in table 4.

Table 4
Total Cornerstone Phase 3 Savings ($M) (Transmission & Distribution)

	2011	2012
OM&A	0.0	8.2
Capital	0.0	5.9
Total	0.0	14.1

Phase 4 (In-Service 2016) - Replace Customer Information System Functionality

The CSS or Customer-1 application was purchased in 1997 from Andersen Consulting (now Accenture). The application has undergone significant modifications in order to address the changes in the Ontario regulatory environment and to meet Ontario Energy Board requirements. This is an extensively customized product which is very costly to maintain and very costly to modify to meet new regulatory and business needs. Accenture no longer supports the application.

To obtain full functionality with the newer systems, and to improve workflow and improve customer satisfaction, the intent of Phase 4 is to replace the existing Customer-1 system with a more integrated application which would interface with the application suite implemented in Phases 1, 2 and 3.

This is Exhibit "D" referred to in the Affidavit of M. Lilly Iannacito sworn April 13, 2016

Lisa Lutwak

Commissioner for Taking Affidavits (or as may be)

LISA S. LUTWAK

Hydro One Inc.
Submission to the Board of Directors

hydro One

Filed: June 15, 2012
EB-2012-0136
Exhibit B-3-1
Attachment 2
Page 1 of 7

Date: May 12, 2011

Subject: Cornerstone Phase 4 – Request for Funding

Submitted by:	**Approved for Submission to the Board by:**
INFORMATION COPY Original Signed by: Carmine Marcello	INFORMATION COPY ORIGINAL SIGNED BY LAURA I. FORMUSA
Carmine Marcello	Laura Formusa
Executive Vice President, Strategy	President and Chief Executive Officer

RECOMMENDATION

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

KEY HIGHLIGHTS

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

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

EXECUTIVE SUMMARY

Background

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

1. Strategic Significance:

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

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

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

2. Purpose

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

Realize Immediate Value:

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

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

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

Address Current Need:

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

Core Deliverables for Phase 4 include:

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

3. Alternatives

a) Proceed indefinitely with the current legacy system

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

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

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

c) Replace CIS after expiry of current outsourcing contract

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

4. Cost Estimate and Recovery

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

The overall Cornerstone Program costs and benefits are as follows:

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

[1] Actual cost of phase 1 and 2 projects

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

5. Regulatory

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

6. Risk Analysis

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

This is Exhibit "E" referred to in the Affidavit of M. Lilly Iannacito sworn April 13, 2016

Commissioner for Taking Affidavits (or as may be)

LISA S. LUTWAK

Filed: June 15, 2012
EB-2012-0136
Exhibit A-4-1
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hydro one

Cornerstone Phase 4

CIS Replacement

Stakeholder Session

Wednesday June 29, 2011
1:30 – 4:00 p.m.
Victoria Room
Metropolitan Hotel
108 Chestnut Street, Toronto

OPTIMUS | SBR

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The presentation materials used in this session and background materials can be found at this link:
www.HydroOne.com/Regulatory Affairs

Participants

Stakeholders

David MacIntosh—Energy Probe
Harold Thiessen—Ontario Energy Board
Jack Hughes—Canadian Manufacturers and Exporters
Jake Brooks—Association of Power Producers of Ontario
Jay Shepherd—School Energy Coalition
Judy Simon—Low Income Energy Network
Julie Girvan—Consumers Council of Canada
Kim McKenzie—Power Workers' Union
Michelle Byck-Johnston – The Society of Energy Professionals
Roger Higgin—Vulnerable Energy Consumers Coalition
Shelly Grice—Association of Major Power Consumers of Ontario
Steve Zebrowski—Veridian Connections

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Myles D'Arcey, Senior Vice President, Customer Operations—Hydro One
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Susan Frank, VP & Chief Regulatory Officer—Hydro One
Allan Cowan, Director, Transmission Applications Regulatory Affairs—Hydro One
Jeff Smith, Director, Project Management & Control—Hydro One
Vicki Power, Advisor, Regulatory Affairs—Hydro One
Alex Hamlyn, Assistant, Network Management Engineer—Hydro One

OPTIMUS|SBR

Bob Betts—OPTIMUS|SBR
Angela Boychuk—OPTIMUS|SBR
Miles Smit—OPTIMUS|SBR

START 1:35pm

1.0 Welcome by Allan Cowan, Director, Major Applications

Allan Cowan welcomed all participants to the Stakeholder update meeting on the CIS Replacement — Phase 4 of the Cornerstone project. He indicated that Hydro One will be advancing this project to 2012, ahead of the previous target of 2016. The presenters will provide a background on the Cornerstone project in general and the Customer Information System (CIS) in more detail, and will be including the reasons for advancing the system in-service date.

OPTIMUS |SBR will be providing the note-taking and facilitation. Allan introduced Bob Betts as the facilitator and to start the meeting.

2.0 Opening Remarks by Bob Betts, Facilitator

1:40pm

Bob Betts welcomed all participants, advising he is facilitating together with OPTIMUS | SBR. Bob introduced the OPTIMUS | SBR team - Angela Boychuk and Miles Smit - as note-takers.

In his presentation, Bob went over housekeeping items - meeting facilities, refreshments, planned break around 2:45pm, and the emergency instructions pointing out the exits in case of need. Note-taking will be done by OPTIMUS | SBR. The session will be recorded and the recordings destroyed once the notes are approved. Any comments made by individuals are done on behalf of the party they represent. Participants were advised if they want comments to be off the record to advise beforehand.

Bob reviewed the agenda for the meeting, indicating the ground rules. Presentations and notes will be posted on Hydro One's website. All participants were asked to introduce themselves for the record.

3.0 CIS Replacement, Cornerstone Phase 4 Update

1:50pm Cornerstone Update - Mike Winters, Senior Vice President, Information Technology

As an introduction to the Cornerstone Project, Mike Winters began the presentation with a review and explanation of Hydro One's overall IT strategy to rationalize applications and transform business processes through the implementation of commercial off-the-shelf (COTS) applications.

This strategy aims at reducing system components, supporting productivity improvement via the business benefits of adopting standard industry processes and best practices, and mitigating the risks associated with unsupported custom solutions.

The current customer service system (CSS) is expensive and cumbersome to maintain and update, being built on an IT platform from the mid-1990's, using Cobol coding and mainframe technology, requiring programming resources and skills that are becoming more scarce worldwide.

Currently, Hydro One relies on outsourced IT management. We would like to rely less on specialized and customized skills and tools, thereby reducing costs on outsourced premium services. Customer service and IT account for about 75% of the total Inergi outsourcing contracted by Hydro One.

Mike Winters provided a summary of the 4-phased Cornerstone project, which started in 2006.

- Phase 1 covered SAP's Enterprise Asset Management including asset management, work management, investment management, supply chain and some reporting. Phase 1 went live in Q2 2008.
- Phase 2 included Finance, HR, payroll, time reporting and business intelligence reporting. Phase 2 went live in Q3 2009.
- Phase 3 comprises a number of smaller scale projects, building on Phases 1 and 2 and includes such projects as supply chain optimization, advanced asset analytics, engineering design transformation, and business planning consolidation all of which are at various stages of completion and implementation.
- Phase 4 involves a CIS to replace the customized, legacy CSS built on discontinued platforms, to simplify interactions for customers and to drive efficiency and effectiveness through innovation and service delivery transformation.

The current CSS application runs on a totally dedicated IBM mainframe for both primary and backup systems, costing approximately $2-3million per year to maintain. By moving to a new SAP CIS, Hydro One can take out the mainframes and eliminate the associated upkeep costs.

Jay Shepherd asked when the predecessor system (CSS) was installed and went live. Mike indicated it was June 1998, using the Customer/1 platform. Andersen Consulting installed the system, but shortly got out of that line of business and re-aligned with the SAP customer care system.

Customer/1 was discontinued shortly after Hydro One went live unfortunately. So we were dependent upon the Customer/1 utility clients to make changes based on unique business needs. There was no standard installation or roadmap, so Hydro One could not ask for service or enhancement packs.

The new SAP system is widely used, and they have plans for service and enhancement service packs that Hydro One can readily install to improve business processes. The SAP system also allows easier integration with current systems (e.g., asset management, work management, supply chain, etc.), thereby reducing the linking software needed to tie systems together.

Mike reviewed a summary of the project process:

1) A Request for Information ("RFI") was issued with focus aimed at software vendors. Hydro One received responses from Oracle and SAP, the only vendors that could meet the requirements of a utility of Hydro One's size;
2) A Request for Proposals ("RFP") was issued for system integrators with 4 responses – 2 with Oracle and 2 with SAP;
3) A rigorous evaluation process resulted in a 3-month discovery phase with the lead integrator and to finalize scope, establish fixed price and benefits.

Jay Shepherd asked who the integration bidders were. Mike indicated that the bidders were HCL AXON (SAP), CGI (Oracle), Accenture (SAP) and PricewaterhouseCoopers (Oracle).

Roger Higgin asked what role "Inergi", Hydro One's current outsourced services provider, would play in the solution. Mike replied that Inergi has 2 roles:

1) Through Vertex (the call centre and customer care provider), Inergi will help define detailed requirements and functional design and assist with testing and implementation.
2) For application and infrastructure management, Inergi will ensure the platform stands up correctly, overseeing capability, load application, and testing.

Jay Shepherd asked if any of the system integrator bidders were related to Vertex or Inergi. Mike indicated that they were not related. Inergi is an affiliate of CapGemini and CapGemini chose not to bid.

HCL AXON was selected as system integrator and during the discovery phase Hydro One negotiated software costs for Itron and SAP. Hydro One used Gartner for third party expertise to discern the level of discount that could be expected from SAP. Hydro One was pleased to report that they were able to achieve an approximate 85% discount from SAP.

Roger Higgin asked if the discount was based on size. Mike answered that Gartner indicated a price band and based on various factors mainly size and current footprint of SAP. Roger opined that Hydro One's other SAP applications likely played a part in choosing SAP and without those applications, Hydro One would not have achieved such a large discount. Mike agreed.

The Board of Directors' approval was received in May 2011 with projected in-service date of late 2012.

The planning and the RFP process for the replacement of Outsourced Services will begin in earnest in Q3 or Q4 2012. The target issue date of the RFP is in early to mid 2013 to get to complete outsourced services switch out in early 2015.

Jay Shepherd asked about Vertex' involvement and requested information on the contracted vendor, contract start date, term and additional costs for the extension, and furthermore whether the extension contract made unit costs steeper.

Mike answered that the main contract is with Inergi as prime with a sub-contract to Vertex for customer care services. The original contract started in 2002 for a 10-year term and with a 3-year extension clause exercised to take Hydro One through 2015. In the extension, Hydro One was actually able to negotiate a steeper decline in cost through the various towers, with improved service levels.

Mike added that the RFI and RFP were used to assess the market, confirm fixed costs and set timelines proceeding to a work-back schedule allowing CIS to go live before having to negotiate new outsourcer contracts. Mike indicated it is not desirable to have a major customer information system change ongoing in a window when the outsourced customer service provider was distracted by other issues, such as bidding and being evaluated on a new outsourcing contract. From a simplicity standpoint, this approach with fewer activities occurring simultaneously also makes for more favourable negotiations on new outsourced services contracts related to customer service and IT once the extension expires: the more commercial off-the-shelf (COTS) applications Hydro One uses, the lower our costs should be.

Roger Higgin asked if the IT service is for on-going customer care services or system integration of software systems. Mike replied that the outsourcing contract deals with both customer services, including customer care, and IT. Specifically to IT services, the IT component involves infrastructure

management for servers, data centre and end user computing devices, application management including making changes for regulatory purposes and end user support. For the customer care piece the expected benefits will be discussed later in the presentation.

Mike Winters reviewed the Cost-Benefit Summary for the Cornerstone Project and noted the net positive benefit associated with the project.

Roger Higgin requested clarification on the type of costs presented. Mike indicated that the costs broken out are the project implementation costs, primarily capital costs with some operations, maintenance and administrative costs. The benefits projected are over 7 years, including cost savings made possible by the system change.

Roger asked what presentation basis of cost and benefit numbers was used: are these capital costs, net present value of operating costs, or some other analysis? He emphasized that he would like to see the costs evaluated on a customer per customer basis in any future analysis.

Mike answered that the costs are project implementation costs for Phase 1 (mostly capital, and some operational and admin costs) and the benefits projected are gross over the 7 years, even though the benefits would run out to 10 or 15 years, if not more.

Roger indicated that he would want to see a "Benefit Realization Plan" including capitalized costs and benefits over reasonable system lifetime and also an understanding of costs on a per-customer or per-bill basis.

Jay Shepherd requested clarification on whether the benefits included tax benefits and the start point of the 7 year time span. Mike and Jeff replied that the projected benefits are gross and exclude tax benefits. The 7 year horizon starts from the implementation of each component.

Jay Shepherd asked why a 7 year horizon was used. Mike answered that it was chosen back in 2006 and asked the group their views on that since the operational life of the CIS would be much more than 7 years.

Julie Girvan suggested the benefits should be projected over the full expected life of system, but that going further out would be meaningless. The group generally agreed that the costs and benefits should be evaluated over a longer period, based on the life expectancy of the system. Mike Winters indicated that they certainly expect to use SAP for more than 7 years with major version upgrades to extend life of the various modules of SAP.

Judy Simon requested cost information on the upgrades. Mike replied that the costs were modelled into the cost structure for the CIS, but he would have to get the firm numbers for a follow-up discussion.

Jay Shepherd asked if the cost-benefit analysis presented for board of director approval is available for review.

Allan Cowan advised that it will be included in the filing.

Jay Shepherd then suggested leveraging the CIS template used by Enbridge, which facilitated cost review both by Enbridge and their ratepayers over the long term. Allan Cowan confirmed that Hydro One has

seen the template and will be looking at how best to present their information, which will be included in the next application.

Mike indicated Hydro One has a rigorous process for tracking and reporting on benefits realization and ensuring they are attained and put into future investment plans and regulatory filings.

Jay Shepherd commented that the impact on costs, relative to the benefits to the ratepayer should be analyzed explicitly, which is a more focused examination compared to the general corporate cost to benefits analysis.

Shelley Grice asked if the costs include software licences and the change-out of the mainframe in the Phase 4 costs. Mike advised that the licences are included in the cost. The decommissioning of the mainframe is part of project cost and the run costs of $2-3M will be removed and reflected in future filings.

Jack Hughes asked if the $172M benefits include the 20% contingency that was built into the $180M cost for Phase 4. Mike confirmed that the 20% contingency is a project cost not reflected in the benefits value. If the project is completed without the 20% contingency the project benefits of $172M will not be impacted, but the project cost of $180M will.

Mike Winters then introduced Myles D'Arcey to present the vision and approach for the CIS build.

2:20 pm CIS Replacement Project – Miles D'Arcey, Senior Vice President, Customer Operations

Myles reviewed three key benefits of system replacement based on the proposed timeline in terms of meeting current needs, realizing immediate value and enabling a future customer vision.

1. The change addresses current needs – the current system was deployed in 1998 and is a custom-code system. Hydro One has invested over $200M in customized modifications since deployment and the CSS is now a stand-alone Hydro One system as a result of all of this customization. As an unsupported system, the risks attached are greater. The need to continue to customize the current system is driving ever increasing costs. There are costs and risks every time Hydro One "lifts the hood" or adds bolt-ons or required functionality to the system.

To this first point, Jay Shepherd asked what had changed in the plan to replace it for 2012 instead of the original date of 2016. Myles D'Arcey indicated generally that it relates to a "window of opportunity" that has opened and that this would be discussed in greater detail on Slide 16: Timeline for Replacement and Jay was satisfied to hear the full response at that time.

2. Customer value – the new system has greater capability and flexibility. SAP and Oracle have incorporated utility industry best practices. Additionally, Hydro One will be able to drive future enhancements to meet customer requirements. Hydro One looked at the costs of implementing the Ontario Clean Energy Benefit changes, and determined that a 70% cost savings would have been possible through SAP system. Thus, a lower total cost will be achieved, as code changes and revisions become easier.

To this second point, Jay Shepherd asked what the average spend is to make changes to the current system. Myles D'Arcey replied that in the last 12 months they have spent $10 - 12M. Recent years have

averaged somewhere between $5-10M in revisions. One reason is that a rate change requires a code change in the current system, whereas SAP is table-driven.

Jack Hughes asked if the study was internal or external and whether the information would be included in future filings. Myles confirmed it was an internal study and it would be included in future filings.

Myles briefly reviewed the Benefits Evaluation information, providing examples of some benefits that would be achieved by the new CIS, including total cost of ownership by eliminating the mainframe computers, plus benefits, including best practices such as improving customer information retention when customers change accounts within the Hydro One territory.

Judy Simon was interested in knowing the detailed implementation strategy from now to 2015, especially concerning the order of components to be implemented. For example, given possible regulatory changes, could one component be completed sooner than others, such as low income customer benefit improvement?

Myles suggested that with a live date of Oct 2012, Hydro One will have the flexibility to implement change at lower cost. Hydro One will review the regulatory timeframe to ensure the best possible alignment.

Susan Frank indicated that the key challenge here is assessing any regulatory changes that need to be applied before the October 2012 timeframe: either changes would have to be built into both platforms at a high cost, or parties will need to consider whether delaying some changes would be more cost-effective.

Myles reviewed the link between the new CIS capabilities and the corporate objectives such as predictive analytics relating to the iCare component (prompting the agent to address the likely issue behind a call), achieving 90% overall customer satisfaction, deploying enhanced tools to improve employee engagement, conservation demand management (CDM), and driving productivity.

Jay Shepherd asked whether such new CIS capabilities are part of the initial solution or if they are add-ons requiring more spend. Myles advised that the examples given are included as part of the initial $180M solution.

Jay Shepherd asked if some proportion of cost is allocated to unregulated activities to cover the CDM component, given that regulated CDM programmes are largely OPA-mandated. Myles answered that there is no allocation for unregulated activities.

Myles summarized the point to say that CIS will provide a holistic view of a customer's bill, history, usage and conservation program enrolment. This will allow for meaningful discussions with the customer as they manage their bills, which is a need-to-have.

Discussion continued with Susan Frank, Jay Shepherd, Julie Girvan and Myles D'Arcey exploring the CDM program example, its purpose and cost allocations. Myles confirmed that the purpose of the CDM component is data mining and to use when servicing a customer.

Susan suggested that the issue could be summed up by saying that the new CIS would be able to generate data for subsequent use in marketing, enrolment and other applied efforts, which belong under CDM costs.

Myles agreed and said that the costs for CDM programming (enrolment, delivery and reporting) are *not* part of the project costs and would be identified and allocated later as required. Julie suggested that the costs of unregulated components be separated from regulated ones in the next filing. Jay added that a fair practice for allocation be used for regulated versus non-regulated elements, to ensure that components or portions of components used to support non-regulated benefits are identified separately and not included in ratepayer costs.

3. Customer vision – ensuring that the system has capability and flexibility for future changes and needs. Future needs are not currently built-in, but Hydro One is looking forward to ensure the system has the flexibility to grow in the ever changing environment. Hydro One is looking to see how they can use the investments already made to provide more data, functionality and capability for the customer's benefit.

To this third point, Mike Winters added that under the current system, it is cost-prohibitive to integrate with core applications such as time tracking, GIS, etc., to improve corporate productivity. The new system will allow better responsiveness to the field. Some less important add-ons have not been included in the current plan to ensure that the approximate ±2800 critical business requirements currently in the CIS implementation plan are completed effectively and efficiently.

Roger Higgin asked which classes of customer should be able to access account information online. Myles D'Arcey replied that with the current CSS system, customers can log onto My Account and will be included in the new CIS. The challenge is to meet the incremental functionality the customer will want going forward. The new system flexibility will provide for that. Customer consumption history is an example of that.

2:50pm Session Break

3:05pm

Myles D'Arcey continued with some information particularly relevant to electricity generation customers at slide 13 of his presentation. Primarily the new CIS will provide greater visibility of data, provide more information, and provide increased opportunities on how to present billing data (e.g., multiple accounts on one bill).

Jake Brooks asked what level of detail is expected. Myles indicated that as an example, today for microFIT, settlements are very simple, with start and end readings and the rate. However; in an outage situation, customers may question discrepancies between projected and actual revenue. With the new CIS, Hydro One will be better-equipped to provide data and analysis to answer these and many other questions in the future.

Julie Girvan asked if there would be charges for this kind of service. Myles responded there will be no incremental costs, because the requisite data is already available.

Jay Shepherd asked whether different reports could be created for customer groups at a future time. Myles replied that like TOU, these reports would be enhancements to the system and they would need to review what will be beneficial for the whole group. Mike Winters commented that any requirements not in the initial scope of the CIS could be considered later.

Susan Frank commented that it would be good to know what kind of functionality Jay was requesting since it may in fact be contained in the original CIS scope. It would be valuable information for Hydro One to assist in planning and budgeting to address those requirements in the future. Myles confirmed that the data will be available, but they need evaluate and understand what functionalities would be required to process the data.

Jay Shepherd indicated that it is important to know what functionalities are built into the current scope so that the costs of any add-ons could be properly accounted for.

Similarly Jake Brooks indicated that it is important to know what is going to be collected as part of the data set regardless of what is currently anticipated to be used for reporting. Myles provided an example, saying that FIT generators receive the same data info as interval-metered customer. For microFIT, customers will see initial and final reads, and rates applied. Jake commented that more information should perhaps be obtained to determine what data is most useful to present. Myles gave a further example of generation information, which must go through the MDM/R and be calculated separately, and which is not currently accessible to the customer.

The data collection and reporting issue is complex enough that it was agreed that it should be discussed further in subsequent consultations.

As an example of pressing concerns relevant to CIS, Myles reviewed some of the new customer requirements for electric vehicle and charging requirements, generation by solar and wind turbine, load management, etc. Currently Hydro One has about 5000 microFIT generators connected, with ±1000 in the hopper for rural Ontario, and another ±4000 by year end, as rooftop or standalone units.

Roger Higgin commented that generation is 1% of the customer base and queried the functionality and cost to be invested on applications versus overall $180M.

Myles countered that only today's requirements are built-in the $180M, and no incremental cost has been added for future functionality. For any additional functionality Hydro One would build a business case and request stakeholder input at that later time. This future information requirement was factored into the vision so that the system would have the future capability to provide those functionalities at reasonable cost. The information illustrated on slide 15 - The Customer of the Future, is not part of the current project.

Myles then reviewed the timeline for the project and addressed Jay Shepherd's earlier question about why the project timing was advanced. The CIS replacement process has a 3-year time frame. The outsourced call centre billing and IT support functions are essential to its successful implementation. Hydro One needs a window of stability with these outsourced functions to complete the CIS implementation in the outsourcing contract term ending 2015. When Hydro One had the opportunity to extend this outsourcing contract and create this period of stability, the window of opportunity opened.

Jay Shepherd asked when the outsourcing contract was extended. Myles replied it was as of May of 2010.

Roger Higgin asked if the advancement of phase 4 and the 3-year extension had been included in the prior regulatory filing. Myles indicated it was not in the filing. The extension was approved on its own merit.

Roger Higgin observed that Hydro One is going to pay an outsourced vendor $20M for participation, and asked whether discounts were negotiated, if benchmarking was done and how costs of billing and customer care could be reduced for the period of the outsourcing contract during which the new CIS was available for use.

Myles first responded that price reductions were built into the contract renewal or extension.

He went on to say that Hydro One has a framework for further potential future benefits, however, savings in this outsourcing arrangements could not be negotiated until real and achievable benefits could be validated when the new system was in place. Within the $172M in benefits, no billing or customer care cost reductions were built in within the 2 year window, as they still needed validation and contractual negotiations. Hydro One is in a strong position after validation to go back to the vendor for potential reductions.

Roger Higgin said that from a ratepayer perspective, he would like to see some benchmarking on customer care cost with other organizations using SAP. He suggested that it be included in Hydro One's regulatory agenda for the balance of the Inergi and Vertex contract.

Jay Shepherd commented that it should extend further, that if Hydro One is expecting future reductions in the next contract.

Myles invited Hydro One's Jeff Smith, Director, Project Management & Control, to present the slides summarizing the Project Cost.

Jeff indicated that about half of the project cost is the labour/implementation services, of which 2/3^{rds} is the integrator, HCL AXON. Jeff added that HCL AXON is number 1 in SAP integration in North America.

Through the discovery phase, Hydro One validated the integrator's assumptions, time and benefit. Mike Winters added that they tested the market by getting proposals from four bidders, and he added that HCL AXON was the lowest bidder.

Jeff went on to point out that HONI and Inergi make up another large portion of the labour cost. The business, IT and call centre services drive the project.

Jay Shepherd enquired about the resources and associated costs. Jeff confirmed that the project uses existing people seconded from other Hydro One roles which are back-filled with temporary staff. Jay asked to know the cost of back-fill staff. Hydro One indicated that they will need to review that and will provide the answer at the next session.

Susan Frank asked whether the concern was the possibility that the labour costs were in some way double-counted. She commented that those labour costs would remain where they are (e.g. ongoing

Settlements efforts), and the cost of moving their efforts into the CIS project would equal, or might exceed the current cost of their efforts.

Jay understood how these people would be used but just wanted to understand what the costs of the back-filling process would be. Jeff said he would determine that and report it at the next opportunity.

Jay Shepherd asked how the new capitalization rules under IFRS would change how interest and overhead are accounted. Susan Frank advised it is premature to be discussing this, but that the matter would be discussed at a later session.

Jeff continued the cost review to examine hardware costs. Hydro One already has existing infrastructure for SAP platforms that would be augmented. Software costs include SAP and Itron costs. Commissioning includes interface with third parties, (such as Symcor for printing bills).

Jay Shepherd asked whether the software costs were up front or an annual licence. Mike Winters responded that there is both an initial cost of $13.4M for first year, plus an annual maintenance expense which is typically 17-22%.

Jay Shepherd questioned if the commissioning cost includes any of Hydro One's internal cost. Jeff Smith said that it does not: it is for interfacing with third parties. This involves a combination of people – Inergi, and HCL AXON as the integrator, although some HONI staff will also be involved.

Jay Shepherd asked for a rough breakdown of interest and overhead numbers. Jeff replied these would be approximately $6M and $12M, respectively.

Jack Hughes asked how Hydro One determined a contingency of 20%, and whether it is projected that the contingency will be required. Mike Winters advised 20% is typical of major IT projects and consistent with Phase 1 and 2. Some of the contingency was used for each of Phases 1 and 2. If it is needed for Phase 4, HONI will follow its governance model. Mike emphasized that the Hydro One Board of Directors approved the 20% contingency on the basis that it could not be used without explicit Board of Directors review and approval.

Jack asked about the amount of contingency used in Phase 1 and 2. Mike indicated that not all the contingency was used for Phase 1 and 2 and the final numbers will be provided.

Susan Frank asked whether the 20% contingency would be included in the amount requested in the application. Mike confirmed that the contingency will be part of the application.

Jeff asked is anyone could think of any additional information that Hydro One should be providing with its application and there were no further requests. Allan Cowan added that the Enbridge template includes much of the required information requested, and it will be reviewed by Hydro One and populated with its data.

Jeff concluded the presentation with a brief review of the Green Energy example to illustrate the lower cost of the new system. The Green Energy Benefit project required 6600 hours to implement the changes. With the new system, the same changes would have taken an estimated 1600-2200 hours, a reduction of about 70%. Thus, there is a significant cost reduction in ongoing efforts to be had by implementing this new system.

Jeff turned the meeting back to Bob Betts for the final question and answer section.

Shelley Grice asked what other utility companies are using a similar SAP CIS. Myles D'Arcey replied that these include Texas Utilities, London Hydro, Blue Water Hydro, SaskPower, BC Hydro and others.

Jake Brooks asked how the Smart Grid Technology will tie into the new CIS system. Myles answered that the CIS is specific to customer system requirements and functionality, but there is potential for other uses of the data that can be collected. Jake suggested that over time there should be a second look to examine co-ordinated evolution and adaption of Smart Grid and CIS applications.

Myles responded that as enterprise systems come online, with dated information, the potential exists for additional and enhanced functionality linking into other Smart Grid options and other platforms like mobile functionality, geo-spatial functionality, GIS, etc. When it comes time for these enhancements a plan will be developed and presented to the stakeholders for input.

Another issue Jake Brooks suggested for consideration is the question of which kind of investments are utility investments, and which should be privately owned. Myles agreed that these questions would need to be considered.

4.0 Close

3:55pm

Allan Cowan concluded the meeting, advising that given the number of relevant questions and issues raised, another stakeholder session would likely be held in September to provide updates on studies and analysis for filing in fall, including further discussion about CIS, the compensation study underway with Mercer, the Density Study, CDM and Load Forecasting and an update on accounting issues and what the filing may look like.

Allan concluded the session by thanking the participants for their questions and information.

ADJOURN 4:00pm

APPENDICES

A. Summary

The CIS Replacement Project presentation was approached by way of an overview of Hydro One's governing IT strategy as well as the status of the 4-phase Cornerstone Initiative, of which the new Customer Information System (CIS) is the 4th phase.

Throughout the session, Stakeholders questioned Hydro One about issues of concern, including timing, costs, software and outsourcing options, benefits and functionalities that attach to CIS. Stakeholders also provided many valuable comments as input to the CIS implementation and regulatory presentation.

Detailed conversation focused on the due diligence conducted in Hydro One's decision-making process, particularly as it relates to:

1) The decision to advance the CIS implementation from 2016 to 2012;
2) The prices obtained from SAP, the integrator HCL AXON, and other contractors;
3) The pending expiry of the current outsourcing contract;
4) The co-ordination of CIS planning with other strategic initiatives;
5) Costs intended for inclusion in the next rate application.

Hydro One gave an account of the rationale, vision and approach for replacing the current, outmoded Customer Service System (CSS) with the more flexible SAP-based CIS, readily capable of handling foreseeable changes in accounting and reporting, as well as future customer and industry account management needs.

A number of direct questions helped identify issues which will require clarification or further research and analysis.

B. Key Action and Notable Items

1) Customer Care costs were requested to be reported also on the basis of cost per customer to facilitate comparisons with other SAP users.
2) Stakeholders indicated a desire to have a "Benefits Realization Plan" developed to track benefits included in the justification of this project.
3) Stakeholders generally agreed that benefits and costs should be analysed of the reasonable life of the CIS asset and not the 7 years currently used.
4) Stakeholders asked for more detail about the expected costs of future system upgrades.

5) Hydro One confirmed that they would file the report originally provided to their Board of Directors that outlined the cost/benefit analysis for the board's consideration of the CIS replacement project.

6) Hydro One has noted and will consult the template completed by Enbridge Gas Distribution as part of its CIS stakeholder consultation process.

7) Ratepayers requested that the cost/benefit analysis provide some focus on the impact to ratepayers, both in costs they will bear and benefits they will receive.

8) Hydro One will provide more detail about the 20% contingency included in the $180M project cost, including:

   a) Cornerstone Phase 1 and 2 contingency budget usage;

   b) How the 20% contingency will be presented for regulatory consideration.

   c) How the contingency will be managed if the project comes in below budget or above budget.

9) Stakeholders generally understood the drivers and the rationale for advancing the timing of the CIS Replacement Project

10) Stakeholders asked that Hydro One file the internal report that analyzed the costs of making changes to the existing CSS.

11) Stakeholders indicated an interest in seeing a detailed implementation plan. The specific interest here was to consider whether certain benefits (such as those to low income consumers) could be realized as early as possible.

12) Hydro One indicated a need to discuss the approach to requested changes to their systems during the transition to a new CIS, to understand and evaluated the costs/benefits of having to make changes twice versus only once.

13) There was general interest in ensuring that the costs of the CIS Replacement and any changes made to the current design are reasonably evaluated and allocated to customer class to ensure that cross subsidization is kept to a minimum.

14) Parties were generally interested in gaining a better understanding of the functionalities that will be built into the new CIS

15) Similar to the previous item, there was interest in further information about the kind of data that will be collected by the new system, so that stakeholders could consider future uses of that data.

16) Stakeholders were interested in learning more about the customer care arrangements with Inergi/Vertex and how they compare to other utilities cost/benefits in delivering the same services. The interest relates both to the recent extension arrangements and the understanding that all will want to consider new arrangements when the current contracts expire.

17) Hydro One agreed to provide more details about the estimated costs for the use of Hydro One personnel in the project, with specific interest in the costs of back-filling for seconded staff.

18) A follow-up CIS Replacement project stakeholder session will be planned for the fall.

C. Meeting Agenda

Stakeholder Consultation

Cornerstone Phase 4 CIS Replacement Stakeholder Session in Support of Hydro One Rate Applications

AGENDA
June 29, 2011
Metropolitan Hotel
108 Chestnut Street, Toronto
Upper Level
Victoria Room
1:30 p.m. – 4:00 p.m.

1:30 p.m.	Welcome	Allan Cowan, Director, Major Applications, Hydro One Networks
1:40 p.m.	Introductions	Bob Betts, Facilitator, OPTIMUS | SBR
1:50 p.m.	Overview of Cornerstone Project	Mike Winters, Senior Vice President, Information Technology, Hydro One
2:00 p.m.	Overview of Cornerstone Phase 4 CIs Replacement	Myles D'Arcey, Senior Vice President, Customer Operations, Hydro One
2:45 p.m.	**BREAK**	
3:00 p.m.	Q&A	Mike Winters, Myles D'Arcey and Bob Betts
3:45 p.m.	Nest Steps and Closing Remarks	Bob Betts / Allan Cowan
4:00 p.m.	**Adjourn**	

Filed: June 15, 2012
EB-2012-0136
Exhibit A-4-1
Appendix D
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Stakeholder Consultation Notes

CDM, Density Cost Allocation, Compensation Benchmarking and Productivity Studies and Cornerstone Phase 4 CIS Replacement in Support of Hydro One Rate Applications

October 19, 2011
Hydro One Networks
Special Event Room, Ground Floor
483 Bay Street, North Tower
1 p.m. to 5 p.m.

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The presentation materials used in this session and background materials can be found at this link:

http://www.HydroOne.com/RegulatoryAffairs

1. Participants

Stakeholders

- Emerissa Babin – Ontario Power Generation
- Michelle Byck Johnston – Society
- Ted Cowan – Ontario Federation of Agriculture
- Vincent DeRose (Conference Call) – Canadian Manufacturers and Exporters
- Phil Dubeski – Toronto Hydro Electric System
- Julie Girvan – Consumers Council of Canada
- Shelley Grice – Association of Major Power Consumers in Ontario
- Bill Harper – Vulnerable Energy Consumers Coalition
- Bayo Kidane – Power Workers' Union
- David MacIntosh – Energy Probe
- Neil Mather – Ontario Energy Board
- John McGee (Conference Call) – Federation of Ontario Cottagers
- Patrick McMahon (Conference Call) –Union Gas
- David Poch (Conference Call) – Green Energy Coalition
- James Sobota (Conference Call) – Pollution Probe
- Harold Theissen – Ontario Energy Board
- Mark Vainberg – PowerNex
- Steve Zebrowski (Conference Call) – Veridian Connections Inc.

Hydro One

- Carm Altomare – Hydro One
- Henry Andre – Hydro One
- Richard Bertolo – Hydro One
- Allan Cowan – Hydro One
- Susan Frank – Hydro One
- Ellen Holden – Hydro One
- Sabrin Lila – Hydro One
- Ian Malpass – Hydro One
- Keith McDonell – Hydro One
- Tony Miles – Hydro One
- Vicki Power – Hydro One
- Anne-Marie Reilly – Hydro One
- Nikita Sheth – Hydro One

Presenters

- Brad Bowness – Hydro One
- Stan But – Hydro One
- Ben Grunfeld – London Economics
- Mark Hirschey – Oliver Wyman
- Iain Morris – Mercer

  Marvin Reyes – Mercer
- Kristi Robins – Mercer

OPTIMUS | SBR

- Bob Betts – OPTIMUS | SBR
- Tara Murphy – OPTIMUS | SBR
- Miles Smit – OPTIMUS | SBR

2. Welcome by Allan Cowan, Director, Major Applications, Hydro One Networks

START 1:00pm

Allan Cowan welcomed all participants to the Stakeholder Consultation meeting. He outlined the Agenda for the day and listed the topics that would be discussed:

1. Conservation and Demand Management (CDM) Study
2. Density Cost Allocation Study
3. Compensation Benchmarking Study
4. Productivity Measures
5. An update on the CIS Replacement – Phase 4 of the Cornerstone project.

OPTIMUS | SBR will be providing the note-taking and facilitation. Allan introduced Bob Betts as the facilitator and to start the meeting.

3. Opening Remarks by Bob Betts, Facilitator

1:07pm

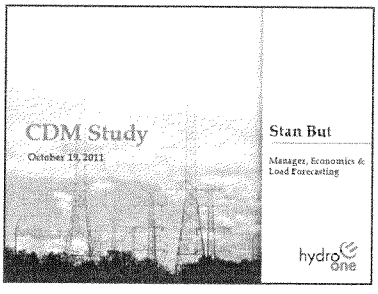
Bob Betts welcomed all participants, and advised that he is facilitating together with OPTIMUS | SBR. Bob introduced the OPTIMUS | SBR team (Tara Murphy and Miles Smit) as note-takers.

Bob began his presentation with several housekeeping items and pointed out the emergency exits. Bob stated that notes will be taken during the meeting and that the meeting and discussions will be recorded. He noted the recordings will be destroyed once the notes are produced. Any comments made will be attributed to the individual and the party they represent. Participants were instructed if they want comments to be off the record to advise beforehand.

Bob asked all attendees to introduce themselves, stating name and company for the record. He reviewed the agenda, asked for phones to be turned off and mentioned that questions are welcome as they arise. The presentations and notes generated will be published on the Hydro One website.

CDM Study, Stan But, Manager, Economics and Load Forecasting, Hydro One Networks

1:15pm



View or download a copy of the CDM Study Presentation

Stan But began his presentation with an explanation of why the CDM study was undertaken. The CDM study was directed by the Ontario Energy Board (OEB), which requested more details about the CDM analysis and particularly credible load forecasts and greater accuracy than has previously been available. The Board accepted Hydro One's CDM estimates used in load forecast, but directed Hydro One to work with the Ontario Power Authority (OPA) to

devise a robust, effective and accurate means of measuring expected impacts of CDM programs. Stan reviewed the recommendations made by stakeholders in the February 2011 and March 2011 consultations:

1. Conduct the CDM study in-house;
2. Review the CDM categories and methodologies used to incorporate CDM impacts into load forecasts by utilities in other jurisdictions;
3. Comprehensive CDM categories that are trackable;
4. Work closely with the OPA to better define and measure CDM impacts for use in load forecasting;
5. Present CDM impacts by sector and customer rate class.

Stan But stated that Hydro One had acknowledged and addressed each of these recommendations.

The study had two main objectives. The first was to develop a robust methodology to forecast CDM impacts and the second was to develop a methodology to incorporate the CDM impacts into Hydro One's load forecast.

The study findings included a Literature Review involving British Columbia, New York, California (as per stakeholder recommendation) and other major utilities in North America with CDM experience. Web-search and personal communication were used to gather data. Hydro One did a comparison study of load forecast methodologies commonly used by other utilities that incorporate CDM impacts into their forecasts. Finally Hydro One has been in close communication with OPA staff over the last 6 months to incorporate this information into CDM estimates.

A Load Forecast Survey was sent to approximately 100 organizations in North America, and 41 responses were received. The Literature Review and Survey provided a roster of well-defined and comprehensive CDM categories:

- Programs initiated by the utility;
- Programs initiated by other organizations;
- Building codes and standards;
- Rate structures;
- Increased conservation effect.

The Load Forecast Survey identified three commonly used models to incorporate CDM impacts in load forecasting.

- Method 1 forecasts using the actual load (without CDM adjustments);
- Method 2 forecasts CDM impacts as a variable on the right-hand side of the econometric equation;
- Method 3 adds historical CDM impacts to the actual load and forecasts forward.

Hydro One reviewed the advantages and challenges associated with each method. On the basis of the review results, Hydro One has adopted Method 3.

Susan Frank asked which method the OPA uses. Stan replied that the OPA also uses Method 3.

Ted Cowan asked for clarification on the main differences with respect to weaknesses in Methods 2 and 3. Ted suggested Method 2 regresses data weakly and Method 3 might contain errors in the CDM data. Stan clarified that both Methods 2 and 3 require CDM estimates for the history, so the same CDM data is used in each Method. Method 2 has a potential to create bias in the forecast because of collinearity issues. Method 3 adds the CDM impact to the actual load, which avoids multiplying any such collinearity issues.

Ted agreed that Method 3 addresses the issue of including CDM impact, but posited that they are still embedded in the initial regression estimates you are subtracting from. He asked if it was correct to say that all of the Methods have some weaknesses, but in Method 3 the weakness is confined to the CDM data. Stan clarified that the same CDM data is used in both models, but the data is used differently to achieve unbiased coefficients in Method 3. Ted responded that Method 2 and 3 do not differ substantially with respect to error.

Stan acknowledged that there are pros and cons for each method. Methods 1 and 2 are not invalid or incorrect, but they have characteristics that make them less suitable for Hydro One's specific requirements.

Ted Cowan asked for Stan's intuitive relative assessment of the merits of the three methods. Stan replied that Hydro One has determined that in light of the Board's request for a robust, accurate model, Method 3 is the most appropriate choice.

Ted inquired about the experience Hydro One has using Method 3. Stan replied that Hydro One has effectively been using Method 3 for a number of years and is comfortable with its performance.

Stan proceeded to review the study findings. He identified that the categories in the Hydro One CDM forecast that are aligned with the OPA Policy Instruments referring to Slide 10 of his presentation:

- Programs, further broken down in Hydro One's forecast into Hydro One/OPA programs, and other influences;
- Codes & Standards;
- Rate Structure.

Hydro One uses a number of methods and models to track customer actions. Accordingly, Hydro One has deployed an additional category called the Increased Conservation Effect. This was defined as customer behaviour to conserve energy that is not influenced by Hydro One, OPA, and other non-government programs.

Ted Cowan asked, regarding rate structure, whether separate analysis is conducted for customers that are demand billed versus customers that are volumetrically billed. He suggested there is a larger price effect for those who are demand billed.

Stan replied that for rate structure Hydro One uses CDM impact data from the OPA, and assumes that it covers all customer data. Ted agreed that all customers are considered, but asked whether demand- and volumetrically-billed customers are distinctly identified in the data. He asked specifically about the possible case of a farmer on demand billing, who conserves more than a farmer on volumetric billing.

Stan said that the impact is accounted for in each billing scenario. Ted inquired whether it is possible to tell the two billing methods apart, because there is a difference in savings for each billing type. Stan did not believe that the data from the OPA breaks the information down by rate class. Ted suggested that the savings differences by volumetric versus demand rate classes should be identified in the data.

John McGee asked whether Hydro One had any figures on the demand reduction from the Smart Meter program. Stan replied that for 2013 the Smart Meter (Time of Use) impact for all Hydro One customers was approximately 20 megawatts.

Bill Harper sought clarification on the definition of the term "Increased Conservation Effect" used by Hydro One. He asked whether the Increased Conservation Effect was equivalent to, or aligned with, the OPA's definition of Natural Conservation. Stan replied that they are not the same effect. Hydro One's definition of the Increased Conservation Effect is any non-program savings above or beyond Natural Conservation.

Bill observed that electricity rates are increasing by 10% and inflation is up 2%. He wondered whether the Increased Conservation Effect could be a response to customer awareness of higher bills. Stan replied that the Increased Conservation Effect does not capture increases due to inflation. Inflation and increases in price are captured in Natural Conservation. Historically, electricity prices trend upward, and a conservation response is expected without additional interventions.

Bill used a potential example to highlight his point: a customer who looks at an energy-efficient product (without a program coupon) and wants to be environmentally conscious is counted in the Increased Conservation Effect if he purchases the product. Alternatively, if the customer chooses to buy the product because of his increased electricity bill it is considered Natural Conservation. Bill suggested that the process to determine whether conservation is increased or natural is unclear, given the definition of the Increased Conservation Effect.

Stan But proceeded to describe the steps taken to understand and align with the savings assumptions used in the OPA's current conservation forecast.

The preliminary CDM impacts for 2011-2013 shown on his Slide 12 include the following categories:

- Impacts of Hydro One and OPA Programs;
- Other Influences;
- Codes and Standards.

Each of these categories is expected to drive increased energy savings over time. Stan did not present data for Rate Structure impacts on energy because the Rate Structure data from the OPA only includes Peak Savings while his Slide focused on energy savings. The fifth category, Increased Conservation Effects was based on data from 2010 actual, forecasting no increase in this category 2011 to 2013.

Stan indicated that the flat-line Increased Conservation Effect forecast was a conservative stop-gap, and Hydro One will need the actual 2011 data to make accurate forecasts beyond 2010.

Bill Harper asked for clarification on the forecasted data. He asked whether the forecast for 2013 was based on impacts from 2013 only or if it was the cumulative impact of programs implemented in 2011,

2012 and 2013. Stan clarified that the forecasted data represents the cumulative impact for that year. Therefore the difference between two years is the incremental change from year to year.

Susan Frank asked for an explanation of how the forecasts for Increased Conservation Effect were calculated. Stan replied that multiple analyses were used to determine the forecasted impact of Increased Conservation Effect. The first was using the hourly load of Hydro One in 2002-2010 to run econometric analysis. The impact of economy and weather were removed and the remaining impact was the total impact attributed to the CDM.

In addition to the econometric analysis, the customer information system was utilized. In this approach the annual energy consumption for over 500,000 residential customers with consistent information was analyzed. The result of this method showed consistent savings with the econometric approach. The final method was using tracking surveys where customers listed their own actions towards conservation and actions driven by programs. This information confirmed that there is an Increased Conservation Impact from the customer.

Julie Girvan questioned the validity of using customer surveys to calculate the increased conservation impact. Stan explained that the large survey (approximately 6000 customers) results were not used in the calculation, but rather to confirm the econometric results.

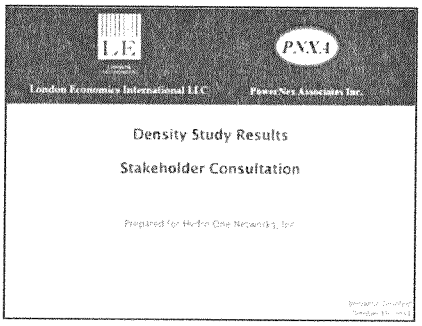
Stan provided a summary of the CDM impact study and indicated that the study was nearing completion, incorporating stakeholders' recommendations and meeting the Board's Directive.

Susan Frank added that the OPA did not evaluate the impact of the Increased Conservation Effect and asked whether other organizations are using this category. Stan replied that the results of a web survey showed that 1 in 5 utilities in the survey use a category that captures Increased Conservation Impact. He mentioned that the state of California is making a major effort to monitor customer behaviour, actions and savings associated with market transformation. This is an emerging issue that is being studied in other organizations.

Julie Girvan asked if the Green Energy Benefit (a 10% discount) would cause customers to reduce conservation efforts. Stan replied that the 10% reduction in the customer's bills is a new feature that was not captured in the analysis. Ben Grunfeld, of London Economics stated that the Green Energy Benefit came out around the same time as HST, which increased customer bills. Therefore from an incremental impact on customer bills the HST likely neutralizes the Green Energy Benefit reduction for the next 3 to 5 years.

4. Density Cost Allocation Study, Ben Grunfeld, London Economics

2:05pm



View or download a copy of the Density Cost Allocation Study Presentation

Ben reviewed the mandate given to London Economics and PNXA to evaluate the relationship between customer density and distribution service costs. He outlined that the study was initiated in response to a request from the OEB. The study also assessed whether the existing density-based rate classes and density weighting factors appropriately reflect this relationship. A third object was to consider the appropriateness and feasibility of establishing alternate customer class definitions. The third objective, while covered in the report would not be discussed to a large degree in this afternoon's presentation.

Referring to his Slide 5, a two phased approach was used to perform the study, with the first phase being the Methodology Development and the second and current phase Methodology Implementation. The methodology consisted of two complementary analyses: Econometric study of the operating areas, and Direct Cost Assignment of smaller sample areas. Both analyses considered operating, maintenance and administrative costs and proxies for capital costs.

Julie Girvan asked for the definition of an operating area. Ben explained that an operating area is a geographic area within the province. Each operating area has service centres used to respond to customer calls, manage maintenance, operating programs and capital programs for that area. Julie asked whether the operating areas are the areas listed on the Hydro One website during an outage. Ben confirmed this is correct.

Ben continued with an outline of the econometric methodology. Using his Slide 6, he explained that the functional form of the econometric model was chosen based on theory and prior experience and pointed out that this is the form used by the OEB. The equation takes into account that an increase in customers from 5 to 500 for a given area equals an increase in cost that is not uniform. Determining the cost function was an iterative process, where a number of different specifications were tested. The five independent variables included in the final model were:

1. Customer Density (stakeholder recommendation);
2. Number of customers;
3. The square of the number of customers
4. Energy density;
5. A time or trend variable.

Ben explained that a representative cross section of sample areas was selected. A total of 11 operating areas were utilized for the direct cost assignment. The study included 62 samples areas, 24 low-density, 22 medium-density and 16 high-density from the 11 operating areas. The sample area selection guidelines included:

- Similar areas, approximately 20 km^2;

- 100 – 200 customers for low density;
- 700 – 1200 customers for medium density; and
- Over 2000 customers for high density.

Ben indicated that the costs were directly assigned to the individual sample areas. These cost groups include:

- Lines and Stations (operations, maintenance and administrative costs);
- Vegetation Management;
- Asset Intensity (representing capital costs in the ground).

Julie asked about other assets not in the ground, specifically the cost of trucks. Ben stated that fixed capital costs are not dealt with in this direct cost assignment study, but maintenance costs for assets such as trucks would be included in maintenance costs for the sample area. Ben stated that the proportion of Hydro One assets reflected by vehicles is small compared to other assets in the ground.

Henry Andre confirmed that the costs associated with trucks and other vehicles are included in maintenance costs. He continued with an example, stating pole replacement costs include the cost of equipment required to replace the pole. Maintenance costs include labour and equipment.

Bill Harper asked if lines and stations administrative and maintenance costs were combined, given that distance is important for lines and not important for stations. Ben Grunfeld replied that they are dealt with separately. He added that station costs were allocated based on the number of distribution stations within an operating area and the way they are used to serve load in the sample areas.

Ben introduced the results portion of his presentation and asked for questions before he continued.

Julie asked if the approach that Ben is undertaking has been used in other jurisdictions. Ben replied that based on the research there are no jurisdictions that have yet used this level of detail to analyze the effects of customer density. He added that he has seen econometric models to predict utility costs that incorporate customer density, as considerations. The OEB cost allocation model uses a number of allocation factors to distribute cost to classes of customers. [This general approach, of allocating costs based on factors, is similar to the one used in the direct cost assignment analysis. However, the direct cost assignment analysis looked at smaller samples of customers that vary with respect to density, as opposed to a complete class - Note this clarification is subsequent to the session.] Ben reiterated that the specific approach of looking at customer density is a unique feature.

Ben continued with the results, stating that the econometric analysis indicates a negative or inverse relationship between cost and customer density. Four distinct models were analyzed, and all showed a negative relationship:

1. OM&A (operations, maintenance and administration) using circuit km.
2. OM&A using sq. km.
3. OM&A and a capital proxy using circuit km.
4. OM&A and a capital proxy using sq. km.

Bill asked for clarification about the final bullet point on Slide 12 suggesting that it should say that according to the fourth model, a fivefold increase in customer density should correlate to a 150 percent decrease in cost per customer. Ben confirmed this is correct.

Julie asked if Ben was referring to cost per customer. Ben replied that it is the measure of total cost. He stated that the number of customers is included in the econometric model so they normalized for scale already. He explained with an example, where if the number of customers stayed the same, but the density increased there would be a decrease in cost.

Ted Cowan sought to clarify Ben's example, asking if, in the hypothetical case of two different $20km^2$ areas, one with 200 customers and one with 1000 (i.e., a fivefold difference in density) the one with 200 customers would see a 50% decrease in cost.

Ben replied that the relationship depends on the number of customers being constant. Ben used an example of a $20km^2$ area and a $4km^2$ area with the same number of customers. In that case, the cost would be different: it would cost 50% more for the less dense area. This is the conclusion from the econometric model, and is also consistent with direct cost assignment approach.

Ben elaborated other results, indicating that the individual sample area results revealed a sharp decline in cost per customer as density increases.

Ted asked whether most of the variation is found in areas under 100 customers per km^2 and whether most of the variation within that range is under 20 customers per km^2. This would mean that most of the variation is in low and very low density. Ben replied that Ted's interpretation was correct.

Bill asked how a density of 100 customers per km^2 would translate into customers per line km. Ben answered that in Hydro One's rate class definition, a cluster of 100 customers and 20 customers per line km. Subsequent to the session Henry Andre confirmed that the definition is based on 15 customers per line km.

Ben stated that the sample mean averages in the study were distinct, and confirmed the negative relationship. He concluded that the two independent analyses confirm that the average cost to serve Hydro One customers increases as the customer density decreases with 99% statistical confidence.

Bill asked if graphs were created for customer per km of line. Ben answered that those graphs were generated and that they could be found in the final report.

Beginning to address the second study objective whether the existing density-based rate classes and density weighting factors appropriately reflect this relationship, Ben discussed customer density as a differentiator on his Slide 15.

He noted four elements of Hydro One's existing rate class structure to consider:

1. Type of rate classes;
2. Number of rate classes;
3. Demarcation points;
4. The cost of allocation factors.

The first significant point he made was that from a rate making perspective, based on "cost causality", it is reasonable to differentiate between customer classes by customer density.

The results also support having different classes, two general service customer classes makes sense, given a much smaller number of customers. There was no strong evidence to support a change in demarcation points.

Vince DeRose asked whether the report would look at municipal or regional boundaries. Ben answered that the report will look at both and the pros and cons associated with each approach.

Julie Girvan asked how Hydro One currently demarcates the rate classes. Ben answered that an urban rate (UR) class is an area that has 3000 customers total and has a line density of more than 60. The Medium density grouping applies to residential (R1 and R2) and has over 100 customers and a line density of 15, the Low density for residential is the remainder. For general service, there is a distinction between urban and non-urban customers.

Ben explained that the last objective was to consider cost allocation factors, of which there are two elements: non-density factors and the density-weighting factors. The study compared the overall results of the cost allocation model to the direct cost assignment analysis. The concern was with the ratio of per customer assigned costs, not the total magnitude. Ben concluded that the existing allocation may not capture the actual differences between the mean costs of serving year-round residential customers in areas with varying customer densities.

Slide 17 of the presentation package showed the comparison between the allocation factors for Hydro One's current UR, R1 and R2 classes, 1.0, 1.6 and 1.7 respectively and the allocation factors resulting from the study for HD, MD and LD, 1.0, 1.7 and 3.8 respectively. While the relative comparison did reflect a higher cost per customer in a low density area versus a higher density area, it indicated that the higher costs are not being fully allocated.

The study further found that:

- The average customer density of the Seasonal rate class falls between that of the R1 and R2 classes;
- The average customer density of the urban GS classes, UGe and UGd, is similar to that of the UR class; and
- The average customer density of the non-urban GS classes, GSe and GSd, falls between that of the R1 and R2 classes.

Ben reviewed the three study objectives. He concluded that two independent analyses demonstrated that there is a statistically significant negative or inverse relationship between customer density and costs. The study demonstrated that cost to serve customers of different densities is different, supporting the use of density-differentiated rate classes.

Existing allocation and weighting factors may not capture the magnitude of the difference in costs to serve customers of varying density. The report addressed alternative customer class definitions, including structures based on municipal boundaries or regional rates. Ben concluded that a move to such a design is a long-term decision that should be considered in the context of a broader provincial

dialogue that looks at rate design across all of the LDCs. Overall, the study's objectives have been accomplished.

Julie asked for a restatement of the conclusion for seasonal classes. Ben replied that the costs currently assigned to seasonal customers is 1.5 times the per customer cost assignment of urban class, this is in line with R1. The average density for seasonal customers is between the R1 and R2 rate classes, this indicates under representation of the costs to serve those customers. A similar conclusion applies for the non-urban general service classes.

Susan Frank pointed out that the results of this extremely comprehensive and expensive study cannot be ignored when it comes to rate design. Susan asked Henry Andre how Hydro One would implement the impact of the study.

Henry replied that the results of the study were very compelling. Some changes to Hydro One's cost allocation and rate design to incorporate the study are warranted, and Hydro One expects to respond appropriately.

The extent of the impact on cost allocation and rate design is dependent on how the results are used within the cost allocation model. Hydro One has not explored this in detail, but they did look at the last cost allocation model that was filed with the 2008 Distribution Application. Based on that model and trying to incorporate the findings of the 2011 study, there could be an approximate decrease of 10-15% in UR rates, and a potential approximate increase of 2-3% for the R2 rate classes.

The increase in R2 rates matching the decrease in UR is less because the volume of revenue collected from the R2 class is significantly more. In terms of delivery rates, delivery is approximately 1/3 of the transmission bill, so one could divide the estimated increase/decrease by 3 in terms of overall bill impacts. These are mere approximations because Hydro One has not utilized the new cost allocation model for the upcoming application. The findings are based on the previous cost allocation.

Julie Girvan asked how the study might help Hydro One rethink the seasonal rate design. Julie stated that she would like Hydro One to be more proactive on the issues involving seasonal rate design. Henry Andre replied that in terms of cost allocation, the study suggests that the cost of serving seasonal customers as a class (made up of low density and higher density area customers), would likely fall between R1 and R2. The current cost allocation model is pinning them at the R1 level (Subsequent to the meeting Hydro One clarified "pinning them at the R1 level" reflects that under the current cost allocation model the total costs per customer allocated to the Seasonal and R1 rate classes are about the same).

Henry stated that he took the point about issues with seasonal rate design. He continued that Hydro One could look at shift between fixed and variable costs, a concern raised by some seasonal customers. The study suggests that the cost to serve seasonal customers is higher because they are made up of medium- and low-density (corrected subsequent to the meeting from high-density) areas.

Bill Harper asked if Hydro One should alter the definition of the class or if they should change the way density is considered in the cost allocation model. Bill noted that the study suggested a change in allocation factors rather than changing the class definitions. Bill asked if Hydro One is considering choosing a different allocation factor other than customer per km to weigh customers by class.

Henry replied that Bill was correct. There is no current plan to change the definition of the rate classes. Hydro One does plan to look at the cost allocation model to consider whether the density weightings need to be changed. He raised the question of whether something else needs to be done at the bottom line to shift costs.

Bill asked if Hydro One was considering a new parameter for the model. Bill noted that changing the bottom line outcome of the model would be a new approach to cost allocation overall.

Henry clarified that his preference would be use the current approach, but the study suggests there is not enough differentiation between the weighting factors. The differentiation between the weighting factors would need to be increased so that more is allocated to the R2 class versus the UR class.

Bill observed that the study analysis assumes relationships between costs and density. He noted that the differences in the end are a function of what allocation factors were used in the analysis and stated that the differences need to be reflected in the Hydro One model. Henry agreed.

Ted Cowan mentioned that the general service class is the life-blood of the economy in rural Ontario. He asked if there would be any changes to their rates based on the results of this study. Henry replied that the ratios for the general service class were not covered in Ben's presentation, but they will be included in the final report. He noted that if the general service class is a blend of R1 and R2 then there might be some adjustments made. Ted asked if this would likely mean a 2% adjustment. Henry replied that he has not made any calculations on the general service class and so could not speculate, but there would be a higher differential based on the results.

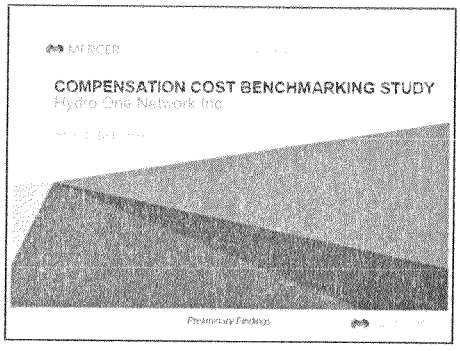
Julie asked when Hydro One was planning to file the Distribution Rate Case. Susan Frank replied that the original filing date was after the November Board Meeting, but the filing would be delayed until the shareholder could review it, including the new Minister.

The filling date will likely be early 2012, after the budget is reviewed by the shareholder.

Vince asked if that meant the Distribution Rate and Transmission Cases would be occurring simultaneously. Susan replied that this is a likely possibility.

5. Compensation Benchmarking Study, Iain Morris, Mercer

3:27pm



View or download a copy of the Compensation Cost Benchmarking Study Presentation

Iain Morris began by discussing the input from the May 2011 Stakeholder consultation. He stated that consideration was given to all Stakeholder requests, but not all could be met in professional opinion of the consultant. For example, Mercer did include a comparison to market average compensation.

Iain described how benchmark positions were determined

and listed the positions used. He noted two differences between the previous study and this one resulting from insufficient available data to benchmark the Field Service Coordinator and the Tree Trimmer positions. In the case of Tree Trimmers, this position is most likely been contracted out at other utilities, and the Field Service Coordinator responsibilities were generally distributed throughout other job classes.

Mercer's experience also suggests that there needs to be a balance in the number of benchmark positions to use because often survey participants will avoid surveys that involve too many benchmark jobs; the 34 they chose is a reasonable balance. He reviewed the chosen jobs in the three Groups, Non-Represented, Professionals and Power Workers contained on Slide 5 of his presentation. He indicated that these jobs collectively represent approximately 3300 employees, or approximately 49% of Hydro One's workforce. In Mercer's opinion this is a representative sample size.

Iain described the process for determining the peer group. A similar approach to the 2008 study was taken. The process met the key objective of creating a single peer group to assess total compensation costs for the entire set of benchmark jobs. The list of peer groups was provided on Slide 7, and Iain noted that because some organizations such as Bruce Power and Bell Canada opted out of the study in 2011 and while others were added, this would generally be expected to result in an overall lower survey group benchmark in the marketplace than the 2008 study.

Iain gave a description of elements included in Total Compensation which are the same as 2008. It focuses on items that can be monetized including:

- base wages or salaries;
- short-term incentives;
- long-term incentives;
- insured benefits;
- retirement plans.

Definitions and methodology for determining total compensation were discussed and outlined on Slides 9 &10. Slide 10 provided the definitions of average and P50 (the 50th percentile). Mercer took this opportunity to once again state their reasoning for relying on the P50 or the middle point in a distribution of data rather than the average, including its representation of the compensation paid by the employer in the middle of the group and its stability coming from ignoring occasional skewing associated with extremely high and extremely low compensation circumstances of some survey participants. However, as requested by some stakeholders, Mercer has provided comparisons on the market mean in addition to the market median.

Iain reviewed the preliminary results in Slides 11 to 17. He compared the Hydro One median to the Market median changes from 2008 to 2011. Overall, there has been a decrease in Hydro One's total compensation from 2008, but total compensation remains above the Market median on a weighted average basis. Iain noted that wage and salary freezes and turnover costs affect total compensation; and further that many organizations in the study have also been attempting to reduce compensation costs just as Hydro One has. Iain explained that as a result of these efforts to reduce labour costs (in addition to the lower survey group benchmark noted earlier), the market median is effectively lower in 2011 than it would have been in 2008; but despite this lower market median, Hydro One has been more effective in reducing its relative compensation costs and has moved closer to the market median in 2011. He also

explained that greater variation between 2008 and 2011 may be driven by low job incumbency and high turnover, where a more junior staff replaces a higher paid senior staff that retired.

Michelle Byck-Johnston asked for a definition of the Engineer F position. Keith McDonnell responded that it is a management-level compensation job (typically a band 7, and may contain some band 6 positions). Iain added that Engineers A to F are generic titles that line up with the Professional Engineers Ontario (PEO) categories.

Shelley Grice asked about the "not applicable sign" beside positions such as Senior Legal Counsel and Area Superintendent. Iain replied that the not applicable sign denotes that insufficient data exists, for example when a statistically significant sample is not available. In the case of Senior Legal Counsel, Area Superintendent, Business Analyst A, Electrical Apprentice and Lines Apprentice, "not applicable" is indicated because these jobs were not included in the 2008 study.

Bill Harper asked for clarification on the weighted averages. He asked if the 2008 weighted average was based on the incumbents in 2008 or those in 2011. Iain replied that the 2008 weighted average was based on incumbents in 2008. Bill asked what the effect of positions that had insufficient data in either year had on the weighted averages. Iain replied that overall the effect was insignificant.

Iain presented the comparison of overall - total compensation averages on Slide 17 as was requested by some stakeholders. He stated that the results did not differ greatly from the overall total compensation median results found on Slide 11. The only strong difference was in the Power Workers category.

Bill asked why the average compensation was not listed for 2008. Iain replied that the average was not calculated in 2008.

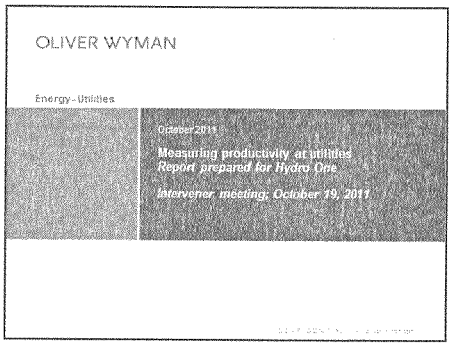
Iain concluded that overall the Hydro One relative position is still above market, but its efforts at controlling compensation costs have been effective and Hydro One has moved closer to market median since the 2008 study.

Ted Cowan asked if there was a comparison for turnover rates. He also asked for information on productivity, asserting that one needs to analyze what is produced to determine value of the compensation package.

Iain replied that he could not comment on turnover as it was not part of the study and was not a metric used in the past. Iain further stated that productivity was also not a factor in the study and mentioned that Mark Hirschey would discuss productivity in his presentation.

Productivity Study, Mark Hirschey, Oliver Wyman

4:05pm



View or download a copy of the Productivity Study Presentation

Mark began by stating that the 2008 Productivity study made reference to compensation and could be consulted to answer at least in part Ted Cowan's question about mapping to compensation.

Mark provided the background to the study, explaining that the Board had requested Hydro One to provide more robust evidence on initiatives to achieve a level of cost per employee closer to market value at its next transmission rate hearing. He noted that the Board will expect any compensation increases to be matched with demonstrated productivity gains.

Mark outlined the approach on his Slide 3, where internal and external research was conducted to build a set of recommendations around how Hydro One could measure productivity. He explained the research, recommendation and implementation processes. The results of the study suggest a number of metrics as candidates to measure productivity.

The primary research used US and Canadian regulators. The majority of regulators examined measured total costs and service quality metrics instead of productivity metrics. In fact, no commission or regulator was found to routinely measure productivity directly.

A survey of utilities' productivity was administered to understand which metrics could be collected internally. The list of survey recipients and respondents was presented on Slide 8. The findings from the productivity survey noted a wide disparity in internal performance measurement. Common metrics for cost, productivity and service quality were collected if measured by at least two utilities. The criteria for choosing a set of metrics was highly dependent on the individual business needs.

Moving to his Slide 15 he focused on the process of selecting appropriate metrics to be used. The first step to determining the area to measure was understanding the breakdown of spend on resources (principally being labour), included in transmission and distribution capital and operations, administrative and maintenance costs. In Slide 16, Mark gave examples including distribution operations, maintenance and administrative project metrics. The eight largest distribution projects had suitable metrics to measure. Most metrics were inconsistent over time and could not be measured.

Ted Cowan stated that he had trouble accepting the inconsistencies attributed to trouble calls over time. He suggested that each trouble call is distinct, but at the end of each year they could be useful as aggregated information and compared from year to year. He used an example of unique ER visits at a hospital, which provide cumulative metrics that can be measured.

Mark granted that Ted's comment was correct, when looking at trouble calls over a multi-annual basis, since weather added a large variability from year to year. Ted noted that there are other examples of projects that can be measured over 5 years. Mark replied that it is difficult to utilize the results on an assessment made every 5 years. Mark acknowledged that further study could possibly establish some consistencies in multi-year trouble call data to allow that to be used in some way as a productivity metric.

Slide 17 listed the twenty-five productivity metrics that have been recommended and which account for approximately 22% of the total project costs. Unfortunately, the last quarter of these metrics reflect no more than 0.2% of Total Costs individually, but they are all associated with discrete units of work that can be measured.

Michelle Byck Johnston noted that there were two metrics titled "Cost per km of line cleared", and asked for clarification regarding their differences. Mark explained that one referred to line clearing in transmission new-build projects and the other in distribution maintenance.

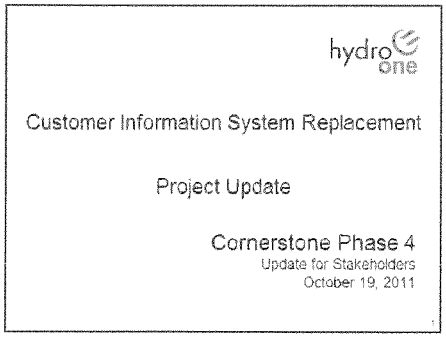
The idea was for Hydro One to choose a set of metrics that could be measured and managed over a shorter time period to begin to effect positive changes. Hydro One will require a detailed plan to develop a set of productivity metrics that are integrated and aligned with the overall corporate scorecard and direction.

Julie Girvan asked if the metrics were strictly field-related, because administration work is contracted out.

Mark replied that the metrics have fully-loaded overhead costs showing savings in overhead over time. Julie asked why there were no service quality indicators or typical customer service measures in the metrics. Mark replied that the customer service measures are associated with a contracted work force; Hydro One's work force aligns with field service measures.

6. Cornerstone Phase 4 CIS Replacement, Brad Bowness, Hydro One

4:37pm



View or download a copy of the Cornerstone Phase 4 CIS Replacement Presentation

Brad Bowness began with a status update, confirming that the CIS project is nearing the end of the Blueprint phase. The project schedule is on track to the baseline plan and the targeted "Go Live" of October 2012. The forecast cost at completion remains at $179.8 million (including contingency, which has not been used thus far). Brad further added that the contingency is "owned" by the Hydro One Board and cannot be used without their prior approval.

The Phase 4 Project involves four phases the first is the Blueprint phase which is nearing completion. One of the key objectives of the Blueprint phases is to validate the benefits and confirm benefits will be

realized as part of the program. The requirements also have to be validated. The other three phases are Realization, Final Preparation, and Verification and Stabilization, which commences following Go-Live. The status of these phases and other Milestones such as Implementation Kickoff and Go-Live are progress reported regularly to senior management and the Hydro One Board.

Brad. explained that the process was intended to minimize customer impact, but that they would follow up about specific touch points with the customer.

Ted Cowan asked whether additional customer inputs through the Customer advisory Board would be included in the design phase. Brad responded that the Blueprint phase will be completed on October 31st, 2011 so the next consultation window would likely come after blueprinting. Ted confirmed that the Customer Advisory Board meets next on December 9th, 2011, and expected the matter could be discussed at that time. As a follow up to this item, it was confirmed that the Customer Advisory Board received an update regarding this project on September 29th.

Brad indicated that the Realization phase will commence in November 2011 and it will involve system configuration, building interfaces and data migration programs, change management communication plans and training design, and making sure that business process changes have been documented and are fully understood. Following Realization comes Final Preparation which ensures that business users understand and accept the system changes. It is also the point that data conversion is fully planned and tested. After Go-Live October 9th, 2012, the new system will be stabilized and verified.

Bill Harper asked when the old system will be retired. Brad responded that the Go-Live Milestone is scheduled for October 9th, 2012. He stated that the process generally requires 3-4 days to shut down the old system, migrate the data, set-up the new system and validate functioning appropriately and begin billing customers.

Susan Frank indicated, from a regulatory perspective, that the Go-Live date may not be the date that the assets go "into service", in the regulatory framework. Hydro One is looking to go to USGAPP, which has criteria as to what is considered an in-service IT system. It is currently believed that some of the testing that occurs in the stabilization and verification phase has to happen before it can be considered "in-service". This is why the words "in service" do not appear in the presentation. The actual in-service date is probably after October 9th, 2011 and could be as late as February 15th, 2013. These additional steps are for regulatory accounting purposes.

Brad then moved to his Slide 5 and outlined details of the CIS that were requested in the last consultation, including that:

- 15 current systems will be retired;
- 40 existing systems will be integrated with the new CIS;
- 68 Business Processes designs are included in this solution
- ±2700 Business Requirements have been met and will used throughout the project;
- 1500 employees and contract employees will be impacted as part of this implementation.

Hydro One will utilize change management methodology to address staff and customer impacts.

Michelle Byck Johnston asked what the total number of systems will be after retiring the old and integrating the new systems occurs.

Brad responded that across the landscape the application portfolio is broken up into 4 types of applications: core business, productivity tools, specialty software and system tools. Business systems (core, productivity, specialty) currently total approximately 800. Detailed information would be included in the filing. They have decommissioned upwards of 400 items across the 4 types driven by the Cornerstone Program, and are continuing to make progress. In follow up Hydro One confirms that it expects 15 business systems and an additional 10-15 system tools will be decommissioned as a part of CIS and replaced with 3 new business systems (SAP, Itron, Streamserve) and a small number of system tools.

The main functions of the CIS are in:

- Customer Service;
- Service Order and Work Management;
- Metering;
- Billing and Payment;
- Retail and Wholesale Market.

Each function in the CIS has several major IT components supporting it. Over 80 Interfaces will be built and tested within the 40 existing systems that will be integrated with the new CIS.

Brad's final Slide 9 provided a high level summary of the $179.8 million Project Total Cost.

ADJOURN 5:00pm

7. Appendices

A. Summary of Stakeholder Session

The Stakeholder Session was structured to afford stakeholders a concise summary of study results and progress reports on a number of fronts with the potential to inform the next round of Rate Applications, and to allow open, frank discussion of important issues and questions concerning:

1. Conservation and Demand Management (CDM);
2. Density and Cost Allocation;
3. Compensation Benchmarking;
4. Productivity and Metrics;
5. Cornerstone Phase 4—Customer Information System (CIS) Replacement.

Throughout the session, there was wide-ranging, free-flowing two-way discussion with Stakeholders, covering questions, issues of concern, requests for detail or explanation, challenges to various study premises and methods, and explicit requests for further input and consultation. Broadly stated, open questions and options include:

- Clarification of the Method used for load forecasting including CDM, and its suitability for co-ordination with OPA;

- Consumer input on the design phase of CIS replacement, through the Customer Advisory Board (Complete);
- Likely schedule for pending Rate Applications.

External consultants and Hydro One internal specialists explained the rationale, approach and results for each study, and indicated where further details and explanations would be forthcoming in the filing dossiers.

B. Key Actions and Notable Items

1. There was stakeholder interest in having volumetric/energy-billed and demand-billed rate classes separately broken out in CDM impact data, to ascertain whether either shows a greater price effect.

2. Stakeholders indicated a desire to have the impact of the Green Energy Benefit factored into CDM impact forecasting.

3. Stakeholders expressed an interest in a more robust and explicit comparison of the merits of the three prevalent Methods of forecasting CDM, including the resolution of data regression and collinearity issues.

4. Stakeholders asked for a clearer definition and explanation of reductions attributable to Increased Conservation Effect as compared to Natural Conservation, and of the specific value or benefit of including Increased Conservation Effect in load forecasting.

5. Hydro One indicated that it would clarify how Increased Conservation Effect growth will be forecast, once 2011 actual data is available.

6. Hydro One will consider including a review of the Seasonal Rate class cost allocation factors when implementing Density Cost Allocation Study results.

7. The CIS project leads were asked to present an update to the Customer Advisory Board at their December 9, 2011 meeting. Subsequently confirmed as complete on September 29th presentation to CAB

8. The exact number of systems affecting and affected by CIS replacement will be confirmed.

9. Hydro One confirmed that CIS Replacement project is "green" (on-track and on-budget) and has not yet had to use any of the contingency funds included in its total budget. Subsequently confirmed to be 15 business systems and approximately 10-15 system tools to be replaced.

10. Hydro One confirmed that the Distribution Rate application filing will be delayed to a date uncertain, but the new filing date will likely be early 2012.

C. Meeting Agenda

Stakeholder Consultation

CDM, Density Cost Allocation, Compensation Benchmarking and Productivity Studies and Cornerstone Phase 4 CIS Replacement in Support of Hydro One Rate Applications

AGENDA
October 19, 2011
Hydro One Networks
Special Event Room, Ground Floor
483 Bay Street, North Tower
1 p.m. to 5 p.m.

1:00 p.m.	Welcome	Allan Cowan, Director, Major Applications, Hydro One Networks
1:10 p.m.	Introduction	Bob Betts, Facilitator, OPTIMUS|SBR
1:20 p.m.	CDM Study	Stan But, Manager, Economics and Load Forecasting, Hydro One Networks
2:00 p.m.	Density Cost Allocation Study	Ben Grunfeld, London Economics
3:00 p.m.	**BREAK**	
3:15 p.m.	Compensation Benchmarking Study	Iain Morris, Mercer
4:00 p.m.	Productivity Study	Mark Hirschey, Oliver Wyman
4:30 p.m.	Cornerstone Phase 4 CIS Replacement	Brad Bowness, Director – Business Architecture, Hydro One Networks
5:00 p.m.	**Adjourn**	

Filed: June 15, 2012
EB-2012-0136
Exhibit A-4-1
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Stakeholder Consultation Notes

2013 Distribution IRM Rate Application

June 5, 2012
Hydro One Networks Inc.
Special Event Room, Ground Floor
483 Bay Street, North Tower
1 p.m. to 4:30 p.m.

Table of Contents

The presentation materials used in this session and background materials can be found at this link:

http://www.hydroone.com/RegulatoryAffairs/Pages/DxRates.aspx

Participants

Stakeholders

- Larry Iwamoto – PowerStream
- Elena Yampolsky – PowerStream
- Patrick McMahon – Union Gas
- David MacIntosh – Energy Probe
- Judy Kwik – Power Workers' Union
- Shelley Grice – Association of Major Power Consumers in Ontario
- Vincent DeRose – Canadian Manufacturers and Exporters (via WebEx, phone)
- John McGee – Federation of Ontario Cottagers (via WebEx, phone)
- Mike Belmore – Society of Energy Professionals
- Ted Cowan – Ontario Federation of Agriculture
- Ethan Kohn – Ontario Power Generation
- Tom Ladanyi – Ontario Power Generation
- Bill Harper – Vulnerable Energy Consumers Coalition
- Mark Rubenstein – SEC
- Harold Thiessen – Ontario Energy Board
- George Vegh – Observer

Hydro One Networks Inc.

- Jim Malenfant – Hydro One
- Nai Yu Zhang – Hydro One

Presenters

- Allan Cowan – Hydro One
- Susan Frank – Hydro One
- Ian Malpass – Hydro One
- Henry Andre – Hydro One

OPTIMUS | SBR

- Bob Betts – OPTIMUS | SBR
- Angela Boychuk – OPTIMUS | SBR
- Tara Murphy – OPTIMUS | SBR

1. Welcome by Allan Cowan, Director, Major Applications, Hydro One

START 1:01pm

Allan Cowan welcomed all participants to the Stakeholder Consultation meeting, the first session for 2013 IRM Application. He stated that OPTIMUS | SBR will be providing the note-taking and facilitation. Allan introduced Bob Betts as the facilitator and to start the meeting.

2. Opening Remarks by Bob Betts, Facilitator, OPTIMUS | SBR

1:02pm

Bob welcomed the participants on the phone and introduced the OPTIMUS | SBR team as note-takers.

Bob began his presentation with several housekeeping items and pointed out the emergency procedures. Bob stated that notes will be taken during the meeting and that the meeting and discussions will be recorded. He mentioned that the recordings will be destroyed once the notes are produced. Any comments made will be attributed to the individual and the party they represent. Participants were instructed if they wanted comments to be off the record to advise beforehand.

Bob asked all attendees to introduce themselves, stating name and company for the record. He outlined the agenda for the day and listed the topics that would be discussed. He stated that all comments are appreciated and that the meeting notes will be available on Hydro One's website.

He stated that Hydro One had established two principle objectives for the consultation session. The first was to ensure that all participants thoroughly understood Hydro One's 2013 Incentive Rate Mechanism ("IRM") application and in particular the Incremental Capital Module ("ICM") component. The second was to identify any additional information that interveners felt would be helpful in their understanding, review and analysis of the application.

Bob invited Allan Cowan to start the first presentation, the 2013 IRM Overview.

3. 2013 Distribution Rate Application (IRM) Overview, Allan Cowan, Director, Major Applications, Hydro One

1:12pm

Allan began his presentation stating that on May 28, 2012 Hydro One filed the Transmission Rate Application and the initial portion of the 2013 Distribution IRM Rate Application with a note that the supporting evidence would be filed mid-June, 2012. Hydro One wanted stakeholder input before finalizing the evidence. Allan provided an overview of the process to determine the 2013 rate impact:

- Hydro One did not file an Incentive Regulation Mechanism (IRM) for 2012; as a result there is actually a slight decrease in the overall distribution rate because riders associated with Green Energy for Smart Grid came off. The net result is a -0.2% decrease;

- The first element of the application is the general Price Cap Index Adjustment ("PCI") of (0.88%);
- The next major element of the application is Hydro One's proposal for an Incremental Capital Module (ICM). In total Hydro One will be seeking recovery of total in-service capital additions of approximately $645 million (2.4% increase);
- The riders associated with Green Energy plan came off on December 31, 2011. Hydro One will be requesting the reinstatement of the rider with respect to Smart Grid OM&A to recover spending of $19.8 million (1.6% increase);
- In the current application Hydro One is not asking for a Z-Factor; but is having a pension valuation currently undertaken, and depending on the results of the valuation, may consider including a Z-Factor to deal with pension issues;
- The next item is the Tax Sharing Credit Refund, which is a decrease in income tax of $1.7 million over one year (0.1% decrease);
- There will be a disposition of the Group 1 Deferral and Variance accounts balance of $37.5 million over 2 years (1.7% decrease);
- There will be no disposition for Smart Meter Funding Adder, due to 150,000 smart meters that are not yet activated; and
- The overall Rate Impact of the application is a 3.1% increase, which equates to a 1.1% Bill Impact increase.

Allan continued by providing an overview of the other requests including:

- Adjustment to the Retail Transmission Service Rates (RTSR) to reflect the Board approved Uniform Transmission Rates (UTR) increases for 2011 and 2012;
- Approval to implement the final step of rate harmonization approved under EB-2007-0681; and
- Approval to implement the results of the Density Study (Board's Directive), because of the cost and results of the study.

Bill Harper asked if the Price Cap Index would have the 2012 Productivity Factor of 0.72 replaced with the 2013 factor. Allan replied that the Productivity Factor of 0.72 would be replaced with the Board approved factor applicable to 2013.

Allan invited Susan Frank and Ian Malpass to the podium for their presentation on the ICM proposal.

4. 2013 ICM Application, Susan Frank, Vice President and Chief Regulatory Officer, & Ian Malpass, Director, Regulatory Pricing and Support, Hydro One

1:25pm

Susan began the presentation by stating that there are varying opinions on what an Incremental Capital Module (ICM) should look like and that it is important to clearly understand the choices. Susan reviewed the presentation agenda and asked Ian to begin.

Ian explained that the Threshold Test is the determination of whether an Ontario utility is eligible for ICM. He explained the formula and how the factors within it are calculated. He stated that based on the Threshold Test Hydro One was eligible to file the ICM.

Bill Harper asked for clarification on the approved rates, specifically whether the base distribution rate in the Threshold Value Formula is exclusive of the riders and adders. Ian confirmed that they were.

Ian then moved to the description of Hydro One's proposed ICM. He indicated that it follows the approach described by Susan and Hydro One in their submissions to the Board in the Renewed Regulatory Framework for Electricity consultation process.

Ian then reviewed the categories of capital investments in the Hydro One ICM, which were:

1. "Typical": Includes historically approved levels of sustainment and development spending;
2. "Escalated Issue": Includes spending on typical categories but at a substantial increase over historically approved levels; and
3. "Non-typical": exceptional items, not occurring often, such as the Customer Information System (CIS) Investment.

Judy Kwik asked if Escalated Issue capital investments occur because investment in previous years was insufficient.

Susan Frank responded that is likely not a factor and that escalated issues generally involve new information, new experiences or new failures. Susan used an example of a storm that damages and identifies multiple weak poles. It is work that is typical but at a higher level because of the new or better information.

Ian continued the presentation, stating that different OEB Panels used different considerations or determinations for assessing the appropriateness of an ICM, including "materiality", "need", "prudence", "extraordinary", "unanticipated", "non-discretionary", and "discrete". Hydro One perceives this as a lack of clarity in the use of the ICM.

Vince DeRose stated his view that the OEB considerations support Non-Typical capital investment and asked if Hydro One felt OEB considerations would also support Escalated Issue capital.

Ian replied that the ICM should cover both Non-Typical and Escalated Issues capital. He said the considerations may not allow Typical capital spending; however, Typical capital spending in excess of approved depreciation should be allowed as part of the ICM.

Ian then reviewed the current ICM approach and associated issues. The issues included:

- Limited testing of the approach,
- Typical capital spending not fully recovered by distributors whose Typical capital spending is significantly great than depreciation during the period of an IRM,
- Escalated Issue capital spending and Non-Typical spending also need to be recovered during IRM periods, and
- The current model results in step increases at Cost of Service rebasing, which Hydro One feels are not customer friendly.

Ian then provided the numerical support for why Typical capital spending is not recovered during the period of an IRM. He reviewed a table which determined the funded growth in rate base and loss in revenue was a result of Typical capital spend. Ian emphasized that depreciation is clearly insufficient to fund capital during an IRM. The table included the following data for the 2013:

- Typical Capital Expenditure ($414 million),
- Rate Base impact of Typical Capital Expenditure ($414 million),
- Less Rate Base funded by Depreciation (-$283 million),
- Less Rate funded by Growth in Revenue ($11 million),
- Unfunded growth in Rate Base ($142 million), and
- Lost Revenue associated with unfunded growth in Rate Base ($14 million).

Ian also explained the derivation of the $11 million Rate Base Funded by Growth in Revenue in detail.

Ted Cowan posed a question about negative growth. He asked if Hydro One looked at the situation where PCI stays stagnant and the negative growth continues to shrink, resulting in larger negatives. He added that the Ontario Federation of Agriculture ("OFA") considered this question and that they were concerned that the Rate Base Funded by Growth in Revenue would be very much below the negative $11 million calculated by Hydro One on slide 8.

Ian responded that Hydro One's loads are forecasted to level off; so for this portion of the equation, there will not be a large increase.

Ted questioned whether loads could level off while capital requirements were growing.

Susan Frank commented that their growth calculation is consistent with what the Board uses in the Threshold, which is a historic base and unaffected by future load changes. When Hydro One looks to the future, load will be flat. Load reduction is coming, especially if they meet CDM requirements. Therefore the concerns are realized at a slower rate. She noted that if a reduction exists, it will be proportionately assigned to Capital and to OM&A. Susan confirmed that Ted's thinking was correct, but that the movement of the load would be realized in the future.

Bill Harper advised that Hydro One was blending a combination of the ICM, using historical and forecasted total capital spend for 2013. He stated that one could do a load forecast for 2013 to determine the actual expected loss.

Susan added that Hydro One is not trying to forecast load for 2013. They are trying to determine the amount of money obtained with the current IRM formula. She said that they are determining how much PCI provides and also if the results are consistent with the Board. In theory you are getting more money from the growth.

Bill replied that he did not disagree, but that Hydro One presently looks at total forecast capital going forward, and asked why Hydro One is not looking at the load growth going forward as well.

Susan responded that when the OEB looks at the capital they always look at what goes in-service in the future year (IRM year), not in the past.

Bill said that Hydro One is departing from existing ICM methodology. The ICM model does not adjust capital based on total capital going into service, and that difference may justify using a future load forecast for the same period. Bill said that he has seen other utilities that include a load forecast in their application. Susan asked what utilities use this method. Bill said that FortisBC was under a similar ICM to the one Hydro One is applying for. It was inflation adjustment on OM&A coupled with a capital spend forecast and a load forecast to determine the capital spend forecast in the rates for the same period of time.

Susan asked how much testing it took for the load forecast. Bill responded that in this case they had a stakeholder group that reviewed the load forecast.

Ted Cowan stated Hydro One may want to look at a different cost allocation model for rate classes. He stated that the current model accelerates the exodus of customers, such as those that go to self-generation. He added that the model should be examined in advance of customers being driven to make their own power, which would create further load loss.

Susan said that this question is more closely related to the Density Study and will be examined in the next presentation.

Ian continued with his presentation, providing a summary of the funding of Typical capital spending.

- Hydro One would incur $14 million in lost revenue in 2013,
- The unfunded growth in rate base would be $142 million in 2013, and
- Other Impacts in 2013:
  - Hydro One will incur lost revenue of approximately $9 million per year due to ½ year rule applied to 2011 COS approved capital; and
  - Hydro One will also incur lost revenue of approximately $9 million per year for ½ year resulting from not applying for 2012 IRM.

John McGee asked Ian to specify the effective date for the 2013 application. Ian confirmed that the effective date is January 1, 2013.

Ian then outlined the potential negative outcomes of the current ICM:

- Hydro One is not in a position, due to credit rating issues, to invest in rate base for which there is no cost recovery; and
- Potential unintended customer outcomes:
  - Lower reliability as assets are not replaced or refurbished prior to breakdown,
  - Not replacing or refurbishing assets when it is economically beneficial to do so, and
  - Increased labour costs as a utility is unable to level work based on the most efficient use of labour resources.

John McGee asked about the cost of connecting renewed energy (Smart Grid). He stated that the amount of money spent does not seem to have a significant impact on rates and asked if that was correct.

Susan replied that when "Green Energy" investments were approved, Hydro One was given a rider to track the cost for all the capital. The rider stopped at the end of 2011, but Hydro One continued tracking

expenditures and revenues. The "Green Energy" investments are going into a variance account for future recovery.

John McGee asked why Hydro One received a credit rating downgrade and whether it was related to "Green Energy".

Ian replied that part of the reason was Hydro One tends to follow the Ontario Government, which was also downgraded. Susan commented that OPG was not so affected because it is not a debt issuer at this time.

Susan added that the DBRS report that came out this week talking about risk factors for regulated utilities was relevant to this conversation. It indicated that an IRM is more risky than cost-of-service (COS), which tends to get a full cost recovery, and makes IRM more risky in the short and long term. It also looked at capital recovery and concerns about having confidence getting recovery of the capital. The ongoing basic level of capital is not recovered today and there is no guarantee that COS will get the recovery. DBRS also said that variance accounts/investments pose a risk for recovery. These three items of the risk profile are all negative for Hydro One, and could affect their credit rating and their cost of debt.

Ian provided further details of Hydro One's 2013 ICM application. The application includes:

- Establishment of a rate rider based on the full capital program for in-service additions in 2013;
- Recovery of full year revenue adjusted for depreciation, PCI and load growth;
- A need and prudence review of forecast changes to rate base; and
- 2013 Board approved cost of capital applied.

Bill Harper asked if Hydro One is applying the 2013 cost of capital factors only to the incremental capital or to the entire amount including the base amount.

Susan replied that the 2013 Board approved cost of capital is applied only to the new incremental capital, not the replacement capital. Susan stated that Hydro One is diverging from the Board. As it is new capital, Hydro One will use the new ROE. Directionally this lowers the ROE for the 2013 application. However, despite that, Hydro One is establishing this precedent to use the new ROE going forward, whether it benefits Hydro One or not. Susan then stated that Hydro One is also using the full year impact, not the half year. The current IRM also uses the full year, because it does not pick up the non-approved half-year from previous year. Susan also reminded parties that Hydro One is not trying to pick up the half year for 2012 that they missed.

Tom Ladanyi asked if he was correct in understanding that Hydro One would ask for a 2013 ICM rider, and then again ask for a 2014, and that would appear in rates, and this pattern would continue until re-basing. Ian confirmed this statement.

Bill Harper asked about 2015 and whether it would have a rider that looks at 2014 and 2015. He also questioned how depreciation should be treated in 2014.

Susan replied that no one should worry too much at this time about 2014 and 2015 and that this is a one year application for 2013 only, it is important to see how this application goes first. She said that Hydro One will have to think about how its 2014 application would look including the handling of depreciation.

Ian continued with his presentation at slide 12 reviewing Investment by Type and the total in-service additions.

That chart showed 2013 revenue requirements for: Typical capital at $14M, Escalated Issue at $7M and Non-Typical at $7M adding to a total of $28M. Those revenues drove distribution rate impacts of 1.2%, 0.6% and 0.6% respectively, totaling to 2.4%.

Bill Harper asked why the revenue impact for Non-typical was so low compared to the impact of the lower spending in the Escalated Issue category.

Allan explained that it was attributable to the accelerated CCA associated with the CIS in the Non-Typical category.

Vince DeRose questioned if Hydro One considered the Customer Information System (CIS) unanticipated.

Allan noted that this was identified as Phase 4 of the Cornerstone Initiative in previous sessions. It was originally targeted for 2016, but was advanced to be implemented in 2011-12 and in-service in 2013 because of back room contracts that would have meant implementation of new CIS and new CIS support in the same year.

Susan added the current billing system cannot accommodate new codes and requirements; therefore Hydro One is currently not in compliance. The CIS contributes to the Non-Typical investment as an IT project. Hydro One uses the normal tax treatment of half-year rule that allows the rider established in 2013 to carry over to the next year. Because the tax impact is so large, Hydro One would be covered over 2 years instead of 1. The difference is 100% recovery of the returns and half-year benefit on the tax.

Ian moved on to the next slide, which highlighted Typical, Escalated Issue and Non-Typical Capital Evidence to support the ICM Application.

- Typical:
  - Summary of capital program.
- Escalated Issue (Stations, Poles and TX Station capital Contribution):
  - 4 years of historic investment information to establish typical spending pattern,
  - Detailed age and asset condition information to defend spending to address escalated issues, and
  - Consistent with program COS evidence.
- Non-Typical (CIS Replacement):
  - Consistent with project COS evidence.

Ian added that requests made by stakeholders in previous sessions were included in the evidence.

Mark Rubenstein asked how capital for Escalated Issue and Non-Typical would fit into the long term capital plan and what the plan was for spend over the next few years.

Susan replied that the Escalated Issue capital would need to be defended again in the next year. Allan added that the evidence would show historical capital, compared to capital for 2013 and then ramped up level for forecast years.

Ted Cowan suggested that Escalated and Non-Typical capital could shift to Typical over long term, presented to Board as a prudent and efficient plan. Ted also suggested that Hydro One should work with other utilities to split cost of projects such as the cost of the new CIS.

Judy Kwik asked if in 2014 Hydro One were to come into an ICM would Escalated Issues from 2013 become Typical in 2014.

Susan replied that Typical costs would not be changed without a cost of service review with Board approval.

Bill Harper wondered if using the summary of Typical capital program would be adequate. He felt that Hydro One would need to demonstrate that 2011 Typical capital is reasonable for comparison to the amount in 2013 and that would depend on the case built for 2011. He also wanted to ensure that the whole program, including total Typical and amount for Escalated Issue spend, and reasons to support the program, would be provided as evidence.

Susan replied that Escalated Issue totals would need to be defended, especially if they are above previous year's escalated totals. She stated that if the Board is repeatedly approving Typical capital investment less evidence is required; it would be a summary of the programs, not a detailed defense.

Tom agreed that there is no need to provide full and detailed evidence.

Mark asked for the planned 2012 Capital Expenditure total. Allan replied that the capital spend for 2012 is $540 million.

Mark asked if there was any thought of doing a half year in 2013 and picking up the other half in 2014.

Susan replied that it would be a larger number then just using 2013.

Ted Cowan commented that capital budget could be 2-3 year forecast and OM&A could be 4 year forecast. Since OM&A is predictable, the Board could approve OM&A budget spend for 4-5 years out.

BREAK 2:48pm

5. Implementation of Density Study Findings, Henry Andre, Manager Pricing, Hydro One

3:07pm

Henry Andre began his presentation to review the findings of the Density Study and the options being considered for implementation of the Density Study as part of Hydro One's IRM application for 2013 rates. There have been 3 previous sessions describing the Density Study. Henry focused on the findings in this session. The three key findings of the study were:

- Statistically significant relationship between density and cost-to-serve;
- Three density based classes for residential and two for General Service classes is appropriate; and
- Do not recommend wholesale changes to existing rate classes at this time.

The key finding was that they were able to quantify the relationship between customer density and cost-to-serve. For OM&A and Fixed Asset Costs:

- A Medium Density area costs 1.9 times more than a High Density area to serve; and
- A Low Density area costs 4.8 times more than a High Density area to serve.

When considering all costs (including customer related, non-density related costs, spread uniformly by customer):

- A Medium Density area costs 1.7 times more than a High Density area to serve; and
- A Low Density area costs 3.9 times more than a High Density area to serve.

Bill Harper asked how the High, Medium and Low Density areas relate to the existing customer classes, specifically he asked where the General Service class would fit.

Henry replied that the General Service would be somewhere between Medium and Low Density, but the study did not look at the specific composition of Hydro One's General Service class.

Bill said that the presentation slides do not make reference to the 2 General Service classes and asked if Henry could make reference to them where applicable. Henry agreed.

Ted Cowan asked if Hydro One reviewed the most costly 5% of the very Low Density and the most costly 5-10% of the General Service Group, how many customers would be in this combined group and what would the costs look like.

Henry replied that Hydro One had not looked at this. This is a question that relates more specifically to the general cost allocation methodology for Hydro One rate classes and they are not looking at revisiting the rate classes as part of the IRM. He stated that making changes to the rate classes would be undertaken in a cost of service (COS) application.

Ted continued saying that these customers (most costly 5%) have 5 times the cost and are in need of rural rate assistance. Ted also suggested that it could be more cost effective to buy this costly group off the grid.

Henry continued his presentation by reviewing the 2010 Cost Allocation Model results. Hydro One used the number of customers associated with each rate class to determine the cost per customer. They looked at the Total Costs and OM&A plus Fixed Asset Costs to determine the ratio.

- Ratio of Total Cost per Customer:
  - Medium Density (R1) was 1.6 times the cost of the High Density (UR);
  - Low Density (R2) was 2.8 times the cost of the High Density (UR); and
  - Seasonal was 1.5 times the cost of the High Density (UR).
- Ratio of OM&A and Fixed Asset Cost per Customer
  - Medium Density (R1) was 1.7 times the cost of the High Density (UR);

- Low Density (R2) was 3.1 times the cost of the High Density (UR); and
- Seasonal was 1.7 times the cost of the High Density (UR).

Henry compared the results of the 2010 Cost Allocation Model to the results of the Density Study, using two alternate approaches, Option A: Total Costs and Option B: OM&A and Fixed Asset Costs. The Density Study adjusted cost allocation model results using Option A identified a much higher differential between the 3 classes than is shown using Option B. Henry stated that Hydro One also did these calculations for the General Service class and found that there is some differential (slightly more than the R1, but not as high as the R2). He focused on the residential classes, because Hydro One believes the General Service classes do not require immediate attention. Henry stated that Hydro One can include the General Service class results in the evidence.

Bill stated that if Hydro One does not want to take immediate action on the General Services classes then they will need to explain why in the evidence.

Henry concluded that based on the Density Study there needs to be some immediate cost allocation adjustments between the residential rate classes. He asked stakeholders if Hydro One should be using Total Costs or the OM&A and Fixed Assets when altering Cost Allocation Model to align with the Density Study.

Ted questioned if the Total Cost per Customer is actually Total Cost per Account. He stated that average farms have three accounts; therefore the individual customer will be receiving three bills and could be interested in consolidating the three bills by going off the grid. Ted added that Hydro One needs to identify the number of customers. Henry advised he will check if total cost is by customer or account.

John McGee requested that in the submission to the OEB, Hydro One should include the number of customers in each of these classes.

Henry replied that the number of customers will be presented upfront in the application.

Bill Harper replied to Henry's question regarding the use of Total Cost vs. OM&A and Fixed Asset to alter the Cost Allocation Model. He advised to use the OM&A and Fixed Asset Costs, which is a Board approved method, rather than using the Total Costs for allocations.

Bill added that if the General Service classes were added to the ratios shown in the options for implementation the results could differ. He also stated that this assumes no density consideration in the differentiation of allocation of cost for other classes, excluding General Service and Residential; he believes there may be some debate over this.

Mark Rubenstein stated that he believes Hydro One should be prepared to include General Service data in the application. Henry indicated that Hydro One would do so in its evidence.

With respect to general Cost Allocation methodology, Ted Cowan stated that Hydro One should consider subdividing each of the classes, so that there is no internal cross-subsidy within a class or external cross-subsidy between classes. He stated that this would help reduce underestimation and generalization of the issues. Henry stated that looking internally within a class would be difficult, but he understood Ted's point. Ted stated that he believed Hydro One has the information that would allow them to do the internal class analysis.

John McGee asked if Hydro One had the amount of the Rural Rate Protection charge, allocated to the R2 class, per customer per month. Henry replied that it is $28.50 per customer per month.

Henry continued his presentation by reviewing the Density Study Adjusted (DSA) Cost Allocation Model results. He reviewed the DSA costs, Revenue Collected, Revenue to Cost (R/C) Ratio and compared the 2010 Approved R/C ratio for both options:

- Option A: Total Costs
  - UR: DSA R/C Ratio = 1.36
  - R1: DSA R/C Ratio = 1.07
  - R2: DSA R/C Ratio = 0.93
  - Seasonal: DSA R/C Ratio = 1.09
- Options B: OM&A and Fixed Asset Costs
  - UR: DSA R/C Ratio = 1.34
  - R1: DSA R/C Ratio = 1.06
  - R2: DSA R/C Ratio = 0.92
  - Seasonal: DSA R/C Ratio = 1.17

Henry stated that the results in both cases show that R2 is underpaying and that the Seasonal Class overpays much more in Option B.

Bill Harper stated that the General Service classes need to be included because currently the revenue collected from General Service is divided between the 4 other classes. Henry replied that he would have to think about the suggestion.

Ted stated that some of the customers in R2 are already paying their full share of the costs, but others are not and the ones currently paying their full share of the costs will be impacted more by the rate adjustment. He restated that Hydro One needs to consider reviewing the internal composition of the classes for internal and external cross-subsidy.

Henry then reviewed the 2013 Implementation of the Study Results. The options are:

1. Bring the density study-adjusted revenue-to-cost ratios for classes exceeding Board limits to previously approved levels.
   - Lower UR R/C ratio to 1.09 and Seasonal R/C ratio to 1.03,
   - Better aligns with previous Board decision,
   - Rates will more closely reflect cost of serving rate class, and
   - Addresses existing rate disparity more quickly.
2. Bring density study-adjusted revenue-to-cost ratios to within Board approved range
   - Lower UR and Seasonal R/C ratio to 1.15,
   - Meets minimum Board Requirements, and
   - Addresses existing rate disparity more slowly.

Henry asked the stakeholders for input on the most appropriate option.

Bill stated that he believes Option B is most appropriate, depending how Hydro One handles the General Service class. He was not sure if using 2010 data to adjust 2014 costs is an overall improvement. He suggested that for the next Cost of Service application the study results will no longer apply to the customer counts and loads and will need to be reviewed for 2015.

Henry stated that the context of the IRM application is to address immediate issues that require attention. He agreed that for a Cost of Service application, the method of incorporating the Density Study findings into the Cost Allocation Model should be considered.

Henry agreed that Option B addresses the problem and that Option A could be impacted by how it rolls through the Cost Allocation Model, and Hydro One does not want to overshoot the target. He stated that bringing it within the range at this time is the best option because more evidence and data would be required to support Option A. Henry stated that perhaps before the next IRM or Cost of Service Hydro One could get that data.

Henry then reviewed the proposed rate class impacts in each of the options. For Option A the average distribution rate impacts are:

- -18.7% for UR,
- No impact for R1,
- +5.4% for R2, and
- -12.3% for Seasonal

For Option B, the average distribution rate impacts are:

- -14.3% for UR,
- No impact for R1,
- +2.5% for R2, and
- -2.1% for Seasonal

Regarding the Total Bill Impacts which were about one-third of Distribution Impacts, John McGee stated that seasonal class customers have a variety of consumption rates, so the total bill impacts would not be constant. He then recommended that Option B should be implemented in order to gradually phase in the changes for all classes. Henry agreed that the impact for low consuming Seasonal Distribution customers will represent more than 1/3 of the Total Bill.

Ted stated that both options have obvious inequality between the classes, but that there is unexposed inequality within the classes. He said that the difference between customers is diluted and the major issue is still hidden in the largest customer class, R2, because of subsidies. He stated that the data will not help the Board understand or help Hydro One find the problem. Option B is a smoother transition, but does not address the problem. Ted stated that the R2 class needs to be analyzed on its own to find the issues.

Susan asked John about his reasoning for choosing Option B, specifically when the next step of phasing should be implemented.

John stated that the OEB should determine the Revenue to Cost ratio ranges, so they would determine the next step in the phasing. He then stated that Hydro One could decrease it slowly each year as long as they had a high level of confidence in the cost allocation. He believes that Hydro One has high confidence in Density Study, therefore each year there should be a minor adjustment to get to 1.00 for all classes.

Bill asked why the total revenue was held constant across the classes when doing the adjustments and if there was any class that had an approved revenue to cost ratio less than 0.92, would the appropriate approach be to move that class up first before addressing the R2.

Susan asked if this comment supported Bill's point earlier about the General Service class.

Bill said that it is the same issue on both sides, the "cost" for the denominator and "revenue" for the numerator. He stated that other rate classes should not be combined or excluded from these calculations.

Susan said that she was struggling with the notion that the Density Study allocates costs differently across Residential and General Service and how the cost allocation would change.

Bill stated that the relativity between classes should be included in the rate distribution costs across all classes. He noted that isolating just residential does not make sense because the isolated costs are the result of the cost allocation that did not properly account for density.

Henry added that one issue may be that the Density Study focused on the relative cost of serving those classes as opposed to the absolute cost. He added that the Cost Allocation model does not allocate cost uniformly across the classes.

Bill stated that the Cost Allocation model does not treat R1 vs. R2 differently than R1 vs. GS customers.

Henry replied that it is not obvious how costs will be allocated differently across the classes.

Susan said that the variables for assigning cost to a UR Residential vs. a UR General Service for example, are not clear. Hydro One has to stay within the Residential and the General Service for the cost step. Susan added that for the revenue to cost ratio can be looked at across all classes.

Shelley Grice advised that AMPCO consistently advocates for revenue to cost ratios to move toward 1 as quickly as possible; therefore she believes Option A is the better approach and that it should be implemented as soon as possible.

Susan stated that Hydro One was going to make a recommendation to the Board based on the Stakeholder feedback, but that they will include all of the evidence and options in the filing. The stakeholders agreed that all options should be presented.

6. Other Interest Areas, Allan Cowan, Director, Major Applications, Hydro One

4:19pm

Allan Cowan concluded the session by thanking all Stakeholder's for their input and stating that it will be taken into consideration when finalizing the evidence. Hydro One is aiming to have the remaining evidence submitted by mid-June 2012.

ADJOURN 4:20pm

7. Appendices

A. Summary of Stakeholder Session

The Stakeholder Session was conducted to present justification and information supporting the 2013 IRM Application with specific attention to the Incremental Capital Module (ICM), as well as implementation of the Density Study findings. This session was aimed to achieve two objectives:

1. To collect stakeholder feedback on the type of information to be submitted as evidence for the 2013 Distribution IRM Application, and
2. To collect stakeholder feedback and opinions on the suggested options to implement the density study findings.

Throughout the session, there was open two-way discussion with Stakeholders, covering questions, issues of concern, additional information for consideration, requests for detail or explanation, and requests for further input and consultation.

Hydro One internal specialists explained the rationale, approach and results for the Application and Density study, and indicated where further details and explanations would be provided in the filing.

B. Key Actions and Notable Items

2013 ICM Application

- Stakeholders asked if Hydro One looked at the situation if PCI remains stagnant and the negative growth shrinks, larger negatives will result, and expressed concern that, in Typical Spend, the value for Rate Base Funded by Growth in Revenue was larger than $11 million.
- Stakeholders requested consideration be given to using a forecasted load if Hydro One is looking at forecasted capital for 2013.
- The representative from the OFA commented that a review of the cost allocation model should happen before agricultural customers are forced to start making their own power and leave the grid.
- Hydro One will consider the handling of depreciation in riders for 2014 and subsequent years, for applications beyond this one for 2013.
- Stakeholders questioned the length of time for depreciation for each of the investment types, expressed concern that the CCA half-year rule would extend risk into 2014 against fallen revenues. Hydro One offered to show the math on the $7 million value.
- Stakeholders requested information to understand how Escalated Issues and Non-typical capital would fit in the long term capital plan. Hydro One will include, as part of evidence, historical units, spend for 2013 and ramped up level for next few years.
- Stakeholders suggested that Escalated and Non-typical spend could be shifted to Typical spend over long term.
- Stakeholders suggested that Hydro One work with other utilities to share the cost of capital projects such as the CIS.

- Stakeholders questioned if using the summary for the Typical capital program would be adequate. They felt that Hydro One would need to demonstrate that 2011 Typical capital is reasonable as a base for 2013.
- Stakeholders wanted to ensure that the application include the whole program, with total Typical and Escalated Issue spending, and reasons supporting the program.

Implementation of Density Study Findings

- Several stakeholders wanted Hydro One to expand the implementation plan for the Density Study to include other classes and other cost allocation methodology issues. Hydro One responded that this was more appropriate for a cost of service application.
- Hydro One indicated that they would explain in the application why the General Services classes were not included in the Density Study implementation.
- Stakeholders questioned if 'Total Cost per Customer' was by customer or account, citing that farms can have 3 accounts. Hydro One to check if total cost is per customer or per account.
- Stakeholders suggested that it would be helpful to include the number of customers or accounts in the table. Hydro One will include the data.
- Stakeholders requested further consideration to having density considerations also include the two General Service classes, not just the 4 residential classes of UR, R1, R2 and Seasonal.
- Stakeholders commented that using the 2010 Cost Allocation Model methodology may not be adequate for adjusting costs to implement the Density Study. For next cost of service, Hydro One will need to think about cost allocation model inputs.
- All stakeholders that responded with their choice of Option A: Total Cost allocation or Option B: OM&A and Fixed Asset Costs allocation chose Option B. With respect to adjusting the revenue-to cost (R/C) ratio Option A: Move to R/C ratios approved by Board in last COS application or Option B: Move to limit of Board approved R/C ranges, all stakeholders that responded with their choice favoured Option B, except for AMPCO based upon their principle of moving to ratios of 1 as quickly as possible. Stakeholders questioned if any classes were below 0.92 in 2010 approved cost allocation, suggesting that there may be other candidates for adjustment before moving R2.
- Stakeholders agreed with Susan Frank that Hydro One should include all evidence and their recommendation for all Options in the filing.

C. Meeting Agenda

AGENDA

June 5, 2012

Hydro One Networks Inc.

Special Event Room, Ground Floor
483 Bay Street, North Tower
1:00 pm to 4:30 pm

TIME	ITEM	PRESENTER
1:00 p.m.	Welcome	Allan Cowan, Director, Major Applications, Hydro One Networks
1:05 p.m.	Introduction	Bob Betts, Facilitator, OPTIMUS | SBR
1:10 p.m.	Overview of 20 13 Distribution Rate Application (IRM)	Allan Cowan, Director, Major Applications, Hydro One Networks
1:30 p.m.	2013 ICM Application	Susan Frank, Vice President and Chief Regulatory Officer, and Ian Malpass, Director Regulatory Pricing and Support, Hydro One Networks
3:00 p.m.	**Break**	
3:15 p.m.	Density Study	Henry Andre, Manager Pricing, Hydro One Networks
4:15 p.m.	Other areas of interest	Allan Cowan, Director, Major Applications, Hydro One Networks
4:30 p.m.	**Adjourn**	

This is Exhibit "F" referred to in the Affidavit of M. Lilly Iannacito sworn April 13, 2016

Lisa Lutwak

Commissioner for Taking Affidavits (or as may be)

LISA S. LUTWAK

hydro one

Customer Information System Replacement

Project Update

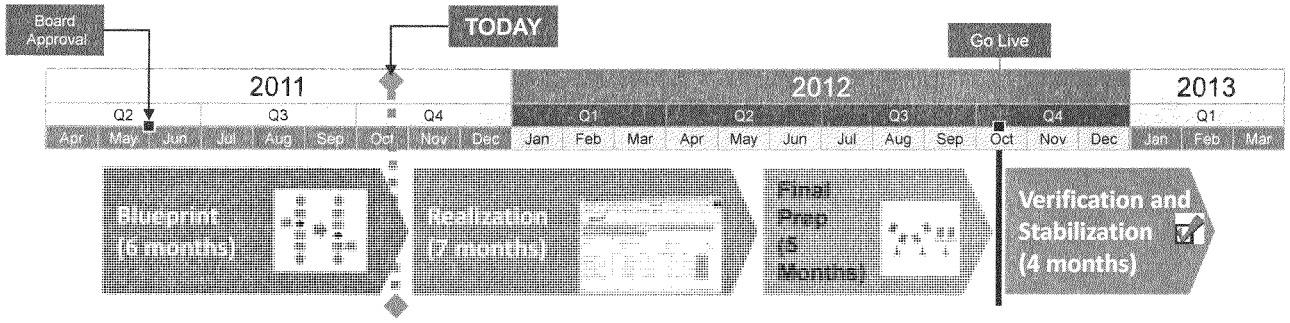
Cornerstone Phase 4

Update for Stakeholders

October 19, 2011

Phase 4 – Current Status

On Track



- The CIS project is nearing the end of the Blueprint phase.
- The project schedule is "on track" to the baseline plan
- Benefits confirmation is being completed as a part of blueprint
- Forecast at completion remains at: $179.8M (including contingency)

Phase 4 - Project Milestones

Milestone	Date	Description	Status
Implementation Kickoff	June 1, 2011	Context: Officially start the implementation phase. Measure: 1. Project team structure has been assembled. 2. Project methodology has been documented and agreed to by all parties. 3. Project leadership team / sponsors assign accountability to the project team.	Complete 
Blueprint phase	October 31, 2011	Context: The CIS project design has been completed. Measure: 1. Hydro One has reviewed and accepted the design documents and solution. 2. Project governance has compared the design criteria against requirements, timeline, cost and benefits and confirmed that the exit criteria to the Realization phase has been met.	In-Progress 
Realization	April 30, 2012	Context: The CIS solution development has been completed and tested. Measure: 1. Development of solution is completed. 2. Systems integration testing has been completed. 3. Business processes changes have been completed.	

Phase 4 - Project Milestones

Milestone	Date	Description	Status
Final Preparation	October 9, 2012	Context: Testing, Training and Sustainment Readiness completed Measure: 1. User acceptance testing completed and signed off by LOB. 2. System data conversion and migration activities have been tested / audited and confirmed ready for Go Live weekend. 3. The Sustainment organization has signed off the Operational Readiness Tests and Commissioning final documents are completed. 4. Training material has been developed and training is tracking to plan.	
Go-Live	October 9, 2012	Context: Go-Live – cutover the CIS solution into production. Measure: 1. Conversion Activities are completed in accordance with the plan 2. Transactional activity begins within new CIS and legacy systems are moved to read only. 3. Users are able to function within the new system. 4. Adequate support is available to aid users through the transition.	
Verification and Stabilization	February 15, 2013	Context: The transition to the sustainment organization for all aspects of support outlined in the services agreement with Inergi. Measure: 1. Hydro One has completed the CIS System Acceptance. 2. The user change management organization is in place and supporting impacted users. 3. Inergi Commissioning final documents are completed.	

CIS Solution Overview

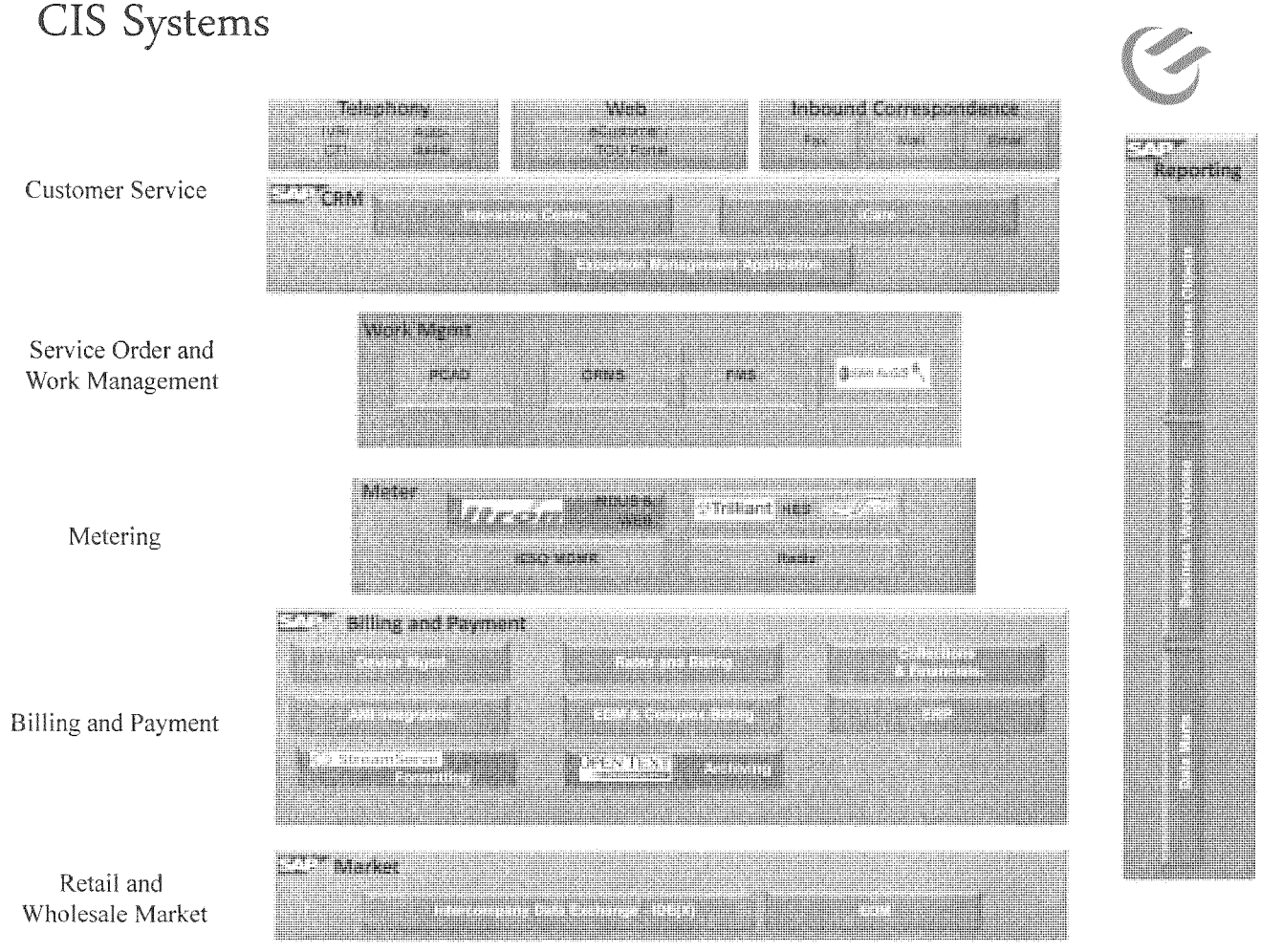
By the Numbers

15	Current systems to be retired
40	Existing systems to be integrated with the new CIS Solution
68	Detailed Business Process Designs (BPDs)
2700	Business Requirements to be met
1500	Employees directly impacted by the transformation across Hydro One, Vertex & Inergi (11 lines of business, 27 departments)

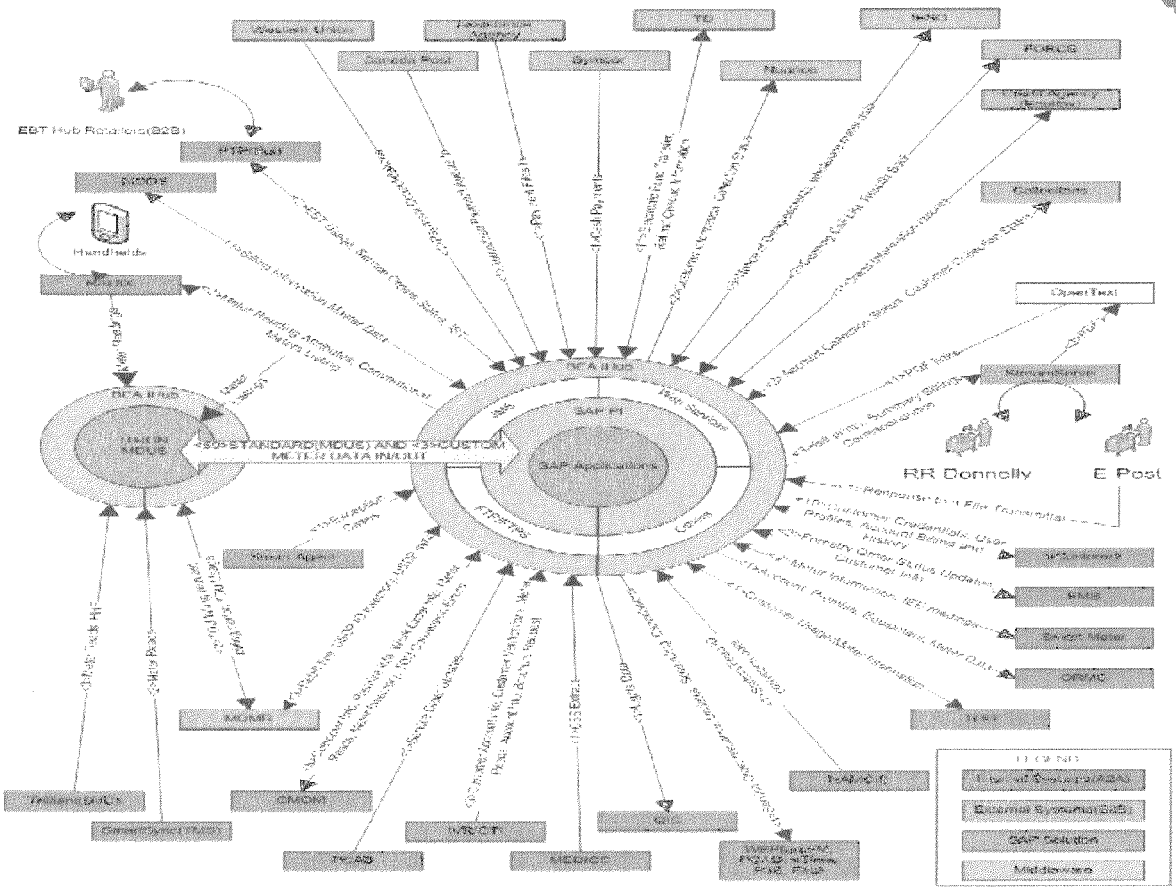
CIS Business Functions

Customer Service	Customer Information and Contact Management	Conservation and Demand Management		
Service Order and Work Management	Service Order Management			
Metering	Meter Device Management	Meter Data Acquisition and Storage		
Billing and Payment	Bill Calculation and Printing	Complex Billing (Interval Metered)	Remittance Processing	Credit and Collections
Retail and Wholesale Market	Wholesale Market Settlements	Retailer Enrollment and Billing		

CIS Systems


Customer Service
Telephony
Web
Inbound Correspondence
CRM
Service Order and Work Management
Work Mgmt
Metering
Meter
Billing and Payment
Billing and Payment
Retail and Wholesale Market
Market
Reporting

80+ Interfaces to be built and tested



Project Costs

On Track

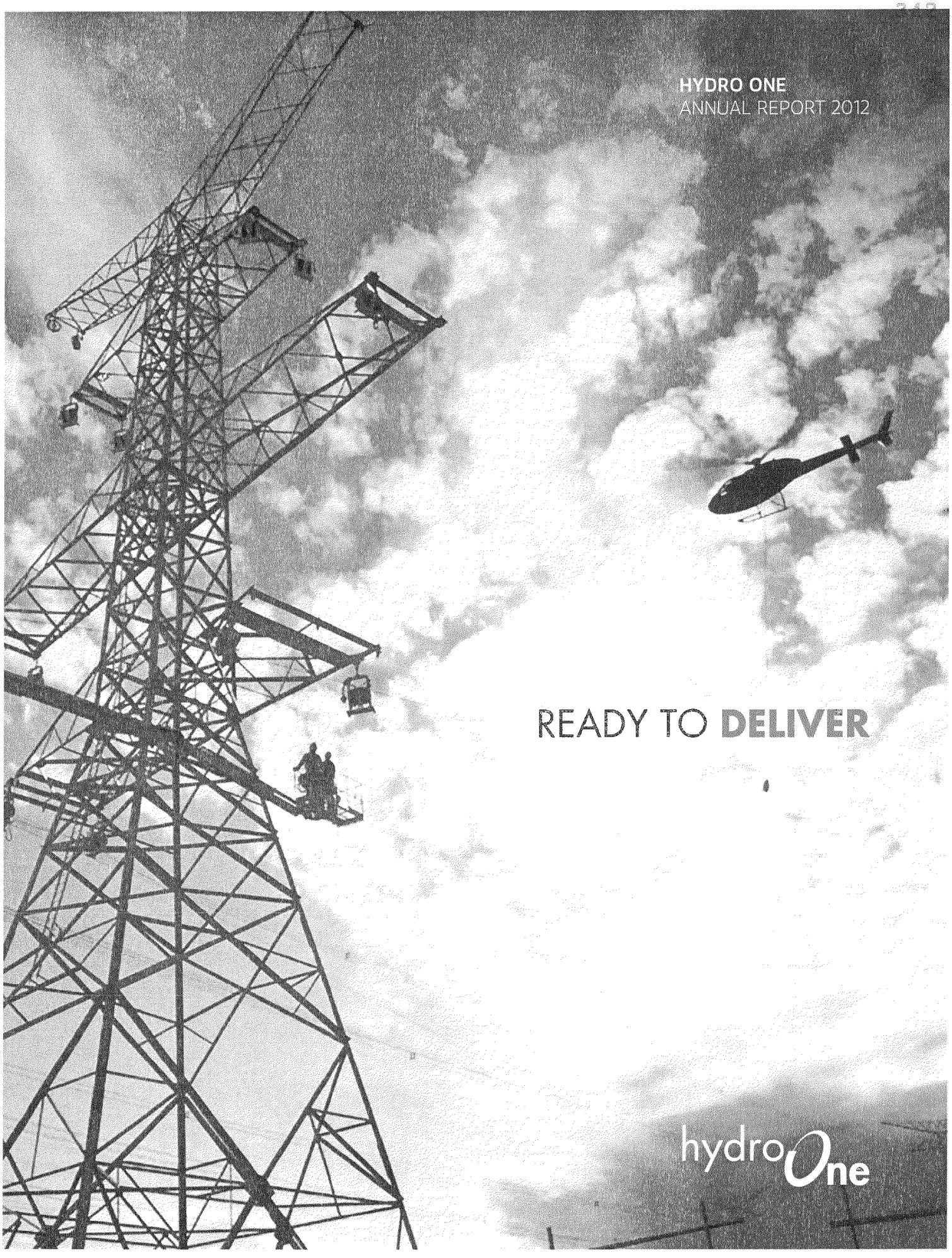
Cost Items	Cost ($Ms)	% of Project
Labour / Services		
HCL Axon	$49.1	
Hydro One	$14.2	
Inergi/Vertex	$19.7	
Subtotal	**$83.0**	**46%**
Hardware	$10.0	
Software	$13.4	
Commissioning and Other Support	$21.3	
Implementation Subtotal	**$127.7**	**71%**
Contingency (20%)	$25.5	
Interest & Overhead	$17.5	
Total Implementation Cost	**$170.7**	**95%**
Discovery Total	$9.1	
PROJECT TOTAL COST	**$179.8**	

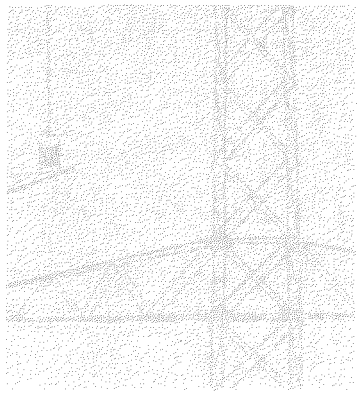
This is Exhibit "G" referred to in the Affidavit of M. Lilly Iannacito sworn April 13, 2016

Lisa Lutwak

Commissioner for Taking Affidavits (or as may be)

LISA S. LUTWAK


HYDRO ONE
ANNUAL REPORT 2012
READY TO DELIVER
hydro One



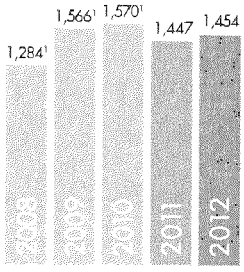
ON THE COVER:
Bruce to Milton Transmission Reinforcement Project
Photo courtesy of Brian Pieters Photography –
www.pietersphoto.com

CONSOLIDATED FINANCIAL HIGHLIGHTS AND STATISTICS

TABLE OF CONTENTS

CAPITAL EXPENDITURES

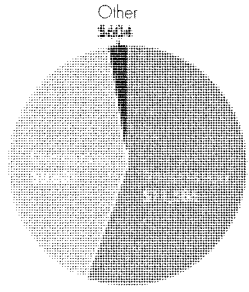
(CAD $ millions)



[1] based on Canadian GAAP

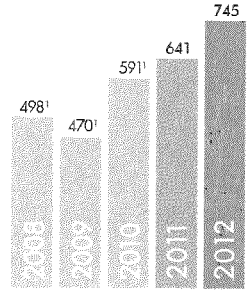
TOTAL ASSETS

December 31, 2012
(CAD $ millions)



NET INCOME

(CAD $ millions)

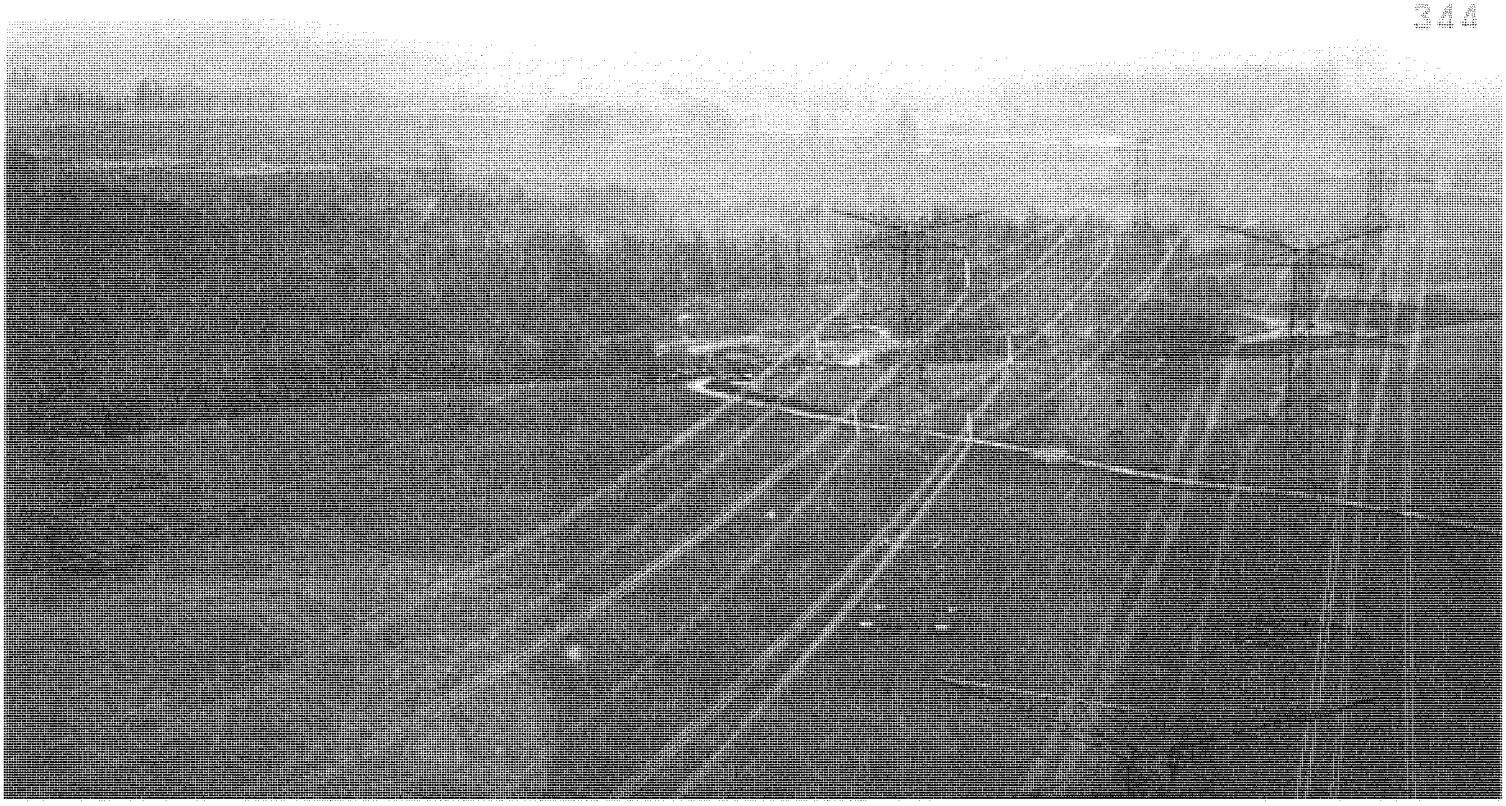


[1] based on Canadian GAAP

Year ended December 31

(Canadian dollars in millions, except as otherwise noted)	2012	2011	$ Change	% Change
Revenues	5,728	5,471	257	5
Purchased power	2,774	2,628	146	6
Operating costs	1,730	1,708	22	1
Net income	745	641	104	16
Net cash from operations	1,285	1,407	(122)	(9)
Average annual Ontario 60-minute peak demand *(MW)*[1]	21,132	21,166	(34)	–
Distribution – units distributed to our customers *(TWh)*[1]	29.2	29.2	–	–

[1] System-related statistics are preliminary.



Cus·tom·er ser·vice: Think like a customer; follow through on promises; seek input, ask questions, look for solutions; stay nimble; seize opportunities to make a difference; engage the brain; recalibrate when necessary; and always be ready to deliver.

LETTER FROM THE CHAIR

Hydro One's Board of Directors worked to further shape and strengthen the organization, enhance Shareholder value and ensure the Company's financial viability through prudent investment and rigorous oversight of expenditures and management practices.

In 2012, Hydro One continued to preserve net income, invested strongly in building the electricity system of the future and enabled the Province to deliver on the goals of the Long-Term Energy Plan.

Net income increased by approximately 16 per cent through lower operation, maintenance and administrative expenditures and cost-effective management of the Transmission Business' work program. Net income was $745 million for the year, compared to $641 million in 2011.

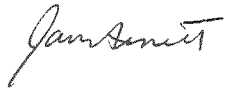
The Company's capital expenditures increased by $7 million in 2012, the result of refurbishing and replacing end-of-life equipment to improve overall reliability and also of investing in upgrade projects to facilitate new generation and customer connections. During the year, more than $1,748 million of capital investments were placed in service.

Hydro One paid dividends of $370 million to its sole shareholder, the Province of Ontario, and recorded a provision for payments in lieu of corporate income taxes of $121 million.

The Company overachieved in areas such as the duration of unplanned customer interruptions within the Transmission Business and targeted level of net income, after tax.

In November, the Board appointed Carmine Marcello President and Chief Executive Officer of the Company, effective in January 2013, as a result of the retirement of Laura Formusa, the Company's former President and Chief Executive Officer. Going forward, management's top strategic objectives are to improve safety performance, forge strong customer relationships and develop a skilled and high-performance culture.

I would like to thank all Hydro One employees and my colleagues on the Board of Directors for their commitment to the Company and its mission of delivering safe, reliable and affordable electricity to the people of Ontario.



James Arnett
Chair of the Board of Directors

LETTER FROM THE PRESIDENT AND CEO

In 2012, Hydro One focused on meeting our commitment to complete major projects safely and on schedule and keep Ontario's transmission and largest distribution system strong and able to deliver a safe, reliable and affordable supply of electricity to our customers and communities across Ontario.

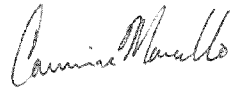
We exist to serve our customers. When they flick a switch, we need to be there to deliver at a price they can afford. When they call us, we need to answer. And when the lights go out, we need to work to get them back on safely and as quickly as possible.

In 2012, Hydro One strengthened the system that allows us to deliver on our promises. The completion of the $700 million Bruce to Milton Project was a watershed event. The construction of this 500-kV transmission line was not only the largest infrastructure expansion in Hydro One's history, it was completed on time and with zero lost-time or serious injuries. The completion of this project enables Hydro One to transmit more than 3,000 MW of clean and renewable electricity from where it is generated to where it is needed.

Our crews demonstrated our best-in-the-business ability to respond to emergencies in Ontario and beyond. Twice we were asked to send help to our southern neighbours, after a severe windstorm in the summer and Hurricane Sandy in the fall, and twice we answered the call by sending hundreds of our skilled-trades employees to where help was needed. For that effort, Hydro One was recognized for storm restoration excellence by the Edison Electric Institute.

In 2012, Hydro One continued its leadership role in leveraging technology to control costs, all with a view to keep rates low for our customers. We are improving productivity by creating more efficient work programming so our crews spend less time driving and more time doing the work that matters to customers. These efforts will be continued in 2013 with the launch of a new Customer Information System to improve our customer experience and strengthen the connection between our Ontario-based call centre and our field operations.

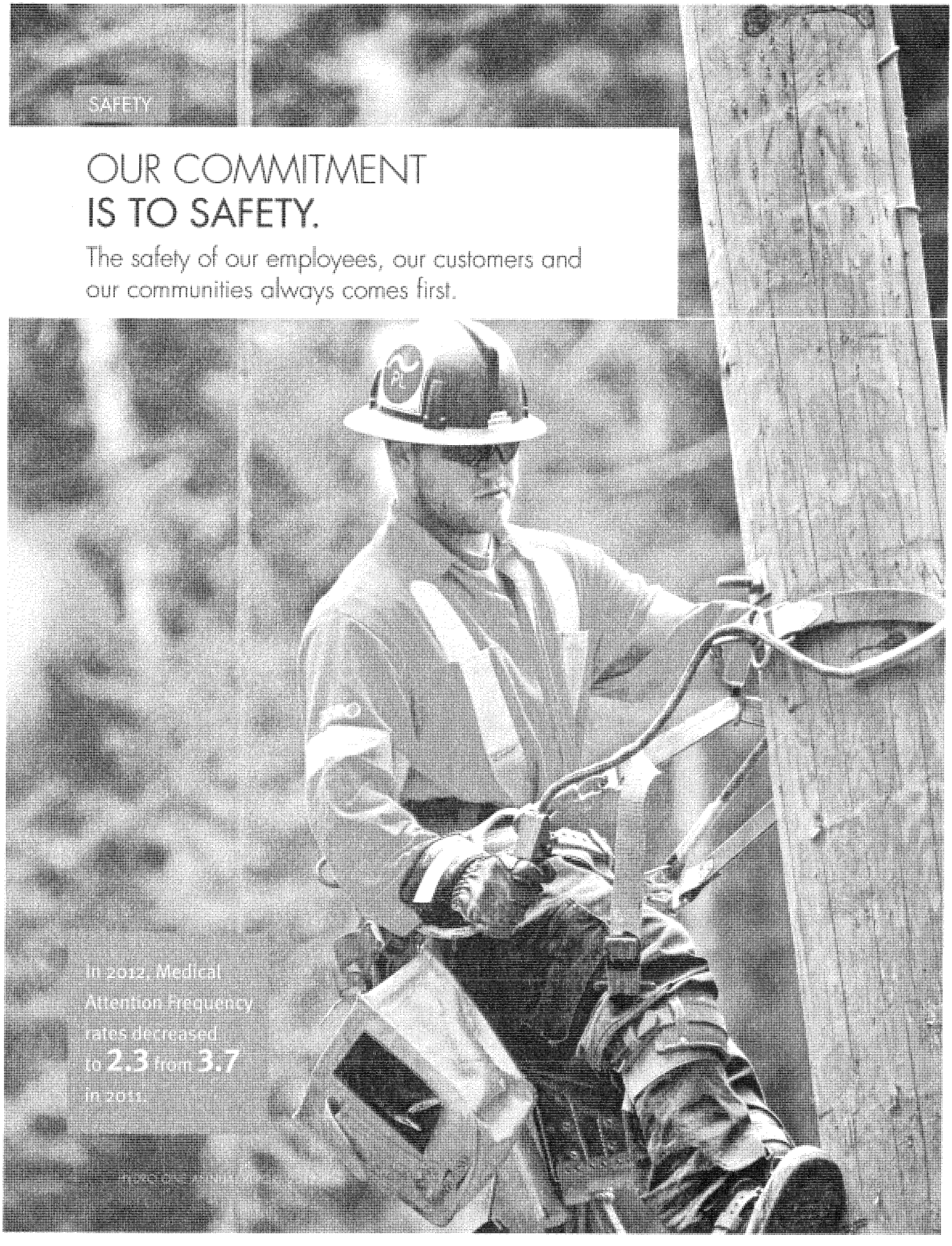
I would like to thank our Board of Directors for their support, my management team for their relentless drive for continuous improvement and our employees for their dedication to safety and excellence.



Carmine Marcello
President and Chief Executive Officer

OUR COMMITMENT IS TO SAFETY.

The safety of our employees, our customers and our communities always comes first.



In 2012, Medical Attention Frequency rates decreased to **2.3** from **3.7** in 2011.

The landmark Bruce to Milton project resulted in 922,000 person-hours of employment, provided work for 500 employees and achieved a significant milestone of zero lost-time injuries and zero serious injuries.

HEALTH AND SAFETY PERFORMANCE IMPROVEMENTS

Hydro One has set a target of becoming a global leader in utility health and safety through its Journey to Zero continuous improvement program.

The Company has shown the strong results associated with this strategic priority: Medical Attention Frequency rates decreased in 2012 to 2.3 from 3.7 in 2011. Lost-time Injury Frequency also decreased, to 0.11 from 0.17 in 2011.

Ongoing employee and apprenticeship training played a significant part in the Company's improved health and safety performance, as did the implementation of safety meeting and presenter training, in-field supervisor training, the launch of a medical attention dashboard and reinforcement of the importance of pre-work stretching and injury prevention techniques for Forestry Services employees.

An innovative technique involving specially-adapted hydraulic equipment for installing poles around live lines is also contributing to improved safety and productivity. The new technique, which allows operators to set up to seven poles in the time it would take a radial boom derrick to set one, requires half as many workers, thereby exposing fewer workers to the safety hazards that can be common with this type of work.

JOURNEY TO ZERO

Building on its 2010 Journey to Zero commitments, in 2012 the Company focused on:

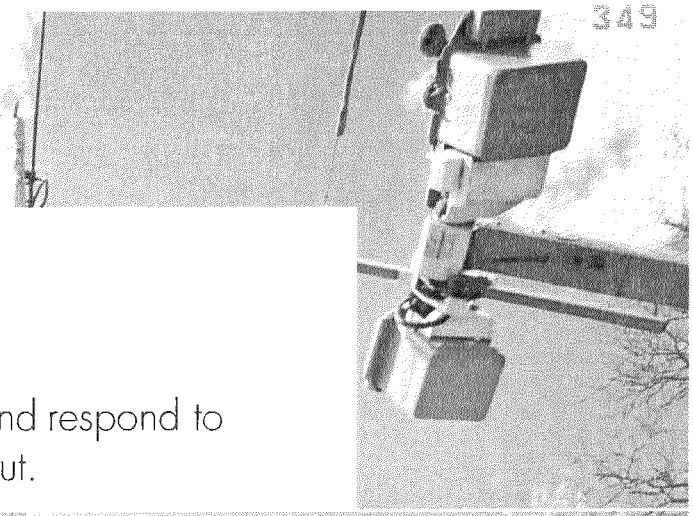
- Developing a work environment in which employees have more direct input about safety in their everyday work and in operational plans.
- Building accountability for individual safe performance, and for that of their co-workers, into management performance contracts.
- Identifying a framework for ensuring that health and safety becomes ingrained in employees' everyday actions.
- Developing a program to increase driver awareness for safety and reduce employees' exposure to motor vehicle accidents.
- Developing a process to celebrate safety performance and safety milestones.

OHSAS 18001 STANDARD

The Company confirmed its decision last year to work toward becoming compliant with the Occupational Health and Safety Assessment Series (OHSAS) 18001 standard, as a way to further reinforce its health and safety culture. OHSAS 18001 registration will allow Hydro One to integrate all its safety policies, procedures and analytics into a single management system, helping to identify health and safety risks, priorities and mitigation.

As a first step, the Company reviewed all existing Health, Safety and Environment Management System (HSEMS) documents with a view to simplifying and streamlining them where possible. The review indicated there was room to simplify the Health, Safety and Environmental Management System Overview document.

As a next step, the Company will review and revise its Hazard Control Registries, design audit tools to assess the HSEMS, establish procedures for communicating new HSEMS-related information to employees and develop a process for updating HSEMS documents.



OUR MANTRA IS **CUSTOMER SERVICE.**

We are prepared to listen, stand ready and respond to customers' needs, every day, day in day out.

In 2012, Hydro One invested **$1,454 million** to replace aging system assets, strengthen the grid and improve service to our customers.

Hydro One was awarded the prestigious Edison Electric Institute's 2012 Emergency Assistance Award for supporting the recovery efforts in the aftermath of Hurricane Sandy in the US.

THE VALUE OF A WELL-OILED, WELL-PRUNED MACHINE

With a 29,000-kilometre high-voltage transmission network and a 122,000-kilometre low-voltage distribution system serving both urban and rural areas, ensuring our equipment functions at peak performance at all times is a top priority.

Reliable customer service starts with keeping overhead lines clear of vegetation, and in 2012, the Company reduced forestry-related service interruptions to four hours from 18 hours (2006–2012) and decreased the average disruption per customer to 0.8 from 1.6 interruptions. Tree branches on 11,195 kilometres of wires were cleared on the Company's distribution system and 2,704 kilometres on its transmission system. In addition, over 900,000 trees were trimmed and/or removed throughout the Company's service territory.

To further improve reliability, the Company also made capital investments of $1,454 million, and more than $1,748 million of capital investments were placed in service, including:

- Replacement of the transformer at the Trafalgar Transformer Station
- New transformer stations in Woodstock and Burlington
- Reconstruction of the Burlington Transformer Station
- Replacement of various assets at the Abitibi Canyon Sub-Station
- Replacement of 11,000 wood poles deteriorating due to age, location, weather, type of wood treatment, insects and wildlife.

MINING DATA FOR INFORMATION

In 2012, Hydro One became the first utility in North America to launch an online asset analytics tool designed to help increase reliability and ratepayer value. Mapping software, coupled with information about the condition and location of each asset in Hydro One's service territory, now allows the Company to efficiently analyze and categorize the condition of all poles, towers, lines and stations across the province. Based on this assessment, Company planners can make more effective and prudent investment decisions, rationalize work programs and prioritize work in high-impact, customer-critical areas.

RENEWABLE POWER FOR GROWING COMMUNITIES, FOR GENERATIONS TO COME

The largest expansion of Ontario's electricity transmission system in over two decades was put into service in May, seven months ahead of schedule. The landmark project means 3,200 megawatts of new electricity for Hydro One customers – enough to meet more than 10 per cent of the province's electricity needs – all from clean and renewable sources.

AN INTEGRAL PART OF COMMUNITY LIFE

Severe weather that affects customers' electricity service can bring community life to a standstill, and when it does, our job is to act quickly and safely to restore power.

Whether it was damage to structures in the vicinity of local mines caused by forest fires, or damage caused by storms following Hurricane Sandy, Hydro One crews put customers first. They provided them with timely updates about their restoration efforts and information about how to stay safe during power outages.

WE INNOVATE TO **IMPROVE SERVICE.**

New technologies will help us to be more nimble, more adaptable and more efficient in meeting our customers' needs.

In 2012, Hydro One reduced overall operation, maintenance and administration expenditures by **$22 million** from 2011 results.

Hydro One's Chief Information Officer (CIO) was named CIO of the Year by Energy Central for initiatives that included the modernization of Hydro One's Customer Information System, development of an advanced distribution system trial area and most advanced use of asset analytics.

SUNNY SCIENCE

Hydro One continues to receive accolades for its expertise in managing 'solar storms' – celestial disturbances so powerful they can change the direction of currents on hydro lines, cause significant damage to equipment and result in power outages. The Company's research team has developed an internationally-renowned preparedness protocol that helps to monitor these rare, but extreme, weather occurrences, determine the safest control actions and manage their impact cost-effectively.

The Company is also making its mark in the industry with the development of fibreglass poles. Now part of the Company's master material inventory system, the new composite poles are an environmentally-friendly substitute for traditional wood poles, providing twice the lifespan and the opportunity for long-term savings.

ADVANCED DISTRIBUTION SYSTEM

Hydro One's Distribution Modernization Initiative hinges on the integration of 'smart' technologies into its distribution system. In partnership with GE, IBM and Telvent, the Company began to identify the applications, equipment and processes required to build its vision of a modern distribution system. The focus will be on improved reliability and operations, shorter unplanned outages, simplified network planning, renewable energy integration, and timely information to help customers better manage their electricity costs.

As part of this initiative, Hydro One established a demonstration home in Owen Sound where it is testing and monitoring the impact of tools such as smart thermostats and energy management and monitoring systems.

In partnership with the Electric Power Research Institute, the Company also began to collect data and measure the impact of using plug-in electric vehicles on its rural distribution system.

POWER OUTAGE? THERE IS AN APP FOR THAT

In May, Hydro One became the first utility in Canada to launch a free mobile application (or mobile app) that allows customers to check the status of planned and unplanned outages anywhere in the Company's 640,000 square kilometre service territory from their smartphones or tablets. The app provides customers with an interactive outage map that is searchable by address and updated every 15 minutes. So even when the power is out, Hydro One customers can still get up-to-date information.

KEEPING COSTS DOWN AND STILL DELIVERING

The Company delivered on its commitment to provide value for ratepayers by keeping overall operation, maintenance and administration expenditures to a year-over-year increase of two per cent (less than the current rate of inflation). In addition, Hydro One Brampton Networks was singled out as first among 76 local distribution companies for having the lowest operation, maintenance and administration expense per customer in the Ontario Energy Board's 2011 Yearbook.

Further to work that began several years ago, Hydro One continued to leverage its investment in SAP technology in support of productivity gains, replacing several older applications and integrating newer ones into the SAP platform. In the next phase of the project, the Company will focus on asset work programs.

OUR STRENGTH IS OUR PEOPLE.

We are a high-performance, accountability-based company, with an acute awareness of the need to deliver on our corporate objectives.

Company representatives continued the Hazard Hamlet program, which teaches children the importance of electrical safety. During the past 16 years, children in more than **230 schools** have participated in the program.

In 2012, Hydro One was recognized by *Corporate Knights* magazine as one of Canada's leading corporate citizens for the sixth year in a row.

PEOPLE STRATEGY

Hydro One is committed to hiring the very best workers – people with new skills, fresh ideas and strong potential. To make sure this workforce is available when we need it, last year the Company continued its partnership with Georgian, Algonquin, Mohawk and Northern colleges to support scholarships and co-placements in the schools' electrical engineering programs. In 2012 Hydro One made its second $3-million contribution to the four colleges since the partnership began in 2007.

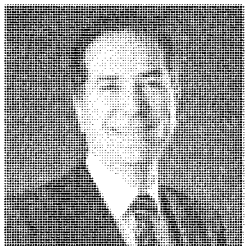
Hydro One also awarded the first two First Nations, Métis and Inuit (FNMI) scholarship awards to students from the Wikwemikong First Nation and the Algonquin First Nation. The awards are granted annually to two FNMI students studying power-related disciplines at a recognized Ontario university or community college. Hydro One also offers recipients a developmental work-term at a Company location.

ENGAGED IN OUR COMMUNITIES

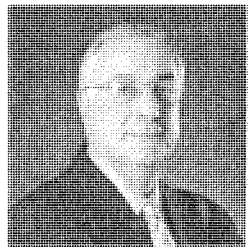
To operate, maintain and manage a vast and expanding electricity system like Hydro One's means hiring and retaining the best employees – people who are not only engaged heart and mind in our business but also contribute to the communities we serve. Here are some of the ways we participated last year in community life:

- Hydro One provided financial support to seven Conservation Authorities within the four watershed areas surrounding the Bruce to Milton Transmission Reinforcement Project. In consultation with local communities, the Company developed 22 different biodiversity projects, with the goal of restoring biological diversity and resilience in the ecosystem covering over 310 hectares.
- The Company's energy efficiency team attended 49 community events, including the Glengarry Highland Games, the Turkey Point Summerfest and the Mount Forest Fireworks Festival, raising awareness of money-saving incentive programs and providing advice to help our customers save on energy at home.
- Hydro One apprentice crews continued a longstanding tradition of participating in the International Plowing Match – an event that draws over 10,000 visitors to Roseville every year. As part of Hydro One's sponsorship of the event, crews erected 325 poles and ran 19 kilometres of wire in order to electrify the grounds.
- Hydro One provides funding to the University of Western Ontario to support the Hydro One Chair in Power Systems Engineering in the Faculty of Engineering, research into power systems conducted by the Faculty of Engineering and student awards and scholarships. It also partners with the University of Waterloo to support the work of the Waterloo Institute for Sustainable Energy, scholarships for electrical engineering students and a professional development program for engineers.
- Enrolment and graduation rates from electrical engineering technician and technology programs have doubled since Hydro One entered into partnership with four Ontario colleges to support electrical engineering and technologist programs.

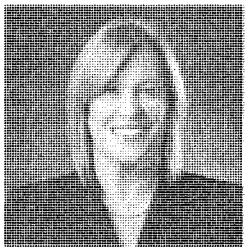
HYDRO ONE SENIOR MANAGEMENT



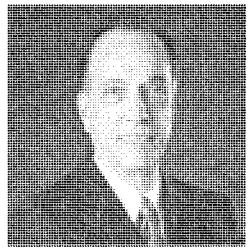
Carmine Marcello
President and
Chief Executive Officer,
Hydro One Inc.



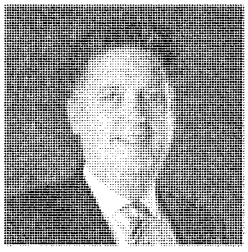
Joe Agostino
General Counsel



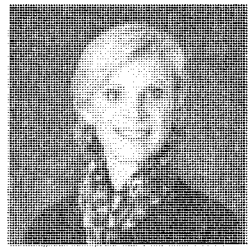
Laura Cooke
Vice President,
Corporate Relations



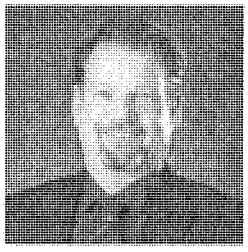
John Fraser
Senior Vice President,
Internal Audit



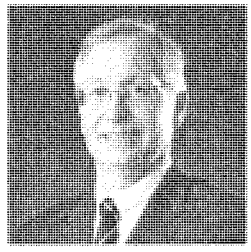
Peter Gregg
Chief Operating Officer



Judy McKellar
Vice President,
People and Culture



Rick Stevens
Vice President,
Customer Service



Sandy Struthers
Chief Administration Officer
and Chief Financial Officer

MANAGEMENT'S DISCUSSION AND ANALYSIS

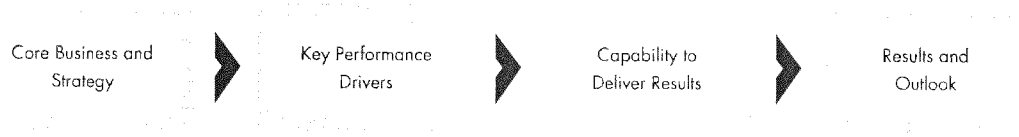
On January 1, 2012, Hydro One Inc. (Hydro One) adopted United States (US) Generally Accepted Accounting Principles (GAAP) as its approved basis for accounting and financial reporting. Comparative 2011 information is presented under US GAAP, unless otherwise noted. All amounts are in Canadian dollars.

The following discussion is based on our Consolidated Financial Statements for the years ended December 31, 2012 and 2011.

EXECUTIVE SUMMARY

We are wholly owned by the Province of Ontario (Province), and our transmission and distribution businesses are regulated by the Ontario Energy Board (OEB). Our mission and vision has been refined to recognize the unique role we play in the economy of the province and as a provider of critical infrastructure to all our customers. We strive to be an innovative and trusted company, delivering electricity safely, reliably and efficiently to create value for our customers. We operate as a commercial enterprise with an independent Board of Directors. Our strategic plan is driven by our values: health and safety; excellence; stewardship; and innovation. Safety is of utmost importance to us because we work in an environment that can be hazardous. We take our responsibility as stewards of critical provincial assets seriously. We demonstrate sound stewardship by managing our assets in a manner that is commercial, transparent and which values our customers. We strive for excellence by being trained, prepared and equipped to deliver high-quality service. We value innovation because it allows us to increase our productivity and develop enhanced methods to meet the needs of our customers. In 2012, we continued to focus on our core businesses and our commitment to our customers and made important contributions to the rebuilding of Ontario's core infrastructure while continuing to meet the requirements of the Green Energy Act (GEA).

We manage our business using the following framework:



Core Business and Strategy

Our corporate strategy is based on our mission and vision and our values. Our strategic goals, which are discussed in the section "Our Strategy," encompass the core values that drive our business. Our strategy touches every part of our core business: health and safety; our customers; innovation; the reliability and efficiency of our systems; the environment; our workforce; shareholder value; and productivity.

Key Performance Drivers

Performance drivers have been identified that relate to achieving certain of our company's strategic goals. We establish specific performance targets for each driver aimed at measuring the achievement of our strategic goals over time. For example, we track the duration of unplanned customer interruptions per delivery point as an indication of our commitment to provide a reliable transmission system for our customers. We measure transmission and distribution unit costs as an indication of our commitment to increasing productivity. These and other key performance drivers are included in our discussion of our performance measures in the section "Performance Measures and Targets."

Capability to Deliver Results

We continue to use a balanced scorecard approach as we strive to manage our performance and deliver results each and every year. In 2012, we set nine stretch targets and we met or exceeded five of them. In 2011, we met or exceeded 13 of 17 stretch targets. We exceeded our target for minimizing the duration of unplanned customer interruptions within our Transmission Business. Our performance with respect to productivity was on target in our subsidiary Hydro One Networks Inc.'s (Hydro One Networks) transmission and distribution businesses.

Our ability to deliver results in each of our strategic areas is limited by risks inherent in our regulatory environment, our business, our workforce and in the economic environment. These risks, as well as our strategies to mitigate them, are discussed in the section "Risk Management and Risk Factors."

Results and Outlook

During 2012, our financial fundamentals remained strong with current year net income of $745 million. Our OEB-approved revenue requirement for our transmission business for 2012 was $1,418 million. Our 2011 distribution rates for Hydro One Networks continued unchanged throughout 2012, and its approved revenue requirement for 2011 was $1,218 million. Approved rates support the work programs required to sustain our critical infrastructure and invest in a sustainable electricity system that supports renewable and cleaner generation. We successfully issued $1,085 million in debt financing in 2012, the proceeds of which were used to fund the retirement of $600 million of debt maturing in the year and to fund a portion of our capital expenditures and other corporate requirements. A full discussion of our results of operations and financing activities can be found in the sections "Results of Operations" and "Liquidity and Capital Resources."

In 2012, we invested more than $1.4 billion in capital expenditures to improve system reliability and performance, address our aging power system, facilitate new generation and improve service to our customers. Capital expenditures for the next few years will include those required to build critical infrastructure identified in the Long-Term Energy Plan (LTEP), which is based on recommendations from the Ontario Power Authority (OPA), and expenditures to address aging infrastructure. Our future capital expenditures are more fully described in the section "Future Capital Expenditures."

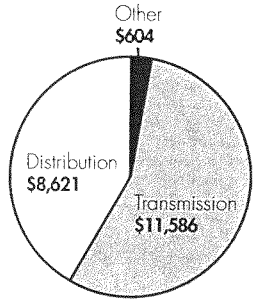
OVERVIEW

Transmission

Substantially all of Ontario's electricity transmission system is owned and operated by our subsidiary Hydro One Networks. Our transmission system forms an integrated transmission grid that is monitored, controlled and managed centrally from our Ontario Grid Control Centre. Our system operates over relatively long distances and links major sources of generation to transmission stations and larger area load centres. In 2012, we earned total transmission revenues of $1,482 million, primarily by transmitting approximately 141 TWh of electricity, directly or indirectly, to substantially all consumers of electricity in Ontario. Our transmission system is one of the largest in North America, and it is linked to five adjoining jurisdictions through 26 interconnections, through which we can accommodate imports of about 4,800 MW and exports of approximately 6,000 MW of electricity. In terms of assets, our Transmission Business is our largest business segment, representing approximately 56% of our total assets at December 31, 2012.

Total Assets

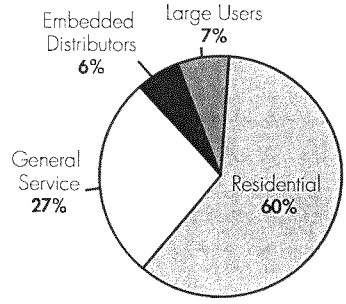
December 31, 2012 (CAD $ millions)



Distribution

Our consolidated distribution system is the largest in Ontario and it spans roughly 75% of the province. We serve approximately 1.4 million rural and urban customers and 440 large user customers. Our subsidiary Hydro One Remote Communities Inc. (Hydro One Remote Communities) operates small, regulated generation and distribution systems in a number of remote communities across northern Ontario that are not connected to Ontario's electricity grid. In 2012, we earned total distribution revenues of $4,184 million. As illustrated in the accompanying chart, over half of our distribution revenues were earned from our residential customers. At December 31, 2012, our Distribution Business assets represented approximately 41% of our total assets.

2012 Distribution Revenues



Other

In 2012, our Other business segment contributed revenues of $62 million, and had assets of $604 million at December 31, 2012, representing 3% of our total assets. This segment primarily represents the operations of our wholly-owned subsidiary, Hydro One Telecom Inc., which markets fibre-optic capacity to telecommunications carriers and commercial customers with broadband network requirements, including a dedicated optical network providing secure, high-capacity connectivity across numerous health care locations in Ontario.

Our Strategy

Our corporate strategy is based on our mission and vision and our values. Our mission and vision is to be an innovative and trusted company delivering electricity safely, reliably and efficiently to create value for our customers. Our values represent our core beliefs:

Health and safety: Nothing is more important than the health and safety of our employees, those who work on our property, and the public.

Excellence: We achieve excellence through continuous training, ensuring we are prepared and equipped to deliver high-quality and cost-effective service, with integrity.

Stewardship: We invest in our assets and people to build a safe, environmentally sustainable electricity network in a commercial manner.

Innovation: We innovate through new processes, people and technology to allow us to find better ways to meet the needs of our customers.

We have eight strategic objectives that are inextricably linked. They drive the fulfillment of our mission and vision.

Creating an injury-free workplace and maintaining public safety. Health and safety must be integrated into all that we do. We must continue to create a passion for preventing injury. We will strengthen our already strong safety culture through our Journey to Zero initiative and achieve world-class results. We will implement the internationally recognized health and safety management system, ISO 18001, to identify health and safety risks, priorities and mitigation in order to further drive our safety culture. We will continue to reinforce that nothing is more important than the health and safety of our employees.

Satisfying our customers. We will meet our commitments, make customers our focus in our planning, communicate effectively, coordinate across lines of business, and maximize opportunities to improve our corporate image. We will develop and deliver targeted customer segment strategies, products and delivery channels that will respond to their unique needs and behaviours.

Continuous innovation. Innovation represents one of our core values and is critical to achieving our mission and vision. Over the next two decades, we will install innovative solutions that improve the reliability and efficiency of the transmission and distribution systems and provide our customers with more capability to manage their power costs. The Advanced Distribution System (ADS) is a key element in our investment in innovation and will improve operation of our distribution assets and deliver further value to our customers.

Building and maintaining reliable, cost-effective transmission and distribution systems. Our transmission strategy is to provide a robust and reliable provincial grid that accommodates Ontario's emerging generation profile, manages an aging asset base and meets demand requirements through prudent expansion and effective maintenance. Our distribution strategy is focused on: incorporating ADS technology to provide greater visibility; increasing control and improving customer service; supporting the connection of renewable energy sources; seeking efficiencies through leveraging technology and operational experience from our transmission system; providing reliable and cost-effective service over a diverse geography; and pursuing commercial arrangements that are anticipated to arise from the rationalization of Ontario's distribution sector.

Protecting and sustaining the environment for future generations. Consistent with our value of stewardship, we play a central role in reducing Ontario's carbon footprint through the delivery of clean and renewable energy and through measures that allow our customers to manage and reduce their energy use. We will engage our customers further regarding how we manage our sustainability obligations and activities on their behalf.

Employee engagement. We believe our primary strength is the capability of our people. In order to sustain this advantage, we must address the issues of corporate culture, labour demographics, diversity, development of critical core competencies and skill and knowledge retention. Our labour strategy should enable us to make significant gains in the areas of labour flexibility, productivity improvement and cost reduction.

Maintaining a commercial culture that increases value for our shareholder. We are committed to keeping rates as low as possible for our customers, and delivering income and dividends to our shareholder. This is possible through our focus on reducing costs, managing our assets effectively and increasing productivity. We will explore and pursue opportunities to increase the revenue-earning potential of our company by leveraging existing assets, technologies, capabilities and the geographic presence of our company.

Achieving productivity improvements and cost-effectiveness. To achieve our mission and vision, we must constantly strive for productivity through efficiency and effective management of costs. Productivity is key to meeting our other strategic objectives and, in particular, to achieving value for our customers and our shareholder.

We recognize the pivotal role innovation will play in building a smart electricity grid that supports a clean environment for Ontario. We are committed to becoming the industry leader in putting innovative solutions to work for the well-being of Ontario's economy and its residents.

Performance Measures and Targets

We target and measure our performance by using a balanced scorecard approach. Key performance drivers are closely monitored throughout the year to ensure that we maintain a focus on our strategic objectives and take mitigating actions as required. In 2012, we met or exceeded five of nine stretch targets. Overall, we are making progress towards achieving many of our strategic goals.

Achieving productivity improvements and cost-effectiveness

One of our strategic objectives is to increase productivity through efficiency improvements and effective management of costs. The measures for this objective for 2012 were transmission unit cost and distribution unit cost.

For 2012, we measured for transmission unit cost the capital expenditures and operation, maintenance and administration costs per dollar of gross in-service assets (expressed as a percentage). For distribution unit cost, the measure is capital expenditures and operation, maintenance and administration costs per kilometre of line ($'000/km) due to the length of line required to connect our rural customers. Our objective with our ongoing work and investment program is to maintain and improve our assets and monitor our productivity year-over-year. Our transmission unit cost target was set at 10.1% and we met this target. The distribution unit cost target was set at $11,000 per kilometre of line and we also met this target.

Building and maintaining reliable, cost-effective transmission and distribution systems

We continue to build and retain public confidence and trust in our operations, as stewards of Ontario's electricity grid. In 2012, we continued our focus on this strategic priority by investing in the key assets of the electricity delivery system and by operating the existing system for customers in a safe, reliable and efficient fashion. We are conscious that commercial customers of all sizes require reliable service to allow them to deliver their products and services and that customers' expectations are for a reasonably limited duration when interruptions occur. Transmission and distribution reliability is measured through the duration of customer interruptions.

For the duration of unplanned customer interruptions within our Transmission Business, the target for 2012 was 10 minutes per delivery point. We more than met this target.

For the Hydro One Networks distribution business, the target for 2012 for the duration of customer interruptions was set at 6.7 hours per customer. We did not meet this target.

Satisfying our customers

Customer satisfaction measures the degree to which our transmission and distribution customers are satisfied with the service they receive from our company. Customer satisfaction is based on the results of customer surveys conducted on our behalf by independent third parties. In 2012, for transmission customers we targeted a customer satisfaction rate of 90%, but did not meet this target. For our distribution customers, we targeted a satisfaction rate of 86%, and we met this target.

Employee engagement

We continue to focus efforts on increasing employee engagement throughout the company. An engaged workforce is one in which employees embrace the corporate values of safety, stewardship, excellence and innovation. The process of measuring and improving such engagement began in 2008 by means of an employee engagement survey administered by an independent third-party expert. Our goal is to improve the grand mean score year-over-year. The target of improving the grand mean score to 4.06 (out of 5) in 2012 was not met.

Maintaining a commercial culture that increases value for our shareholder

Achievement of strong financial performance is measured by a performance measure of targeted level of net income after tax. Our target was $643 million net income after tax and we exceeded our target.

Creating an injury-free workplace and maintaining public safety

The safety of our employees is paramount. In 2012, we used medical attentions, defined as injuries that require treatment by a medical practitioner (beyond first aid), as the performance measure for this strategic objective. The medical attentions measure reflects incidents that are reported to the Workplace Safety and Insurance Board and is calculated as the number of attentions per 200,000 hours worked. In 2012, Hydro One set a target of no higher than 2.2 attentions per 200,000 hours worked. In an effort to achieve this target, we engaged in a number of activities, such as: continued emphasis on improving health and safety through face-to-face sessions; continuation of our Journey to Zero initiative; better monitoring of mandatory skills and safety training; an enhanced driver training/evaluation program; and field coaching to increase the expectations from supervisors and staff. The number of attentions in 2012 improved by 35% compared to the number in 2011 but was still slightly higher than our target for 2012.

REGULATION

Our electricity transmission and distribution businesses are licenced and regulated by the OEB. The OEB sets rates following oral or written public hearings. Our transmission revenues primarily include our transmission tariff, which is based on the province-wide uniform transmission rates (UTRs) approved by the OEB for all transmitters across Ontario. Our distribution revenues primarily include our distribution tariff, which is also based on OEB-approved rates, and the recovery of the cost of purchased power used by our customers. Consequently, our Distribution Business does not have commodity price risk. Transmission and distribution tariff rates are set based on an approved revenue requirement that provides for cost recovery and a return on deemed common equity. In addition, the OEB approves rate riders to allow for the recovery or disposition of specific regulatory accounts over specified timeframes.

Electricity Rates

Under the current market structure, low-volume and designated consumers pay electricity rates established through the Regulated Price Plan (RPP) and wholesale electricity consumers pay a blend of regulated, contract and wholesale spot market prices. The OEB sets prices for RPP customers based on both a two-tiered electricity pricing structure, with seasonal consumption thresholds, and a three-tiered electricity pricing structure with Time of Use (TOU) thresholds. The majority of our RPP customers are now on TOU billing. Unexpected shortfalls or overpayments associated with the RPP are temporarily financed by the OPA. Prices are reviewed by the OEB every six months and may change based on an updated OEB forecast and any accumulated differences between the amount that customers paid for electricity and the amount paid to generators in the previous period.

We started migrating our customers to TOU rates in 2010 and the majority of our customers were transitioned to TOU rates by the end of 2011. We received an exemption from the OEB, effective until December 31, 2014, from implementing mandatory TOU pricing for approximately 120,000 customers that are currently out of reach of our smart meter telecommunications infrastructure.

Customers who are not eligible for the RPP and wholesale customers pay the market price for electricity, adjusted for the difference between market prices and prices paid to generators by the Independent Electricity System Operator (IESO) under the *Electricity Act, 1998*. The IESO is responsible for overseeing and operating the wholesale market as well as ensuring the reliability of the integrated power system.

Transmission Rates

The IESO facilitates payments to us based on the Ontario UTRs approved by the OEB for all transmitters across Ontario.

On May 19, 2010, we submitted our application for 2011 and 2012 transmission rates in continued support of our aging critical infrastructure and supply mix objectives for generation, including off-coal initiatives and initiation of investments in support of the GEA. This application sought the approval of revenue requirements of approximately $1,446 million for 2011 and $1,547 million for 2012, which represented estimated rate increases of 15.7% and 9.8%, respectively, or 1.2% and 0.7% on an average customer's monthly bill.

On December 23, 2010, the OEB issued its decision, which resulted in a revenue requirement effective January 1, 2011 of $1,346 million for 2011 and $1,658 million for 2012, reflecting transmission rate changes of approximately 7% in 2011 and 26% in 2012, or 0.5% and 2%, respectively, on an average customer's total bill. Our 2012 revenue requirement was impacted by the OEB directing us to adopt a cost capitalization policy consistent with International Financial Reporting Standards (IFRS). This specific accounting revision resulted in an increased revenue requirement of about $200 million for 2012.

Consistent with an approval from the Ontario Securities Commission (OSC) to adopt US GAAP for our external financial reporting and securities filings, on July 15, 2011 we filed a Motion to Vary the OEB's 2012 rate decision. Our application sought approval to adopt US GAAP as a basis for regulatory accounting and rate setting in place of the OEB's approved modified IFRS basis. On November 23, 2011, the OEB approved the use of US GAAP by our Transmission Business, which resulted in the reversal of the $200 million adjustment that was made by the OEB in its December 2010 rate decision.

On December 1, 2011, we submitted to the OEB a draft 2012 transmission revenue requirement that reflects the approved adoption of US GAAP for rate-setting purposes as well as the OEB-directed update to 2012 cost-of-capital parameters. On December 20, 2011, the proposed $1,418 million 2012 revenue requirement was approved by the OEB along with new 2012 UTRs effective January 1, 2012. The new rates resulted in an approximate 8% transmission rate increase, or 0.6% on an average customer's total bill. The adoption of US GAAP in lieu of modified IFRS as a basis for rate setting decreased the approved rates by about 1.5%.

To achieve the necessary funding in support of aging critical infrastructure and investments, we submitted a cost-of-service rate application to the OEB for our 2013 and 2014 transmission rates on May 28, 2012. The application sought OEB approval for revenue requirement increases of approximately 0.6% and 9.1% in 2013 and 2014, respectively, or estimated increases of 0% in 2013 and 0.7% in 2014, on an average customer's total bill. A settlement conference was held in October 2012, where Hydro One Networks and the intervenors reached an agreement, settling all issues apart from Export Transmission Service. This is anticipated to be settled in early 2013 but is not expected to affect our company's results of operations. The settlement agreement was reviewed and approved by the OEB on November 8, 2012. On November 30, 2012, we submitted a draft rate order, which includes revenue requirements of approximately $1,438 million and $1,528 million for 2013 and 2014, respectively. For the transmission portion of the bill, this represents no change from existing 2012 OEB-approved rate levels in 2013 and a 5.8% increase in 2014. On an average customer total bill basis, this represents increases of nil for 2013 and 0.5% for 2014. On December 20, 2012, the OEB issued a final Rate Order, approving Hydro One Networks' 2013 transmission revenue requirement for use in setting the 2013 Ontario UTRs.

Distribution Rates

As a distributor, we are responsible for delivering electricity and billing our customers for our approved distribution rates, purchased power costs and other approved regulatory charges. Substantially all of our purchased power costs and other approved regulatory charges are settled through the IESO, which facilitates payments to other parties such as generators, the Ontario Electricity Financial Corporation (OEFC) and itself.

In 2006, the OEB established a multi-year electricity distribution rate-setting plan whereby a distributor's rates are set via a cost-of-service rebasing application followed by an Incentive Regulation Mechanism (IRM) that uses a formulaic approach to establish rates for the next three years. In 2012, the OEB issued a new regulatory framework that included three rate-setting methods available to distributors (see "Renewed Regulatory Framework").

Hydro One Networks

On July 13, 2009, our subsidiary Hydro One Networks filed a cost-of-service application with the OEB for 2010 and 2011 distribution rates.

On April 9, 2010, the OEB released its decision approving revenue requirements of $1,146 million for 2010 and $1,236 million for 2011 to support the necessary work programs, the implementation of the GEA and the installation of smart meters.

On November 15, 2010, the OEB issued its cost-of-capital parameter updates for rates effective January 1, 2011. The lowering of the return on equity (ROE) produced a revised revenue requirement of $1,218 million. The approved 2011 revenue requirement resulted in an average distribution rate increase of approximately 8.7% for 2011, or 3.4% on an average (i.e. consuming 800 kWh per month) customer's total bill.

On March 23, 2012, the OEB approved our request for Hydro One Networks' distribution business to adopt US GAAP for rate setting and regulatory accounting and reporting. Hydro One Networks did not seek a distribution cost-of-service rate adjustment for 2012 and rates continued unchanged at 2011 levels.

On June 15, 2012, Hydro One Networks filed evidence in support of its application for 2013 distribution rates on the basis of the OEB's 3rd Generation IRM process. Hydro One Networks and intervenors subsequently reached a settlement and submitted a settlement agreement to the OEB. On December 14, 2012, the OEB issued its decision accepting the agreement as filed. On December 20, 2012, the OEB issued a final Rate Order. The distribution rate of an average residential customer will increase by approximately 1.3% in 2013, or by 0.4% when considering total bill impacts. In addition, the Retail Transmission Service Rates adjustment, which was accepted in the Settlement, will bring the total bill increase in 2013 to approximately 1.5%.

Hydro One Brampton Networks

On June 30, 2010, our subsidiary Hydro One Brampton Networks submitted its 2011 cost-of-service application, which was subsequently adjusted in September to reflect the optional deferral of the adoption of modified IFRS until January 1, 2012, consistent with a decision by the Canadian Accounting Standards Board (AcSB). The AcSB later extended the optional deferral to January 1, 2014 and Hydro One Brampton Networks has decided to exercise this option.

Following another adjustment to the application in November 2010, the revenue requirement was approximately $63 million. On April 4, 2011, the OEB issued a decision that approved a revenue requirement of $59.5 million for 2011. The revised rates were approved with an effective date of January 1, 2011 and an implementation date of May 1, 2011. Included in the rates is an amount of $1.52 per month per metered customer for smart meters and approval of a GEA funding adder of $0.02 per month per metered customer. The new rates result in a total bill increase for an average customer (i.e. consuming 800 kWh per month) of approximately 0.5%.

On September 15, 2011, Hydro One Brampton Networks filed an application for 2012 rates on the basis of the OEB's 3rd Generation IRM process. On December 22, 2011, the OEB issued its decision and on December 31, 2011, the OEB declared Hydro One Brampton Networks' existing rates interim as of January 1, 2011. On January 5, 2012, the OEB released a decision that resulted in a reduction in rates of approximately 13.2%, or a 1.7% reduction on the average customer's total bill in the year. These rate reductions were primarily due to OEB-approved adjustments to depreciation rates.

On August 3, 2012, Hydro One Brampton Networks filed an application for 2013 rates on the basis of the OEB's 3rd Generation IRM process, requesting new distribution rates effective January 1, 2013. Hydro One Brampton Networks subsequently amended its rate application and on December 6, 2012, the OEB approved the amended application. The rate impact on the distribution component associated with a typical residential customer was an increase of approximately 0.3%, or less than 0.1% on the customer's total bill.

Hydro One Remote Communities

On October 15, 2010, Hydro One Remote Communities filed an application for 2011 distribution rates on the basis of the OEB's 3rd Generation IRM. The application sought approval for an increase of approximately 0.4% to basic rates for the distribution and generation of electricity effective May 1, 2011. On March 28, 2011, the OEB approved the application. The overall impact of the new rates on an average (i.e. consuming 800 kWh per month) residential customer's total bill was marginal.

On November 25, 2011, Hydro One Remote Communities filed its application for 2012 distribution rates on the basis of the OEB's 3rd Generation IRM. On March 22, 2012, the OEB issued its decision approving a rate increase of 1.08% effective May 1, 2012, representing an increase of about $1 on an average residential customer's monthly bill.

Consistent with the OEB's decision affirming the use of US GAAP for rate-setting purposes by Hydro One Networks' transmission and distribution businesses, we made a similar request to use US GAAP for Hydro One Remote Communities. On April 3, 2012, the OEB approved the request to use US GAAP as the basis for rate setting within Hydro One Remote Communities effective January 1, 2012.

On September 17, 2012, Hydro One Remote Communities filed a cost-of-service application for 2013 rates to be effective May 1, 2013. If approved as filed, the electricity rate of an average customer will increase by 3.5% in 2013. In its rate application, Hydro One Remote Communities also requested approval to establish a Rural and Remote Rate Protection of $35 million in 2013. The OEB Hearing and decision are anticipated to occur in the first quarter of 2013.

Recent Industry Developments

Long-Term Energy Plan

On November 23, 2010, the Ministry of Energy released Ontario's LTEP, which sets out the province's expected electricity needs until 2030 and supports the continued procurement of new, cleaner generation. The LTEP addresses seven key areas: demand; supply; conservation; transmission; aboriginal communities; capital investments; and electricity prices. On February 17, 2011, the Province issued a Supply Mix Directive that required the OPA to prepare a 20-year Integrated Power System Plan (IPSP) to meet the goals set out in the LTEP. On May 9, 2011, the OPA announced that it was beginning consultations to update Ontario's IPSP and issued the *IPSP Planning and Consultation Overview* document. On June 17, 2011, we submitted our comments on the IPSP, as requested of stakeholders by the OPA. Stakeholder comments will form part of the evidence when the OPA submits the revised IPSP to the OEB for its review.

On February 28, 2011, the OEB issued a decision amending Hydro One Networks' transmission licence in accordance with a directive from the Minister of Energy to the OEB. The licencee amendment requires Hydro One Networks to develop and either seek approvals for, or implement, specified transmission projects and upgrades to safely and reliably accommodate additional renewable energy in accordance with recommendations from the OPA. In a letter dated April 7, 2011, the OPA provided the scope and timing to increase short circuit and/or transformer capacity at ten of 15 transformer stations noted in the licence to accommodate small-scale renewable generation. Six of these upgrades have been completed and we are currently anticipating that one additional station upgrade will be placed in service in 2013. Alternative solutions have been identified for the other three upgrades. In accordance with the Memorandum of Agreement between Her Majesty the Queen in Right of the Province of Ontario as represented by the Minister of Energy (Shareholder) and our company, the Shareholder made a declaration, dated April 19, 2011, pursuant to subsection 108 (3) of the *Business Corporations Act (Ontario)* pertaining to the cost recovery of the expenditures related to the February 28, 2011 licence condition amendment. As o result, the recovery of the seven station upgrades was restricted. We charged $17 million to operation, maintenance and administration expense in 2012 and charged $19 million to operation, maintenance and administration expense in 2011, in respect of these projects.

In June 2011, the OPA recommended the scope and timing of the project to re-conductor two circuits between Sarnia and London, our West of London Transmission Upgrade Project, with a required in-service date of December 2014. This project is needed to satisfy government policy relating to the incorporation of 10,700 MW of non-hydroelectric renewable generation resources by 2018. On November 8, 2012, the OEB issued a decision approving our Section 92, Leave to Construct, application for this project. In October 2011, the OPA recommended the scope and timing of the Southwestern Ontario Reactive Compensation Priority Project, recommending that we install a Static Var Compensator (SVC) at our Milton Switching Station to increase the capability of our Bruce to Milton Line. An OPA recommendation regarding the construction of a new transmission line west of the City of London is not expected in the foreseeable future.

Framework for Transmission Development Plans

On August 26, 2010, the OEB released its new policy entitled *Framework for Transmission Project Development Plans*. This policy sets out a framework for new transmission investment in Ontario by introducing competition for transmission development through an open process. On March 29, 2011, the Minister of Energy expressed the Province's interest in the OEB commencing a transmitter designation process for the East-West Tie Line. The East-West Tie Project is the first transmission network line expansion covered under the new competitive approach. The proposed route is a 400 km, 230 kV double-circuit line between its transformer stations at Wawa in the east and Lakehead in the west.

The target in-service date, set by the OPA in its report issued June 30, 2011, is 2017. The East-West Tie LP, an equally-shared partnership of three entities including our company, obtained a transmission licence on May 31, 2012, and is participating in the East-West Tie Project bid process.

The OEB adopted a two-phase process for the East-West Tie proceeding. On July 12, 2012, the OEB issued its Phase 1 decision and order, thus concluding Phase 1 of the proceeding by finalizing various filing requirements and process issues and directing registered transmitters to file their applications for designation by January 4, 2013. The proceeding is now in Phase 2 and the OEB received six applications for designation from the registered transmitters in the proceeding, including one from the East-West Tie LP. The timeline for Phase 2, which will take the form of a written hearing, has not yet been set.

Renewed Regulatory Framework

On December 17, 2010, the OEB initiated a coordinated consultation process for the development of a renewed regulatory framework for electricity distributors and transmitters. On October 18, 2012, the OEB issued its report *A Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach*, marking the completion of its consultation process. The report identified three rate-setting models available to provide choices suitable for distributors having varying capital requirements: a 4th Generation IRM, which builds on the current 3rd Generation model by adding one year to the IRM period; a Custom IRM, which involves rate setting based on a five-year forecast of a distributor's revenue requirement and sales volume; and an Annual Incentive Rate-setting Index method, which involves annual adjustment of rates by a simple price cap index formula. The report also provided information on performance measurement, continuous improvement ond implementation of the new framework.

Four working groups were established to provide expert assistance to review and advise the OEB's staff on proposals regarding certain implementation matters: Asset Redefinition and Regional Infrastructure Planning Process; Distribution Network Investment Planning; Performance, Benchmarking, and Rate Adjustment Indices; and Smart Grid. Hydro One Networks is represented on all four groups. Working group meetings began in November 2012 and are scheduled through February 2013. Consultations will conclude with the issuance of filing requirements and guidance, code amendments, and/or supplemental Board policies in support of the new framework. The OEB is expecting that policies will be largely implemented in time for the 2014 rate year. We are currently assessing the rate-setting methods available.

OEB Transmission and Distribution System Codes

Under the Transmission System Code, the transmitter covers the initial pooling of the costs of enabler lines, with generators paying their pro-rata share when ready to connect, based on generator capacity.

Under the Distribution System Code (DSC), there are three classes of distribution assets associated with the connection of renewable energy generation: connection assets, expansion assets, and renewable enabling improvements. Generators that connect directly to a distributor's system pay the costs of connection assets, while distributors fund: all expansion costs identified in a plan; other generator-requested expansion costs up to a cap of $90,000/MW per project (generator pays the rest); and all renewable enabling improvements.

In 2011, the OEB granted us an exemption from mandatory DSC timelines for the connection of micro-embedded generation facilities. The OEB decision increased the timeline for processing indirect connections that require a site assessment and approved amendments to the conditions that must be met before we are required to connect micro-embedded generation facilities to our distribution system. On August 3, 2012, Hydro One Networks applied to the OEB for an extension of the exemption and on November 8, 2012, the OEB granted the extension for a period ending August 3, 2013, or six months after the conclusion of its consultation on micro-embedded generation issues, whichever is earlier.

Ontario Clean Energy Benefit

Effective January 1, 2011, the Province introduced the *Ontario Clean Energy Benefit Act, 2010*, which is designed to assist Ontario electricity consumers through the transition to a cleaner electricity system. Under this Act, eligible residential, farm and small business consumers receive a 10% benefit with respect to the total cost of electricity on their bills, including tax, for a five-year period. This benefit is applied to customers' electricity costs for each billing period. Effective September 1, 2012, the 10% rebate is applied only to the first 3,000 kWh of electricity consumed per month.

Revenue Decoupling for Distributors

In 2010, the OEB initiated a consultation process to examine the revenue adjustment and cost recovery mechanisms available to electricity and natural gas distributors to address revenue erosion resulting from unforecasted changes in volume of energy sold. These mechanisms are commonly referred to as "revenue decoupling" mechanisms as each involves some means of disconnecting the link between the volume of energy consumed by customers and the recovery by energy distributors of their approved revenue requirement.

On November 26, 2012, the OEB initiated a project to complete the work begun on revenue decoupling for electricity and natural gas distributors. The OEB will coordinate its consideration of revenue decoupling with the new rate-setting policies proposed in the renewed regulatory framework for electricity. The OEB will examine how best to address changes in demand, including potential declines in average use. This consultation will review the options for potential revenue decoupling in addition to the existing lost revenue decoupling mechanism (i.e. the Lost Revenue Adjustment Mechanism or LRAM). The OEB expects to release a draft policy in early 2013. The OEB will solicit stakeholder comments in writing before finalizing the policy.

Distribution Sector Consolidation

On April 13, 2012, the Province announced it was launching a comprehensive review of Ontario's electricity sector to explore options to improve efficiencies, including local distribution companies (LDCs) consolidation. As a result, the Province created the Ontario Distribution Sector Review Panel (Panel). On December 13, 2012, the Panel released its report, *Renewing Ontario's Electricity Distribution Sector: Putting the Consumer First*, with recommendations for electricity sector consolidation. This report recommends that the 73 LDCs comprising the focus of the report be consolidated into eight to 12 larger regional electricity distributors within a two-year timeframe. Specifically, it recommends there be two regional distributors in northern Ontario and between six and ten regional distributors in southern Ontario with a minimum of 400,000 customers each. Given our company's position as the largest LDC, the report recommends that Hydro One Networks be given unambiguous direction to lead and engage in the discussion of the merger of distribution assets with the appropriate interested utilities on a commercial basis. At present, the Province is reviewing the report and assessing the recommendations.

FIT and microFIT

On October 1, 2009, the OPA launched its Feed-in Tariff (FIT) Program which is designed to procure energy from a wide range of renewable energy sources, including wind, solar, photovoltaic, bio-energy and waterpower up to 50 MW.

On March 22, 2012, the Province announced the results of its two-year FIT Program Review, including recommended changes to reflect input received from stakeholders. The OPA implemented these recommendations and re-launched its microFIT program on July 12, 2012. The revised program encourages greater community and aboriginal participation and the protection of agricultural lands. In August 2012, the OPA began to release approvals allowing microFIT projects to proceed. On December 14, 2012, the OPA announced that it will award up to 200 MW of Small FIT applications, received between December 14, 2012 and January 18, 2013, for renewable energy projects with a proposed capacity between ten and 500 kilowatts. The OPA is not accepting Large FIT applications at this time. The timing for the Large FIT project application window will be communicated once details are finalized.

Conservation and Demand Management (CDM)

The OPA continues to be responsible for coordinating the delivery and funding of Ontario's CDM programs. Our CDM programs funded through the OPA in 2012 amounted to approximately $25 million, compared to $15 million in 2011. These programs included: the Peaksaver Program; the Low Income Home Assistance Program; Appliance Retirement and Exchange Events; and the Process and System Upgrade Incentive Program.

The *Ontario Energy Board Act, 1998*, as amended by the GEA, provides direction to the OEB to take steps to establish CDM targets to be met by LDCs and other licencees. A province-wide CDM target for Ontario's LDCs was set in 2010. The two key CDM targets for LDCs over the four-year period beginning January 1, 2011 were to collectively reduce 1,330 MW of provincial summer peak demand and to provide 6,000 GWh of cumulative energy savings. The OEB issued its CDM Code for Electricity Distributors (CDM Code) on September 16, 2010 and on November 12, 2010, it issued final CDM targets to each LDC. Our company was allocated a 259 MW reduction of provincial peak demand and a 1,320 GWh reduction of electricity consumption, representing, respectively, 19.5% and 22.0% of the total target savings established for all LDCs. The CDM Code also set out the conditions and rules that LDCs are required to follow if they choose to use OEB-approved CDM programs to meet their CDM targets.

On April 26, 2012, the OEB issued its CDM guidelines for all electricity distributors. One key change is that savings associated with TOU pricing are eligible to be counted towards the CDM targets. Savings will be evaluated by the OPA for the entire province and then allocated to each distributor. The other key change is the establishment of the LRAM variance account, which captures the variance between the level of CDM included in a distributor's load forecast and the verifiable results of impacts of CDM activities undertaken between 2011 and 2014 for both OPA-contracted and OEB-approved CDM programs.

On September 28, 2012 and September 30, 2012, in accordance with the CDM Code, Hydro One Brampton Networks and Hydro One Networks, respectively, filed their 2011 Annual CDM Reports with the OEB. Our combined results for 2011 were 40 MW in peak demand savings, representing 15.6% of our target, and 99 GWh of annual energy savings. These energy savings will produce 388 GWh towards our target, representing 29.4% of our cumulative target. We anticipate meeting our 2014 cumulative demand and energy savings targets.

On December 21, 2012, the Minister of Energy issued a directive to the OPA to extend funding for its CDM programs for one additional year, to December 31, 2015. This extension aims to provide added stobility, support the momentum of province-wide programs and ensure that projects with longer completion times can continue to participate in key conservation initiatives. This extension will also provide an opportunity for the OPA and LDCs to collaboratively work to strengthen the current framework and deliver innovative programs that support Ontario families and businesses. The OPA will be reaching out to distributors to further solicit insight and advice on the implementation of this extension.

Advanced Distribution System

The *Energy Conservation Responsibility Act, 2006* further broadened the objectives of CDM by providing the framework for the installation of smart meters in all homes and small businesses in Ontario. In 2007, the Province appointed the IESO as the interim smart meter entity that would oversee the collection and management of data from installed smart meters. LDCs, including our distribution businesses, are accountable for the deployment of smart meter infrastructure and related communications technology to meet minimum regulatory requirements, as well as the implementation of TOU rates.

In 2011, we carried out a number of studies on advanced distribution technologies and initiated the Smart Zone Pilot Project in the Owen Sound area. The Smart Zone Pilot consists of testing and demonstrating power system equipment, IT systems and communication systems that will be required to help facilitate the connection of a large number of Distributed Generation (DG) connections to our distribution system. In 2012, we successfully completed the deployment of the Distribution Management System (DMS) within the Owen Sound pilot area. This integrates the Network Management System, the Outage Response Management System and field devices. Further releases of the ADS will look at optimizing outage response through more effective dispatch, automation to isolate faults where needed and the dynamic regulation of voltage to reduce losses. All releases leverage a core infrastructure and build on each other, and as pilot elements are proven, business cases will be developed for the provincial roll out which will ultimately comprise the ADS.

RESULTS OF OPERATIONS

Revenues

Year ended December 31 (millions of dollars)	**2012**	2011	$ Change	% Change
Transmission	**1,482**	1,389	93	7
Distribution	**4,184**	4,019	165	4
Other	**62**	63	(1)	(2)
	5,728	5,471	257	5
Average annual Ontario 60-minute peak demand *(MW)*[1]	**21,132**	21,166	(34)	–
Distribution – units distributed to customers *(TWh)*[1]	**29.2**	29.2	–	–

[1] System-related statistics are preliminary.

Transmission

Transmission revenues primarily consist of our transmission tariff, which is based on the monthly peak electricity demand across our high-voltage network. The tariff is designed to recover revenues necessary to support a transmission system with sufficient capacity to accommodate the maximum expected demand. Demand is primarily influenced by weather and economic conditions. Transmission revenues also include export revenues associated with transmitting excess generation to surrounding markets and ancillary revenues which are mostly attributable to maintenance services provided primarily to generators and secondary use of our land rights.

Our transmission revenues were higher by $93 million, or 7%, compared to 2011. On December 23, 2010, the OEB rendered its decision on our 2011 and 2012 transmission rate application. On December 20, 2011, the OEB approved new transmission tariff rates, effective January 1, 2012, which reflected higher in-service assets and the use of US GAAP as our basis for rate setting. The decisions resulted in higher transmission revenues of $106 million for the year ended December 31, 2012, and the average peak demand for 2012 resulted in a slight increase of $3 million, compared to the prior year.

Increases were partially offset by a $9 million reduction in revenue following the completion of recovery of a transmission regulatory account effective December 31, 2011, a $6 million reduction in transmission-related external revenues and a $1 million reduction associated with other OEB-approved regulatory accounts.

Distribution

Our consolidated Distribution Business consists of the separate distribution businesses of our subsidiaries Hydro One Networks, Hydro One Brampton Networks, and Hydro One Remote Communities. Distribution revenues include our distribution tariff and amounts to recover the cost of purchased power used by the customers of our consolidated Distribution Business. Accordingly, our distribution revenues are influenced by the amount of electricity we distribute, the cost of purchased power and our distribution tariff rates. Distribution revenues also include minor ancillary distribution services revenues, such as fees related to the joint use of our distribution poles by the telecommunications and cable television industries as well as miscellaneous charges, such as those for late payments.

Our 2012 distribution revenues were higher by $165 million, or 4%, compared to 2011. The increase was primarily due to the recovery of higher purchased power costs of $146 million, as described below under "Purchased Power." Our distribution revenues were also higher by $18 million due to our placement of new ADS and smart meter investments in service. Given that these investments relate to new technologies, they are currently recovered through separate rate mechanisms.

Distribution revenues for the year reflect additional external revenues of $7 million, an increase in Hydro One Remote Communities' revenues of $2 million and a $1 million increase associated with OEB-approved regulatory accounts. These increases were partially offset by a $7 million reduction due to lower energy consumption, resulting primarily from the milder winter we experienced in 2012 compared to 2011, and by a decrease of $2 million in Hydro One Brampton Networks' distribution tariff revenues.

Purchased Power

Purchased power costs are incurred by our Distribution Business and represent the cost of electricity delivered to customers within our distribution service territories. These costs comprise the wholesale commodity cost of energy, the IESO's wholesale market service charges, and transmission charges levied by the IESO. The commodity cost of energy for certain low-volume and designated customers is based on the OEB's RPP, which consists of a two-tiered pricing structure with threshold amounts and a separate pricing structure for RPP customers on TOU billing, both of which are adjusted twice annually. We began transitioning our RPP customers to TOU billing in May 2010, and a large majority of our RPP customers are now on TOU billing. Customers who are not eligible for the RPP pay the market price for electricity, adjusted for the difference between market prices and the prices paid to generators under the *Electricity Restructuring Act, 2004*.

A summary of the RPP for the reporting and comparative periods is provided below.

RPP	Tier Threshold (kWh/month)		Tier Rates (cents/kWh)	
Effective Date	**Residential**	**Non-Residential**	**First Tier**	**Second Tier**
November 1, 2010	1,000	750	6.4	7.4
May 1, 2011	600	750	6.8	7.9
November 1, 2011	1,000	750	7.1	8.3
May 1, 2012	600	750	7.5	8.8
November 1, 2012	1,000	750	7.4	8.7

RPP TOU	Rates (cents/kWh)		
Effective Date	**On Peak**	**Mid Peak**	**Off Peak**
November 1, 2010	9.9	8.1	5.1
May 1, 2011	10.7	8.9	5.9
November 1, 2011	10.8	9.2	6.2
May 1, 2012	11.7	10.0	6.5
November 1, 2012	11.8	9.9	6.3

Purchased power costs increased by $146 million, or 6%, to $2,774 million for the year, compared to 2011. The increase in our purchased power costs was primarily due to an increase of $118 million resulting from the impact of changes in the OEB's RPP rates for residential and other eligible customers, a $33 million increase resulting from the OEB transmission rate decision effective January 1, 2012 that affected the transmission charges levied by the IESO, and a $7 million increase related to higher electricity demand. The effect of these increases was partially offset by an $11 million reduction compared to 2011 in wholesale market service charges levied by the IESO, which include certain costs for operating the transmission grid, and a $1 million decrease resulting from lower purchased power costs for customers who are not eligible for the RPP.

Operation, Maintenance and Administration

Our operation, maintenance and administration costs consist of labour, material, equipment and purchased services which support the operation and maintenance of the transmission and distribution systems. Also included in these costs are property taxes and payments in lieu thereof related to certain of our transmission and distribution facilities.

Operation, maintenance and administration costs for each of our three business segments were as follows:

Year ended December 31 (millions of dollars)	**2012**	2011	$ Change	% Change
Transmission	**402**	422	(20)	(5)
Distribution	**608**	609	(1)	–
Other	**61**	61	–	–
	1,071	1,092	(21)	(2)

Our company continues to focus on managing its costs, resulting in a decrease in total operation, maintenance and administration expenditures in 2012, compared to 2011, while continuing to substantially complete the planned work programs for both our transmission and distribution businesses.

Transmission

Operation, maintenance and administration expenditures incurred to sustain our high-voltage transmission stations, lines and rights-of-way decreased by $20 million, or 5%, in 2012 compared to last year. Within our work programs, we continued to invest in the safe and reliable operation of our transmission system that spans Ontario. Our work program requirements were lower by $33 million compared to last year mainly due to: lower demand for station-related corrective maintenance, particularly for power equipment; lower demand for underground cable corrective maintenance; and reduced autotransformer remediation work. We also incurred lower expenditures compared to last year related to the OPA's recommendation to increase short circuit and/or transformer capacity at a number of our transmission stations to enable

the connection of small renewable projects, for which recovery is restricted (see "Regulation – Long-Term Energy Plan"). Most of this work has now been completed. Expenditures in support of our transmission system increased by $13 million, compared to 2011, due to a redirection of resources from our Distribution Business, partially offset by management cost reduction initiatives.

Distribution

Operation, maintenance and administration expenditures required to maintain our low-voltage distribution system decreased slightly by $1 million compared to last year. Our work program expenditures decreased by $5 million mainly due to decreased power restoration expenditures resulting from overall lower storm activity in Ontario in 2012 compared to 2011. Reductions also resulted from lower lines maintenance requirements, partially offset by increased requirements within our forestry program resulting from higher tree densities experienced this year. Our expenditures in support of our distribution system increased by $4 million mainly due to spending in support of the Customer Information System (CIS) phase of our entity-wide information system replacement and improvement project. The impact of this increase was partially offset by cost reduction initiatives and o redirection of resources in support of our Transmission Business.

Depreciation and Amortization

Depreciation and amortization expense increased by $43 million, or 7%, in 2012, compared to 2011. This increase was attributable to higher depreciation expense of $40 million, when compared to 2011, primarily related to our placement of new assets in service consistent with our ongoing capital work program. Slightly higher asset removal costs of $3 million contributed the remainder of the variance from the prior year.

Financing Charges

Financing charges increased by $14 million, or 4%, to $358 million for 2012 compared to 2011. Higher financing costs were mainly due to an increased average level of debt and partially offset by a lower average effective interest rate.

Provision for Payments in Lieu of Corporate Income Taxes (PILs)

The provision for PILs decreased by $29 million, or 19%, to $121 million in 2012, compared to 2011. This decrease primarily resulted from a reduction in the statutory tax rate from 28.25% to 26.50%, changes in net temporary differences, and an increase in research and development tax credits related to our ADS project. This reduction was partially offset by the impact of higher levels of pre-tax income compared to 2011.

Net Income

Net income of $745 million was higher by $104 million, or 16%, than our comparable 2011 results. Higher revenues reflect the recovery of prior year investments which are now in service and which will improve the province's electricity system. Our net income was also positively impacted by lower operation, maintenance and administration expenditures resulting from cost-effectively managing the work program within our Transmission Business and by lower PILs resulting from a lower combined federal and provincial statutory income tax rate compared to 2011. In addition, our 2012 net income reflects higher depreciation expense resulting from our placement of new assets in service, consistent with our increased capital work program, and increased financing charges reflecting our higher average level of debt.

QUARTERLY RESULTS OF OPERATIONS

The following table sets forth unaudited quarterly information for each of the eight quarters, from the quarter ended March 31, 2011 through December 31, 2012. This information has been derived from our unaudited interim Consolidated Financial Statements and our audited annual Consolidated Financial Statements which include all adjustments, consisting only of normal recurring adjustments, necessary for fair presentation of our financial position and results of operations for those periods. These operating results are not necessarily indicative of results for any future period and should not be relied upon to predict our future performance.

(millions of dollars)	**2012**				2011			
Quarter ended	**Dec. 31**	**Sept. 30**	**Jun. 30**	**Mar. 31**	Dec. 31	Sept. 30	Jun. 30	Mar. 31
Total revenue	**1,435**	**1,466**	**1,359**	**1,468**	1,359	1,384	1,268	1,460
Net income	**165**	**201**	**169**	**210**	120	167	142	212
Net income to common shareholder	**160**	**197**	**164**	**206**	115	163	137	208

Electricity demand generally follows normal weather-related variations, and consequently, our electricity-related revenues and profit, all other things being equal, would tend to be higher in the first and third quarters than in the second and fourth quarters.

LIQUIDITY AND CAPITAL RESOURCES

Our primary sources of liquidity and capital resources are funds generated from our operations, debt capital market borrowings and bank financing. These resources will be used to satisfy our capital resource requirements, which continue to include our capital expenditures, servicing and repayment of our debt, and dividends.

Summary of Sources and Uses of Cash

Year ended December 31 (millions of dollars)	**2012**	2011
Operating activities	**1,285**	1,407
Financing activities		
Long-term debt issued	**1,085**	700
Long-term debt retired	**(600)**	(500)
Dividends paid	**(370)**	(168)
Investing activities		
Capital expenditures	**(1,454)**	(1,447)
Other financing and investing activities	**21**	64
Net change in cash and cash equivalents	**(33)**	56

Operating Activities

Net cash from operating activities decreased by $122 million to $1,285 million in 2012, compared to 2011. The decrease was primarily due to changes in accrued liabilities related to customer prepayments, and a reduction in taxes payable, resulting from a tax payment made in the first quarter of 2012 related to the 2011 taxation year, as well as the timing of tax installment payments in 2012, compared to 2011. The decrease was partly offset by higher 2012 net income, compared to 2011.

Financing Activities

Short-term liquidity is provided through funds from operations, our Commercial Paper Program, under which we are authorized to issue up to $1,000 million in short-term notes with a term to maturity of less than 365 days, our revolving credit facility, and through our holding of Province of Ontario Floating-Rate Notes.

Our Commercial Paper Program is supported by a total of $1,500 million in liquidity facilities comprised of our $1,250 million committed revolving credit facility with a syndicate of banks, which matures in June 2017, and a long-term investment in Province of Ontario Floating-Rate Notes of $250 million (with a fair value of $251 million at December 31, 2012). The short-term liquidity under this program and anticipated levels of funds from operations should be sufficient to fund our normal operating requirements.

At December 31, 2012, we had $8,460 million in long-term debt outstanding, including the current portion. Our notes and debentures mature between 2013 and 2062. Long-term financing is provided by our access to the debt markets, primarily through our Medium-Term Note (MTN) Program. The maximum authorized principal amount of medium-term notes issuable under this program is $3,000 million. At December 31, 2012, $1,515 million remained available until September 2013.

	Rating	
Rating Agency	**Short-term Debt**	**Long-term Debt**
DBRS Limited	R-1 (middle)	A (high)
Moody's Investors Service Inc.[1]	Prime-1	A1
Standard & Poor's (S&P)[2]	A-1	A+

[1] On April 27, 2012, Moody's Investors Service Inc. downgraded our senior unsecured rating to A1 from Aa3.

[2] On April 25, 2012, S&P revised their outlook on our company to negative from stable.

We have the customary covenants normally associated with long-term debt. Among other things, our long-term debt covenants limit our permissible debt as a percentage of our total capitalization, limit our ability to sell assets, and impose a negative pledge provision, subject to customary exceptions. The credit agreements related to our credit facilities have no material adverse change clauses that could trigger default. However, the credit agreements require that we provide notice to the lenders of any material adverse change within three business days of the occurrence. The agreements also provide limitations that debt cannot exceed 75% of total capitalization and that third-party debt issued by our subsidiaries cannat exceed 10% of the total book value of our assets. We were in compliance with all these covenants and limitations at December 31, 2012.

In 2012, we successfully issued $1,085 million in cost-effective long-term debt under our MTN Program, consisting of $300 million issued in the first quarter, $425 million issued in the second quarter, $310 million issued in the third quarter, and $50 million issued in the fourth quarter of 2012. In the third quarter of 2012, we also called and redeemed $600 million of our long-term debt, prior to its maturity date of November 15, 2012.

In 2011, we issued $700 million in long-term debt under our MTN Program, consisting of $300 million issued in the first quarter, $300 million issued in the third quarter, and $100 million issued in the fourth quarter of 2011. In 2011, we also repaid $500 million in maturing long-term debt, $250 million in the first quarter and $250 million in the fourth quarter.

We had no short-term notes outstanding as at December 31, 2012 or December 31, 2011.

Common dividends are declared at the sole discretion of our Board of Directors, and are recommended by management based on results of operations, maintenance of the deemed regulatory capital structure, financial condition, cash requirements, and other relevant factors such as industry practice and shareholder expectations. Common dividends pertaining to our quarterly financial results are generally declared and paid in the immediately following quarter.

In 2012, we paid dividends to the Province in the amount of $370 million, consisting of $352 million in common dividends and $18 million in preferred dividends. In 2011, we paid dividends in the amount of $168 million, consisting of $150 million in common dividends and $18 million in preferred dividends.

In 2012, cash dividends per common share were $3,523, compared to $1,500 per common share in 2011. Cash dividends per preferred share were $1.375 in each of 2012 and 2011.

Our objectives with respect to our capital structure are to maintain effective access to capital on a long-term basis at reasonable rates and to deliver appropriate financial returns to our shareholder.

Investing Activities

Cash used for investing activities, primarily representing capital expenditures to enhance and reinforce our transmission and distribution infrastructure in the public interest, was as follows:

Year ended December 31 (millions of dollars)	**2012**	2011	$ Change	% Change
Transmission	**776**	810	(34)	(4)
Distribution	**671**	628	43	7
Other	**7**	9	(2)	(22)
	1,454	1,447	7	–

Transmission

Transmission capital expenditures decreased by $34 million, or 4%, to $776 million in 2012, compared to 2011. Investments to expand and reinforce our transmission system were $313 million, representing a decrease of $103 million from last yeor. The majority of our expenditures were made on inter-area network projects to support the Province's supply mix objectives for generation, although we continue to make significant investments in load customer connection and local area supply projects to address growing loads. The 2012 decrease in our expenditures results from the completion of several large projects in 2011. Major inter-area network projects completed and put into service in 2011 included the installation of SVCs at our Nanticoke, Detweiler, Porcupine and Kirkland Lake transformer stations. Also contributing to the reduction in expenditures were lower expenditures in 2012 related to our Woodstock Area Transmission Reinforcement Project to increase capacity and ensure supply reliobility in the Woodstock area, and our Bruce to Milton Transmission Reinforcement Project connecting refurbished nuclear and new wind generation sources in the Huron-Grey-Bruce area. These projects were successfully put into service in March and May of this year, respectively. The impact of the reductions in expenditures in both periods was partially offset by increases in our expenditures resulting from laad customer connection and local area supply projects progressing into their build phases, and investments in our transformer stations related to the ADS Project, which supports clean DG connected to our distribution system consistent with the GEA.

On June 18, 2012, our subsidiary Hydro One Networks entered into an agreement with the Chippewas of Nawash First Nation and the Chippewas of Saugeen First Nation, collectively known as the Saugeen Ojibway Nation (SON). The agreement contemplates a new Limited Partnership (LP) to hold only the lines and related land rights of our Bruce to Milton Transmission Reinforcement Project. The carrying value of these assets is expected to be approximately $600 million when they are transferred to the LP in late 2013. Under the terms of our agreement, the SON will be eligible to purchase a non-controlling equity interest in the LP at fair value. The LP is anticipated to become a rate-regulated entity under the jurisdiction of the OEB. Transfer of our assets to the LP and subsequent sale of an equity interest to the SON are both subject to the receipt of future regulatory approvals from the OEB. On December 18, 2012, the SON, Hydro One Networks and Hydro One signed a Letter Agreement in connection with the establishment of the LP. The Letter Agreement addresses, among other things, the terms of the LP Agreement to be entered into on closing and the terms on which Hydro One Networks will operate the Bruce to Milton Line on behalf of the LP. The closing is conditional on certain regulatory approvals and tax rulings.

Our local area supply project expenditures include investments in our Switchyard Reconstruction Project at our Burlington Transformer Station, which will address aging infrastructure to increase the load supply capacity and to ensure reliability of supply to customers in the area. The project successfully went into service on December 21, 2012. We continue to invest in our Midtown Electricity Infrastructure Renewal Project to replace aging cable and overhead line facilities and to provide additional supply capability to meet future load growth in midtown Toronto as well as areas to the west. Work is progressing at our Hearn Switching Station to rebuild an existing switchyard that has reached its end-of-life. This project will also increose short circuit capability to accommodate future connection of renewable generation in central and downtown Toronto.

Significant expenditures within our load customer connection projects include investments to build our Commerce Way Transformer Station, a new load supply station in the City of Woodstock that was partially put into service on December 19, 2012. This project will provide additional transformation and line capacity to address load growth issues in the Woodstock area.

Expenditures to sustain our existing transmission system were $392 million in 2012, representing an increase of $57 million compared to 2011. During the year, we made significant investments in the refurbishment and replacement of end-of-life equipment, including end-of-life oil circuit breakers, switches, insulators and protections at our Abitibi Canyon switching station, and deteriorated autotransformers at our Trafalgar and Claireville transformer stations. Of these projects, the autotransformer at our Trafalgar transformer station and one of two at our Claireville transformer station were successfully put into service this year. During the year, we also experienced an increase in replacements for end-of-life protection and control equipment.

Our other transmission capital expenditures were $71 million in 2012, representing an increase of $12 million compared to 2011. The majority of these increased expenditures were related to fleet acquisitions and to information technology (IT) investments.

Distribution

Our distribution capital expenditures increased by $43 million, or 7%, to $671 million in 2012, compared to 2011. Capital investments to expand and reinforce our distribution network were $284 million in 2012, representing an increase of $15 million compared to 2011. We experienced increases in 2012 related to our continued investments in our ADS Project, a multi-year initiative to identify, deploy, analyze and assess equipment and applications to modernize our distribution system. The ADS Project will protect distributed generators from power interruption and is anticipated to improve outage restoration, reduce construction and ongoing maintenance costs, and reduce power loss as it flows across the electricity grid. Increased capital expenditures in 2012 were also due to investments related to our other distribution projects and upgrades to safely and reliably accommodate additional renewable energy, and to higher volumes of new customer connections and upgrades, partially offset by reduced expenditures within our Smart Meter Project as it nears completion.

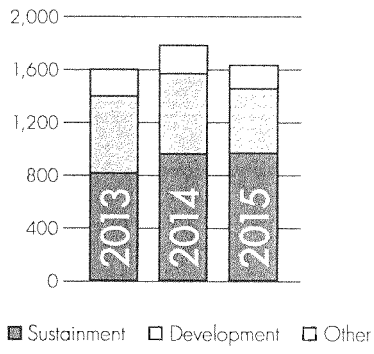
Expenditures to sustain our distribution system network were $245 million in 2012, representing an increase of $5 million compared to 2011. The increase in our sustainment program was primarily impacted by increased work accomplished within our lines and distribution station refurbishment programs, as well as higher expenditures related to the strategic purchase of power transformers compared to the prior year. These impacts were partially offset by lower storm restoration work given lower storm activity in 2012 compared to two major storms in Ontario in 2011.

Other distribution capital expenditures were $142 million in 2012, representing an increase of $23 million, compared to 2011. The majority of these expenditures were related to the CIS phase of our enterprise-wide information system replacement and improvement project. In addition to replacing end-of-life systems, this implementation will result in process improvements that are expected to provide many benefits, including enhancements to customer satisfaction through reduced call times and first call resolution of issues given faster availability of information. Productivity savings are anticipated to result from performance improvements, consolidation of systems, and decommissioning of over a dozen legacy systems.

Future Capital Expenditures

Our capital expenditures for 2013 are budgeted at approximately $1,600 million. Our 2013 capital budgets for our transmission and distribution businesses are about $1,000 million and $600 million, respectively. Consolidated capital expenditures are expected to be approximately $1,750 million in 2014 and $1,650 million in 2015. These expenditure levels reflect meeting the sustainment requirements of our aging infrastructure. Our sustainment program is expected to be approximately $800 million in 2013, $950 million in 2014 and $1,000 million in 2015. Our development projects include the ADS, inter-area network upgrades that reflect supply mix policies, local area supply requirements, and requirements to enable DG. Our development expenditures are expected to be approximately $600 million in 2013, $600 million in 2014, and $450 million in 2015. These development investments also reflect customer demand work. Other capital expenditures are expected to be approximately $200 million in each of 2013, 2014 and 2015. These expenditures include investments to replace our end-of-life customer billing system and smaller projects related to the continued realization of increased productivity from our enterprise-wide SAP information system.

Future Capital Expenditures
(CAD $ millions)



Transmission

Transmission capital expenditures include significant investments to manage the replacement and refurbishment of our aging transmission infrastructure in order to ensure a continued reliable supply of energy to customers throughout the province. Our investment plan includes sustainment investments to replace end-of-life air blast circuit breakers and switchgear, high-voltage underground cable, and aging power transformers and to comply with North American Electricity Reliability Corporation cyber security requirements. These sustaining investments are necessary to ensure that we continue to meet all regulatory, compliance, safety and environmental objectives.

Major capital investments include our Oshawa Area Transformer Station Project to install additional auto-transformer capacity at our proposed Clarington Transformer Station, for which the OPA has requested that Hydro One develop an implementation plan and initiate work. Planning and environmental studies are currently being undertaken for this project. Investments also include our Midtown Electricity Infrastructure Renewal Project that will provide additional supply capability to meet future load growth in midtown Toronto as well as areas to the west, our SVC installation to be completed at our Milton station, and our project to rebuild the switching station at our Hearn Transformer Station, which is expected to be completed by 2014. Transmission investments for ADS and requirements to enable DG are also included in the investment plan. The Hearn Transformer Station Project, when combined with four other transformer station upgrades, will collectively enable up to 600 MW of new transmission capacity.

On December 22, 2010, we received a letter from the Minister of Energy requesting us to proceed with the necessary planning and development work for specified transmission projects and upgrades to safely and reliably accommodate additional renewable energy. On April 7, 2011, the OPA provided the scope and timing to increase short circuit and/or transformer capacity at ten of 15 transformer stations. These upgrades are substantially complete. Expenditures for these upgrades have been recorded within operation, maintenance and administration (see "Regulation – Long-Term Energy Plan"). Two of the three priority specified transmission projects are reflected in our budgeted capital expenditures. The West of London Transmission Upgrade Project generally requires restringing conductor on existing towers along an existing right-of-way and will enable the connection of additional renewable generation in the west of London area. The Southwestern Ontario Reactive Compensation Priority Project will increase the transmission capability of the Bruce transmission system. We are awaiting direction on the third priority project from the OPA (see "Regulation – Long-Term Energy Plan").

In August 2010, the OEB introduced a framework for competitive designation for the development of eligible transmission projects. As a result, we did not include in our budgeted capital expenditures any projects that could meet the definition of expansions under the OEB's competitive framework. We do not plan to undertake large capital expenditures without a reasonable expectation of recovering them in our rates.

The actual timing and expenditures of many development projects are uncertain as they are dependent upon: various approvals including OEB leave to construct approvals and environmental assessment approvals; negotiations with customers, neighbouring utilities and other stakeholders; and consultations with First Nations and Métis communities. Projects are also dependent on the timing and level of generator contributions for enabling facilities.

Distribution

Distribution capital expenditures include investments to support the sustainment of our capital infrastructure. Our core work will continue to focus on the performance of our aging distribution asset base in order to improve system reliability. There are continuing investments to replace end-of-life equipment and components, implement ADS as part of this renewal and a focus on wood pole replacements to maintain reliability. In addition, we will continue to address customer demand projects through connectivity for DG, the demand for new load connections, trouble calls, storm restoration and system capability reinforcement.

Distribution development expenditures over the period are primarily related to the development of an ADS system and related grid modernization standards, customer demand work such as connections and upgrades, work to facilitate DG connections, including station upgrades, protection and control, new lines and some contestable work for which we receive capital contributions. During the 2013 and 2014 periods, we expect to manage a significant number of projects throughout the province to address load growth and the stress on our system components.

DG expenditures are based on our estimate of the number of anticipated connections, which have been reduced based on the experience gained since 2009 and changes that have occurred to the FIT Program. The budget only reflects expenditures for projects with FIT and microFIT Program contracts from the OPA that are expected to connect to our distribution system.

In 2013, the ADS Project will look at optimizing outage response through more effective dispatch, automation to isolate faults where needed and the dynamic regulation of voltage to reduce losses.

Summary of Contractual Obligations and Other Commercial Commitments

There are no off-balance-sheet arrangements that have, or are reasonably likely to have, a material current or future effect on our financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources.

The following table presents a summary of our debt and other major contractual obligations, as well as other major commercial commitments.

December 31, 2012 (millions of dollars)	**Total**	**2013**	**2014/2015**	**2016/2017**	**After 2017**
Contractual Obligations *(due by year)*					
Long-term debt – principal repayments	8,460	600	1,300	1,100	5,460
Long-term debt – interest payments	7,336	410	735	651	5,540
Pension[1]	330	158	172	–	–
Environmental and asset retirement obligations[2]	313	30	73	40	170
Inergi LP (Inergi) outsourcing agreement[3]	287	136	151	–	–
Operating lease commitments	53	10	15	14	14
Total Contractual Obligations[4]	16,779	1,344	2,446	1,805	11,184
Other Commercial Commitments *(by year of expiry)*					
Bank line[5]	1,250	–	–	1,250	–
Letters of credit[6]	150	150	–	–	–
Guarantees[6]	326	326	–	–	–
Total Other Commercial Commitments	1,726	476	–	1,250	–

[1] Contributions to the Hydro One Pension Fund are generally made one month in arrears. The 2013 and 2014 minimum contributions are based on an actuarial valuation filed in May 2012 and effective December 31, 2011. Based on expected levels of 2012 pensionable earnings, our total 2012 annual pension contributions were approximately $160 million. Future minimum contributions beyond 2014 will be based on an actuarial valuation effective no later than December 31, 2014, and will depend on future investment returns, changes in benefits or actuarial assumptions. Pension contributions beyond 2014 are not estimable at this time.

[2] We record a liability for the estimated future expenditures associated with the phase-out and destruction of polychlorinated biphenyl (PCB)-contaminated insulating oil from electrical equipment and for the assessment and remediation of contaminated lands, as well as asset retirement obligations for the removal of asbestos-contaminated materials from our facilities and the decommissioning and removal of certain switching stations. The expenditure pattern reflects our planned work programs for the periods.

[3] On March 1, 2002, Inergi began providing a range of services to us for a ten-year period, including IT, customer care, supply chain and certain human resources and finance services. On May 1, 2010, consistent with the terms of the contract, our company extended the Master Services Agreement with Inergi for a further three-year period, to expire on February 28, 2015. Given the complexities involved, we have begun developing a plan of action for end-of-term and anticipate working towards a request for proposal in 2013. The amounts disclosed include an estimated annual inflation adjustment in the range of 1.8% to 3.0%.

[4] In addition, our company has entered into various agreements to purchase goods or services in support of our work programs that are enforceable and legally binding. None of these agreements is considered individually material, and the majority do not extend beyond December 31, 2013.

[5] In support of our liquidity requirements, we have a $1,250 million revolving standby credit facility with a syndicate of banks that matures in June 2017.

[6] We currently have outstanding bank letters of credit of $127 million relating to retirement compensation arrangements. On April 27, 2012, our highest credit rating declined from the "Aa" category to the "A" category. Based on this credit rating category, we began providing prudential support to the IESO in the form of letters of credit, the amount of which is calculated based on forecasted monthly power consumption. As at December 31, 2012, we provided letters of credit to the IESO in the amount of $22 million to meet our current prudential requirement. The other $1 million pertains to operating letters of credit. We have also provided prudential support to the IESO on behalf of our subsidiaries as required by the IESO's Market Rules, using parental guarantees of up to a maximum of $325 million, and on behalf of two distributors using guarantees of up to a maximum of $0.7 million.

The amounts in the above table under long-term debt – principal repayments are not charged to our results of operations, but are reflected on our Consolidated Balance Sheets and Consolidated Statements of Cash Flows. Interest associated with this debt is recorded under financing charges on our Consolidated Statements of Operations and Comprehensive Income or as a cost of our capital programs. Payments in respect of operating leases and our outsourcing agreement with Inergi are recorded under operation, maintenance and administration expense on our Consolidated Statements of Operations and Comprehensive Income or as a cost of our capital programs.

RELATED PARTY TRANSACTIONS

Related party transactions primarily consist of our transmission revenues received from, and our power purchase payments made to the IESO, which is a related party by virtue of its status as an agency of the Province. The year-over-year changes related to these amounts are described more fully in the discussion of our transmission revenues and purchased power costs. Other significant related party transactions include our dividends, which are paid to the Province, and our PILs and some of our property taxes, which are paid or payable to the OEFC. In January 2010, we purchased $250 million of Province of Ontario Floating-Rate Notes, maturing on November 19, 2014, as a form of alternate liquidity to supplement our bank credit facilities.

CONSIDERATIONS OF CURRENT ECONOMIC CONDITIONS

Effect of Load on Revenue

Our load, based on normal weather patterns, is expected to marginally decline in 2013 due to the impact of CDM and embedded generation, partially offset by load growth associated with economic growth in all sectors of the Ontario economy. Overall load growth due to the economy alone is forecasted to be approximately 1.3%, with the commercial and industrial sectors slightly outperforming the residential sector. The load impacts of CDM and embedded generation are expected to have a negative impact on load growth of approximately 1.1% and 0.3%, respectively. On the whole, our load is expected to decline by about 0.1% in 2013. Our approved revenue requirement for 2013 has taken the expected load decline into account. A reduction in load, beyond our load forecast included in our approved revenue requirement, would negatively impact our financial results.

Effect of Interest Rates

Changes in interest rates will impact the calculation of the revenue requirements upon which our rates are based. The first component impacted by interest rates is our ROE. The OEB-approved adjustment formula for calculating ROE will increase or decrease by 50% of the change between the current Long Canada Bond Forecast and the risk-free rate established at 4.25% and 50% of the change in the spread in 30-year "A"-rated Canadian utility bonds over the 30-year benchmark Government of Canada bond yield established at 1.415%. All other things being equal, we estimate that a 1% decrease in the forecasted long-term Government of Canada bond yield used in determining our ROE would reduce Hydro One Networks' transmission and distribution businesses' results of operations by approximately $19 million and $10 million, respectively. As interest rates decline, there is more risk of a decline in our net income. The second component of revenue requirement that would be impacted by interest rates is the return on debt. The difference between actual interest rates on new debt issuances and those approved for return by the OEB would impact our results of operations.

Input Costs and Commodity Pricing

In support of our ongoing work programs, we are required to procure materials, supplies and services. To manage our total costs, we regularly establish security of supply, strategic material and services contracts, general outline agreements, and vendor alliances and we also manage a stock of commonly used items. Such arrangements are for a defined period of time and are monitored. Where advantageous, we develop long-term contractual relationships with suppliers to optimize the cost of goods and services and to ensure the availability and timely supply of critical items. As a result of our strategic sourcing practices, we do not foresee any adverse impacts on our business from current economic conditions in respect of adequacy and timing of supply and credit risk of our counterparties. Further, we have been able to realize significant savings through our strategic sourcing initiatives.

Debt Financing

Cash generated from operations, after the payment of expected dividends, will not be sufficient to fund capital expenditures or meet debt maturity repayments and other liquidity requirements (see "Risk Management and Risk Factors – Risk Associated with Arranging Debt Financing"). We rely on debt financing through our MTN Program and Commercial Paper Program. Our Commercial Paper Program is supported by a total of $1,500 million in liquidity facilities as at December 31, 2012, which is comprised of a $1,250 million syndicated bank line of credit and the holding of $250 million of Province of Ontario Floating-Rate Notes. In 2012, we continued issuing sufficient cost-effective debt financing through the MTN Program in the Canadian capital markets and we arranged sufficient available liquidity. Economic conditions were challenging in 2012 and we expect they will remain challenging in 2013.

Pension

In 2012, we contributed approximately $160 million to our pension plan and incurred $207 million in net periodic pension benefit cost. An actuarial valuation filed in May 2012 and effective December 31, 2011 did not result in significant changes to our 2012 required contributions or our 2012 net periodic benefit cost. Actuarial valuations are minimally required to be filed every three years. We currently estimate our total annual pension contributions to be approximately $160 million for 2013 and 2014, based on the projected level of

pensionable earnings and the same actuarial valuation effective December 31, 2011. Future minimum contributions beyond 2014 will be based on the actuarial valuation effective no later than December 31, 2014. Our pension plan experienced positive returns of about 9.19% in 2012. Our pension obligation is impacted by interest rates. The 1% decrease in the discount rate, from 5.25% at December 31, 2011 to 4.25% at December 31, 2012, resulted in an increase in the pension obligation of $862 million and an increase to our post-retirement and post-employment benefit obligation of $241 million. No new benefits were introduced and over the last number of years benefits have been reduced through re-negotiations with certain of our unions as well as our management employees.

RISK MANAGEMENT AND RISK FACTORS

We have an Enterprise Risk Management (ERM) Program that aims at balancing business risks and returns. An enterprise-wide approach enables regulatory, strategic, operational and financial risks to be managed and aligned with our strategic goals. Our ERM program helps us to better understand uncertainty and its potential impact on our strategic goals. It sets out the uniform principles, processes and criteria for identifying, assessing, evaluating, treating, monitoring and communicating risks across all lines of business. It supports our Board of Directors' corporate governance needs and the due diligence responsibilities of senior management.

While our philosophy is that risk management is the responsibility of all employees, the Board of Directors annually reviews our company's risk tolerances, risk management policies, processes and accountabilities. Twice per year, the Board of Directors reviews our risk profile, which is the list of key risks prepared by senior management, that represents the greatest threats to meeting our strategic objectives. The Audit and Finance Committee of our Board of Directors annually reviews the status of our internal control framework.

Our President and Chief Executive Officer (CEO) has ultimate accountability for risk management. Our Leadership Team provides senior management oversight of our risk portfolio and our risk management processes. The leadership team provides direction on the evolution of these processes and identifies priority areas of focus for risk assessment and mitigation planning.

Our Chief Administration Officer and Chief Financial Officer (CAO and CFO) is responsible for ensuring that the risk management program is an integral part of our business strategy, planning and objective setting. The CAO and CFO has specific accountability for ensuring that enterprise risk management processes are established, properly documented and maintained by our company.

Our senior managers, line and functional managers are responsible for managing risks within the scope of their authority and accountability. Risk acceptance or mitigation decisions are made within the risk tolerances specified by the head of the subsidiary or function.

The CAO and CFO provides support to the Audit and Finance Committee of our Board of Directors, the President and CEO, the senior management team and key managers within our company. This support includes developing risk management frameworks, policies and processes, introducing and promoting new techniques, establishing risk tolerances, preparing annual corporate risk profiles, maintaining a registry of key business risks and facilitating risk assessments across our company. Our internal audit staff is responsible for performing independent reviews of the effectiveness of risk management policies, processes and systems. Starting in 2013, our Board of Directors has taken on an enhanced role in our governance structure. Each committee of the Board of Directors will take accountability for reviewing specific risks of our company.

Key elements of our ERM Program enable us to identify, assess and monitor our risks effectively. These include having an ERM policy and framework which communicates our philosophy and process for risk management across our company. A discussion of risks is an integral part of each line of business' planning documents on an annual basis. Risk identification is also considered as part of each business case for investments. Finally, discrete risk assessments and workshops are performed for specific lines of business, key projects and various profiles, such as customer relationships and regulatory compliance.

In order to drive consistency throughout our risk identification and risk management processes, we use a standard list of risk sources known as our risk universe. These sources are maintained in a single database that provides a consistent basis for risk identification and classification and serves as a repository for our risk assessments. All risk assessments in our company start with this risk universe. We also use standard risk criteria, which establish the metrics and terminology used for assessing and communicating on risks, and help ensure a consistent basis for our risk assessments and risk evaluations across all lines of business. Risk criteria include formally established risk tolerances and standard scales for assessing the probability of a risk materializing and the strength of controls in place to mitigate them.

Ownership by the Province

The Province owns all of our outstanding shares. Accordingly, the Province has the power to determine the composition of our Board of Directors and appoint the Chair, and influence our major business and corporate decisions. We and the Province have entered into a memorandum of agreement relating to certain aspects of the governance of our company. Pursuant to such agreement, in September 2008, the Province made a declaration removing certain powers from our company's Directors pertaining to the off-shoring of jobs under the outsourcing arrangement with Inergi. In 2009, the Province required our company, among other entities, to adhere to certain accountability measures regarding consulting contracts and employee travel, meal and hospitality expenses. The Province may require us to adhere to further accountability measures or may make similar declarations in the future, some of which may have a material adverse effect on our business. Our credit ratings may change with the credit ratings of the Province, to the extent the credit rating agencies link the two ratings by virtue of Hydro One's ownership by the Province.

Conflicts of interest may arise between us and the Province as a result of the obligation of the Province to act in the best interests of the residents of Ontario in a broad range of matters, including the regulation of Ontario's electricity industry and environmental matters, any future sale or other transaction by the Province with respect to its ownership interest in our company, including any potential outcomes arising out of the recommendations of the Ontario Distribution Sector Review Panel's report, the Province's ownership of Ontario Power Generation Inc., and the determination of the amount of dividend or proxy tax payments. We may not be able to resolve any potential conflict with the Province on terms satisfactory to us which could have a material adverse effect on our business.

Regulatory Risk

We are subject to regulatory risks, including the approval by the OEB of rates for our transmission and distribution businesses that permit a reasonable opportunity to recover the estimated costs of providing safe and reliable service on a timely basis and earn the approved rates of return.

The OEB approves our transmission and distribution rates based on projected electricity load and consumption levels. If actual load or consumption materially falls below projected levels, our net income for either, or both, of these businesses could be materially adversely affected. Also, our current revenue requirements for these businesses are based on cost assumptions that may not materialize. There is no assurance that the OEB would allow rate increases sufficient to offset unfavourable financial impacts from unanticipated changes in electricity demand or in our costs.

Our load could also be negatively affected by successful CDM programs. We are also subject to risk of revenue loss from other factors, such as economic trends and weather.

We expect to make investments in the coming years to connect new renewable generating stations. There is the possibility that we could incur unexpected capital expenditures to maintain or improve our assets, particularly given that new technology is required to support renewable generation and unforeseen technical issues may be identified through implementation of projects. The risk exists that the OEB may not allow full recovery of such investments in the future. To the extent possible, we aim to mitigate this risk by ensuring prudent expenditures, seeking from the regulator clear policy direction on cost responsibility, and pre-approval of the need for capital expenditures.

While we expect all of our expenditures to be fully recoverable after OEB review, any future regulatory decision to disallow or limit the recovery of such costs would lead to potential asset impairment and charges to our results of operations, which could have a material adverse effect on our company.

In Ontario, the Market Rules mandate that we comply with the reliability standards established by North American Electric Reliability Corporation and Northeast Power Coordinating Council Inc. As a result, we will be required to comply with the Federal Energy Regulatory Commission's definition of "bulk electric system" unless we are granted an exemption which will allow the application of the new definition in a cost-effective manner. We will look for recovery for costs incurred in meeting the definition in our rates; however an adverse decision on an exemption for recovery of costs could have an adverse effect on our company.

Risk Associated with Arranging Debt Financing

We expect to borrow to repay our existing indebtedness and fund a portion of capital expenditures. We have substantial amounts of existing debt which mature between 2013 and 2016, including $600 million maturing in 2013 and $750 million maturing in 2014. We plan to incur capital expenditures of approximately $1.6 billion in 2013 and $1.8 billion in 2014. Cash generated from operations, after the payment of expected dividends, will not be sufficient to fund the repayment of our existing indebtedness and capital expenditures. Our ability to arrange sufficient and cost-effective debt financing could be materially adversely affected by numerous factors, including the regulatory environment in Ontario, our results of operations and financial position, market conditions, the ratings assigned to our debt securities by credit rating agencies and general economic conditions. Any failure or inability on our part to borrow substantial amounts of debt on satisfactory terms could impair our ability to repay maturing debt, fund capital expenditures and meet other obligations and requirements and, as a result, could have a material adverse effect on our company.

Risk Associated with Transmission Projects

The amount of power that can flow through transmission networks is constrained due to the physical characteristics of transmission lines and operating limitations. Within Ontario, new and expected generation facility connections, including those renewable energy generation facilities connecting as a result of the FIT program stemming from the GEA, and load growth have increased such that parts of our transmission and distribution systems are operating at or near capacity. These constraints or bottlenecks limit the ability of our network to reliably transmit power from new and existing generation sources (including expanded interconnections with neighbouring utilities) to load centres or meet customers' increasing loads. As a result, investments have been initiated to increase transmission capacity and enable the reliable delivery of power from existing and future generation sources to Ontario consumers.

In many cases, these investments are contingent upon one or more of the following approvals and/or processes: environmental approval(s); receipt of OEB approvals which can include expropriation; and appropriate consultation processes with First Nations and Métis. Obtaining OEB and/or environmental assessment approvals and carrying out these processes may also be impacted by opposition to the proposed site of transmission investments which could adversely affect transmission reliability and/or our service quality, both of which could have a material adverse effect on our company.

With the introduction on August 26, 2010 of the OEB's competitive transmission project development planning process, in the absence of a government directive, all interested transmitters will be required to submit a bid to the OEB for identified enabler facilities and network enhancement projects. Historically, we would have been awarded such projects through our rates and Section 92, Leave to Construct, applications. The facilitation of competitive transmission could impact our future work program and our ability to expand our current transmission footprint. In addition, bid costs are only recoverable by the successful proponent. This could have a material adverse effect on our company.

Asset Condition

We continually monitor the condition of our assets and maintain, refurbish or replace them to maintain equipment performance and provide reliable service quality. Our capital programs have been increasing to maintain the performance of our aging asset base. Execution of these plans is partially dependent on external factors, such as outage planning with the IESO and transmission-connected customers, funding approval by the OEB, and supply chain availability for equipment suppliers and consulting services. In addition, opportunities to remove equipment from service to accommodate construction and maintenance are becoming increasingly limited due to customer and generator priorities.

Adjustments to accommodate these external dependencies have been made in our planning process, and we are focused on overcoming these challenges to execute our work programs. However, if we are unable to carry out these plans in a timely and optimal manner, equipment performance will degrade which may compromise the reliability of the provincial grid, our ability to deliver sufficient electricity and/or customer supply security and increase the costs of operating and maintaining these assets. This could have a material adverse effect on our company.

Workforce Demographic Risk

By the end of 2012, approximately 18% of our employees were eligible for retirement and by 2013 there could be up to 20% eligible to retire. Accordingly, our success will be tied to our ability to attract and retain sufficient qualified staff to replace those retiring. This will be challenging as we expect the skilled labour market for our industry to be highly competitive in the future. In addition, many of our employees possess experience and skills that will also be highly sought after by other organizations both inside and outside the electricity sector. We are therefore focused on earlier identification and more rapid development of staff who demonstrate management potential. Moreover, we must also continue to advance our technical training and apprenticeship programs and succession plans to ensure that our future operational staffing needs will be met. If we are unable to attract and retain qualified personnel, it could have a material adverse effect on our business.

Environmental Risk

Our health, safety and environmental management system is designed to ensure hazards and risks are identified and assessed, and controls are implemented to mitigate significant risks. This system includes a standing committee of our Board of Directors that has governance over environmental matters. Given the territory that our system encompasses and the amount of equipment that we own, we cannot guarantee, however, that all such risks will be identified and mitigated without significant cost and expense to our company. The following are some of the areas that may have a significant impact on our operations.

We are subject to extensive Canadian federal, provincial and municipal environmental regulation. Failure to comply could subject us to fines and other penalties. In addition, the presence or release of hazardous or other harmful substances could lead to claims by third parties and/or governmental orders requiring us to take specific actions such as investigating, controlling and remediating the effects of these substances. We are currently undertaking a voluntary land assessment and remediation (LAR) program covering most of our stations and service centres. This program involves the systematic identification of any contamination at or from these facilities, and, where necessary, the development of remediation plans for our company and adjacent private properties. Any contamination of our properties could limit our ability to sell these assets in the future.

We record a liability for our best estimate of the present value of the future expenditures required to comply with Environment Canada's PCB regulations and for the present value of the future expenditures to complete our LAR program. The future expenditures required to discharge our PCB obligation are expected to be incurred over the period ending 2025, while our LAR expenditures are expected to be incurred over the period ending 2020. Actual future environmental expenditures may vary materially from the estimates used in the calculation of the environmental liabilities on our balance sheet. We do not have insurance coverage for these environmental expenditures.

Under applicable regulations, we expect to incur future expenditures to identify, remove and dispose of asbestos-containing materials installed in some of our facilities. We record an asset retirement obligation for the present value of the estimated future expenditures. The estimates are based on an external, expert study of the current expenditures associated with removing such materials from our facilities. Actual future expenditures may vary materially from the estimates used for the amount of the asset retirement obligation.

There is also risk associated with obtaining governmental approvals, permits, or renewals of existing approvals and permits related to constructing or operating facilities. This may require environmental assessment or result in the imposition of conditions, or both, which could result in delays and cost increases.

We anticipate that all of our future environmental expenditures will continue to be recoverable in future electricity rates. However, any future regulatory decision to disallow or limit the recovery of such costs could have a material adverse effect on our company.

Scientists and public health experts have been studying the possibility that exposure to electric and magnetic fields emanating from power lines and other electric sources may cause health problems. If it were to be concluded that electric and magnetic fields present a health risk, or governments decide to implement exposure limits, we could face litigation, be required to take costly mitigation measures such as relocating some of our facilities or experience difficulties in locating and building new facilities. Any of these could have a material adverse effect on our company.

Risk of Natural and Other Unexpected Occurrences

Our facilities are exposed to the effects of severe weather conditions, natural disasters, man-made events including cyber and physical terrorist type attacks and, potentially, catastrophic events, such as a major accident or incident at a facility of a third party (such as a generating plant) to which our transmission or distribution assets are connected. Although constructed, operated and maintained to industry standards, our facilities may not withstand occurrences of this type in all circumstances. We do not have insurance for damage to our transmission and distribution wires, poles and towers located outside our transmission and distribution stations resulting from these events. Losses from lost revenues and repair costs could be substantial, especially for many of our facilities that are located in remote areas. We could also be subject to claims for damages caused by our failure to transmit or distribute electricity. Our risk is partly mitigated because our transmission system is designed and operated to withstand the loss of any major element and possesses inherent redundancy that provides alternate means to deliver large amounts of power. In the event of a large uninsured loss we would apply to the OEB for recovery of such loss; however, there can be no assurance that the OEB would approve any such applications, in whole or in part, which could have a material adverse effect on our net income.

Risk Associated with Information Technology Infrastructure

Our ability to operate effectively in the Ontario electricity market is in part dependent upon us developing, maintaining and managing complex IT systems which are employed to operate our transmission and distribution facilities, financial and billing systems, and business systems. Our increasing reliance on information systems and expanding data networks increases our exposure to information security threats. We mitigate this risk through various methods including the use of security event management tools on our power and business systems, by separating our power system network from our business system network, by performing scans of our systems for known cyber threats and by providing company-wide awareness training to our personnel. We also engage the services of external experts to evaluate the security of our IT infrastructure and controls. We perform vulnerability assessments on our critical cyber assets and we ensure security and privacy controls are incorporated into new IT capabilities. Although these security and system disaster recovery controls are in place, there can be no guarantee that there will not be system failures or security breaches. Upon occurrence, the focus would shift from prevention to isolation, remediation and recovery until the incident has been fully addressed. Any such system failures or security breaches could have a material adverse effect on our company.

We are currently in the process of a planned phased replacement of key enterprise IT systems. The last phase of this project is underway and will replace our existing billing and customer system with a new CIS. With projects of this size and complexity, there is risk to the Company if the resulting solution encounters performance problems or calculation errors. Any such system problems could have a material adverse effect on our company. To mitigate this risk, extensive testing and user training is taking place. Testing includes performance, system integration, parallel billing (comparing legacy system bill calculation to the new system), and operational/business readiness. Since this system directly impacts our end customers, stringent test exit criteria must be met prior to placing it into production.

Pension Plan Risk

We have a defined benefit registered pension plan for the majority of our employees. Contributions to the pension plan are established by actuarial valuations which are filed with the Financial Services Commission of Ontario on a triennial basis. The most recently filed valuation was prepared as at December 31, 2011 and was filed in May 2012. Our company contributed $148 million in respect of 2011 and approximately $160 million in respect of 2012 to its pension plan to satisfy minimum funding requirements. An additional contribution of $3.8 million was also made in 2011 to complete the funding associated with the partial plan wind-up. Contributions beyond 2012 will depend on investment returns, changes in benefits and actuarial assumptions and may include additional voluntary contributions from time to time. Nevertheless, future contributions are expected to be significant. A determination by the OEB that some of our pension expenditures are not recoverable from customers could have a material adverse effect on our company, and this risk may be exacerbated as the quantum of required pension contributions increase.

Market and Credit Risk

Market risk refers primarily to the risk of loss that results from changes in commodity prices, foreign exchange rates and interest rates. We do not have commodity risk. We do have foreign exchange risk as we enter into agreements to purchase materials and equipment associated with our capital programs and projects that are settled in foreign currencies. This foreign exchange risk is not material. We could in the future decide to issue foreign currency-denominated debt which we would anticipate hedging back to Canadian dollars, consistent with our company's risk management policy. We are exposed to fluctuations in interest rates as our regulated rate of return is derived using a formulaic approach. The OEB-approved adjustment formula for calculating ROE will increase or decrease by 50% of the change between the current Long Canada Bond Forecast and the risk-free rate established at 4.25% and 50% of the change in the spread in 30-year "A"-rated Canadian utility bonds over the 30-year benchmark Government of Canada bond yield established at 1.415%. We estimate that a 1% decrease in the forecasted long-term Government of Canada bond yield used in determining our rate of return would reduce our Transmission Business' net income by approximately $19 million and our Hydro One Networks' Distribution Business' net income by approximately $10 million. Our net income is adversely impacted by rising interest rates as our maturing long-term debt is refinanced at market rates. We periodically utilize interest-rate swap agreements to mitigate elements of interest-rate risk.

Financial assets create a risk that a counterparty will fail to discharge an obligation, causing a financial loss. Derivative financial instruments result in exposure to credit risk, since there is a risk of counterparty default. We monitor and minimize credit risk through various techniques, including dealing with highly-rated counterparties, limiting total exposure levels with individual counterparties, and by entering into master agreements which enable net settlement and by monitoring the financial condition of counterparties. We do not trade in any energy derivatives. We do, however, have interest-rate swap contracts outstanding from time to time. Currently, there are no significant concentrations of credit risk with respect to any class of financial assets. We are required to procure electricity on behalf of competitive retailers and embedded LDCs

for resale to their customers. The resulting concentrations of credit risk are mitigated through the use of various security arrangements, including letters of credit, which are incorporated into our service agreements with these retailers in accordance with the OEB's Retail Settlements Code. The failure to properly manage these risks could have a material adverse effect on our company.

Labour Relations Risk

The substantial majority of our employees are represented by either the Power Workers' Union (PWU) or the Society of Energy Professionals. Over the past several years, significant effort has been expended to increase our flexibility to conduct operations in a more cost-efficient manner. Although we have achieved improved flexibility in our collective agreements, including a reduction in pension benefits for Society staff hired after November 2005 similar to a previous reduction affecting management staff, we may not be able to achieve further improvement. The existing collective agreement with the PWU will expire on March 31, 2013 and the existing Society collective agreement will expire on March 31, 2013. We face financial risks related to our ability to negotiate collective agreements consistent with our rate orders. In addition, in the event of a labour dispute, we could face operational risk related to continued compliance with our licence requirements of providing service to customers. Any of these could have a material adverse effect on our company.

First Nation and Métis Claims Risk

Some of our current and proposed transmission and distribution lines may traverse lands over which First Nations and Métis have aboriginal, treaty or other legal claims. Although we have a recent history of successful negotiations and consultations with First Nations and Métis in Ontario, some communities and/or their citizens have expressed an increasing willingness to assert their claims through the courts, tribunals, or by direct action, which in turn can affect business activities. As a result, there exists uncertainty relating to business operations and project planning which could have an adverse effect on our company.

Risk from Transfer of Assets Located on Reserves

The transfer orders by which we acquired certain of Ontario Hydro's businesses as of April 1, 1999 did not transfer title to some assets located on Reserves. Currently, OEFC holds legal title to these assets and we manage them until we have obtained necessary authorizations to complete the title transfer. To occupy Reserves, we must have valid permits issued by Her Majesty the Queen in the Right of Canada. For each permit, we must negotiate an agreement (in the form of a Memorandum of Understanding) with the First Nation, OEFC and any members of the First Nation who have occupancy rights. The agreement includes provisions whereby the First Nation consents to the federal Department of Aboriginal Affairs and Northern Development issuing a permit. It is difficult to predict the aggregate amount that we may have to pay, either on an annual or one-time basis, to obtain the required agreements from First Nations. However, we anticipate that the amount will exceed the approximately $943,000 that we paid in 2012. OEFC will continue to hold these assets until we are able to negotiate agreements with First Nations and occupants. If we cannot reach satisfactory agreements and obtain federal permits, we may have to relocate these assets to other locations at a cost that could be substantial. In a limited number of cases, it may be necessary to abandon a line and replace it with diesel generation facilities. The costs relating to these assets could have a material adverse effect on our net income if we are not able to recover them in future rate orders.

Risk Associated with Outsourcing Arrangement

Consistent with our strategy of reducing operating costs, we amended and extended our outsourcing services agreement with Inergi, effectively renewing the arrangement until February 28, 2015. If the agreement with Inergi is terminated for any reason, we could be required to incur significant expenses to transfer to another service provider, which could have a material adverse effect on our business, operating results, financial condition or prospects.

Risk from Provincial Ownership of Transmission Corridors

Pursuant to the *Reliable Energy and Consumer Protection Act, 2002*, the Province acquired ownership of our transmission corridor lands underlying our transmission system. Although we have the statutory right to use the transmission corridors, we may be limited in our ability to expand our systems. Also, other uses of the transmission corridors by third parties in conjunction with the operation of our systems may increase safety or environmental risks, which could have an adverse effect on our company.

CRITICAL ACCOUNTING ESTIMATES

The preparation of our Consolidated Financial Statements requires us to make estimates and judgements that affect the reported amounts of assets, liabilities, revenues and costs, and related disclosures of contingencies. We base our estimates and judgements on historical experience, current conditions and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgements about the carrying values of assets and liabilities as well as identifying and assessing our accounting treatment with respect to commitments and contingencies. Actual results may differ from these estimates and judgements under different assumptions or conditions.

We believe the following critical accounting estimates involve the more significant estimates and judgements used in the preparation of our Consolidated Financial Statements:

Regulatory Assets and Liabilities

At December 31, 2012, regulatory assets amounted to $3,127 million and these amounts principally relate to regulatory offsets to pension, deferred income tax, post-retirement and post-employment benefits and environmental liabilities, which are anticipated to be recovered through rates over time. We have also recorded regulatory liabilities amounting to $221 million as at December 31, 2012. These amounts pertain primarily to OEB deferral and variance accounts. These assets and liabilities can be recognized for rate-setting and financial reporting purposes only if the relevant amounts have been approved for inclusion in the rate-setting process by the OEB or if such approval is judged to be probable by management. If management judges that it is no longer probable that the OEB will include a regulatory item in the setting of future rates, the relevant regulatory asset or liability would be charged or credited to results of operations in the period in which that judgement is made.

Environmental Liabilities

We record liabilities and related regulatory assets based on the present value of the estimated future expenditures to be made to satisfy obligations related to legacy environmental contamination inherited upon our de-merger from Ontario Hydro in 1999. These liabilities fall into two main categories: the management of assets contaminated with PCB-laden mineral oils and the assessment and remediation of contaminated lands. In determining the amounts to be recorded as environmental liabilities, we estimate the current cost of completing mitigation work now and make assumptions for when the future expenditures will actually be incurred in order to generate future cash flow information. A long-term inflation assumption of 2% is used to express our current cost estimates as estimated future expenditures. Future estimated LAR expenditures are expected to be incurred over the period ending 2020 and are discounted using factors ranging from 3.57% to 4.87%, depending on the appropriate rate for the period when the particular obligation was recarded. Consistent with the current requirements of Environment Canada's PCB regulations, estimated future PCB remediation expenditures are expected to be incurred over the period ending 2025 and are discounted using factors ranging from 5.14% to 6.25%, depending on the appropriate rate in effect in the period when each obligation was originally recorded.

Recording a liability for such long-term future expenditures requires that many other assumptions be made, such as the number of contaminated properties and the extent of contamination; the number of assets to be inspected, tested and mitigated; oil volumes; contamination levels of equipment that may have PCBs; and the timing of work. All factors used in deriving our environmental liabilities represent management's best estimates based on our planned approach of meeting current legislative and regulatory requirements. These requirements include Environment Canada's regulations governing the management, storage and disposal of PCBs. However, it is reasonably possible that numbers or volumes of contaminated assets, current cost estimates, inflation estimates and the actual pattern of annual future cash flows may differ significantly from our current assumptions. Estimated environmental liabilities are reviewed annually or more frequently if significant changes in regulation or other relevant facts occur. Regulatory changes are reflected when enacted. Estimate changes are accounted for prospectively.

Employee Future Benefits

We provide future benefits to our current and retired employees, including pension, group life insurance, health care and long-term disability.

In accordance with our rate orders, we record pension costs when employer contributions are paid to the pension fund (the Fund) in accordance with the *Pension Benefits Act* (Ontario). Our annual pension contributions in respect of 2012 were approximately $160 million, based on an actuarial valuation effective December 31, 2011. Contributions after 2014 will be based on an actuarial valuation effective no later than December 31, 2014, and will depend on investment returns, changes in benefits or actuarial assumptions. Pension costs are also disclosed in the notes to the Consolidated Financial Statements on an accrual basis. The discount rate used to calculate the accrued benefit obligation, on an accrual accounting basis, is calculated differently from what would be used to determine the funding requirement, and is determined each year end by referring to the most recently available market interest rates based on AA corporate bond yields reflecting the duration of the applicable employee future benefit plan. The discount rates at December 31, 2012 declined to 4.25% from 5.25% used at December 31, 2011, in conjunction with decreases in bond yields over this period. The decrease in discount rates has resulted in a corresponding increase in liabilities for accounting purposes. We also record employee future benefit costs other than pension on an accrual accounting basis. The accrual costs are determined by independent actuaries using the projected benefit method prorated on service and based on assumptions that reflect management's best estimates. The assumptions were determined by management recognizing the recommendations of our actuaries. There were no changes in benefits afforded to employees.

The assumed return on pension plan assets of 6.25% per annum is based on expectations of long-term rates of return at the beginning of the fiscal year and reflects a pension asset mix consistent with the Fund's investment policy. During the year the Fund's target asset mix was 60% equities, 35% fixed income and 5% in alternative assets consisting of real estate and infrastructure. Returns on the respective portfolios are determined with reference to published Canadian and U.S. stock indices and long-term bond and treasury bill indices. The assumed rate of return on pension plan assets reflects our long-term expectations. We believe that this assumption is reasonable because, with the Fund's balanced investment approach, the higher volatility of equity investment returns is intended to be offset by the greater stability of fixed-income and short-term investment returns. The net result, on a long-term basis, is a somewhat lower return than might be expected by investing in equities alone. In the short term, the plan can experience aberrations in actual return. In 2012, the return on pension plan assets of 9.19% was higher than this long-term assumption and was higher than in 2011.

Yields on AA corporate bonds declined by approximately 80 – 100 basis points between December 31, 2011 and December 31, 2012. Based on the duration of the plan's liabilities, discount rates would be 4.25% per annum for each of the pension plan, the post-retirement benefit plan and the post-employment plan. The overall discount rate applied to all plans for liability accounting purposes as at December 31, 2012 was 4.25%.

Further, based on differences between long-term Government of Canada nominal bonds and real return bonds, the implied inflation rate has decreased from 2.0% per annum as at December 31, 2011 to approximately 1.90% per annum as at December 31, 2012. Given the Bank of Canada's commitment to keep long-term inflation between 1.00% and 3.00%, management believes that the current implied rate is reasonable to use as a long-term assumption and as such, has used a 2.0% per annum inflation rate for liability valuation purposes as at December 31, 2012.

The costs of employee future benefits other than pension are determined at the beginning of the year. The costs are based on assumptions for expected claims experience and future health care cost inflation. A 1% increase in the health care cost trends would result in an increase in service cost and interest cost of about $17 million per year and an increase in the year-end obligation of about $246 million.

Employee future benefits are included in labour costs that are either charged to results of operations or capitalized as part of the cost of fixed and intangible assets. Changes in assumptions will affect the accrued benefit obligation of the employee future benefits and the future years' amounts that will be charged to our results of operations or capitalized as part of the cost of fixed and intangible assets.

Asset Impairment

Within our regulated businesses, carrying costs of our other assets are recovered in our revenue requirements and are included in rate base, where they earn a return. Such assets would need to be tested for impairment only in the event that the OEB disallowed recovery or if such a disallowance was judged to be probable. We periodically monitor the assets of our unregulated Telecom Business for indications of impairment. No asset impairments have been recorded to date within any of our businesses.

TRANSITION TO US GAAP

Accounting Framework for External Reporting

In 2011, the OSC and our Board of Directors approved our application to adopt US GAAP as the basis for our accounting, external financial reporting and periodic securities filings, without becoming a Securities and Exchange Commission (SEC) registrant, for our 2012, 2013 and 2014 fiscal years. As a result, our Consolidated Financial Statements and accompanying notes as at, and for the year ended, December 31, 2012 have been prepared in accordance with US GAAP. These are our first US GAAP annual Consolidated Financial Statements. Our first US GAAP unaudited interim Consolidated Financial Statements were as at, and for the three months ended, March 31, 2012.

Our company's Consolidated Financial Statements were prepared in accordance with Part V of the Canadian Institute of Chartered Accountants (CICA) Handbook until December 31, 2011. Canadian GAAP differs in some areas from US GAAP as disclosed in the reconciliation to US GAAP included in Note 24 to the annual Consolidated Financial Statements as at, and for the year ended, December 31, 2012. Descriptions of the effect of the transition from Canadian GAAP to US GAAP on our financial position, financial performance and cash flows as at, and for the year ended, December 31, 2011 are also provided in Note 24 to our annual Consolidated Financial Statements for the year ended December 31, 2012. The accounting policies set out in the annual Consolidated Financial Statements for the year ended December 31, 2012 have been consistently applied to all the periods presented. The comparative figures in respect of 2011 were retrospectively restated effective January 1, 2011 to reflect our adoption of US GAAP.

Accounting Framework for Rate Setting

Consistent with the OSC's decision to approve our adoption of US GAAP, two of our subsidiaries, Hydro One Networks and Hydro One Remote Communities requested that the OEB approve the adoption of US GAAP as the basis for future rate setting and regulatory accounting and reporting in place of its standard modified IFRS basis. The OEB approved Hydro One Networks' request to adopt US GAAP for its regulated transmission and distribution businesses, and approved Hydro One Remote Communities' request to adopt US GAAP as its approved basis for rate setting, all effective January 1, 2012. We did not make a request to adopt US GAAP for rate-setting purposes on behalf of our subsidiary, Hydro One Brampton Networks. Our subsidiary Hydro One Brampton Networks has deferred its adoption of modified IFRS until the fiscal year beginning January 1, 2014, as allowed by the Canadian Accounting Standards Board. Currently, Hydro One Brampton Networks will continue to have its rates set based on Part V of the CICA Handbook until it begins reporting under modified IFRS.

Debt Covenants

None of our financial covenants were impacted by our conversion to US GAAP.

Internal Controls over Financial Reporting and Disclosure Controls and Procedures

Our transition to US GAAP did not result in any significant revisions to our internal controls over financial reporting and disclosure controls and procedures.

Financial Reporting Expertise

Given the similarities between US GAAP and Canadian GAAP for our company, there has also been no significant impact from the transition to US GAAP with respect to financial reporting expertise. Our US GAAP training efforts have been focused on specific areas of difference between the two accounting frameworks and these efforts have been targeted to specific finance staff, senior executive management and the Audit and Finance Committee of our Board of Directors. We continue to provide additional training to our other finance and operational staff, concentrating on communicating the key differences between Canadian and US GAAP at a level of detail that is appropriate to meet their respective needs. During 2013, we will continue to focus our US GAAP training on new accounting and reporting developments and on emerging issues.

Information Systems

Given the similarities between US GAAP and Canadian GAAP, we did not experience any significant impacts from the transition to US GAAP with respect to our information systems.

IFRS

Prior to our adoption of US GAAP as the basis for our accounting, external financial reporting and periodic securities filings, we had planned to adopt IFRS effective January 1, 2012, with comparative restatement of our 2011 results. Accordingly, by mid-2011, we had substantively completed our four-phase IFRS Conversion Project, which included separate diagnostic, design and planning, solution development, and implementation phases. Our IFRS conversion project involved, among other initiatives, a detailed assessment of the effects of IFRS on our financial statements, a review and upgrade of our information systems to meet IFRS requirements, an assessment of our internal controls over financial reporting and disclosure controls and processes, as well as training of our key finance and operational staff.

As a result of our 2011 decision to adopt US GAAP, our IFRS Conversion Project efforts were effectively halted. However, our IFRS conversion work has been, and will continue to be, managed in such a way that it can effectively be restarted if a future transition to IFRS is required. We continue to monitor major accounting developments arising from initiatives of the international standard setter, particularly as several major projects are joint efforts with the US Financial Accounting Standards Board.

Training of our key finance and operational staff commenced in 2007, and continues on a reduced but ongoing basis, as we have certain subsidiaries that are required to prepare their own separate financial statements in accordance with IFRS. IFRS training was also previously provided to our Audit and Finance Committee and senior executive management. In 2013, we will continue to monitor new IFRS accounting and reporting developments and emerging issues and will provide IFRS training to specific staff as applicable.

Our company has the customary financial covenants normally associated with long-term debt. Among other things, our long-term debt covenants limit our permissible debt as a percentage of our total capitalization. Depending on the outcome of various international standard setting initiatives, including the International Accounting Standards Board's (IASB) Rate Regulated Accounting Project, a potential future adoption of IFRS could result in changes to our financial position and increased volatility in our results of operations that could impact our debt covenants. We continue to monitor the potential impact that an IFRS conversion could have under various scenarios.

As part of a company-wide information systems improvement project, many of our major financial systems were replaced in 2008 and 2009. Our new financial systems were designed with maximum flexibility given the uncertainty of the outcome of certain impactive IASB projects. Our financial systems have the ability and capacity to handle current accounting and reporting processes in accordance with IFRS, should that be required in the future.

DISCLOSURE CONTROLS AND INTERNAL CONTROLS OVER FINANCIAL REPORTING (ICFR)

To optimize our customer service operations, we have started the final major phase of our planned SAP enterprise-wide information system by initiating our CIS Project. This new system will increase productivity by replacing multiple legacy applications currently providing service to our distribution customers and key constituents for billing, customer contacts, field services, settlements and customer choice administration. With the design phase complete, the CIS Project is currently in the system integration phase. Internal controls have been documented and will be tested for adequacy and effectiveness with any remediation effort to be completed prior to the go-live date in 2013. In addition to the benefits associated with our CIS, we continue to leverage our other SAP enterprise systems to gain other productivity improvements.

In compliance with the requirements of National Instrument 52-109, *Certification of Disclosure in Issuers' Annual and Interim Filings*, our Certifying Officers have reviewed and certified the Consolidated Financial Statements for the year ended December 31, 2012, together with other financial information included in our annual securities filings. Our Certifying Officers have also certified that disclosure controls and procedures (DC&P) have been designed to provide reasonable assurance that material information relating to our company is made known within our company. Based on the evaluation of the design and operation of our DC&P, our Certifying Officers concluded that our DC&P was effective as at December 31, 2012. Further, our Certifying Officers have also certified that our ICFRs have been designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of Consolidated Financial Statements. Based on the evaluation of the design and operating effectiveness of our company's ICFR, our Certifying Officers concluded that our ICFR was effective as at December 31, 2012.

SELECTED ANNUAL INFORMATION

The following table sets forth audited annual information for each of the three years ended December 31, 2012, 2011 and 2010. This information has been derived from our audited annual Consolidated Financial Statements.

Consolidated Statements of Operations

Year ended December 31 (millions of dollars, except amounts per share)	**2012**	2011	2010[1]
Revenues	**5,728**	5,471	5,124
Net income	**745**	641	591
Basic and fully diluted earnings per common share	**7,280**	6,228	5,727
Cash dividends per common share	**3,523**	1,500	100
Cash dividends per preferred share	**1.375**	1.375	1.375

Consolidated Balance Sheets

December 31 (millions of dollars)	**2012**	2011	2010
Total assets	**20,811**	18,836	17,344
Total long-term debt	**8,479**	8,008	7,783

[1]Based on Canadian GAAP. US GAAP results would not differ significantly.

OUTLOOK

To achieve our mission and vision to be an innovative and trusted company delivering electricity safely, reliably and efficiently to create value for our customers, we will continue to concentrate on our strategic objectives of safety, customer satisfaction, continuous innovation, reliability, protection of the environment, employee engagement, shareholder value and productivity and cost-effectiveness. Given the nature of the work undertaken by our employees and contractors, safety remains our top priority. We will continue to focus on creating an injury-free workplace and maintaining public safety through several health and safety initiatives.

We will continue to focus our efforts to improve our customers' satisfaction by meeting the unique needs of our diverse customer base through dialogue to understand their needs. We will install innovative solutions that improve the reliability and efficiency of the transmission and distribution systems and provide our customers more capability to manage their own costs. Most importantly, we are focused on becoming the customer's trusted advisor by providing access to specialized energy conservation teams to discuss the customer's opportunities to lower consumption, and through the use of a special team of agents to handle distributed generator inquiries and requirements.

Our assets are in the midst of a demographic change with an increasing proportion of assets reaching end-of-life and an increasing average asset age. Our focus is to address aging infrastructure, and to make needed asset replacement and maintenance investments, to maintain current and future system reliability for customers, within the policy set by the OEB. We will invest in technology that will provide us with real time asset condition and performance data giving us the visibility to make asset optimization life-cycle decisions, and opportunities through planning and scheduling data to improve materials procurement and to deploy work crews to better manage work programs to meet customer needs.

It is expected that the implementation of new asset management tools, such as Asset Analytics and Asset Investment Planning, will enhance risk-based investment planning, which considers such factors as asset condition, safety, performance, system function, customer impact, and statutory requirements allowing for targeted investment.

We will also continue to strive for productivity through efficiency and effective management of costs, which is key to achieving value for our customers and our shareholder.

Over the last four years, we have replaced most of our core information technology systems with an enterprise-wide IT system. We will leverage this investment as a platform for further effectiveness and efficiency gains, including enhancements in strategic sourcing. Further development of the existing IT platform will provide tools which are being developed to allow our company to effectively plan and reprioritize work and integrate customers' needs into multi-year investment plans. The outcomes are consistent with the OEB's direction in its new Outcomes-Based Approach to regulation.

We will be implementing the new CIS in 2013 that will improve customer service and corporate productivity by allowing the earlier investments in SAP to operate as an integrated platform. In addition, the first elements of the next generation of work delivery to be introduced through the Workflow of the Future Program in 2013 and 2014, and the use of information within the SAP systems, are expected to improve field-level productivity.

We are planning significant investments in transmission and distribution infrastructure and we will continue to focus on the operating and economic performance of our core utility operations in the provision of safe, cost-effective and reliable electricity delivery services to our customers, and in providing increasing enterprise value to the people of the province of Ontario. Productivity, value for money and improved employee and customer communications will be key areas of focus. We will continue to connect and support DG and investments made consistent with the LTEP.

Significant opportunity resides with smart meters and the proliferation of an ADS, including energy efficiency, demand response and distributed-resources technologies. We will invest in the development of an ADS and related grid modernization standards, customer demand work (connections and upgrades), smart meters, DG connections, including station upgrades, protection and control, new lines and some contestable work, for which the Company will receive capital contributions. There is little flexibility to reduce this work as most of it is customer demand driven.

As part of our new ADS, a new DMS will provide a monitoring and centralized control capability similar to that which already exists in the transmission system, and in selected areas of the distribution system. The new DMS was introduced in the Owen Sound pilot area and it will be expanded over time, as warranted. Future enhancements will also integrate the Outage Response Management System with the Advanced Meter Infrastructure (i.e. smart meters) and with the DMS, to reduce System Average Interruption Duration Index and System Average Interruption Frequency Index.

The actual timing and expenditures in our business plan are predicated on obtaining various approvals including: OEB approvals and environmental assessment approvals; successful negotiations with customers, neighbouring utilities and other stakeholders; and consultations with First Nations and Métis communities.

As stewards of significant electricity assets, we are committed to the protection and sustainment of the environment for future generations. We are working towards being an environmental leader in our industry, by distributing clean and renewable energy, by upgrading our electricity grid, by minimizing the impacts of our own operations, and by ensuring that environmental factors are considered in making our business decisions.

Key enablers of the successful implementation of our work programs are our human and material resourcing strategies. Our human resource strategy is focused on hiring through our apprenticeship program and our association with universities, colleges and our unions, as well as skills development and retention, including earlier identification and more rapid development of staff who demonstrate management potential. Effective use of human resources and ensuring correct skills will be critical to attaining the balance between meeting the asset needs and mitigating rate impact on the customer. Although our work program is assumed to grow moderately over the 2013 and 2014 years, no increase in regular staff numbers is anticipated over that period. With regard to materials, we are seeing a need for increasing lead times and costs as market shortages emerge globally. Consequently, materials sourcing strategies continue to be developed and implemented to ensure the availability of materials to support our work programs.

We remain committed to a prudent and measured approach to distribution rationalization. We have considered and will continue to consider and respond to opportunities for acquisitions or divestitures, on a voluntary and commercial basis. Our plan does not include funding for LDC acquisitions or assume any disposition of our service territory. These opportunities will be managed as they arise. Our plan also does not incorporate any projects related to competitive transmission. However, as leaders in the sector, we plan to bid on key projects. The OEB notes in its *Framework for Transmission Project Development Plans* that where projects are otherwise equivalent or close in other factors, information such as socio-economic benefits, including First Nations involvement, could prove decisive in a competitive bid. As such, First Nations involvement in competitive bids is likely to become more prevalent.

APPOINTMENT OF CARMINE MARCELLO

On November 14, 2012, our Board of Directors appointed Carmine Marcello to the role of President and Chief Executive Officer, effective January 1, 2013. Mr. Marcello assumes his responsibilities following the planned retirement of outgoing President and Chief Executive Officer, Laura Formusa. Mr. Marcello has over 25 years' experience with our company as a senior executive, strategic planner and advisor on transmission and distribution utility processes in the electric utility industry.

APPOINTMENT OF YEZDI PAVRI

On December 6, 2012, Yezdi Pavri was appointed to our Board of Directors. Mr. Pavri is a Chartered Accountant and a former Vice-Chairman of Deloitte Canada. Mr. Pavri currently holds the position of Chair of the Board of Trustees of the United Way of Toronto.

FORWARD-LOOKING STATEMENTS AND INFORMATION

Our oral and written public communications, including this document, often contain forward-looking statements that are based on current expectations, estimates, forecasts and projections about our business and the industry in which we operate, and include beliefs and assumptions made by the management of our company. Such statements include, but are not limited to: statements about our strategy, including our strategic objectives; statements regarding our transmission and distribution rates; statements regarding load changes and associated impacts; statements regarding CDM programs and targets; the estimated impact of changes in the forecasted long-term Government of Canada bond yield (used in determining our regulated rate of return) on our results of operations; statements related to economic conditions; expectations regarding energy-related revenues and profit and their trend; statements related to the GEA, the IPSP and the Ministry's LTEP and Supply Mix Directive, including additional investments arising therefrom and the timing and content of OPA recommendations; statements regarding our liquidity and capital resources and operational requirements; statements about our standby credit facility; expectations regarding our financing activities; statements regarding our maturing debt; statements regarding our ongoing and planned projects and/or initiatives including the expected results of these projects and/or initiatives and their completion dates; expectations regarding the recoverability of large capital expenditures; statements regarding expected future capital and development expenditures, the timing of these expenditures and our investment plans; statements regarding contractual obligations and other commercial commitments; statements related to the OEB, including the renewed regulatory framework and revenue decoupling; statements regarding future pension contributions, our pension plan and actuarial valuation; statements about our outsourcing arrangement with Inergi; statements relating to US GAAP and our adoption of US GAAP; statements regarding accounting-related international standard setting initiatives, including the potential future adoption of IFRS and its associated impacts as well as our training and conversion plans; statements related to our agreement with the SON; statements related to our outlook including statements regarding our approach to distribution rationalization; and statements related to the FIT program. Words such as "expect", "anticipate", "intend", "attempt", "may", "plan", "will", "believe", "seek", "estimate", "goal", "aim", "target", and variations of such words and similar expressions are intended to identify such forward-looking statements. These statements are not guarantees of future performance and involve assumptions and risks and uncertainties that are difficult to predict. Therefore, actual outcomes and results may differ materially from what is expressed, implied or forecasted in such forward-looking statements. We do not intend, and we disclaim any obligation, to update any forward-looking statements, except as required by law.

These forward-looking statements are based on a variety of factors and assumptions including, but not limited to the following: no unforeseen changes in the legislative and operating framework for Ontario's electricity market; favourable decisions from the OEB and other regulatory bodies concerning outstanding rate and other applications; no delays in obtaining required approvals; no unforeseen changes in rate orders or rate structures for our Distribution and Transmission businesses; a stable regulatory environment; no unfavourable changes in environmental regulation; and no significant event occurring outside the ordinary course of business. These assumptions are based on information currently available to us, including information obtained from third-party sources. Actual results may differ materially from those predicted by such forward-looking statements. While we do not know what impact any of these differences may have, our business, results of operations, financial

condition and our credit stability may be materially adversely affected. Factors that could cause actual results or outcomes to differ materially from the results expressed or implied by forward-looking statements include, among other things:

- the impact of the GEA and the Province's Long-Term Energy Plan, including unexpected expenditures arising therefrom;
- the risk that unexpected capital expenditures may be needed to support renewable generation or resolve unforeseen technical issues;
- the risks associated with the impending expiry of our collective agreements with both the Society and the PWU;
- the risk that previously granted regulatory approvals may be subsequently challenged, appealed or overturned;
- the risks associated with the OEB's competitive transmission project development planning process;
- public opposition to and delays or denials of the requisite approvals and accommodations for our planned projects;
- the risks associated with being controlled by the Province including the possibility that the Province may make declarations pursuant to the memorandum of agreement, as well as potential conflicts of interest that may arise between us, the Province and related parties;
- the risks associated with being subject to extensive regulation including risks associated with OEB action or inaction;
- unanticipated changes in electricity demand or in our costs;
- the risk that we are not able to arrange sufficient cost-effective financing to repay maturing debt and to fund capital expenditures and other obligations;
- the risks associated with the execution of our capital and operation, maintenance and administration programs necessary to maintain the performance of our aging asset base;
- the result of regulatory decisions regarding our revenue requirements, cost recovery and rates;
- the risk to our facilities posed by severe weather conditions, natural disasters or catastrophic events and our limited insurance coverage for losses resulting from these events;
- future interest rates, future investment returns, inflation, and changes in benefits and actuarial assumptions;
- the risks related to our workforce demographic and our potential inability to attract and retain qualified personnel;
- the risks associated with information system security, with maintaining a complex information technology system infrastructure, and with transitioning key enterprise IT systems;
- the risk that the presence or release of hazardous or harmful substances could lead to claims by third parties and/or governmental orders;
- the risk that future environmental expenditures are not recoverable in future electricity rates;
- the risk that it may be determined that exposure to electric and magnetic fields emanating from power lines and other electric sources may cause health problems;
- the risks associated with changes in interest rates;
- the risks of counterparty default on our outstanding derivative contracts;
- the risks associated with current economic uncertainty and financial market volatility;
- the risk that our long-term credit rating would deteriorate;
- the risk that we may incur significant costs associated with transferring assets located on Indian lands;
- the risks associated with the fact that some of our current and proposed transmission and distribution lines may traverse lands which First Nations and Métis have aboriginal, treaty or other legal claims;
- the potential that we may incur significant expenses to replace some or all of the functions currently outsourced if our agreement with Inergi is terminated; and
- the impact of the ownership by the Province of lands underlying our transmission system.

We caution the reader that the above list of factors is not exhaustive. Some of these and other factors are discussed in more detail in the section "Risk Management and Risk Factors" in this Management's Discussion and Analysis (MD&A). You should review this section in detail.

In addition, we caution the reader that information provided in this MD&A regarding our outlook on certain matters, including future expenditures, is provided in order to give context to the nature of some of our future plans and may not be appropriate for other purposes.

This MD&A is dated as at February 14, 2013. Additional information about our company, including our Annual Information Form, is available on SEDAR at www.sedar.com.

MANAGEMENT'S REPORT

The Consolidated Financial Statements, Management's Discussion and Analysis (MD&A) and related financial information presented in this Annual Report have been prepared by the management of Hydro One Inc. (Hydro One or the Company). Management is responsible for the integrity, consistency and reliability of all such information presented. The Consolidated Financial Statements have been prepared in accordance with United States Generally Accepted Accounting Principles and applicable securities legislation. The MD&A has been prepared in accordance with National Instrument 51-102, Part 5.

The preparation of the Consolidated Financial Statements and information in the MD&A involves the use of estimates and assumptions based on management's judgement, particularly when transactions affecting the current accounting period cannot be finalized with certainty until future periods. Estimates and assumptions are based on historical experience, current conditions and various other assumptions believed to be reasonable in the circumstances, with critical analysis of the significant accounting policies followed by the Company as described in Note 2 to the Consolidated Financial Statements. The preparation of the Consolidated Financial Statements and the MD&A includes information regarding the estimated impact of future events and transactions. The MD&A also includes information regarding sources of liquidity and capital resources, operating trends, risks and uncertainties. Actual results in the future may differ materially from the present assessment of this information because future events and circumstances may not occur as expected. The Consolidated Financial Statements and MD&A have been properly prepared within reasonable limits of materiality and in light of information up to February 14, 2013.

In meeting its responsibility for the reliability of financial information, management maintains and relies on a comprehensive system of internal control and internal audit. The system of internal control includes a written corporate conduct policy; implementation of a risk management framework; effective segregation of duties and delegation of authorities; and sound and conservative accounting policies that are regularly reviewed. This structure is designed to provide reasonable assurance that assets are safeguarded and that reliable information is available on a timely basis. In addition, internal and disclosure controls have been documented, evaluated, tested and identified consistent with National Instrument 52-109 (Bill 198). The effectiveness of these internal controls is evaluated and findings are reported to management and the Audit and Finance Committee of the Hydro One Board of Directors, as required.

The Consolidated Financial Statements have been examined by KPMG LLP, independent external auditors appointed by the Hydro One Board of Directors. The external auditors' responsibility is to express their opinion on whether the Consolidated Financial Statements are fairly presented in accordance with United States Generally Accepted Accounting Principles. The Independent Auditors' Report outlines the scope of their examination and their opinion.

The Hydro One Board of Directors, through its Audit and Finance Committee, is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal controls. The Audit and Finance Committee of Hydro One met periodically with management, the internal auditors and the external auditors to satisfy itself that each group had properly discharged its respective responsibility and to review the Consolidated Financial Statements before recommending approval by the Board of Directors. The external auditors had direct and full access to the Audit and Finance Committee, with and without the presence of management, to discuss their audit and their findings as to the integrity of the financial reporting and the effectiveness of the system of internal controls.

The Company's President and Chief Executive Officer and Executive Vice-President and Chief Financial Officer have certified Hydro One's annual Consolidated Financial Statements and annual MD&A filed under provincial securities legislation, related disclosure controls and procedures and the design and effectiveness of related internal controls over financial reporting pursuant to National Instrument 52-109.

On behalf of Hydro One Inc.'s management:

Carmine Marcello
President and Chief Executive Officer

Sandy Struthers
Chief Administration Officer and Chief Financial Officer

INDEPENDENT AUDITORS' REPORT

To the Shareholder of Hydro One Inc.

We have audited the accompanying consolidated financial statements of Hydro One Inc., which comprise the consolidated balance sheets as at December 31, 2012 and December 31, 2011, the consolidated statements of operations and comprehensive income, changes in shareholder's equity and cash flows for the years ended December 31, 2012 and December 31, 2011, and notes, comprising a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with United States Generally Accepted Accounting Principles, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the consolidated financial position of Hydro One Inc. as at December 31, 2012 and December 31, 2011, and its consolidated statements of operations and comprehensive income, changes in shareholder's equity and cash flows for the years ended December 31, 2012 and December 31, 2011 in accordance with United States Generally Accepted Accounting Principles.

KPMG LLP

Chartered Accountants, Licensed Public Accountants

Toronto, Canada
February 14, 2013

CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME

Year ended December 31 (millions of dollars, except per share amounts)	**2012**	2011
Revenues		*(Note 24)*
Distribution (includes $155 related party revenues; 2011 – $155) *(Note 19)*	**4,184**	4,019
Transmission (includes $1,482 related party revenues; 2011 – $1,372) *(Note 19)*	**1,482**	1,389
Other	**62**	63
	5,728	5,471
Costs		
Purchased power (includes $2,409 related party costs; 2011 – $2,427) *(Note 19)*	**2,774**	2,628
Operation, maintenance and administration *(Note 19)*	**1,071**	1,092
Depreciation and amortization *(Note 4)*	**659**	616
	4,504	4,336
Income before financing charges and provision for payments in lieu of corporate income taxes	**1,224**	1,135
Financing charges *(Note 5)*	**358**	344
Income before provision for payments in lieu of corporate income taxes	**866**	791
Provision for payments in lieu of corporate income taxes *(Notes 6, 19)*	**121**	150
Net income	**745**	641
Other comprehensive income	**1**	–
Comprehensive income	**746**	641
Basic and fully diluted earnings per common share *(dollars) (Note 17)*	**7,280**	6,228
Dividends per common share declared *(dollars) (Note 18)*	**3,523**	1,500

See accompanying notes to Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS

December 31 (millions of dollars)	**2012**	2011
Assets		*(Note 24)*
Current assets:		
Short-term investments *(Note 12)*	**195**	228
Accounts receivable (net of allowance for doubtful accounts – $23; 2011 – $18) *(Note 7)*	**845**	805
Due from related parties *(Note 19)*	**154**	156
Regulatory assets *(Note 10)*	**29**	24
Materials and supplies	**23**	25
Deferred income tax assets *(Note 6)*	**18**	19
Derivative instruments *(Note 12)*	**–**	1
Other	**22**	19
	1,286	1,277
Property, plant and equipment *(Note 8)*:		
Property, plant and equipment in service	**22,650**	21,008
Less: accumulated depreciation	**8,145**	7,679
	14,505	13,329
Construction in progress	**1,055**	1,436
Future use land, components and spares	**147**	138
	15,707	14,903
Other long-term assets:		
Regulatory assets *(Note 10)*	**3,098**	1,966
Long-term investment *(Notes 11, 12, 19)*	**251**	250
Intangible assets (net of accumulated amortization – $305; 2011 – $257) *(Note 9)*	**267**	224
Goodwill	**133**	133
Deferred debt costs	**34**	32
Derivative instruments *(Note 12)*	**19**	33
Deferred income tax assets *(Note 6)*	**14**	17
Other	**2**	1
	3,818	2,656
Total assets	**20,811**	18,836

See accompanying notes to Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS (continued)

December 31 (millions of dollars, except number of shares)	**2012**	2011 *(Note 24)*
Liabilities		
Current liabilities:		
Bank indebtedness *(Note 12)*	**42**	39
Accounts payable	**140**	154
Accrued liabilities *(Notes 6, 14, 15)*	**582**	575
Due to related parties *(Note 19)*	**257**	342
Accrued interest	**95**	85
Regulatory liabilities *(Note 10)*	**40**	25
Long-term debt payable within one year *(Notes 11, 12)*	**600**	600
	1,756	1,820
Long-term debt (includes $769 measured at fair value; 2011 – $783) *(Notes 11, 12)*	**7,879**	7,408
Other long-term liabilities:		
Post-retirement and post-employment benefit liability *(Note 14)*	**1,416**	1,163
Deferred income tax liabilities *(Note 6)*	**944**	758
Pension benefit liability *(Note 14)*	**1,515**	779
Environmental liabilities *(Note 15)*	**227**	235
Regulatory liabilities *(Note 10)*	**181**	169
Net unamortized debt premiums	**23**	23
Asset retirement obligations *(Note 16)*	**15**	15
Long-term accounts payable and other liabilities	**25**	12
	4,346	3,154
Total liabilities	**13,981**	12,382
Contingencies and commitments (Notes 21, 22)		
Preferred shares (authorized: unlimited; issued: 12,920,000) *(Notes 17, 18)*	**323**	323
Shareholder's Equity		
Common shares (authorized: unlimited; issued: 100,000) *(Notes 17, 18)*	**3,314**	3,314
Retained earnings	**3,202**	2,827
Accumulated other comprehensive loss	**(9)**	(10)
Total shareholder's equity	**6,507**	6,131
Total liabilities, preferred shares and shareholder's equity	**20,811**	18,836

See accompanying notes to Consolidated Financial Statements.

On behalf of the Board of Directors:

James Arnett
Chair

Michael J. Mueller
Chair, Audit and Finance Committee

CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDER'S EQUITY

Year ended December 31, 2012 (millions of dollars)	**Common Shares**	**Retained Earnings**	**Accumulated Other Comprehensive Loss**	**Total Shareholder's Equity**
January 1, 2012	**3,314**	**2,827**	**(10)**	**6,131**
Net income	**–**	**745**	**–**	**745**
Other comprehensive income	**–**	**–**	**1**	**1**
Dividends on preferred shares	**–**	**(18)**	**–**	**(18)**
Dividends on common shares	**–**	**(352)**	**–**	**(352)**
December 31, 2012	**3,314**	**3,202**	**(9)**	**6,507**

Year ended December 31, 2011 (millions of dollars) (Note 24)	Common Shares	Retained Earnings	Accumulated Other Comprehensive Loss	Total Shareholder's Equity
January 1, 2011	3,314	2,354	(10)	5,658
Net income	–	641	–	641
Other comprehensive income	–	–	–	–
Dividends on preferred shares	–	(18)	–	(18)
Dividends on common shares	–	(150)	–	(150)
December 31, 2011	3,314	2,827	(10)	6,131

See accompanying notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

Year ended December 31 (millions of dollars)	**2012**	2011
Operating activities		*(Note 24)*
Net income	**745**	641
Environmental expenditures	**(18)**	(16)
Adjustments for non-cash items:		
Depreciation and amortization (excluding removal costs)	**589**	550
Regulatory assets and liabilities	**12**	47
Deferred income taxes	**(9)**	(12)
Asset retirement obligations	**–**	4
Other	**6**	9
Changes in non-cash balances related to operations *(Note 20)*	**(40)**	184
Net cash from operating activities	**1,285**	1,407
Financing activities		
Long-term debt issued	**1,085**	700
Long-term debt retired	**(600)**	(500)
Dividends paid	**(370)**	(168)
Change in bank indebtedness	**3**	39
Other	**(1)**	(4)
Net cash from (used in) financing activities	**117**	67
Investing activities		
Capital expenditures		
Property, plant and equipment	**(1,363)**	(1,371)
Intangible assets	**(91)**	(76)
Other	**19**	29
Net cash used in investing activities	**(1,435)**	(1,418)
Net change in cash and cash equivalents	**(33)**	56
Cash and cash equivalents, beginning of year	**228**	172
Cash and cash equivalents, end of year	**195**	228

See accompanying notes to Consolidated Financial Statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. DESCRIPTION OF THE BUSINESS

Hydro One Inc. (Hydro One or the Company) was incorporated on December 1, 1998, under the *Business Corporations Act (Ontario)* and is wholly owned by the Province of Ontario (Province). The principal businesses of Hydro One are the transmission and distribution of electricity to customers within Ontario. These businesses are regulated by the Ontario Energy Board (OEB).

2. SIGNIFICANT ACCOUNTING POLICIES

Basis of Consolidation

These Consolidated Financial Statements include the accounts of the Company and its wholly-owned subsidiaries: Hydro One Networks Inc. (Hydro One Networks), Hydro One Remote Communities Inc. (Hydro One Remote Communities), Hydro One Brampton Networks Inc. (Hydro One Brampton Networks), Hydro One Telecom Inc. (Hydro One Telecom), Hydro One Lake Erie Link Management Inc., and Hydro One Lake Erie Link Company Inc.

Intercompany transactions and balances have been eliminated.

Basis of Accounting

These Consolidated Financial Statements are prepared and presented in accordance with United States (US) Generally Accepted Accounting Principles (GAAP) and in Canadian dollars. These statements are to be read in conjunction with Note 24 – Transition to US GAAP, which discloses information on the Canadian GAAP per Part V of the CICA Handbook (Canadian GAAP) to US GAAP transition and related reconciliations from Canadian GAAP to US GAAP. The results of operations for the year ended December 31, 2011 and the Consolidated Balance Sheet at December 31, 2011 have been restated under US GAAP for comparative purposes. The Company's Consolidated Financial Statements were previously prepared using Canadian GAAP.

Hydro One performed an evaluation of subsequent events for the accompanying Consolidated Financial Statements and notes through to February 14, 2013, the date these Consolidated Financial Statements were issued, to determine whether the circumstances warranted recognition and disclosure of any events or transactions. No such events or transactions were identified.

Use of Management Estimates

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues, expenses, gains and losses during the reporting periods. Management evaluates these estimates on an ongoing basis based upon: historical experience; current conditions; and assumptions believed to be reasonable at the time the assumptions are made with any adjustments being recognized in results of operations in the period they arise. Significant estimates relate to regulatory assets and regulatory liabilities, environmental liabilities, pension benefits, post-retirement and post-employment benefits, asset retirement obligations (AROs), goodwill and asset impairments, contingencies, unbilled revenues, allowance for doubtful accounts, derivative instruments, and deferred income tax assets and liabilities. Actual results may differ significantly from these estimates, which may be impacted by future decisions made by the OEB or the Province.

Rate Setting

The Company's consolidated Distribution Business includes the separately regulated distribution businesses of Hydro One Networks, Hydro One Brampton Networks, and Hydro One Remote Communities. The OEB has approved US GAAP as the basis for rate setting for Hydro One Networks' Transmission and Distribution businesses and by Hydro One Remote Communities all effective January 1, 2012. Hydro One Brampton Networks' rates are currently set under Canadian GAAP, and are expected to be set under the OEB's modified International Financial Reporting Standards (IFRS) framework commencing in 2015, once its current Incentive Regulation Mechanism (IRM) period is complete.

Transmission

In May 2010, Hydro One Networks filed a cost-of-service application for 2011 and 2012 transmission rates in continued support of the Company's aging critical infrastructure and the supply mix objectives for generation, including off-coal initiatives and initiation of investments in support of the Green Energy Act (GEA). This application sought the approval of revenue requirements of approximately $1,446 million for 2011 and $1,547 million for 2012.

In December 2010, the OEB approved revenue requirements of $1,346 million for 2011 and $1,658 million for 2012. The approved 2012 revenue requirement was higher than that applied for, reflecting OEB direction to Hydro One to adopt a cost capitalization policy based on modified IFRS. This adjustment was subsequently reversed, when the OEB approved the use of US GAAP for transmission rate-setting purposes beginning January 1, 2012. Consequently, the OEB approved a revenue requirement of $1,418 million for 2012, along with new 2012 uniform transmission rates, with an effective date of January 1, 2012.

Distribution

In 2009, Hydro One Networks filed a cost-of-service application with the OEB for 2011 distribution rates, seeking approval for a revenue requirement of approximately $1,264 million. The application reflected the Company's plan to invest in its network assets to meet objectives regarding public and employee safety, regulatory and legislative compliance, maintenance of system security and reliability of system growth requirements, and to make investments required by the GEA. In April 2010, the OEB approved a revenue requirement of $1,236 million for 2011. The OEB also approved certain distribution regulatory account balances sought by Hydro One Networks in its application, including retail settlement variance accounts, retail cost variance accounts and smart meters. In November 2010, the OEB issued its cost-of-capital parameter updates for rates effective January 1, 2011. A lowering of the return on equity produced a revised revenue requirement of $1,218 million. The approved 2011 revenue requirement resulted in an average distribution rate increase of approximately 8.7% for 2011. Hydro One Networks elected to retain the same distribution rates for 2012 as approved by the OEB for the 2011 rate year.

In 2010, Hydro One Brampton Networks filed a cost-of-service application with the OEB for 2011 distribution rates, seeking approval for a revenue requirement of approximately $63 million. In 2011, the OEB approved a revenue requirement of approximately $60 million for 2011, with an effective date of January 1, 2011. The reduced approved revenue requirement included a reduction to approved operation, maintenance and administration costs. In September 2011, Hydro One Brampton Networks filed an IRM application with the OEB for 2012 distribution rates, with an effective date of January 1, 2012. In January 2012, the OEB released a decision that resulted in a reduction in distribution rates of approximately 13.2% for 2012. These rate reductions were primarily due to OEB-approved adjustments to depreciation rates.

In October 2010, Hydro One Remote Communities filed an IRM application with the OEB for 2011 rates. In March 2011, the OEB approved an increase of approximately 0.4% to basic rates for the distribution and generation of electricity, with an effective date of May 1, 2011. In November 2011, Hydro One Remote Communities filed an IRM application with the OEB for 2012 rates. In March 2012, the OEB approved an increase of approximately 1.1% to basic rates for the distribution and generation of electricity, with an effective date of May 1, 2012.

Regulatory Accounting

The OEB has the general power to include or exclude revenues, costs, gains or losses in the rates of a specific period, resulting in a change in the timing of accounting recognition from that which would have applied in an unregulated company. Such change in timing involves the application of rate-regulated accounting, giving rise to the recognition of regulatory assets and liabilities. The Company's regulatory assets represent certain amounts receivable from future customers and costs that have been deferred for accounting purposes because it is probable that they will be recovered in future rates. In addition, the Company has recorded regulatory liabilities that generally represent amounts that are refundable to future electricity customers. The Company continually assesses the likelihood of recovery of each of its regulatory assets and continues to believe that it is probable that the OEB will factor its regulatory assets and liabilities into the setting of future rates. If, at some future date, the Company judges that it is no longer probable that the OEB will include a regulatory asset or liability in setting future rates, the appropriate carrying amount will be reflected in results of operations in the period that the assessment is made.

Cash and Cash Equivalents

Cash and cash equivalents include cash and short-term investments. Short-term investments have an original maturity of three months or less.

Revenue Recognition

Transmission revenues are collected through OEB-approved rates, which are based on an approved revenue requirement that includes a rate of return. Such revenue is recognized as electricity is transmitted and delivered to customers.

Distribution revenues are recognized on an accrual basis and include billed and unbilled revenues. Distribution revenues attributable to the delivery of electricity are based on OEB-approved distribution rates and are recognized as electricity is delivered to customers. The Company estimates monthly revenue for a period based on wholesale electricity purchases because customer meters are not generally read at the end of each month. At the end of each month, the electricity delivered to customers, but not billed, is estimated and revenue is recognized. The unbilled revenue estimate is affected by energy demand, weather, line losses and changes in the composition of customer classes.

Distribution revenue also includes an amount relating to rate protection for rural, residential and remote customers, which is received from the Independent Electricity System Operator (IESO) based on a standardized customer rate that is approved by the OEB. Current legislation provides rate protection for prescribed classes of rural, residential and remote consumers by reducing the electricity rates that would otherwise apply.

Revenues also include amounts related to sales of other services and equipment. Such revenue is recognized as services are rendered or as equipment is delivered.

Revenues are recorded net of indirect taxes.

Accounts Receivable and Allowance for Doubtful Accounts

Accounts receivable are recorded at the invoiced amount or net realizable value, if unbilled. Overdue amounts related to regulated billings bear interest at OEB-approved rates. The allowance for doubtful accounts reflects the Company's best estimate of losses on accounts receivable balances. The allowance is based on accounts receivable aging, historical experience and other currently available information. The Company estimates the allowance for doubtful accounts on customer receivables by applying internally developed loss rates to the outstanding receivable balances by risk segment. Risk segments represent groups of customers with similar credit quality indicators and are computed based on various attributes, including number of days receivables are past due, delinquency of balances and payment history. Loss rates applied to the accounts receivable balances are based on historical average write-offs as a percentage of accounts receivable in each risk segment. An account is considered delinquent if the amount billed is not received within 120 days of the invoiced date. Accounts receivable are written off against the allowance when they are deemed uncollectible. The existing allowance for uncollectible accounts will continue to be affected by changes in volume, prices and economic conditions.

Corporate Income Taxes

Under the *Electricity Act, 1998*, Hydro One is required to make payments in lieu of corporate income taxes (PILs) to the Ontario Electricity Financial Corporation (OEFC). These payments are calculated in accordance with the rules for computing income and other relevant amounts contained in the *Income Tax Act* (Canada) and the *Taxation Act, 2007* (Ontario) as modified by the *Electricity Act, 1998* and related regulations.

Current and deferred income taxes are computed based on the tax rates and tax laws enacted at the balance sheet date. Tax benefits associated with income tax positions taken, or expected to be taken, in a tax return are recorded only when the "more-likely-than-not" recognition threshold is satisfied and are measured at the largest amount of benefit that has a greater than 50% likelihood of being realized upon settlement. Management evaluates each position based solely on the technical merits and facts and circumstances of the position, assuming the position will be examined by a taxing authority having full knowledge of all relevant information. Significant management judgement is required to determine recognition thresholds and the related amount of tax benefits to be recognized in the Consolidated Financial Statements. Management re-evaluates tax positions each period in which new information about recognition or measurement becomes available.

Current Income Taxes

The provision for current taxes and the assets and liabilities recognized for the current and prior periods are measured at the amounts receivable from, or payable to, the OEFC.

Deferred Income Taxes

Deferred income taxes are provided for using the liability method. Deferred income taxes are recognized based on the estimated future tax consequences attributable to temporary differences between the carrying amount of assets and liabilities in the Consolidated Financial Statements and their corresponding tax bases.

Deferred income tax liabilities are generally recognized on all taxable temporary differences. Deferred tax assets are recognized to the extent that it is more-likely-than-not that these assets will be realized from taxable income available against which deductible temporary differences can be utilized.

Deferred income taxes are calculated at the tax rates that are expected to apply in the period when the liability is settled or the asset is realized, based on the tax rates and tax laws that have been enacted at the balance sheet date. Deferred income taxes that are not included in the rate-setting process are charged or credited to the Consolidated Statements of Operations and Comprehensive Income.

If management determines that it is more-likely-than-not that some or all of a deferred income tax asset will not be realized, a valuation allowance is recorded against the tax asset to report the net balance at the amount expected to be realized. Previously unrecognized deferred income tax assets are reassessed at each balance sheet date and are recognized to the extent that it has become more-likely-than-not that the tax benefit will be realized.

The Company records regulatory assets and liabilities associated with deferred income taxes that will be included in the rate-setting process.

The Company uses the flow-through method to account for investment tax credits (ITCs) earned on eligible scientific research and experimental development expenditures, and apprenticeship job creation. Under this method, only the ITCs are recognized as a reduction to income tax expense.

Materials and Supplies

Materials and supplies represent consumables, small spare parts and construction materials held for internal construction and maintenance of property, plant and equipment. These assets are carried at average cost less any impairments recorded.

Property, Plant and Equipment

Property, plant and equipment is recorded at original cost, net of customer contributions received in aid of construction and any accumulated impairment losses. The cost of additions, including betterments and replacement asset components, is included on the Consolidated Balance Sheets as property, plant and equipment.

The original cost of property, plant and equipment includes direct materials, direct labour (including employee benefits), contracted services, attributable capitalized financing costs, asset retirement costs, and direct and indirect overheads that are related to the capital project or program. Indirect overheads include a portion of corporate costs such as finance, treasury, human resources, information technology and executive costs. Overhead costs, including corporate functions and field services costs, are capitalized on a fully allocated basis, consistent with an OEB-approved methodology.

Property, plant and equipment in service consists of transmission, distribution, communication, administration and service assets and land easements. Property, plant and equipment also includes future use assets, such as land, major components and spare parts, and capitalized project development costs associated with deferred capital projects.

Transmission

Transmission assets include assets used for the transmission of high-voltage electricity, such as transmission lines, support structures, foundations, insulators, connecting hardware and grounding systems, and assets used to step up the voltage of electricity from generating stations for transmission and to step down voltages for distribution, including transformers, circuit breakers and switches.

Distribution

Distribution assets include assets related to the distribution of low-voltage electricity, including lines, poles, switches, transformers, protective devices and metering systems.

Communication

Communication assets include the fibre-optic and microwave radio system, optical ground wire, towers, telephone equipment and associated buildings.

Administration and Service

Administration and service assets include administrative buildings, personal computers, transport and work equipment, tools and other minor assets.

Easements

Easements include statutory rights of use for transmission corridors and abutting lands granted under the *Reliable Energy and Consumer Protection Act, 2002*, as well as other land access rights.

Intangible Assets

Intangible assets separately acquired or internally developed are measured on initial recognition at cost, which comprises purchased software, direct labour (including employee benefits), consulting, engineering, overheads and attributable capitalized financing charges. Following initial recognition, intangible assets are carried at cost, net of any accumulated amortization and accumulated impairment losses. The Company's intangible assets primarily represent major administrative computer applications.

Capitalized Financing Costs

Capitalized financing costs represent interest costs attributable to the construction of property, plant and equipment or development of intangible assets. The financing cost of attributable borrowed funds is capitalized as part of the acquisition cost of such assets. The capitalized portion of financing costs is a reduction to financing charges recognized in the Consolidated Statements of Operations and Comprehensive Income. Capitalized financing costs are calculated using the Company's weighted average effective cost of debt.

Construction and Development in Progress

Construction and development in progress consists of the capitalized cost of constructed assets that are not yet complete and which have not yet been placed in service.

Depreciation and Amortization

The cost of property, plant and equipment and intangible assets is depreciated or amortized on a straight-line basis based on the estimated remaining service life of each asset category, except for transport and work equipment, which is depreciated on a declining balance basis.

The Company periodically initiates an external independent review of its property, plant and equipment and intangible asset depreciation and amortization rates, as required by the OEB. Any changes arising from OEB approval of such a review are implemented on a remaining service life basis, consistent with their inclusion in electricity rates. The last review resulted in changes to rates effective January 1, 2007.

A summary of average service lives and depreciation and amortization rates for the various classes of assets is included below:

	Average Service Life	Rate (%) Range	Average
Transmission	56 years	1% – 3%	2%
Distribution	42 years	1% – 13%	2%
Communication	19 years	1% – 13%	5%
Administration and service	15 years	1% – 20%	8%

The cost of intangible assets is included primarily within the administration and service classification above. Amortization rates for computer applications software and other intangible assets range from 9% to 11%.

In accordance with group depreciation practices, the original cost of property, plant and equipment, or major components thereof, and intangible assets that are normally retired, is charged to accumulated depreciation, with no gain or loss being reflected in results of operations. Where a disposition of property, plant and equipment occurs through sale, a gain or loss is calculated based on proceeds and such gain or loss is included in depreciation expense. Depreciation expense also includes the costs incurred to remove property, plant and equipment where no ARO has been recorded.

Goodwill

Goodwill represents the cost of acquired local distribution companies that is in excess of the fair value of the net identifiable assets acquired at the acquisition date. Goodwill is not included in rate base.

Goodwill is evaluated for impairment on an annual basis, or more frequently if circumstances require. Per Accounting Standards Update (ASU) 2011-08, Intangibles – Goodwill and Other (Topic 350), Testing Goodwill for Impairment, issued by the Financial Accounting Standards Board (FASB) in September 2011, the Company performs a qualitative assessment to determine whether it is more-likely-than-not that the fair value of the applicable reporting unit is less than its carrying amount. If the Company determines, as a result of its qualitative assessment, that it is not more-likely-than-not that the fair value of the applicable reporting unit is less than its carrying amount, no further testing is required. If the Company determines, as a result of its qualitative assessment, that it is more-likely-than-not that the fair value of the applicable reporting unit is

less than its carrying amount, a goodwill impairment assessment is performed using a two-step, fair value-based test. The first step compares the fair value of the applicable reporting unit to its carrying amount, including goodwill. If the carrying amount of the applicable reporting unit exceeds its fair value, a second step is performed. The second step requires an allocation of fair value to the individual assets and liabilities using purchase price allocation in order to determine the implied fair value of goodwill. If the implied fair value of goodwill is less than the carrying amount, an impairment loss is recorded as a reduction to goodwill and as a charge to results of operations.

For the year ended December 31, 2012, based on the qualitative assessment performed, the Company has determined that it is not more-likely-than-not that the fair value of each applicable reporting unit assessed is less than its carrying amount. As a result, no further testing was performed, and the Company has concluded that goodwill was not impaired ot December 31, 2012.

Long-Lived Asset Impairment

When circumstances indicate the carrying value of long-lived assets may not be recoverable, the Company evaluates whether the carrying value of such assets, excluding goodwill, has been impaired. For such long-lived assets, impairment exists when the carrying value exceeds the sum of the future estimated undiscounted cash flows expected to result from the use and eventual disposition of the asset. When alternative courses of action to recover the carrying amount of a long-lived asset are under consideration, a probability-weighted approach is used to develop estimates of future undiscounted cash flows. If the carrying value of the long-lived asset is not recoverable based on the estimated future undiscounted cash flows, an impairment loss is recorded, measured as the excess of the carrying value of the asset over its fair value. As a result, the asset's carrying value is adjusted to its estimated fair value.

Within its regulated business, the carrying costs of most of Hydro One's long-lived assets are included in rate base where they earn an OEB-approved rate of return. Asset carrying values and the related return are recovered through approved rates. As a result, such assets are only tested for impairment in the event that the OEB disallows recovery, in whole or in part, or if such a disallowance is judged to be probable.

Hydro One regularly monitors the assets of its unregulated Hydro One Telecom subsidiary for indications of impairment. Management assesses the fair value of such long-lived assets using commonly accepted techniques, and may use more than one. Techniques used to determine fair value include, but are not limited to, the use of recent third party comparable sales for reference and internally developed discounted cash flow analysis. Significant changes in market conditions, changes to the condition of an asset, or a change in management's intent to utilize the asset are generally viewed by management as triggering events to reassess the cash flows related to these long-lived assets. As at December 31, 2012, no asset impairment had been recorded for assets within either the Company's regulated or unregulated businesses.

Costs of Arranging Debt Financing

For financial liabilities classified as other than held-for-trading, the Company defers the external transaction costs related to obtaining debt financing and presents such amounts as deferred debt costs on the Consolidated Balance Sheets. Deferred debt costs are amortized over the contractual life of the related debt on an effective-interest basis and the amortization is included within financing charges in the Consolidated Statements of Operations and Comprehensive Income. Transaction costs for items classified as held-for-trading are expensed immediately.

Comprehensive Income

Comprehensive income is comprised of net income and other comprehensive income (OCI). OCI includes the amortization of net unamortized hedging losses on the Company's discounted cash flow hedges, and the change in fair value on the existing cash flow hedges to the extent that the hedge is effective. The Company amortizes its unamortized hedging losses on discontinued cash flow hedges to financing charges using the effective-interest method over the term of the allocated hedged debt. Hydro One presents net income and OCI in a single continuous Consolidated Statement of Operations and Comprehensive Income.

Financial Assets and Liabilities

All financial assets and liabilities are classified into one of the following five categories: held-to-maturity; loans and receivables; held-for-trading; other liabilities; or available-for-sale. Financial assets and liabilities classified as held-for-trading are measured at fair value. All other financial assets and liabilities are measured at amortized cost, except accounts receivable and amounts due from related parties, which are measured at the lower of cost or fair value. Accounts receivable and amounts due from related parties are classified as loans and receivables. The Company considers the carrying amounts of accounts receivable and amounts due from related parties to be reasonable estimates of fair value because of the short time to maturity of these instruments. Provisions for impaired accounts receivable are recognized as adjustments to the allowance for doubtful accounts and are recognized when there is objective evidence that the Company will not be able to collect amounts according to the original terms.

Derivative instruments are measured at fair value. Gains and losses from fair valuation are included within financing charges in the period in which they arise. The Company determines the classification of its financial assets and liabilities at the date of initial recognition. The Company designates certain of its financial assets and liabilities to be held at fair value, when it is consistent with the Company's risk management policy disclosed in Note 12 – Fair Value of Financial Instruments and Risk Management.

Short-term investments have an original maturity of three months or less and are generally classified as held-to-maturity. However, the Company may classify pools of short-term investments as held-for-trading where there is no intention to hold a pool of assets to maturity. Documentation of the short-term investment classification is made on inception. As at December 31, 2012 and 2011, all short-term investments were classified as held-to-maturity.

The Company's long-term investment in Province of Ontario Floating-Rate Notes, which is held as an alternate form of liquidity to supplement the bank credit facilities, is classified as held-for-trading and is measured at fair value.

All financial instrument transactions are recorded at trade date.

Derivative Instruments and Hedge Accounting

The Company closely monitors the risks associated with changes in interest rates on its operations and, where appropriate, uses various instruments to hedge these risks. Certain of these derivative instruments qualify for hedge accounting and are designated as accounting hedges, while others either do not qualify as hedges or have not been designated as hedges (hereinafter referred to as undesignated contracts) as they are part of economic hedging relationships.

The accounting guidance for derivative instruments requires the recognition of all derivative instruments not identified as meeting the normal purchase and sale exemption as either assets or liabilities recorded at fair value on the Consolidated Balance Sheets. For derivative instruments that qualify for hedge accounting, the Company may elect to designate such derivative instruments as either cash flow hedges or fair value hedges. The Company offsets fair value amounts recognized in its Consolidated Balance Sheets related to derivative instruments executed with the same counterparty under the same master netting agreement.

For derivative instruments that qualify for hedge accounting and which are designated as cash flow hedges, the effective portion of any gain or loss, net of tax, is reported as a component of accumulated OCI (AOCI) and is reclassified to results of operations in the same period or periods during which the hedged transaction affects results of operations. Any gains or losses on the derivative instrument that represent either hedge ineffectiveness or hedge components excluded from the assessment of effectiveness are recognized in results of operations. For fair value hedges, changes in fair value of both the derivative instrument and the underlying hedged exposure are recognized in the Consolidated Statement of Operations and Comprehensive Income in the current period. The gain or loss on the derivative instrument is included in the same line item as the offsetting gain or loss on the hedged item in the Consolidated Statements of Operations and Comprehensive Income. Additionally, the Company enters into derivative agreements that are economic hedges that either do not qualify for hedge accounting or have not been designated as hedges. The changes in fair value of these undesignated derivative instruments are reflected in results of operations.

Embedded derivative instruments are separated from their host contracts and carried at fair value on the Consolidated Balance Sheets when: (a) the economic characteristics and risks of the embedded derivative are not clearly and closely related to the economic characteristics and risks of the host contract; (b) the hybrid instrument is not measured at fair value, with changes in fair value recognized in results of operations each period; and (c) the embedded derivative itself meets the definition of a derivative. The Company does not engage in derivative trading or speculative activities and had no embedded derivatives at December 31, 2012.

Hydro One periodically develops hedging strategies taking into account risk management objectives. At the inception of a hedging relationship where the Company has elected to apply hedge accounting, Hydro One formally documents the relationship between the hedged item and the hedging instrument, the related risk management objective, the nature of the specific risk exposure being hedged, and the method for assessing the effectiveness of the hedging relationship. The Company also assesses, both at the inception of the hedge and on a quarterly basis, whether the hedging instruments are effective in offsetting changes in fair values or cash flows of the hedged items.

Employee Future Benefits

Employee future benefits provided by Hydro One include pension, post-retirement and post-employment benefits. The costs of the Company's pension, post-retirement and post-employment benefit plans are recorded over the periods during which employees render service.

The Company recognizes the funded status of its pension, post-retirement and post-employment plans on its Consolidated Balance Sheets and subsequently recognizes the changes in funded status at the end of each reporting year. Pension, post-retirement and post-employment plans are considered to be underfunded when the projected benefit obligation exceeds the fair value of the plan assets. Liabilities are recognized in the Consolidated Balance Sheets for any net underfunded projected benefit obligation. The net underfunded projected benefit obligation may be disclosed as a current liability, long-term liability, or both. The current portion is the amount by which the actuarial present value of benefits included in the benefit obligation payable in the next 12 months exceeds the fair value of plan assets. If the fair value of plan assets exceeds the projected benefit obligation of the plan, an asset is recognized equal to the net overfunded projected benefit obligation. The net asset for an overfunded plan is classified as a long-term asset in the Consolidated Balance Sheets. The post-retirement and post-employment benefit plans are unfunded because there are no related plan assets.

Pension Benefits

Hydro One records a regulatory asset equal to the net underfunded projected benefit obligation for its pension plan. The regulatory asset for the net underfunded projected benefit obligation for the pension plan, in the absence of regulatory accounting, would be recognized in AOCI. A regulatory asset is recognized because management considers it to be probable that pension benefit costs will be recovered in the future through the rate-setting process. The pension regulatory assets are remeasured at the end of each year based on the current status of the pension plan.

In accordance with the OEB's rate orders, pension costs are recorded on a cash basis as employer contributions are paid to the pension fund in accordance with the *Pension Benefits Act* (Ontario). Pension costs are also calculated on an accrual basis for financial reporting purposes. Pension costs are actuarially determined using the projected benefit method prorated on service and are based on assumptions that reflect management's best estimate of the effect of future events, including future compensation increases. Past service costs from plan amendments and all actuarial gains and losses are amortized on a straight-line basis over the expected average remaining service period of active employees in the plan, and over the estimated remaining life expectancy of inactive employees in the plan. Pension plan assets, consisting primarily of listed equity securities as well as corporate and government debt securities, are fair valued at the end of each year.

All future pension benefit costs are attributed to labour and are either charged to results of operations or capitalized as part of the cost of property, plant and equipment and intangible assets.

Post-Retirement and Post-Employment Benefits

Hydro One records a regulatory asset equal to the incremental net unfunded projected benefit obligation for post-retirement and post-employment plans recorded on transition to US GAAP and at each year end based on annual actuarial reports. The regulatory asset for the incremental net unfunded projected benefit obligation for post-retirement and post-employment plans, in the absence of regulatory accounting, would be recognized in AOCI. A regulatory asset is recognized because management considers it to be probable that post-retirement and post-employment benefit costs will be recovered in the future through the rate-setting process.

Post-retirement and post-employment benefits are recorded and included in rates on an accrual basis. Costs are determined by independent actuaries using the projected benefit method prorated on service and based on assumptions that reflect management's best estimates. Past service costs from plan amendments are amortized to results of operations based on the expected average remaining service period.

For post-retirement benefits, all actuarial gains or losses are deferred using the "corridor" approach. The amount calculated above the "corridor" is amortized to results of operations on a straight-line basis over the expected average remaining service life of active employees in the plan and over the remaining life expectancy of inactive employees in the plan. The post-retirement benefit obligation is remeasured to its fair value at each year end based on an annual actuarial report, with an offset to the associated regulatory asset, to the extent of the remeasurement adjustment.

For post-employment obligations, the associated regulatory liabilities representing actuarial gains on transition to US GAAP are amortized to results of operations based on the "corridor" approach. Post transition, the actuarial gains and losses on post-employment obligations that are

incurred during the year are recognized immediately to results of operations. The post-employment benefit obligation is remeasured to its fair value at each year end based on an annual actuarial report, with an offset to associated regulatory asset, to the extent of the remeasurement adjustment.

All post-retirement and post-employment future benefit costs are attributed to labour and are either charged to results of operations or capitalized as part of the cost of property, plant and equipment and intangible assets.

Multiemployer Pension Plan

Employees of Hydro One Brampton Networks participate in the Ontario Municipal Employees Retirement System Fund (OMERS), a multiemployer, contributory, defined benefit public sector pension fund. OMERS provides retirement pension payments based on members' length of service and salary. Both participating employers and members are required to make plan contributions. The OMERS plan assets are pooled together to provide benefits to all plan participants and the plan assets are not segregated by member entity. OMERS is registered with the Financial Services Commission of Ontario under Registration #0345983.

The OMERS plan is accounted for as a defined contribution plan by Hydro One because it is not practicable to determine the present value of the Company's obligation, the fair value of plan assets or the related current service cost applicable to Hydro One Brampton Networks' employees. Hydro One recognizes its contributions to the OMERS plan as pension expense, with a portion being capitalized. The expensed amount is included in operation, maintenance and administration costs in the Consolidated Statements of Operations and Comprehensive Income.

At December 31, 2011, OMERS had approximately 419,000 members, with approximately 277 members being current employees of Hydro One Brampton Networks.

Loss Contingencies

Hydro One is involved in certain legal and environmental matters that arise in the normal course of business. In the preparation of its Consolidated Financial Statements, management makes judgements regarding the future outcome of contingent events and records a loss for a contingency based on its best estimate when it is determined that such loss is probable and the amount of the loss can be reasonably estimated. Where the loss amount is recoverable in future rates, a regulatory asset is also recorded. When a range estimate for the probable loss exists and no amount within the range is a better estimate than any other amount, the Company records a loss at the minimum amount within the range.

Management regularly reviews current information available to determine whether recorded provisions should be adjusted and whether new provisions are required. Estimating probable losses may require analysis of multiple forecasts and scenarios that often depend on judgements about potential actions by third parties, such as federal, provincial and local courts or regulators. Contingent liabilities are often resolved over long periods of time. Amounts recorded in the Consolidated Financial Statements may differ from the actual outcome once the contingency is resolved. Such differences could have a material impact on future results of operations, financial position and cash flows of the Company.

Provisions are based upon current estimates and are subject to greater uncertainty where the projection period is lengthy. A significant upward or downward trend in the number of claims filed, the nature of the alleged injuries, and the average cost of resolving each claim could change the estimated provision, as could any substantial adverse or favourable verdict at trial. A federal or provincial legislative outcome or structured settlement could also change the estimated liability. Unless otherwise required by GAAP, legal fees are expensed as incurred.

Environmental Liabilities

Environmental liabilities are recorded in respect of past contamination when it is determined that future environmental remediation expenditures are probable under existing statute or regulation and the amount of the future expenditures can be reasonably estimated. Hydro One records a liability for the estimated future expenditures associated with the contaminated land assessment and remediation (LAR) and for the phase-out and destruction of polychlorinated biphenyl (PCB)-contaminated mineral oil removed from electrical equipment, based on the present value of these estimated future expenditures. The Company determines the present value with a discount rate equal to its credit-adjusted risk-free interest rate on financial instruments with comparable maturities to the pattern of future environmental expenditures. As the Company anticipates that the future expenditures will continue to be recoverable in future rates, an offsetting regulatory asset has been recorded to reflect the future recovery of these environmental expenditures from customers. Hydro One reviews its estimates of future environmental expenditures annually, or more frequently if there are indications that circumstances have changed.

Asset Retirement Obligations

AROs are recorded for legal obligations associated with the future removal and disposal of long-lived assets. Such obligations may result from the acquisition, construction, development and/or normal use of the asset. Conditional AROs are recorded when there is a legal obligation to perform a future asset retirement activity but where the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the Company. In such a case, the obligation to perform the asset retirement activity is unconditional even though uncertainty exists about the timing and/or method of settlement.

When recording an ARO, the present value of the estimated future expenditures required to complete the asset retirement activity is recorded in the period in which the obligation is incurred, if a reasonable estimate can be made. In general, the present value of the estimated future expenditures is added to the carrying amount of the associated asset and the resulting asset retirement cost is depreciated over the estimated useful life of the asset. Where an asset is no longer in service when an ARO is recorded, the asset retirement cost is recorded in results of operations.

Some of the Company's transmission and distribution assets, particularly those located on unowned easements and rights-of-way, may have AROs, conditional or otherwise. The majority of the Company's easements and rights-of-way are either of perpetual duration or are automatically renewed annually. Land rights with finite terms are generally subject to extension or renewal. As the Company expects to use the majority of its facilities in perpetuity, no ARO currently exists for these assets. If, at some future date, a particular facility is shown not to meet the perpetuity assumption, it will be reviewed to determine whether an estimable ARO exists. In such a case, an ARO would be recorded at that time.

The Company's AROs recorded to date relate to estimated future expenditures associated with the removal and disposal of asbestos-containing materials installed in some of its facilities and with the decommissioning of specific switching stations located on unowned sites.

3. NEW ACCOUNTING PRONOUNCEMENTS

Recently Adopted Accounting Pronouncements

In September 2011, the FASB issued ASU 2011-09, Disclosures About an Employer's Participation in a Multiemployer Benefit Plan. This ASU requires an employer to provide quantitative and qualitative disclosures about its participation in significant multiemployer plans that offer pension, post-retirement and post-employment benefits. The ASU's objective is to enhance the transparency of disclosures about the significant multiemployer plans in which an employer participates, the level of the employer's participation in those plans, the financial health of the plans, and the nature of the employer's commitments to the plans. An employer that is not able to provide some of the quantitative information required by this ASU must disclose what information has been omitted and why it could not obtain the information. This ASU does not change the recognition and measurement guidance for an employer's participation in a multiemployer plan. As this ASU only requires enhanced disclosures, the adoption of this ASU did not have a significant impact on the Company's Consolidated Financial Statements.

In September 2011, the FASB issued ASU 2011-08, Intangibles – Goodwill and Other (Topic 350), Testing Goodwill for Impairment. This ASU is intended to reduce the cost and complexity of the annual goodwill impairment test by providing entities an option to perform a qualitative assessment to determine whether further impairment testing is necessary. An entity has the option to first assess qualitative factors to determine whether it is necessary to perform the current two-step test. If an entity believes, as a result of its qualitative assessment, that it is more-likely-than-not that the fair value of a reporting unit is less than its carrying amount, the quantitative impairment test is required. Otherwise, no further testing is required. An entity can choose to perform the qualitative assessment on none, some or all of its reporting units. Moreover, an entity can bypass the qualitative assessment for any reporting unit in any period and proceed directly to step one of the impairment test, and then resume performing the qualitative assessment in any subsequent period. The adoption of this ASU did not have a significant impact on the Company's Consolidated Financial Statements.

In June 2011, the FASB issued ASU 2011-05, Presentation of Comprehensive Income to clarify that an entity has the option to present the total of comprehensive income, the components of net income, and the components of OCI either in a single continuous statement of comprehensive income or in two separate but consecutive statements. In both choices, an entity is required to present each component of net income along with total net income, each component of OCI along with a total for OCI, and a total amount for comprehensive income. This update eliminates the option to present the components of OCI as part of the statement of changes in shareholder's equity. The amendments in this ASU do not change the items that must be reported in OCI or when an item of OCI must be reclassified to net income. Hydro One has elected to present OCI and net income in a single continuous Consolidated Statement of Operations and Comprehensive Income.

In May 2011, the FASB issued ASU 2011-04, Fair Value Measurement (Topic 820): Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs. This ASU is the result of joint efforts by the FASB and the International Accounting Standards Board to develop common, converged fair value guidance on how to measure fair value and on what disclosures to provide about fair value measurements. This ASU is largely consistent with existing US GAAP fair value measurement principles under Accounting Standards Codification 820. However, this ASU expands the existing disclosure requirements for fair value measurements, particularly of Level 3 inputs, and requires categorization by level of the fair value hierarchy for items that are not measured at fair value on the Consolidated Balance Sheets but for which the fair value is required to be disclosed. Required disclosures have been included in Note 12 – Fair Value of Financial Instruments and Risk Management. As this ASU only requires enhanced disclosures, the adoption of this ASU did not have a significant impact on the Company's Consolidated Financial Statements.

Recent Accounting Guidance Not Yet Adopted

In December 2011, the FASB issued ASU 2011-11, Balance Sheet (Topic 210): Disclosures about Offsetting Assets and Liabilities. This ASU requires on entity to disclose both gross and net information about financial instruments and transactions eligible for offset on the Consolidated Balance Sheets as well as financial instruments and transactions executed under a master netting or similar arrangement. The ASU was issued to enable users of financial statements to understand the effects or potential effects of those arrangements on an entity's financial position. This ASU is required to be applied retrospectively and is effective for fiscal years, and interim periods within those years, beginning on or after January 1, 2013. As this ASU only requires enhanced disclosures, the adoption of this ASU is not anticipated to have a significant impact on the Company's Consolidated Financial Statements.

4. DEPRECIATION AND AMORTIZATION

Year ended December 31 (millions of dollars)	**2012**	2011
Depreciation of property, plant and equipment	**522**	485
Amortization of intangible assets	**48**	45
Asset removal costs	**70**	66
Amortization of regulatory assets	**19**	20
	659	616

5. FINANCING CHARGES

Year ended December 31 (millions of dollars)	**2012**	2011
Interest on long-term debt	**421**	412
Other	**12**	5
Less: Interest capitalized on construction and development in progress	**(59)**	(58)
Gain on interest-rate swap agreements	**(12)**	(12)
Interest earned on investments	**(4)**	(3)
	358	344

6. PROVISION FOR PAYMENTS IN LIEU OF CORPORATE INCOME TAXES

The major components of income tax expense are as follows:

Year ended December 31 (millions of dollars)	**2012**	2011
Current provision for PILs	**130**	162
Deferred recovery of PILs	**(9)**	(12)
Provision for PILs	**121**	150

The provision for PILs differs from the amount that would have been recorded using the combined Canadian Federal and Ontario statutory income tax rate. The reconciliation between the statutory and the effective tax rates is provided as follows:

Year ended December 31 (millions of dollars)	**2012**	2011
Income before provision for PILs	**866**	791
Canadian Federal and Ontario statutory income tax rate	**26.50%**	28.25%
Provision for PILs at statutory rate	**230**	223
Increase (decrease) resulting from:		
Net temporary differences included in amounts charged to customers:		
Capital cost allowance in excess of depreciation and amortization	**(42)**	(34)
Pension contributions in excess of pension expense	**(23)**	(17)
Interest capitalized for accounting but deducted for tax purposes	**(15)**	(16)
Overheads capitalized for accounting but deducted for tax purposes	**(14)**	(12)
Non-refundable investment tax credits	**(8)**	–
Environmental expenditures	**(5)**	(4)
Post-retirement and post-employment benefit expense in excess of cash payments	**–**	5
Other	**(3)**	3
Net temporary differences	**(110)**	(75)
Net permanent differences	**1**	2
Total provision for PILs	**121**	150
Current provision for PILs	**130**	162
Deferred recovery of PILs	**(9)**	(12)
Total provision for PILs	**121**	150
Effective income tax rate	**13.96%**	18.96%

The current provision for PILs of $130 million represents the amount paid or payable to the OEFC with respect to current year income. The outstanding balance due to the OEFC at December 31, 2012 was $10 million (2011 – $85 million).

The total provision for PILs includes deferred recovery of PILs of $9 million that is not included in the rate-setting process, using the balance sheet liability method of accounting. Deferred PILs balances expected to be included in the rate-setting process are offset by regulatory assets and liabilities to reflect the anticipated recovery or disposition of these balances within future electricity rates.

Deferred Income Tax Assets and Liabilities

Deferred income tax assets and liabilities arise from differences between the carrying amounts and tax bases of the Company's assets and liabilities. At December 31, deferred income tax assets and liabilities consisted of the following:

December 31 (millions of dollars)	**2012**	2011
Deferred income tax assets		
Depreciation and amortization in excess of capital cost allowance	**3**	6
Post-retirement and post-employment benefits expense in excess of cash payments	**7**	5
Environmental expenditures	**4**	5
Other	**–**	1
Total deferred income tax assets	**14**	17
Less: current portion	**–**	–
	14	17

December 31 (millions of dollars)	**2012**	2011
Deferred income tax liabilities		
Capital cost allowance in excess of depreciation and amortization	**(1,344)**	(1,106)
Post-retirement and post-employment benefits expense in excess of cash payments	**519**	356
Environmental expenditures	**62**	61
Regulatory amounts receivable that are not recognized for tax purposes	**(147)**	(36)
Goodwill	**(19)**	(18)
Other	**3**	4
Total deferred income tax liabilities	**(926)**	(739)
Less: current portion	**18**	19
	(944)	(758)

During 2012, the deferred tax liability increased by $60 million as a result of the change in the rate applicable to future taxes. At December 31, 2012, unused tax losses carried forward were less than $1 million (2011 – less than $1 million).

7. ACCOUNTS RECEIVABLE

December 31 (millions of dollars)	**2012**	2011
Accounts receivable – billed	**224**	235
Accounts receivable – unbilled	**644**	588
Accounts receivable, gross	**868**	823
Allowance for doubtful accounts	**(23)**	(18)
Accounts receivable, net	**845**	805

The following table shows the movements in the allowance for doubtful accounts for the years ended December 31, 2012 and 2011.

Year ended December 31 (millions of dollars)	**2012**	2011
Allowance for doubtful accounts – January 1	**(18)**	(25)
Write-offs	**17**	30
Additions to allowance for doubtful accounts	**(22)**	(23)
Allowance for doubtful accounts – December 31	**(23)**	(18)

8. PROPERTY, PLANT AND EQUIPMENT

December 31 (millions of dollars)	Property, Plant and Equipment	Accumulated Depreciation	Construction in Progress	Total
2012				
Transmission	**11,840**	**3,990**	**641**	**8,491**
Distribution	**8,005**	**2,879**	**234**	**5,360**
Communication	**1,024**	**516**	**57**	**565**
Administration and Service	**1,314**	**668**	**123**	**769**
Easements	**614**	**92**	**–**	**522**
	22,797	**8,145**	**1,055**	**15,707**
2011				
Transmission	10,906	3,810	1,079	8,175
Distribution	7,596	2,706	253	5,143
Communication	919	468	43	494
Administration and Service	1,232	607	61	686
Easements	493	88	–	405
	21,146	7,679	1,436	14,903

Financing charges capitalized on property, plant and equipment under construction were $56 million in 2012 (2011 – $57 million).

9. INTANGIBLE ASSETS

December 31 (millions of dollars)	Intangible Assets	Accumulated Amortization	Development in Progress	Total
2012				
Computer applications software	**451**	**301**	**116**	**266**
Other	**5**	**4**	**–**	**1**
	456	**305**	**116**	**267**
2011				
Computer applications software	427	254	49	222
Other	5	3	–	2
	432	257	49	224

Financing charges capitalized on intangible assets under development were $3 million in 2012 (2011 – $1 million). The estimated annual amortization expense for intangible assets for each of the next five years is $42 million.

10. REGULATORY ASSETS AND LIABILITIES

Regulatory assets and liabilities arise as a result of the rate-setting process. Hydro One has recorded the following regulatory assets and liabilities:

December 31 (millions of dollars)	**2012**	2011
Regulatory assets:		
Pension benefit regulatory asset	**1,515**	779
Deferred income tax regulatory asset	**954**	763
Post-retirement and post-employment benefits	**320**	123
Environmental	**249**	257
Pension cost variance	**61**	42
Rider 2	**10**	11
Long-term project development costs	**5**	5
Other	**13**	10
Total regulatory assets	**3,127**	1,990
Less: current portion	**29**	24
	3,098	1,966
Regulatory liabilities:		
External revenue variance	**61**	39
Retail settlement variance accounts	**54**	39
Rider 8	**45**	41
Deferred income tax regulatory liability	**16**	25
PST savings deferral	**13**	8
Rider 3	**9**	9
Rural and remote rate protection variance	**6**	8
Hydro One Brampton Networks rider	**–**	2
Other	**17**	23
Total regulatory liabilities	**221**	194
Less: current portion	**40**	25
	181	169

Pension Benefit Regulatory Asset

The Company recognizes the net unfunded status of pension obligations on the Consolidated Balance Sheets with an offset to the associated regulatory asset. A regulatory asset is recognized because management considers it to be probable that pension benefit costs will be recovered in the future through the rate-setting process. The pension benefit obligation is remeasured to its fair value at each year end based on an annual actuarial report, with an offset to the associated regulatory asset, to the extent of the remeasurement adjustment. In the absence of rate-regulated accounting, 2012 OCI would have been lower by $736 million (2011 – higher by $482 million).

Deferred Income Tax Regulatory Asset and Liability

Deferred income taxes are recognized on temporary differences between the carrying amount of assets and liabilities in the financial statements and the corresponding tax bases used in the computation of taxable profit. The Company has recognized regulatory assets and liabilities that correspond to deferred income taxes that flow through the rate-setting process. In the absence of rate-regulated accounting, the Company's provision for PILs would have been recognized using the liability method and there would be no regulatory accounts established for taxes to be recovered through future rates. As a result, the 2012 provision for PILs would have been higher by approximately $136 million (2011 – $70 million), including the impact of a change in enacted tax rates.

Post-Retirement and Post-Employment Benefits

The Company recognizes the net unfunded status of post-retirement and post-employment obligations on the Consolidated Balance Sheets with an incremental offset to the associated regulatory assets. A regulatory asset is recognized because management considers it to be probable that post-retirement and post-employment benefit costs will be recovered in the future through the rate-setting process. The post-retirement and post-employment benefit obligation is remeasured to its fair value at each year end based on an annual actuarial report, with an offset to the associated regulatory asset, to the extent of the remeasurement adjustment. In the absence of rate-regulated accounting, 2012 OCI would have been lower by $197 million (2011 – higher by $30 million).

Environmental

Hydro One records a liability for the estimated future expenditures required to remediate past environmental contamination (see Note 15 – Environmental Liabilities). Because such expenditures are expected to be recoverable in future rates, the Company has recorded an equivalent amount as a regulatory asset. In 2012, this regulatory asset decreased by $3 million (2011 – $55 million) to reflect related changes in the Company's PCB liability, and increased by $2 million (2011 – $5 million) due to changes in the LAR liability. The environmental regulatory asset is amortized to results of operations based on the pattern of actual expenditures incurred and charged to environmental liabilities. The OEB has the discretion to examine and assess the prudency and the timing of recovery of all of Hydro One's actual environmental expenditures. In the absence of rate-regulated accounting, 2012 operation, maintenance and administration expenses would have been lower by $1 million (2011 – $50 million). In addition, 2012 amortization expense would have been lower by $18 million (2011 – $16 million), and 2012 financing charges would have been higher by $11 million (2011 – $14 million).

Pension Cost Variance

A pension cost variance account was established for each of Hydro One Networks' Transmission and Distribution businesses to track the difference between the actual pension expense incurred and estimated pension costs approved by the OEB. The balance in this account reflects the excess of pension costs paid as compared to OEB-approved amounts. In December 2010, the OEB approved the December 31, 2009 balance, including accrued interest, to be recovered over a one-year period from January 1, 2011 to December 31, 2011. In the absence of rate-regulated accounting, 2012 revenue would have been lower by $18 million (2011 – $14 million).

Rider 2

In April 2006, the OEB announced its decision regarding the Company's rate application in respect of the Distribution Business of Hydro One Networks. As part of this decision, the OEB also approved the distribution-related deferral account balances sought by Hydro One. The Rider 2 regulatory asset includes retail settlement and cost variance amounts and distribution low-voltage service amounts, plus accrued interest.

Long-Term Project Development Costs

In May 2009, the OEB approved the creation of a deferral account to record Hydro One Networks' costs of preliminary work to advance certain transmission projects identified in the Company's 2009 and 2010 transmission rate applications. In March 2010, the OEB issued a decision amending the scope of the account to include the 20 major transmission projects identified in the September 2009 request from the Ministry of Energy and Infrastructure. In December 2010, the OEB approved the recovery of the December 31, 2009 balance, including accrued interest, to be recovered over a one-year period from January 1, 2011 to December 31, 2011. In the absence of rate-regulated accounting, 2011 operation, maintenance and administration expenses would have been lower by $2 million.

External Revenue Variance

In May 2009, the OEB approved forecasted amounts related to export service revenue, external revenue from secondary land use, and external revenue from station maintenance and engineering and construction work. These revenue sources are taken into account in structuring the Company's revenue requirement and as such, the OEB requested the establishment of new variance accounts to capture any difference between the approved forecasted external revenue amounts used in establishing the revenue requirement and actual external revenues. The external revenue variance account balance reflects the excess of actual external revenue compared to the OEB-approved forecasted amounts. In December 2010, the OEB approved the disposition of the December 31, 2009 balance, including accrued interest, to be disposed over a one-year period from January 1, 2011 to December 31, 2011.

Retail Settlement Variance Accounts (RSVAs)
Hydro One has deferred certain retail settlement variance amounts under the provisions of Article 490 of the OEB's Accounting Procedures Handbook. In April 2010, the OEB approved the disposition of the total RSVA balance accumulated from May 2008 to December 2009, including accrued interest, to be disposed over a 20-month period from May 1, 2010 to December 31, 2011. Hydro One has continued to accumulate a net liability in its RSVA accounts since December 31, 2009.

Rider 8
In April 2010, the OEB requested the establishment of deferral accounts which capture the difference between the revenue recorded on the basis of Green Energy Plan expenditures incurred and the actual recoveries received.

PST Savings Deferral Account
The provincial sales tax (PST) and goods and services tax (GST) were harmonized in July 2010. Unlike the GST, the PST was included in operation, maintenance and administrative expenses or capital expenditures for past revenue requirements approved during a full cost of service hearing. Under the harmonized sales tax (HST) regime, the HST included in operation, maintenance and administrative expenses or capital expenditures is not a cost ultimately borne by the Company and as such, a refund of the prior PST element in the approved revenue requirement is applicable and calculations for tracking and refund were requested by the OEB. For the Hydro One Networks Transmission revenue requirement, PST was included between July 1, 2010 and December 31, 2010 and recorded in a deferral account per direction from the OEB. For the Hydro One Networks Distribution revenue requirement, PST was included between July 1, 2010 and December 31, 2012 and recorded in a deferral account per direction from the OEB.

Rider 3
In December 2008, the OEB approved certain distribution-related deferral account balances sought by Hydro One, including RSVA amounts, deferred tax changes, OEB costs and smart meters. The OEB approved the disposition of the Rider 3 balance accumulated up to April 2008, including accrued interest, to be disposed over a 27-month period from February 1, 2009 to April 30, 2011.

Rural and Remote Rate Protection Variance (RRRP)
Hydro One receives rural rate protection amounts from the IESO. A portion of these amounts is provided to retail customers of Hydro One Networks who are eligible for rate protection. The OEB has approved a mechanism to collect the RRRP through the Wholesale Market Service Charge. Variances between the amounts remitted by the IESO to Hydro One and the fixed entitlements defined in the regulation, and subsequent OEB utility rate decisions, are tracked by the Company in the RRRP variance account.

Hydro One Brampton Networks Rider
In April 2010, the OEB issued a decision regarding the 2010 distribution rates of Hydro One Brampton Networks. Included in the OEB's decision was the approval of certain deferral account balances, primarily RSVAs, sought by Hydro One Brampton Networks in its application. The OEB ordered that the approved balances be aggregated into a single regulatory account and disposed of through a rate rider over a two-year period from May 1, 2010 to April 30, 2012.

11. DEBT AND CREDIT AGREEMENTS

Short-Term Notes

Hydro One meets its short-term liquidity requirements in part through the issuance of commercial paper under its Commercial Paper Program with a maximum amount of $1,000 million. These short-term notes are denominated in Canadian dollars with varying maturities not exceeding 365 days. Hydro One had no commercial paper borrowings outstanding as at December 31, 2012 and 2011.

The Commercial Paper Program is supported by a total of $1,500 million in liquidity facilities comprised of a $1,250 million committed revolving standby credit facility with a syndicate of banks and a long-term investment in Province of Ontario Floating-Rate Notes with a fair value of $251 million at December 31, 2012.

Long-Term Debt

The Company issues notes for long-term financing under its Medium-Term Note (MTN) Program. The maximum authorized principal amount of notes issuable under this program is $3,000 million. At December 31, 2012, $1,515 million remained available until September 2013.

The following table presents the outstanding long-term debt at December 31, 2012 and 2011:

December 31 (millions of dollars)	**2012**	2011
5.77% Series 3 notes due 2012	**–**	600
5.00% Series 15 notes due 2013	**600**	600
3.13% Series 19 notes due 2014[1]	**750**	750
2.95% Series 21 notes due 2015[1]	**500**	500
Floating-rate Series 22 notes due 2015[2]	**50**	50
4.64% Series 10 notes due 2016	**450**	450
Floating-rate Series 27 notes due 2016[2]	**50**	–
5.18% Series 13 notes due 2017	**600**	600
4.40% Series 20 notes due 2020	**300**	300
3.20% Series 25 notes due 2022	**600**	–
7.35% debentures due 2030	**400**	400
6.93% Series 2 notes due 2032	**500**	500
6.35% Series 4 notes due 2034	**385**	385
5.36% Series 9 notes due 2036	**600**	600
4.89% Series 12 notes due 2037	**400**	400
6.03% Series 17 notes due 2039	**300**	300
5.49% Series 18 notes due 2040	**500**	500
4.39% Series 23 notes due 2041	**300**	300
6.59% Series 5 notes due 2043	**315**	315
5.00% Series 11 notes due 2046	**325**	325
4.00% Series 24 notes due 2051	**225**	100
3.79% Series 26 notes due 2062	**310**	–
	8,460	7,975
Add: Unrealized marked-to-market loss[1]	**19**	33
Less: Long-term debt payable within one year	**(600)**	(600)
Long-term debt	**7,879**	7,408

[1] The unrealized marked-to-market loss relates to $500 million of the Series 19 notes due 2014, and $250 million of the Series 21 notes due 2015. The unrealized marked-to-market loss is offset by a $19 million (2011 – $33 million) unrealized marked-to-market gain on the related fixed-to-floating interest-rate swap agreements, which are accounted for as fair value hedges. See Note 12 – Fair Value of Financial Instruments and Risk Management for details of fair value hedges.

[2] The interest rates of the floating-rate notes are referenced to the 3-month Canadian dollar bankers' acceptance rate, plus a margin.

In 2012, Hydro One issued $1,085 million of long-term debt under the MTN Program, consisting of $300 million issued in the first quarter, $425 million issued in the second quarter, $310 million issued in the third quarter, and $50 million issued in the fourth quarter of 2012. In September 2012, the Company also redeemed the $600 million MTN Series 3 notes.

The long-term debt is unsecured and denominated in Canadian dollars. The long-term debt is summarized by the number of years to maturity in Note 12 – Fair Value of Financial Instruments and Risk Management.

Credit Agreements

Hydro One has a $1,250 million committed and unused revolving standby credit facility with a syndicate of banks, maturing in June 2017. If used, interest on the facility would apply based on Canadian benchmark rates. This credit facility supports the Company's Commercial Paper Program.

The Company may use the credit facility for general corporate purposes, including meeting short-term funding requirements. The obligation of each lender to make any credit extension to the Company under its credit facility is subject to various conditions including, among other things, that no event of default has occurred or would result from such credit extension.

12. FAIR VALUE OF FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

Fair value is considered to be the exchange price in an orderly transaction between market participants to sell an asset or transfer a liability at the measurement date. The fair value definition focuses on an exit price, which is the price that would be received in the sale of an asset or the amount that would be paid to transfer a liability.

Hydro One classifies its fair value measurements based on the following hierarchy, as prescribed by the accounting guidance for fair value, which prioritizes the inputs to valuation techniques used to measure fair value into three levels:

Level 1 inputs are unadjusted quoted prices in active markets for identical assets or liabilities that Hydro One has the ability to access. An active market for the asset or liability is one in which transactions for the asset or liability occur with sufficient frequency and volume to provide ongoing pricing information.

Level 2 inputs are those other than quoted market prices that are observable, either directly or indirectly, for an asset or liability. Level 2 inputs include, but are not limited to, quoted prices for similar assets or liabilities in an active market, quoted prices for identical or similar assets or liabilities in markets that are not active and inputs other than quoted market prices that are observable for the asset or liability, such as interest rate curves and yield curves observable at commonly quoted intervals, volatilities, credit risk and default rates. A Level 2 measurement cannot have more than an insignificant portion of the valuation based on unobservable inputs.

Level 3 inputs are any fair value measurements that include unobservable inputs for the asset or liability for more than an insignificant portion of the valuation. A Level 3 measurement may be based primarily on Level 2 inputs.

Non-Derivative Financial Assets and Liabilities

At December 31, 2012 and 2011, the Company's carrying amounts of accounts receivable, due from related parties, short-term investments, bank indebtedness, accounts payable, accrued liabilities, and due to related parties are representative of fair value because of the short-term nature of these instruments.

Fair Value Measurements of Long-Term Debt

The fair values and carrying values of the Company's long-term debt at December 31, 2012 and 2011 are as follows:

December 31 (millions of dollars)	**2012 Carrying Value**	**2012 Fair Value**	2011 Carrying Value	2011 Fair Value
Long-term debt				
$500 million of MTN Series 19 notes[1]	**512**	**512**	521	521
$250 million of MTN Series 21 notes[2]	**257**	**257**	262	262
Other notes and debentures[3]	**7,710**	**9,188**	7,225	8,615
	8,479	**9,957**	8,008	9,398

[1] The fair value of $500 million of the MTN Series 19 notes subject to hedging is primarily based on changes in the present value of future cash flows due to a change in the yield in the swap market for the related swap (hedged risk).

[2] The fair value of $250 million of the MTN Series 21 notes subject to hedging is primarily based on changes in the present value of future cash flows due to a change in the yield in the swap market for the related swap (hedged risk).

[3] The fair value of other notes and debentures, and the portions of the MTN Series 19 notes and the MTN Series 21 notes that are not subject to hedging, represents the market value of the notes and debentures and is based on unadjusted period-end market prices for the same or similar debt of the same remaining maturities.

Fair Value Measurements of Derivative Instruments

At December 31, 2012, the Company had interest-rate swaps totaling $750 million (2011 – $750 million) that were used to convert fixed-rate debt to floating-rate debt. These swaps are classified as fair value hedges. The Company's fair value hedge exposure was equal to about 9% (2011 – 9%) of its total long-term debt of $8,479 million (2011 – $8,008 million). At December 31, 2012, the Company had the following interest-rate swaps designated as fair value hedges:

(a) two $250 million fixed-to-floating interest-rate swap agreements to convert $500 million of the $750 million MTN Series 19 notes maturing November 19, 2014 into three-month variable rate debt; and

(b) two $125 million fixed-to-floating interest-rate swap agreements to convert $250 million of the $500 million MTN Series 21 notes maturing September 11, 2015 into three-month variable rate debt.

At December 31, 2012, the Company also had interest-rate swaps with a total notional value of $900 million classified as undesignated contracts. The undesignated contracts consist of the following interest-rate swaps:

(c) three $250 million floating-to-fixed interest-rate swap agreements that lock in the floating rate the Company pays on a portion of the above fixed-to-floating interest-rate swaps from December 11, 2012 to December 11, 2013, from February 21, 2012 to February 19, 2013, and from February 19, 2013 to February 19, 2014, respectively;

(d) two $50 million floating-to-fixed interest-rate swap agreements that lock in the floating rate the Company pays on the $50 million floating-rate MTN Series 22 notes from January 24, 2012 to January 24, 2013, and from January 24, 2013 to January 24, 2014; and

(e) a $50 million floating-to-fixed interest-rate swap agreement that locks in the floating rate the Company pays on the $50 million floating-rate MTN Series 27 notes from March 4, 2013 to December 3, 2013.

At December 31, 2012 and 2011, the Company's carrying amounts of derivative instruments were representative of fair value.

Fair Value Hierarchy

The fair value hierarchy of financial assets and liabilities at December 31, 2012 and 2011 is as follows:

December 31, 2012 (millions of dollars)	**Carrying Value**	**Fair Value**	**Level 1**	**Level 2**	**Level 3**
Assets:					
Short-term investments	**195**	**195**	**–**	**195**	**–**
Long-term investment	**251**	**251**	**–**	**251**	**–**
Derivative instruments					
Fair value hedges – interest-rate swaps	**19**	**19**	**–**	**19**	**–**
	465	**465**	**–**	**465**	**–**
Liabilities:					
Bank indebtedness	**42**	**42**	**42**	**–**	**–**
Long-term debt	**8,479**	**9,957**	**–**	**9,957**	**–**
	8,521	**9,999**	**42**	**9,957**	**–**

December 31, 2011 (millions of dollars)	Carrying Value	Fair Value	Level 1	Level 2	Level 3
Assets:					
Short-term investments	228	228	–	228	–
Long-term investment	250	250	–	250	–
Derivative instruments					
Fair value hedges – interest-rate swaps	33	33	–	33	–
Undesignated contracts – interest-rate swaps	1	1	–	1	–
	512	512	–	512	–
Liabilities:					
Bank indebtedness	39	39	39	–	–
Long-term debt	8,008	9,398	–	9,398	–
	8,047	9,437	39	9,398	–

The short-term investments represent investments with an original maturity of three months or less. The fair value of the short-term investments is determined using inputs other than quoted prices that are observable for the assets. The Company obtains quotes for the fair value of the short-term investments from an independent third party.

The long-term investment represents the Province of Ontario Floating-Rate Notes. The fair value of the long-term investment is determined using inputs other than quoted prices that are observable for the asset, with unrecognized gains or losses recognized in financing charges. The Company obtains quotes from an independent third party for the fair value of the long-term investment, who uses the market price of similar securities adjusted for changes in observable inputs such as maturity dates and interest rates.

The fair value of the derivative instruments is determined using other than quoted prices that are observable for these assets. The fair value is primarily based on the present value of future cash flows using a swap yield curve to determine the assumptions for interest rates.

The fair value of the hedged portion of the long-term debt is primarily based on the present value of future cash flows using a swap yield curve to determine the assumption for interest rates. The fair value of the unhedged portion of the long-term debt is based on unadjusted period-end market prices for the same or similar debt of the same remaining maturities.

There were no significant transfers between any of the levels during the years ended December 31, 2012 and 2011.

See Note 14 – Pension and Post-Retirement and Post-Employment Benefits for further information regarding the fair value and related valuation techniques for pension plan assets.

Risk Management

Exposure to market risk, credit risk and liquidity risk arises in the normal course of the Company's business.

Market Risk

Market risk refers primarily to the risk of loss that results from changes in commodity prices, foreign exchange rates and interest rates. The Company does not have commodity risk. The Company does have foreign exchange risk as it enters into agreements to purchase materials and equipment associated with capital programs and projects that are settled in foreign currencies. This foreign exchange risk is not material, although the Company could in the future decide to issue foreign currency-denominated debt which would be hedged back to Canadian dollars consistent with its risk management policy. Hydro One is exposed to fluctuations in interest rates as the regulated rate of return for the Company's transmission and distribution businesses is derived using a formulaic approach that is based on the forecast for long-term Government of Canada bond yields and the spread in 30-year "A"-rated Canadian utility bonds over the 30-year benchmark Government of Canada bond yield. The Company estimates that a 1% decrease in the forecasted long-term Government of Canada bond yield or the "A"-rated Canadian utility spread used in determining the Company's rate of return would reduce the Transmission Business' results of operations by approximately $18 million (2011 – $18 million) and Hydro One Networks' Distribution Business' results of operations by approximately $10 million (2011 – $10 million).

The Company uses a combination of fixed and variable-rate debt to manage the mix of its debt portfolio. The Company also uses derivative financial instruments to manage interest-rate risk. The Company utilizes interest-rate swaps, which are typically designated as fair value hedges, as a means to manage its interest rate exposure to achieve a lower cost of debt. In addition, the Company may utilize interest-rate derivative instruments to lock in interest rate levels in anticipation of future financing. Hydro One may also enter into derivative agreements such as forward-starting pay fixed-interest-rate swap agreements to hedge against the effect of future interest rate movements on long-term fixed-rate borrowing requirements. Such arrangements are typically designated as cash flow hedges. No cash flow hedge agreements were outstanding as at December 31, 2012 or 2011.

A hypothetical 10% increase in the interest rates associated with variable-rate debt would not have resulted in a significant decrease in Hydro One's results of operations for the years ended December 31, 2012 or 2011.

Fair Value Hedges

For derivative instruments that are designated and qualify as fair value hedges, the gain or loss on the derivative as well as the offsetting loss or gain on the hedged item attributable to the hedged risk are recognized in the Consolidated Statements of Operations and Comprehensive

Income. The net unrealized loss (gain) on the hedged debt and the related interest rate swaps for the years ended December 31, 2012 and 2011 are included in financing charges as follows:

Year ended December 31 (millions of dollars)	**2012**	2011
Unrealized loss (gain) on hedged debt	**(14)**	25
Unrealized loss (gain) on fair value interest-rate swaps	**14**	(25)
Net unrealized loss (gain)	**–**	–

At December 31, 2012, Hydro One had $750 million (2011 – $750 million) of notional amounts of fair value hedges outstanding related to interest-rate swaps, with assets at fair value of $19 million (2011 – $33 million). During the years ended December 31, 2012 and 2011, there was no significant impact on the results of operations as a result of any ineffectiveness attributable to fair value hedges.

Credit Risk

Financial assets create a risk that a counterparty will fail to discharge an obligation, causing a financial loss. At December 31, 2012 and 2011, there were no significant concentrations of credit risk with respect to any class of financial assets. The Company's revenue is earned from a broad base of customers. As a result, Hydro One did not earn a significant amount of revenue from any individual customer. At December 31, 2012 and 2011, there was no significant accounts receivable balance due from any single customer.

At December 31, 2012, the Company's provision for bad debts was $23 million (2011 – $18 million). Adjustments and write-offs were determined on the basis of a review of overdue accounts, taking into consideration historical experience. At December 31, 2012, approximately 3% of the Company's accounts receivable were aged more than 60 days (2011 – 3%).

Hydro One manages its counterparty credit risk through various techniques including: entering into transactions with highly-rated counterparties; limiting total exposure levels with individual counterparties consistent with the Company's Board-approved Credit Risk Policy; entering into master agreements which enable net settlement and the contractual right of offset; and monitoring the financial condition of counterparties. In addition to payment netting language in master agreements, the Company establishes credit limits, margining thresholds and collateral requirements for each counterparty. Counterparty credit limits are based on an internal credit review that considers a variety of factors, including the results of a scoring model, leverage, liquidity, profitability, credit ratings and risk management capabilities. The determination of credit exposure for a particular counterparty is the sum of current exposure plus the potential future exposure with that counterparty. The current exposure is calculated as the sum of the principal value of money market exposures and the market value of all contracts that have a positive mark-to-market position on the measurement date. The Company would only offset the positive market values against negative values with the same counterparty where permitted by the existence of a legal netting agreement such as an International Swap Dealers Association master agreement. The potential future exposure represents a safety margin to protect against future fluctuations of interest rates, currencies, equities, and commodities. It is calculated based on factors developed by the Bank of International Settlements, following extensive historical analysis of random fluctuations of interest rates and currencies. To the extent that a counterparty's margining thresholds are exceeded, the counterparty is required to post collateral with the Company as specified in each agreement. The Company monitors current and forward credit exposure to counterparties both on on individual and an aggregate basis. The Company's credit risk for accounts receivable is limited to the carrying amounts on the Consolidated Balance Sheets.

Derivative financial instruments result in exposure to credit risk since there is a risk of counterparty default. The credit exposure of derivative contracts, before collateral, is represented by the fair value of contracts at the reporting date. At December 31, 2012, the counterparty credit risk exposure on the fair value of these interest-rate swap contracts was $22 million (2011 – $36 million). At December 31, 2012, Hydro One's credit exposure for all derivative instruments, and applicable payables and receivables, had a credit rating of investment grade, with four financial institutions as the counterparties. The credit exposure of each of the four counterparties accounted for more than 10% of the total credit exposure.

Liquidity Risk

Liquidity risk refers to the Company's ability to meet its financial obligations as they come due. Hydro One meets its short-term liquidity requirements using cash and cash equivalents on hand, funds from operations, the issuance of commercial paper, the revolving standby credit facility, and by holding Province of Ontario Floating-Rate Notes. The Commercial Paper Program is supported by a total of $1,500 million in liquidity facilities comprised of a $1,250 million committed revolving credit facility with a syndicate of banks maturing in June 2017 and the Province of Ontario Floating-Rate Notes with a fair value of $251 million. The short-term liquidity under this program and anticipated levels of funds from operations should be sufficient to fund normal operating requirements.

At December 31, 2012, accounts payable and accrued liabilities in the amount of $722 million are expected to be settled in cash at their carrying amounts within the next year.

At December 31, 2012, Hydro One had issued long-term debt in the notional amount of $8,460 million (2011 – $7,975 million). Long-term debt maturing during the next year is $600 million (2011 – $600 million). Interest payments for the next 12 months on the Company's outstanding long-term debt amount to $410 million (2011 – $408 million). Principal outstanding, interest payments and related weighted average interest rates are summarized by the number of years to maturity in the following table.

Years to Maturity	Principal Outstanding on Long-term Debt *(millions of dollars)*	Interest Payments[1] *(millions of dollars)*	Weighted Average Interest Rate[1] *(%)*
1 year	600	410	5.0
2 years	750	379	3.1
3 years	550	356	2.8
4 years	500	331	4.3
5 years	600	320	5.2
	3,000	1,796	4.1
6 – 10 years	900	1,403	3.6
Over 10 years	4,560	4,138	5.6
	8,460	7,337	4.9

[1] Interest payments and weighted average interest rates beyond 1 year exclude the impact of the $50 million floating-rate Series 22 notes due 2015 and the $50 million floating-rate Series 27 notes due 2016.

13. CAPITAL MANAGEMENT

The Company's objectives with respect to its capital structure are to maintain effective access to capital on a long-term basis at reasonable rates, and to deliver appropriate financial returns. In order to ensure ongoing effective access to capital, the Company targets to maintain an "A" category long-term credit rating.

The Company considers its capital structure to consist of shareholder's equity, preferred shares, long-term debt, and cash and cash equivalents. At December 31, 2012 and 2011, the Company's capital structure was as follows:

December 31 (millions of dollars)	**2012**	2011
Long-term debt payable within one year	**600**	600
Less: Cash and cash equivalents	**195**	228
	405	372
Long-term debt	**7,879**	7,408
Preferred shares	**323**	323
Common shares	**3,314**	3,314
Retained earnings	**3,202**	2,827
	6,516	6,141
Total capital	**15,123**	14,244

The Company has customary covenants typically associated with long-term debt. Among other things, Hydro One's long-term debt and credit facility covenants limit the permissible debt to 75% of the Company's total capitalization, limit the ability to sell assets and impose a negative pledge provision, subject to customary exceptions. At December 31, 2012 and 2011, Hydro One was in compliance with all of these covenants and limitations.

14. PENSION AND POST-RETIREMENT AND POST-EMPLOYMENT BENEFITS

Hydro One has a defined benefit pension plan, a supplementary pension plan, and post-retirement and post-employment benefit plans. The defined benefit pension plan (Pension Plan) is contributory and covers all regular employees of Hydro One and its subsidiaries, except Hydro One Brampton Networks. Employees of Hydro One Brampton Networks participate in the OMERS plan, a multiemployer public sector pension fund. The supplementary pension plan provides members of the Pension Plan with benefits that would have been earned and payable under the Pension Plan but for the limitations imposed by the *Income Tax Act* (Canada). The supplementary pension plan obligation is included with other post-retirement and post-employment benefit obligations on the Consolidated Balance Sheets.

The OMERS Plan

Hydro One contributions to the OMERS plan for the year ended December 31, 2012 were $2 million (2011 – $1 million). Company contributions payable at December 31, 2012 and included in accrued liabilities on the Consolidated Balance Sheets were $0.2 million (2011 – $0.2 million). Hydro One contributions do not represent more than 5% of total contributions to the OMERS plan, as indicated in OMERS's most recently available annual report for the year ended December 31, 2011.

At December 31, 2011, the OMERS plan was 88.7% funded, with an unfunded liability of $7,290 million. This unfunded liability will likely result in future payments by participating employers and members. Hydro One future contributions could be increased substantially if other entities withdraw from the plan.

Pension Plan, Post-Retirement and Post-Employment Plans

The Pension Plan provides benefits based on highest three-year average pensionable earnings. For new management employees who commenced employment on or after January 1, 2004, and for new Society of Energy Professionals-represented staff hired after November 17, 2005, benefits are based on highest five-year average pensionable earnings. After retirement, pensions are indexed to inflation.

Company and employees' contributions to the Pension Plan are based on actuarial valuations performed at least every three years. Annual Pension Plan contributions for 2012 of $163 million (2011 – $152 million) were based on an actuarial valuation effective December 31, 2011 and the level of 2012 pensionable earnings. Estimated annual Pension Plan contributions for 2013 are $162 million, based on the December 31, 2011 valuation and the projected level of pensionable earnings.

Hydro One recognizes the overfunded or underfunded status of the Pension Plan, and post-retirement and post-employment plans (Plans) as an asset or liability on its Consolidated Balance Sheets, with offsetting regulatory assets and liabilities as appropriate. The underfunded benefit obligations for the Plans, in the absence of regulatory accounting, would be recognized in AOCI. The impact of changes in assumptions used to measure pension, post-retirement and post-employment benefit obligations is generally recognized over the expected average remaining service period of the employees. For the year ended December 31, 2012, the measurement date for the Plans was December 31.

Year ended December 31 (millions of dollars)	Pension Benefits 2012	Pension Benefits 2011	Post-Retirement and Post-Employment Benefits 2012	Post-Retirement and Post-Employment Benefits 2011
Change in projected benefit obligation				
Projected benefit obligation, beginning of year	**5,461**	4,996	**1,206**	1,178
Current service cost	**123**	108	**29**	30
Interest cost	**285**	286	**63**	68
Reciprocal transfers	**1**	4	**–**	–
Benefits paid	**(291)**	(289)	**(42)**	(42)
Net actuarial loss (gain)	**928**	356	**203**	(28)
Projected benefit obligation, end of year	**6,507**	5,461	**1,459**	1,206
Change in plan assets				
Fair value of plan assets, beginning of year	**4,682**	4,699	**–**	–
Actual return on plan assets	**425**	102	**–**	–
Reciprocal transfers	**1**	4	**–**	–
Benefits paid	**(291)**	(289)	**–**	–
Employer's contributions	**163**	153	**–**	–
Employees' contributions	**27**	27	**–**	–
Administrative expenses	**(15)**	(14)	**–**	–
Fair value of plan assets, end of year	**4,992**	4,682	**–**	–
Unfunded status	**1,515**	779	**1,459**	1,206

Hydro One presents its benefit obligations and plan assets net on its Consolidated Balance Sheets within the following line items:

December 31 (millions of dollars)	Pension Benefits 2012	Pension Benefits 2011	Post-Retirement and Post-Employment Benefits 2012	Post-Retirement and Post-Employment Benefits 2011
Accrued liabilities	**–**	–	**43**	43
Pension benefit liability	**1,515**	779	**–**	–
Post-retirement and post-employment benefit liability	**–**	–	**1,416**	1,163
Unfunded status	**1,515**	779	**1,459**	1,206

The funded/unfunded status of the pension, post-retirement and post-employment benefit plans refers to the difference between the fair value of plan assets and the projected benefit obligations for the Plans. The funded/unfunded status changes over time due to several factors, including contribution levels, assumed discount rates and actual returns on plan assets.

The following table provides the projected benefit obligation (PBO), accumulated benefit obligation (ABO) and fair value of plan assets for the Pension Plan.

December 31 (millions of dollars)	**2012**	2011
PBO	**6,507**	5,461
ABO	**6,074**	5,038
Fair value of plan assets	**4,992**	4,682

On an ABO basis, the plans were funded at 82% at December 31, 2012 (2011 – 93%). On a PBO basis, the plans were funded at 77% at December 31, 2012 (2011 – 86%). The ABO differs from the PBO in that the ABO includes no assumption about future compensation levels.

Components of Net Periodic Benefit Costs

The following table provides the components of the net periodic benefit costs for the years ended December 31, 2012 and 2011 for all plans:

	Pension Benefits		Post-Retirement and Post-Employment Benefits	
Year ended December 31 (millions of dollars)	**2012**	2011	**2012**	2011
Current service cost, net of employee contributions	**96**	81	**30**	30
Interest cost	**285**	286	**63**	67
Expected return on plan assets net of expenses	**(289)**	(291)	**–**	–
Actuarial loss amortization	**112**	68	**8**	7
Prior service cost amortization	**3**	4	**3**	4
Net Periodic Benefit Cost	**207**	148	**104**	108
Charged to results of operations[1]	**76**	93	**48**	61

[1] The Company follows the cash basis of accounting consistent with the inclusion of pension costs in OEB-approved rates. During the year ended December 31, 2012, pension costs of $163 million (2011 – $153 million) were attributed to labour, of which $76 million (2011 – $93 million) was charged to operations and $87 million (2011 – $60 million) was capitalized as part of the cost of property, plant and equipment and intangible assets.

Assumptions

The measurement of the obligations of the Plans and costs of providing benefits under Plans involves various factors, including the development of valuation assumptions and accounting policy elections. When developing the required assumptions, the Company considers historical information as well as future expectations. The measurement of benefit obligations and costs is impacted by several assumptions including the discount rate applied to benefit obligations, the long-term expected rate of return on plan assets, Hydro One's expected level of contributions to the Plans, the incidence of mortality, the expected remaining service period of plan participants, the level of compensation and rate of compensation increases, employee age, length of service, and the anticipated rate of increase of health care costs, among other factors. The impact of changes in assumptions used to measure the obligations of the Plans is generally recognized over the expected average remaining service period of the plan participants. In selecting the expected rate of return on plan assets, Hydro One considers historical economic indicators (including inflation and GDP growth) that impact asset returns, as well as expectations regarding future long-term capital market performance, weighted by target asset class allocations. In general, equity securities, real estate and private equity investments are forecasted to have higher returns than fixed income securities.

The following weighted average assumptions were used to determine the benefit obligations and benefit expense at December 31, 2012 and 2011. Assumptions used to determine current year-end benefit obligations are the assumptions used to estimate the subsequent year's net periodic benefit costs.

Year ended December 31	Pension Benefits **2012**	Pension Benefits 2011	Post-Retirement and Post-Employment Benefits **2012**	Post-Retirement and Post-Employment Benefits 2011
Significant assumptions:				
For net periodic benefit cost, year ended December 31:				
Weighted average expected rate of return on plan assets	**6.25%**	6.25%	–	–
Weighted average discount rate	**5.25%**	5.75%	**5.25%**	5.75%
Rate of compensation scale escalation (without merit)	**2.50%**	2.50%	**2.50%**	2.50%
Rate of cost of living increase	**2.00%**	2.00%	**2.00%**	2.00%
Average remaining service life of employees *(years)*	**11**	11	**11**	11
Rate of increase in health care cost trends[1]	–	–	**4.41%**	4.91%
For projected benefit obligation, at December 31:				
Weighted average discount rate	**4.25%**	5.25%	**4.25%**	5.25%
Rate of compensation scale escalation (without merit)	**2.50%**	2.50%	**2.50%**	2.50%
Rate of cost of living increase	**2.00%**	2.00%	**2.00%**	2.00%
Rate of increase in health care cost trends[2]	–	–	**4.39%**	4.41%

[1] 7.03% per annum in 2012, grading down to 4.41% per annum in and after 2031 (2011 – 7.56% in 2011, grading down to 4.91% per annum in and after 2029)

[2] 6.91% per annum in 2013, grading down to 4.39% per annum in and after 2031 (2011 – 7.03% in 2012, grading down to 4.41% per annum in and after 2031)

The discount rate used to determine the current year pension obligation and the subsequent year's net periodic benefit costs is based on a yield curve approach. Under the yield curve approach, expected future benefit payments for each plan are discounted by a rate on a third party bond yield curve corresponding to each duration. The yield curve is based on AA long-term corporate bonds. A single discount rate is calculated that would yield the same present value as the sum of the discounted cash flows.

The effect of 1% change in health care cost trends on the post-retirement and post-employment benefits is as follows:

Year ended December 31 (millions of dollars)	**2012**	2011
Effect of 1% increase in health care cost trends on:		
Projected benefit obligation at December 31	**246**	174
Service cost and interest cost	**17**	20
Effect of 1% decrease in health care cost trends on:		
Projected benefit obligation at December 31	**(191)**	(138)
Service cost and interest cost	**(13)**	(14)

Estimated Future Benefit Payments

At December 31, 2012, estimated future benefit payments by the Company to Plan participants were:

(millions of dollars)	Pension Benefits	Post-Retirement and Post-Employment Benefits
2013	299	51
2014	306	54
2015	313	57
2016	318	61
2017	324	64
2018 through to 2022	1,690	374
Total estimated future benefit payments through to 2022	3,250	661

Components of Regulatory Assets

A portion of actuarial gains and losses and prior service costs is recorded within regulatory assets on Hydro One's Consolidated Balance Sheets to reflect the expected regulatory inclusion of these amounts in future rates, which would otherwise be recorded in OCI. The following table provides the actuarial gains and losses and prior service costs recorded within regulatory assets:

	Pension Benefits		Post-Retirement and Post-Employment Benefits	
Year ended December 31 (millions of dollars)	**2012**	2011	**2012**	2011
Actuarial loss (gain) for the year	**807**	558	**203**	(27)
Actuarial loss amortization	**(112)**	(68)	**(8)**	(7)
Prior service cost amortization	**(3)**	(4)	**(3)**	(3)
	692	486	**192**	(37)

The following table provides the components of regulatory assets that have not been recognized as components of net periodic benefit costs for the years ended December 31, 2012 and 2011:

	Pension Benefits		Post-Retirement and Post-Employment Benefits	
Year ended December 31 (millions of dollars)	**2012**	2011	**2012**	2011
Prior service cost	**5**	7	**5**	7
Actuarial loss	**1,510**	772	**315**	116
	1,515	779	**320**	123

The following table provides the components of regulatory assets at December 31 that are expected to be amortized as components of net periodic benefit costs in the following year:

	Pension Benefits		Post-Retirement and Post-Employment Benefits	
Year ended December 31 (millions of dollars)	**2012**	2011	**2012**	2011
Prior service cost	**2**	3	**3**	3
Actuarial loss	**175**	112	**17**	4
	177	115	**20**	7

Pension Plan Assets

Investment Strategy

On a regular basis, Hydro One evaluates its investment strategy to ensure that plan assets will be sufficient to pay Pension Plan benefits when due. As part of this ongoing evaluation, Hydro One may make changes to its targeted asset allocation and investment strategy. The Pension Plan is managed at a net asset level. The main objective of the Pension Plan is to sustain a certain level of net assets in order to meet the pension obligations of the Company. The Pension Plan fulfills its primary objective by adhering to specific investment policies outlined in its Summary of Investment Policies and Procedures (SIPP), which is reviewed and approved by the Investment-Pension Committee of Hydro One's Board of Directors. The Company manages net assets by engaging knowledgeable external investment managers who are charged with the responsibility of investing existing funds and new funds (current year's employee and employer contributions) in accordance with the approved SIPP. The performance of the managers is monitored through a governance structure. Increases in net assets are a direct result of investment income generated by investments held by the Pension Plan and contributions to the Pension Plan by eligible employees and by the Company. The main use of net assets is for benefit payments to eligible Pension Plan members.

Pension Plan Asset Mix

At December 31, 2012, the Pension Plan target asset allocations and weighted average asset allocations were as follows:

December 31, 2012	Target Allocation (%)	Pension Plan Assets (%)
Equity securities	60.0	64.1
Debt securities	35.0	35.8
Other[1]	5.0	0.1
	100.0	100.0

[1] Other investments include real estate and infrastructure investments.

At December 31, 2012, the Pension Plan held $20 million of Hydro One corporate bonds (2011 – $27 million) and $243 million of debt securities of the Province (2011 – $214 million).

Concentrations of Credit Risk

Hydro One evaluated its Pension Plan's asset portfolio for the existence of significant concentrations of credit risk as at December 31, 2012 and 2011. Concentrations that were evaluated include, but are not limited to, investment concentrations in a single entity, concentrations in a type of industry, and concentrations in individual funds. At December 31, 2012 and 2011, there were no significant concentrations (defined as greater than 10% of plan assets) of risk in the Pension Plan's assets.

The Pension Plan manages its counterparty credit risk with respect to bonds by investing in investment-grade and government bonds and with respect to derivative instruments by transacting only with financial institutions rated at least "AA" by S&P or "Aa2" by Moody's Investors Service Inc. and also by utilizing exposure limits to each counterparty. The risk of default on transactions in listed securities is considered minimal, as the trade will fail if either party to the transaction does not meet its obligation.

Fair Value Measurements

The following table presents the Pension Plan assets measured and recorded at fair value on a recurring basis and their level within the fair value hierarchy at December 31, 2012 and 2011:

December 31, 2012 (millions of dollars)	Level 1	Level 2	Level 3	Total
Pooled funds	2	15	104	121
Cash and cash equivalents	125	–	–	125
Short-term securities	–	100	–	100
Real estate	–	–	2	2
Corporate shares – Canadian	920	–	–	920
Corporate shares – Foreign	2,077	–	–	2,077
Bonds and debentures – Canadian	–	1,643	–	1,643
Total fair value of plan assets[1]	3,124	1,758	106	4,988

[1] At December 31, 2012, the total fair value of Pension Plan assets excludes $16 million of interest and dividends receivable, $4 million relating to accruals for pending sales transactions and $8 million relating to accruals for pension administration expense.

December 31, 2011 (millions of dollars)	Level 1	Level 2	Level 3	Total
Pooled funds	3	15	165	183
Cash and cash equivalents	128	–	–	128
Short-term securities	–	38	–	38
Real estate	–	–	2	2
Corporate shares – Canadian	820	–	–	820
Corporate shares – Foreign	1,820	–	–	1,820
Bonds and debentures – Canadian	–	1,675	–	1,675
Bonds and debentures – Foreign	–	1	–	1
Total fair value of plan assets[1]	2,771	1,729	167	4,667

[1] At December 31, 2011, the total fair value of Pension Plan assets excludes $17 million of interest and dividends receivable, $8 million of receivables relating to pending sales transactions, and $10 million relating to accruals for pension administration expense.

See Note 12 – Fair Value of Financial Instruments and Risk Management for a description of levels within the fair value hierarchy.

Changes in the Fair Value of Financial Instruments Classified in Level 3

The following table summarizes the changes in fair value of financial instruments classified in Level 3 for the years ended December 31, 2012 and 2011. The Pension Plan classifies financial instruments as Level 3 when the fair value is measured based on at least one significant input that is not observable in the markets or due to lack of liquidity in certain markets. The gains and losses presented in the table below may include changes in fair value based on both observable and unobservable inputs.

Year ended December 31 (millions of dollars)	**2012**	2011
Fair value, beginning of year	**167**	167
Realized and unrealized gains	**5**	18
Purchases	**6**	9
Sales and disbursements	**(72)**	(27)
Fair value, end of year	**106**	167

There have been no material transfers into or out of Level 3 of the fair value hierarchy.

The Company performs sensitivity analysis for fair value measurements classified in Level 3, substituting the unobservable inputs with one or more reasonably possible alternative assumptions. These sensitivity analyses resulted in negligible changes in the fair value of financial instruments classified in this level.

Valuation Techniques Used to Determine Fair Value

Pooled Funds

The pooled fund category mainly consists of private equity investments. Private equity investments represent private equity funds that invest in operating companies that are not publicly traded on a stock exchange. Investment strategies in private equity include limited partnerships in businesses that are characterized by high internal growth and operational efficiencies, venture capital, leveraged buyouts and special situations such as distressed investments. Private equity valuations are reported by the fund manager and are based on the valuation of the underlying investments which includes inputs such as cost, operating results, discounted future cash flows and market-based comparable data. Since these valuation inputs are not highly observable, private equity investments have been categorized as Level 3 within pooled funds.

Cash Equivalents

Demand cash deposits held with banks and cash held by the investment managers are considered cash equivalents and are included in the fair value measurements hierarchy as Level 1.

Short-Term Securities

Short-term securities are valued at cost plus accrued interest, which approximates fair value due to their short-term nature. Short-term securities have been categorized as Level 2.

Real Estate

Real estate investments represent private equity investments in holding companies that invest in real estate properties. The investments in the holding companies are valued using net asset values reported by the fund manager. Real estate investments are categorized as Level 3.

Corporate Shares

Corporate shares are valued based on quoted prices in active markets and are categorized as Level 1. Investments denominated in foreign currencies are translated into Canadian currency at year-end rates of exchange.

Bonds and Debentures

Bonds and debentures are presented at published closing trade quotations, and are categorized as Level 2.

15. ENVIRONMENTAL LIABILITIES

The Company has accrued the following discounted amounts for environmental liabilities on the Consolidated Balance Sheets at December 31, 2012 and 2011:

December 31 (millions of dollars)	**PCB**	**LAR**	**Total**
2012			
Environmental liabilities, January 1	**199**	**58**	**257**
Interest accretion	**9**	**2**	**11**
Expenditures	**(8)**	**(10)**	**(18)**
Revaluation adjustment	**(3)**	**2**	**(1)**
Environmental liabilities, December 31	**197**	**52**	**249**
Less: current portion	**(13)**	**(9)**	**(22)**
	184	**43**	**227**

December 31 (millions of dollars)	PCB	LAR	Total
2011			
Environmental liabilities, January 1	251	58	309
Interest accretion	12	2	14
Expenditures	(9)	(7)	(16)
Revaluation adjustment	(55)	5	(50)
Environmental liabilities, December 31	199	58	257
Less: current portion	(13)	(9)	(22)
	186	49	235

The following table illustrates the reconciliation between the undiscounted basis of the environmental liabilities and the amount recognized in the Consolidated Balance Sheets after factoring in the discount rate:

December 31 (millions of dollars)	**PCB**	**LAR**	**Total**
2012			
Undiscounted environmental liabilities, December 31	**233**	**54**	**287**
Less: discounting accumulated liabilities to present value	**(36)**	**(2)**	**(38)**
Discounted environmental liabilities, December 31	**197**	**52**	**249**

December 31 (millions of dollars)	PCB	LAR	Total
2011			
Undiscounted environmental liabilities, December 31	242	61	303
Less: discounting accumulated liabilities to present value	(43)	(3)	(46)
Discounted environmental liabilities, December 31	199	58	257

Estimated future environmental expenditures for each of the five years subsequent to December 31, 2012 and in total thereafter are as follows: 2013 – $22 million; 2014 – $38 million; 2015 – $36 million; 2016 – $22 million; 2017 – $17 million; and thereafter – $152 million. At December 31, 2012, of the total estimated future environmental expenditures, $233 million relate to PCB (2011 – $242 million) and $54 million relate to LAR (2011 – $61 million).

Consistent with its accounting policy for environmental costs, Hydro One records a liability for the estimated mandatory future expenditures associated with the removal and destruction of PCB-contaminated insulating oils and related electrical equipment and for the assessment and remediation of chemically-contaminated lands.

There are uncertainties in estimating future environmental costs due to potential external events such as changes in legislation or regulations and advances in remediation technologies. All factors used in estimating the Company's environmental liabilities represent management's best estimates of the present value of the cost required to meet existing legislation or regulations. However, it is reasonably possible that numbers or volumes of contaminated assets, cost estimates to perform work, inflation assumptions and the assumed pattern of annual cash flows may differ significantly from the Company's current assumptions. In addition, with respect to the PCB environmental liability, the availability of critical resources such as skilled labour and replacement assets and the ability to take maintenance outages in critical facilities may influence the timing of expenditures. Estimated environmental liabilities are reviewed annually or more frequently if significant changes in regulation or other relevant factors occur. Estimate changes are accounted for prospectively. The Company records a regulatory asset reflecting its expectation that future environmental costs will be recoverable in rates.

In determining the amounts to be recorded as environmental liabilities, the Company estimates the current cost of completing required work and makes assumptions as to when the future expenditures will actually be incurred, in order to generate future cash flow information. A long-term inflation assumption of approximately 2% has been used to express these current cost estimates as estimated future expenditures. Future environmental expenditures have been discounted using factors ranging from 3.75% to 6.25%, depending on the appropriate rate for the period when increases in the obligations were first recorded.

PCBs

In September 2008, Environment Canada published its final regulations governing the management, storage and disposal of PCBs. These regulations were enacted under the *Canadian Environmental Protection Act, 1999*. These regulations impose timelines for disposal of PCBs based on certain criteria, including type of equipment, in-use status and PCB-contamination thresholds. All PCBs in concentrations of 500 parts per million (ppm) or more, except for specified equipment, had to be disposed of by the end of 2009, with the exception of specifically exempted equipment. Under the regulations, PCBs in equipment in concentrations greater than 50 ppm and less than 500 ppm, or greater than 50 ppm for pole-top transformers, pole-top auxiliary electrical equipment and light ballasts must be disposed of by the end of 2025.

Management judges that the Company currently has very few PCB-contaminated assets in excess of 500 ppm. Assets to be disposed of by 2025 primarily consist of pole-mounted distribution line transformers and light ballasts. Contaminated distribution and transmission station equipment will generally be replaced or will be decontaminated by removing PCB-contaminated insulating oil and retro filling with replacement oil that contains PCBs in concentrations of less than 2 ppm.

The Company's best estimate of the total estimated future expenditures to comply with current PCB regulations is approximately $233 million. These expenditures are expected to be incurred over the period from 2013 to 2025. As a result of its most recent cost estimate to comply with current PCB regulations, the Company recorded a revaluation adjustment to reduce the PCB environmental liability by approximately $3 million (2011 – $55 million).

LAR

The Company's best estimate of the total estimated future expenditures to complete its LAR program is approximately $54 million. These expenditures are expected to be incurred over the period from 2013 to 2020. As part of its annual review of environmental liabilities, the Company also reviewed its liability for LAR. As a result of this review, the Company recorded a revaluation adjustment to increase the LAR environmental liability by approximately $2 million (2011 – $5 million).

16. ASSET RETIREMENT OBLIGATIONS

AROs, which represent legal obligations associated with the retirement of certain tangible long-lived assets, are computed as the present value of the projected expenditures for the future retirement of specific assets and are recognized in the period in which the liability is incurred, if a reosonable estimate of fair value can be made. If the asset remains in service at the recognition date, the present value of the liability is added to the corrying amount of the associated asset in the period the liability is incurred and this additional carrying amount is depreciated over the remaining life of the asset. If an ARO is recorded in respect of an out-of-service asset, the asset retirement cost is charged to results of operations. Subsequent to the initial recognition, the liability is adjusted for any revisions to the estimated future cash flaws associated with the ARO (with corresponding adjustments to property, plant and equipment), which can occur due to a number of factors including, but not limited to, cost escolation, changes in technology applicable to the assets to be retired ond changes in federal, state or local regulations, as well as for accretion of the liability due to the passage of time until the obligation is settled. Depreciation expense is adjusted prospectively for any increases or decreases to the carrying amount of the associated asset.

All factors used in estimating the Company's AROs represent management's best estimates of the costs required to meet existing legislation or regulations. However, it is reasonably possible that numbers or volumes of contaminated assets, cost estimates to perform work, inflation assumptions and the assumed pattern of annual cash flows may differ significantly from the Company's current assumptions. AROs are reviewed annually or more frequently if significont changes in regulation or other relevant factors occur. Estimate changes are accounted for prospectively.

In determining the amounts to be recorded as AROs, the Company estimates the current fair value for completing required removal and remediation work and makes assumptions as to when the future expenditures will actually be incurred, in order to generate future cash flow information. A long-term inflation assumption of approximately 2% has been used to express these current cost estimates as estimated future expenditures. Future expenditures hove been discounted using factors ranging from approximately 3% to 5%, depending on the appropriate rate for the period when expenditures are expected to be incurred.

At December 31, 2012, Hydro One had recorded AROs of $15 million (2011 – $15 million), consisting of $7 million (2011 – $7 million) related to the estimated future expenditures associated with the removal and disposal of asbestos-containing materials installed in some of its facilities, as well as $8 million (2011 – $8 million) related to the future decommissioning and removal of two of its switching stations.

The Company's liability for the estimated future expenditures associated with the removal and disposal of asbestos-containing materials installed in some of its facilities is based on management's best estimate of the present value of the estimated future expenditures to comply with current regulations. In 2010, the Company completed a study with the aid of an expert external consultant to estimate the future expenditures required to remove asbestos prior to facility demolition. The amount of interest recorded is nominal and there have been no expenditures associated with these obligations to date.

In 2011, Hydro One recarded an ARO of $4 million related to the future decommissioning and removal of one of its switching stations, in addition to the ARO of $4 million recorded in a prior year related to the future decommissioning and removal of another switching station. The amount of interest recorded is nominal and there have been no expenditures associated with these obligations to date.

17. SHARE CAPITAL

Preferred Shares

The Company has 12,920,000 issued and outstanding 5.5% cumulative preferred shares with a redemption value of $25 per share or $323 million total value. The Company is authorized to issue an unlimited number of preferred shares.

The Company's preferred shares are entitled to an annual cumulative dividend of $18 million, or $1.375 per share, which is payable on a quarterly basis. The preferred shares are not subject to mandatory redemption (except on liquidation) but are redeemable in certain circumstances. The shares are redeemable at the option of the Province at the redemption value, plus any accrued and unpaid dividends, if the Province sells a number of the common shares which it owns to the public such that the Province's holdings are reduced to less than 50% of the common shares of the Company. Hydro One may elect, without condition, to pay all or part of the redemption price by issuing additional common shares to the Province. If the Province does not exercise its redemption right, the Company would have the ability to adjust the dividend on the preferred shares to produce a yield that is 0.50% less than the then-current dividend market yield for similarly rated preferred shares. The preferred shares do not carry voting rights, except in limited circumstances, and would rank in priority over the common shares upon liquidation.

These preferred shares have conditions for their redemption that are outside the control of the Company because the Province can exercise its right to redeem in the event of change in ownership without approval of the Company's Board of Directors. Because the conditional redemption feature is outside the control of the Company, the preferred shares are classified outside of Shareholder's Equity on the Consolidated Balance Sheets. Management believes that it is not probable that the preferred shares will become redeemable. No adjustment to the carrying value of the preferred shares has been recognized at December 31, 2012. If it becomes probable in the future that the preferred shares will be redeemed, the redemption value would be adjusted.

Common Shares

The Company has 100,000 issued and outstanding common shares. The Company is authorized to issue an unlimited number of common shares.

Common share dividends are declared at the sole discretion of the Hydro One Board of Directors, and are recommended by management based on results of operations, maintenance of the deemed regulatory capital structure, financial conditions, cash requirements, and other relevant factors, such as industry practice and shareholder expectations.

Earnings per Share

Earnings per share is calculated as net income for the year, after cumulative preferred dividends, divided by the weighted average number of common shares outstanding during the year.

18. DIVIDENDS

In 2012, preferred share dividends in the amount of $18 million (2011 – $18 million) and common share dividends in the amount of $352 million (2011 – $150 million) were declared.

19. RELATED PARTY TRANSACTIONS

Hydro One is owned by the Province. The OEFC, IESO, Ontario Power Authority (OPA), Ontario Power Generation Inc. (OPG) and the OEB are related parties to Hydro One because they are controlled or significantly influenced by the Province. Transactions between these parties and Hydro One were as follows:

Hydro One received revenue for transmission services from the IESO, based on uniform transmission rates approved by the OEB. Transmission revenues include $1,474 million (2011 – $1,366 million) related to these services. Hydro One receives amounts for rural rate protection from the IESO. Distribution revenues include $127 million (2011 – $127 million) related to this program. In 2012, Hydro One also received revenue related to the supply of electricity to remote northern communities from the IESO. Distribution revenues include $28 million (2011 – $28 million) related to these services.

In 2012, Hydro One purchased power in the amount of $2,392 million (2011 – $2,401 million) from the IESO-administered electricity market; $10 million (2011 – $16 million) from OPG; and $7 million (2011 – $10 million) from the OEFC.

Under the *Ontario Energy Board Act, 1998*, the OEB is required to recover all of its annual operating costs from gas and electricity distributors and transmitters. In 2012, Hydro One incurred $11 million (2011 – $11 million) in OEB fees.

Hydro One has service level agreements with OPG. These services include field, engineering, logistics and telecommunications services. In 2012, revenues related to the provision of construction and equipment maintenance services with respect to these service level agreements were $10 million (2011 – $7 million), primarily for the Transmission Business. Operation, maintenance and administration costs related to the purchase of services with respect to these service level agreements were $2 million in 2012 (2011 – $2 million).

The OPA funds substantially all of the Company's Conservation and Demand Management (CDM) programs. The funding includes program costs, incentives, and management fees. In 2012, Hydro One received $39 million (2011 – $39 million) from the OPA related to the CDM programs.

The provision for PILs and payments in lieu of property taxes were paid or payable to the OEFC, and dividends were paid or payable to the Province.

Sales to and purchases from related parties occur at normal market prices or at a proxy for fair value based on the requirements of the OEB's Affiliate Relationships Code. Outstanding balances at period end are unsecured, interest free and settled in cash. At December 31, 2012, the Company held Province of Ontario Floating-Rate Notes with a fair value of $251 million (2011 – $250 million).

The amounts due to and from related parties as a result of the transactions referred to above are as follows:

December 31 (millions of dollars)	**2012**	2011
Due from related parties	**154**	156
Due to related parties[1]	**(257)**	(342)
Long-term investment	**251**	250

[1] Included in due to related parties at December 31, 2012 are amounts owing to the IESO in respect of power purchases of $199 million (2011 – $209 million).

20. CONSOLIDATED STATEMENTS OF CASH FLOWS

The changes in non-cash balances related to operations consist of the following:

Year ended December 31 (millions of dollars)	**2012**	2011
Accounts receivable	**(30)**	(18)
Due from related parties	**2**	(32)
Materials and supplies	**2**	(4)
Other assets	**(4)**	(11)
Accounts payable	**(14)**	29
Accrued liabilities	**10**	98
Due to related parties	**(85)**	61
Accrued interest	**10**	1
Long-term accounts payable and other liabilities	**13**	–
Post-retirement and post-employment benefit liability	**56**	60
	(40)	184

Supplementary information:		
Net interest paid	**411**	410
Payments in lieu of corporate income taxes	**197**	80

21. CONTINGENCIES

Legal Proceedings

Hydro One is involved in various lawsuits, claims and regulatory proceedings in the normal course of business. In the opinion of management, the outcome of such matters will not have a material adverse effect on the Company's consolidated financial position, results of operations or cash flows.

Transfer of Assets

The transfer orders by which the Company acquired certain of Ontario Hydro's businesses as of April 1, 1999 did not transfer title to some assets located on Reserves (as defined in the *Indian Act* (Canada)). Currently, the OEFC holds these assets. Under the terms of the transfer orders, the Company is required to manage these assets until it has obtained all consents necessary to complete the transfer of title of these assets to itself. The Company cannot predict the aggregate amount that it may have to pay, either on an annual or one-time basis, to obtain the required consents. However, the Company anticipates having to pay more than the $1 million that it paid in 2012. If the Company cannot obtain the required consents, the OEFC will continue to hold these assets for an indefinite period of time. If the Company cannot reach a satisfactory settlement, it may have to relocate these assets to other locations at a cost that could be substantial or, in a limited number of cases, to abandon a line and replace it with diesel-generation facilities. The costs relating to these assets could have a material adverse effect on the Company's results of operations if the Company is not able to recover them in future rate orders.

22. COMMITMENTS

Agreement with Inergi LP (Inergi)

Effective March 1, 2002, Inergi, a wholly-owned subsidiary of Cap Gemini Canada Inc., began providing services to Hydro One. On May 1, 2010, consistent with the terms of the contract, the Company extended the Master Services Agreement with Inergi for a further three-year period. This agreement will expire on February 28, 2015. As a result of this agreement, Hydro One receives from Inergi a range of services including business processing and information technology outsourcing services, as well as core system support related primarily to SAP implementation and optimization. Inergi billings for these services have ranged between $93 million and $130 million per year and are subject to external benchmarking every three years to ensure Hydro One is receiving a defined, competitive and continuously improved price.

At December 31, 2012, the annual commitments under the Inergi agreement are as follows: 2013 – $136 million; 2014 – $130 million; 2015 – $21 million; 2016 and thereafter – nil.

Prudential Support

Purchasers of electricity in Ontario, through the IESO, are required to provide security to mitigate the risk of their default based on their expected activity in the market. As at December 31, 2012, the Company provided prudential support to the IESO on behalf of Hydro One Networks and Hydro One Brampton Networks using parental guarantees of $325 million (2011 – $325 million), and on behalf of two distributors using guarantees of $0.7 million (2011 – $0.7 million). On April 27, 2012, Hydro One's highest credit rating declined from the "Aa" category to the "A" category. Based on the new credit rating category, the Company has provided letters of credit in the amount of $22 million to the IESO. The IESO could draw on these guarantees and/or letters of credit if these subsidiaries or distributors fail to make a payment required by a default notice issued by the IESO. The maximum potential payment is the face value of any letters of credit plus the nominal amount of the parental guarantees.

Retirement Compensation Arrangements

Bank letters of credit have been issued to provide security for the Company's liability under the terms of a trust fund established pursuant to the supplementary pension plan for the employees of Hydro One and its subsidiaries. The supplementary pension plan trustee is required to draw upon these letters of credit if Hydro One is in default of its obligations under the terms of this plan. Such obligations include the requirement to provide the trustee with an annual actuarial report as well as letters of credit sufficient to secure the Company's liability under the plan, to pay benefits payable under the plan and to pay the letter of credit fee. The maximum potential payment is the face value of the letters of credit. At December 31, 2012, Hydro One had letters of credit of $127 million (2011 – $124 million) outstanding relating to retirement compensation arrangements.

Operating Leases

Hydro One is committed as lessee to irrevocable operating lease contracts for buildings used in administrative and service related functions and storing telecommunication equipment. These leases have an average life of between one and five years with renewal options for periods ranging from one to 10 years included in some of the contracts. All leases include a clause to enable upward revision of the rental charge on an annual basis or on renewal according to prevailing market conditions. There are no restrictions placed upon Hydro One by entering into these leases. Hydro One Networks and Hydro One Telecom are the principal entities concerned.

At December 31, 2012, the future minimum lease payments under non-cancellable operating leases were as follows:

December 31 (millions of dollars)	**2012**	2011
Within one year	**10**	8
After one year but not more than five years	**29**	26
More than five years	**14**	20
	53	54

During the year ended December 31, 2012, the Company made lease payments totaling $9 million (2011 – $6 million).

23. SEGMENTED REPORTING

Hydro One has three reportable segments:

- The Transmission Business, which comprises the core business of providing electricity transportation and connection services, is responsible for transmitting electricity throughout the Ontario electricity grid;
- The Distribution Business, which comprises the core business of delivering and selling electricity to customers; and
- Other, the operations of which primarily consist of those of the telecommunications business.

The designation of segments has been based on a combination of regulatory status and the nature of the products and services provided. Operating segments for the Company are determined based on information used by the chief operating decision maker in deciding how to allocate resources and evaluate the performance at each of the segments. The Company evaluates segment performance based on income before financing charges and provision for PILs from continuing operations (excluding certain allocated corporate governance costs).

The accounting policies followed by the segments are the same as those described in the summary of significant accounting policies (see Note 2 – Significant Accounting Policies). Segment information on the above basis is as follows:

Year ended December 31, 2012 (millions of dollars)	**Transmission**	**Distribution**	**Other**	**Consolidated**
Segment profit				
Revenues	**1,482**	**4,184**	**62**	**5,728**
Purchased power	**–**	**2,774**	**–**	**2,774**
Operation, maintenance and administration	**402**	**608**	**61**	**1,071**
Depreciation and amortization	**320**	**329**	**10**	**659**
Income (loss) before financing charges and provision for PILs	**760**	**473**	**(9)**	**1,224**
Financing charges				**358**
Income before provision for PILs				**866**
Capital expenditures	**776**	**671**	**7**	**1,454**

Year ended December 31, 2011 (millions of dollars)	Transmission	Distribution	Other	Consolidated
Segment profit				
Revenues	1,389	4,019	63	5,471
Purchased power	–	2,628	–	2,628
Operation, maintenance and administration	422	609	61	1,092
Depreciation and amortization	302	304	10	616
Income (loss) before financing charges and provision for PILs	665	478	(8)	1,135
Financing charges				344
Income before provision for PILs				791
Capital expenditures	810	628	9	1,447

December 31 (millions of dollars)	**2012**	2011
Total assets		
Transmission	**11,586**	10,589
Distribution	**8,621**	7,594
Other	**604**	653
	20,811	18,836

All revenues, costs and assets, as the case may be, are earned, incurred or held in Canada.

24. TRANSITION TO US GAAP

The adoption of US GAAP has been made on a retrospective basis with restatement of comparative information to reflect US GAAP requirements in effect at that time. The Company's transition date to US GAAP is January 1, 2011, which is the commencement of the 2011 comparative period to the Company's 2012 Consolidated Financial Statements.

Measurement and classification differences resulting from Hydro One's adoption of US GAAP are presented below. With respect to measurement and classification differences, the tables under the heading US GAAP Differences represent quantitative reconciliations of the Consolidated Balance Sheets and the Consolidated Statements of Changes in Shareholder's Equity, previously presented in accordance with Canadian GAAP, to the respective amounts and classifications under US GAAP, together with descriptions of the various significant measurement and classification differences arising from the adoption of US GAAP. Consolidated Balance Sheets and Consolidated Statements of Changes in Shareholder's Equity reconciliations are presented as at January 1, 2011 and December 31, 2011, representing the commencement and ending dates of the comparative financial year to 2012. There were no measurement or classification differences resulting from Hydro One's adoption of US GAAP on the Consolidated Statements of Operations and Comprehensive Income.

Except as otherwise disclosed in this note, the change in basis of accounting from Canadian GAAP to US GAAP did not materially impact accounting policies or disclosures. Reference should be made to the previously filed Canadian GAAP Consolidated Financial Statements as at and for the year ended December 31, 2011 for additional information on Canadian GAAP accounting policies and practices.

The following table summarizes the increases (decreases) to total assets:

(millions of dollars)	Notes	**January 1, 2011**	**December 31, 2011**
Total assets – Canadian GAAP		17,322	18,368
Deferred debt costs	A	32	32
Deferred pension asset	B	(460)	(466)
Regulatory assets	B	450	902
Total assets – US GAAP		17,344	18,836

The following table summarizes the increases (decreases) to total liabilities:

(millions of dollars)	Notes	**January 1, 2011**	**December 31, 2011**
Total liabilities – Canadian GAAP		11,341	11,914
Long-term debt	A	5	9
Net unamortized debt premiums	A	27	23
Pension benefit liability	B	297	779
Post-retirement and post-employment benefit liability	B	153	123
Regulatory liabilities	B	(460)	(466)
Total liabilities – US GAAP		11,363	12,382

US GAAP Differences

The reconciliations of the January 1, 2011 and December 31, 2011 Consolidated Balance Sheets from Canadian GAAP to US GAAP are as follows:

January 1, 2011 (millions of dollars)	Notes	Canadian GAAP	Effect of transition to US GAAP	US GAAP
Assets				
Current assets:				
Cash		33	–	33
Short-term investments		139	–	139
Accounts receivable	F	911	(124)	787
Due from related parties	F	–	124	124
Regulatory assets		42	–	42
Materials and supplies		21	–	21
Deferred income tax assets		35	–	35
Derivative instruments	C	–	1	1
Other	C	8	(1)	7
		1,189	–	1,189
Property, plant and equipment:				
Property, plant and equipment in service (net of accumulated depreciation)		12,520	–	12,520
Construction in progress		1,402	–	1,402
Future use land, components and spares		139	–	139
		14,061	–	14,061
Other long-term assets:				
Regulatory assets	B	1,013	450	1,463
Deferred pension asset	B	460	(460)	–
Long-term investment		249	–	249
Intangible assets (net of accumulated amortization)		189	–	189
Goodwill		133	–	133
Deferred debt costs	A	–	32	32
Derivative instruments	C	–	7	7
Deferred income tax assets		19	–	19
Other	C	9	(7)	2
		2,072	22	2,094
Total assets		17,322	22	17,344

January 1, 2011 (millions of dollars)	Notes	Canadian GAAP	Effect of transition to US GAAP	US GAAP
Liabilities				
Current liabilities:				
Accounts payable and accrued charges	D, F	884	(884)	–
Accounts payable	D	–	125	125
Accrued liabilities	D	–	478	478
Due to related parties	F	–	281	281
Accrued interest		84	–	84
Regulatory liabilities		72	–	72
Long-term debt payable within one year		500	–	500
		1,540	–	1,540
Long-term debt	A	7,278	5	7,283
Other long-term liabilities:				
Post-retirement and post-employment benefit liability	B	980	153	1,133
Deferred income tax liabilities		693	–	693
Pension benefit liability	B	–	297	297
Environmental liabilities		287	–	287
Regulatory liabilities	B	540	(460)	80
Net unamortized debt premiums	A	–	27	27
Asset retirement obligations		11	–	11
Long-term accounts payable and other liabilities		12	–	12
		2,523	17	2,540
Total liabilities		11,341	22	11,363
Preferred shares	E	–	323	323
Shareholder's equity				
Preferred shares	E	323	(323)	–
Common shares		3,314	–	3,314
Retained earnings		2,354	–	2,354
Accumulated other comprehensive loss		(10)	–	(10)
Total shareholder's equity		5,981	(323)	5,658
Total liabilities, preferred shares and shareholder's equity		17,322	22	17,344

December 31, 2011 (millions of dollars)	Notes	Canadian GAAP	Effect of transition to US GAAP	US GAAP
Assets				
Current assets:				
Short-term investments		228	–	228
Accounts receivable	F	961	(156)	805
Due from related parties	F	–	156	156
Regulatory assets		24	–	24
Materials and supplies		25	–	25
Deferred income tax assets		19	–	19
Derivative instruments	C	–	1	1
Other	C	20	(1)	19
		1,277	–	1,277
Property, plant and equipment:				
Property, plant and equipment in service (net of accumulated depreciation)		13,329	–	13,329
Construction in progress		1,436	–	1,436
Future use land, components and spares		138	–	138
		14,903	–	14,903
Other long-term assets:				
Regulatory assets	B	1,064	902	1,966
Deferred pension asset	B	466	(466)	–
Long-term investment		250	–	250
Intangible assets (net of accumulated amortization)		224	–	224
Goodwill		133	–	133
Deferred debt costs	A	–	32	32
Derivative instruments	C	–	33	33
Deferred income tax assets		17	–	17
Other	C	34	(33)	1
		2,188	468	2,656
Total assets		18,368	468	18,836

December 31, 2011 (millions of dollars)	Notes	Canadian GAAP	Effect of transition to US GAAP	US GAAP
Liabilities				
Current liabilities:				
Bank indebtedness		39	–	39
Accounts payable and accrued charges	D, F	1,071	(1,071)	–
Accounts payable	D	–	154	154
Accrued liabilities	D	–	575	575
Due to related parties	F	–	342	342
Accrued interest		85	–	85
Regulatory liabilities		25	–	25
Long-term debt payable within one year		600	–	600
		1,820	–	1,820
Long-term debt	A	7,399	9	7,408
Other long-term liabilities:				
Post-retirement and post-employment benefit liability	B	1,040	123	1,163
Deferred income tax liabilities		758	–	758
Pension benefit liability	B	–	779	779
Environmental liabilities		235	–	235
Regulatory liabilities	B	635	(466)	169
Net unamortized debt premiums	A	–	23	23
Asset retirement obligations		15	–	15
Long-term accounts payable and other liabilities		12	–	12
		2,695	459	3,154
Total liabilities		11,914	468	12,382
Preferred shares	E	–	323	323
Shareholder's equity				
Preferred shares	E	323	(323)	–
Common shares		3,314	–	3,314
Retained earnings		2,827	–	2,827
Accumulated other comprehensive loss		(10)	–	(10)
Total shareholder's equity		6,454	(323)	6,131
Total liabilities, preferred shares and shareholder's equity		18,368	468	18,836

The adjustments to the January 1, 2011 and December 31, 2011 equity from Canadian GAAP to US GAAP are as follows:

January 1, 2011 (millions of dollars)	Common Shares	Preferred Shares	Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Total Shareholder's Equity
Canadian GAAP	3,314	323	(10)	2,354	5,981
Other comprehensive income	–	–	–	–	–
Preferred shares reclassified outside shareholder's equity	–	(323)	–	–	(323)
US GAAP	3,314	–	(10)	2,354	5,658

December 31, 2011 (millions of dollars)	Common Shares	Preferred Shares	Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Total Shareholder's Equity
Canadian GAAP	3,314	323	(10)	2,827	6,454
Other comprehensive income	–	–	–	–	–
Preferred shares reclassified outside shareholder's equity	–	(323)	–	–	(323)
US GAAP	3,314	–	(10)	2,827	6,131

Notes to the Transitional Adjustments

Under US GAAP, the Company (i) measures certain assets and liabilities differently than it had under Canadian GAAP (see details on each measurement change below); and (ii) discloses certain assets, liabilities and equity on different lines in the Consolidated Financial Statements than it had under Canadian GAAP (see details on each classification change below).

A. Debt Issuance Costs (classification change)

Under Canadian GAAP, costs of arranging debt financing, premiums and discounts were netted against long-term debt. Under US GAAP, costs of arranging debt financing are included in "Deferred debt costs" as part of "Other long-term assets", and net unamortized premiums are included in "Net unamortized debt premiums" as part of "Other long-term liabilities".

At January 1, 2011 and December 31, 2011, the effect on the Consolidated Balance Sheets is reflected by the following increases:

(millions of dollars)	**January 1, 2011**	**December 31, 2011**
Other long-term assets:		
Deferred debt costs	32	32
Other long-term liabilities:		
Net unamortized debt premiums	27	23
Long-term debt	5	9

B. Pension, Post-Retirement and Post-Employment Benefits (measurement change)

Under Canadian GAAP, the Company disclosed, but was not required to recognize, the net unfunded status of pension, post-retirement and post-employment benefit obligations on the Consolidated Balance Sheets. Under US GAAP, the Company recognized the unfunded status of pension, post-retirement and post-employment benefit obligations on the Consolidated Balance Sheets with an offset to associated regulatory assets for the transitional fair value adjustments as the incremental obligations are expected to be recovered through future rates charged to customers. The deferred tax assets and liabilities arising on recognition of incremental pension, post-retirement and post-employment benefit obligations and the associated regulatory assets offset each other, with no material impact on the Consolidated Statements of Operations and Comprehensive Income. In the absence of regulatory accounting, the related tax impact on the opening transitional adjustments would result in the recognition of deferred tax assets of $113 million on January 1, 2011 and $224 million on December 31, 2011.

At January 1, 2011 and December 31, 2011, the effect on the Consolidated Balance Sheets is reflected by the following increases (decreases):

(millions of dollars)	January 1, 2011	December 31, 2011
Other long-term assets:		
Deferred pension asset	(460)	(466)
Regulatory assets[1]	450	902
Other long-term liabilities:		
Pension benefit liability	297	779
Post-retirement and post-employment benefit liability	153	123
Regulatory liabilities[2]	(460)	(466)

[1] Represents offsetting regulatory assets for incremental obligations for pension and non-pension obligations of $297 million and $153 million on January 1, 2011, and $779 million and $123 million on December 31, 2011, respectively.

[2] Represents write-off of deferred pension asset regulatory liability under Canadian GAAP.

C. Derivative Instruments (classification change)

Under Canadian GAAP, the Company classified its derivative instruments in designated hedging relationships and in economic hedging relationships under the category of "Other assets" on the Consolidated Balance Sheets. Under US GAAP, the Company has included these balances in "Derivative instruments".

At January 1, 2011 and December 31, 2011, the effect on the Consolidated Balance Sheets is reflected by the following increases (decreases):

(millions of dollars)	January 1, 2011	December 31, 2011
Current assets:		
Derivative instruments	1	1
Other	(1)	(1)
Other long-term assets:		
Derivative instruments	7	33
Other	(7)	(33)

D. Accounts Payable (classification change)

Under Canadian GAAP, trade and non-trade payables were disclosed as "Accounts payable and accrued charges". Under US GAAP, trade payables are recognized in "Accounts payable" and non-trade payables are recognized in "Accrued liabilities".

At January 1, 2011 and December 31, 2011, the effect on the Consolidated Balance Sheets is reflected by the following increases (decreases):

(millions of dollars)	January 1, 2011	December 31, 2011
Current liabilities:		
Accounts payable	125	154
Accrued liabilities	478	575
Accounts payable and accrued charges	(603)	(729)

E. Preferred Shares (classification change)

Under Canadian GAAP, Hydro One's preferred shares were classified as equity, and preferred dividends were deducted from retained earnings and accrued as declared. Under US GAAP, the preferred shares are classified outside shareholder's equity because of conditional redemption features in the preferred share agreement. Under US GAAP, the preferred dividends continue to be deducted from retained earnings and accrued as declared (see Note 17 – Share Capital).

At January 1, 2011 and December 31, 2011, the effect on the Consolidated Balance Sheets is reflected by the following increases (decreases):

(millions of dollars)	**January 1, 2011**	**December 31, 2011**
Preferred shares	323	323
Shareholder's equity:		
Preferred shares	(323)	(323)

F. Related Party Balances (classification change)

Under Canadian GAAP, receivables from related parties and payables to related parties were disclosed as "Accounts receivable" and "Accounts payable and accrued charges", respectively. Under US GAAP, receivables from related parties are recognized in "Due from related parties" and payables to related parties are recognized in "Due to related parties".

At January 1, 2011 and December 31, 2011, the effect on the Consolidated Balance Sheets is reflected by the following increases (decreases):

(millions of dollars)	**January 1, 2011**	**December 31, 2011**
Current assets:		
Due from related parties	124	156
Accounts receivable	(124)	(156)
Current liabilities:		
Due to related parties	281	342
Accounts payable and accrued charges	(281)	(342)

25. COMPARATIVE FIGURES

The comparative Consolidated Financial Statements have been reclassified from statements previously presented to conform to the presentation of the December 31, 2012 Consolidated Financial Statements.

FIVE-YEAR SUMMARY OF FINANCIAL AND OPERATING STATISTICS

Statements of Operations Data

Year ended December 31 (millions of dollars)	**2012[1]**	2011[1]	2010[2]	2009[2]	2008[2]
Revenues					
Distribution	**4,184**	4,019	3,754	3,534	3,334
Transmission	**1,482**	1,389	1,307	1,147	1,212
Other	**62**	63	63	63	51
	5,728	5,471	5,124	4,744	4,597
Costs					
Purchased power	**2,774**	2,628	2,474	2,326	2,181
Operation, maintenance and administration	**1,071**	1,092	1,078	1,057	965
Depreciation and amortization	**659**	616	583	537	548
	4,504	4,336	4,135	3,920	3,694
Income before financing charges and provision for payments in lieu of corporate income taxes	**1,224**	1,135	989	824	903
Financing charges	**358**	344	342	308	292
Income before provision for payments in lieu of corporate income taxes	**866**	791	647	516	611
Provision for payments in lieu of corporate income taxes	**121**	150	56	46	113
Net income	**745**	641	591	470	498
Basic and fully diluted earnings per common share *(dollars)*	**7,280**	6,228	5,727	4,528	4,797
Dividends per common share declared *(dollars)*	**3,523**	1,500	100	1,700	2,410

Balance Sheets Data

December 31 (millions of dollars)	**2012[1]**	2011[1]	2010[1]	2009[2]	2008[2]
Assets					
Distribution	**8,621**	7,594	6,915	6,481	5,873
Transmission	**11,586**	10,589	9,820	8,993	7,877
Other	**604**	653	609	161	128
Total Assets	**20,811**	18,836	17,344	15,635	13,878
Liabilities					
Current liabilities (including current portion of long-term debt)	**1,756**	1,820	1,540	1,655	1,300
Long-term debt	**7,879**	7,408	7,283	6,281	5,733
Other long-term liabilities	**4,346**	3,154	2,540	2,281	1,721
Preferred shares	**323**	323	323	–	–
Shareholder's equity					
Preferred shares	**–**	–	–	323	323
Common shares	**3,314**	3,314	3,314	3,314	3,314
Retained earnings	**3,202**	2,827	2,354	1,791	1,497
Accumulated other comprehensive income	**(9)**	(10)	(10)	(10)	(10)
Total liabilities, preferred shares and shareholder's equity	**20,811**	18,836	17,344	15,635	13,878

[1] Based on US GAAP

[2] Based on Canadian GAAP

Other Financial Data

Year ended December 31	**2012**	2011	2010	2009	2008
Capital expenditures *(millions of dollars)*					
Distribution	**671**	628	629	643	570
Transmission	**776**	810	936	918	704
Other	**7**	9	5	5	10
Total capital expenditures	**1,454**	1,447	1,570	1,566	1,284
Ratios					
Net asset coverage on long-term debt ratio[1]	**1.81**	1.81	1.77	1.79	1.84
Earnings coverage ratio[2]	**2.83**	2.71	2.39	2.15	2.63
Operating statistics					
Transmission					
Units transmitted *(TWh)*[3]	**141.3**	141.5	142.2	139.2	148.7
Ontario 20-minute system peak demand *(MW)*[3]	**24,768**	25,505	25,145	24,477	24,231
Ontario 60-minute system peak demand *(MW)*[3]	**24,636**	25,450	25,075	24,380	24,195
Total transmission lines *(circuit-kilometres)*	**29,327**	28,942	28,951	28,924	29,039
Distribution					
Units distributed to Hydro One customers *(TWh)*[3]	**29.2**	29.2	29.1	28.9	29.9
Units distributed through Hydro One lines *(TWh)*[3,4]	**42.4**	42.5	42.5	43.5	44.7
Total distribution lines *(circuit-kilometres)*	**121,525**	120,514	123,552	123,528	123,260
Customers	**1,381,926**	1,365,379	1,345,177	1,333,920	1,325,745
Total regular employees	**5,811**	5,781	5,717	5,427	5,032

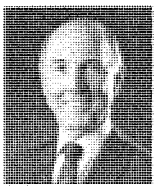
[1] The net asset coverage on long-term debt ratio is calculated as total assets minus total liabilities excluding long-term debt (including current portion) divided by long-term debt (including current portion).

[2] The earnings coverage ratio has been calculated as the sum of net income, financing charges and provision for payments in lieu of corporate income taxes divided by the sum of financing charges, capitalized interest and cumulative preferred dividends.

[3] System-related statistics include preliminary figures for December.

[4] Units distributed through Hydro One lines represent total distribution system requirements and include electricity distributed to consumers who purchased power directly from the IESO.

BOARD OF DIRECTORS
(as at December 31, 2012)



James Arnett[2]
Chair of the Board of Directors, Hydro One Inc.

Carmine Marcello
President and Chief Executive Officer, Hydro One Inc.

Elected January 1, 2013

Kathryn A. Bouey[1,4,6]
President, TBG Strategic Services Inc.

Corporate Director

George Cooke[1,5,7]
Chief Executive Officer, The Dominion of Canada General Insurance Company

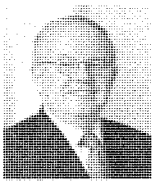
Laura Formusa
President and Chief Executive Officer, Hydro One Inc.

Retired December 31, 2012

Janet Holder[5,6,7]
Executive Vice President, Western Access, Enbridge Inc.

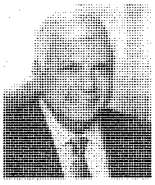
Don MacKinnon[5,6]
President, Power Workers' Union

Michael J. Mueller[1,2,4]
Corporate Director



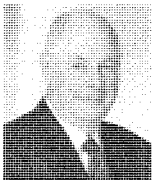
Walter Murray[1,3,7]
Corporate Director

Robert L. Pace[2,3,7]
President and CEO, The Pace Group Ltd.



Yezdi Pavri[1,4]
Corporate Director

Gale Rubenstein[2,3,5]
Partner, Goodmans LLP



Douglas E. Speers[3,4,6]
Corporate Director

Board Committees

[1] *Audit and Finance Committee* The Audit and Finance Committee oversees the integrity of accounting policies and financial reporting, internal controls, internal audit, financial risk exposures, financial compliance and ethics policies. The committee met seven times in 2012.

[2] *Corporate Governance Committee* The Corporate Governance Committee is responsible for the Board's governance of the Company. It recommends issues to be discussed at meetings of the Board of Directors, reviews the mandate of the Board and each committee of the Board, conducts Board Assessments, monitors the quality of management's relationship with the Board and recommends suitable nominees for election to the Board of Directors. The committee met five times in 2012.

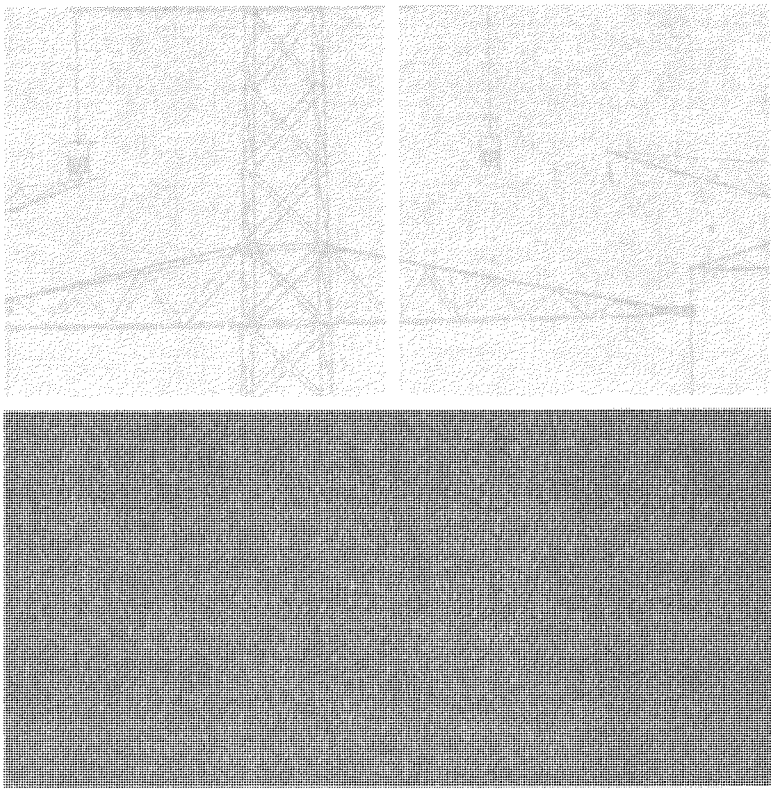
[3] *Human Resources Committee* The Human Resources Committee is responsible for reviewing the appropriateness of our current and future organizational structure, succession plans for corporate and divisional officers, the code of business conduct, and the performance and remuneration of our senior executives, including recommending to the Board the remuneration of the President and CEO. The committee met eleven times in 2012.

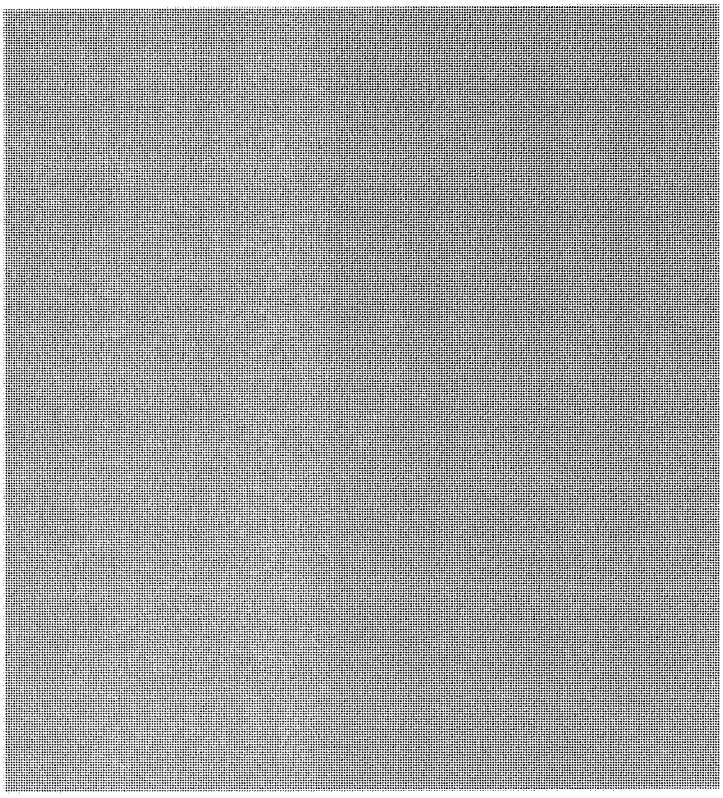
[4] *Business Transformation Committee* The Business Transformation Committee is responsible for assisting the Board in its oversight responsibilities in all matters related to the Company's cornerstone project, the Advanced Distribution System and Continuous Innovation Strategy, and the planning, development and implementation of major transmission system or distribution projects, including projects described in the Corporation's Green Energy Implementation Plan. The committee met six times in 2012.

[5] *Regulatory and Public Policy Committee* The Regulatory and Public Policy Committee monitors the Company's compliance with applicable regulatory requirements and legislation and is responsible for identifying, assessing and providing advice to the Board of Directors on public affairs issues that have a significant impact on us. The committee oversees compliance programs, policies, standards and procedures and reviews the Company's proposals for rate applications, compliance actions and reports. The committee met four times in 2012.

[6] *Health, Safety and Environment Committee* The Health, Safety and Environment Committee is responsible for reviewing occupational health, safety and environment policies, standards, and programs, compliance with occupational health, safety and environmental legislation, policies and standards, and public health and safety issues. The committee met four times in 2012.

[7] *Investment – Pension Committee* The Investment – Pension Committee's primary function is to assist the Board in fulfilling its oversight responsibilities in all matters related to the Corporation's Pension Plan including the Hydro One Pension Fund. The committee met four times in 2012.





Hydro One Inc.
Is a holding company with subsidiaries that operate in the business areas of electricity transmission and distribution and telecom services.

Hydro One Networks Inc.
Represents the majority of our business, which is regulated by the Ontario Energy Board. It is involved in the planning, construction, operation and maintenance of our transmission and distribution networks.

Hydro One Brampton Networks Inc.
Distributes electricity to one of the fastest-growing urban centres in Canada, just 30 kilometres outside of Toronto.

Hydro One Remote Communities Inc.
Operates and maintains the generation and distribution assets used to supply electricity to 21 remote communities across Northern Ontario that are not connected to the province's electricity transmission grid.

Hydro One Telecom Inc.
Markets our fibre-optic capacity to business customers. This business represents less than one per cent of our total assets.

CORPORATE INFORMATION

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Toronto, Ontario M5G 2P5
(416) 345-5000
1-877-955-1155
www.HydroOne.com

Investor Relations
(416) 345-6867
investor.relations@HydroOne.com

Media Inquiries
(416) 345-6868
1-877-506-7584

Customer Inquiries
Power outage and emergency number:
1-800-434-1235

Residential, farm and small business accounts:
1-888-664-9376

Business accounts:
1-877-447-4412

Auditors
KPMG LLP

This is Exhibit "H" referred to in the Affidavit of M. Lilly Iannacito sworn April 13, 2016

Commissioner for Taking Affidavits (or as may be)

LISA S. LUTWAK

SHARED SERVICES CAPITAL - CORNERSTONE

1.0 OVERVIEW

The Cornerstone Project is part of the overall information technology ("IT") strategy to replace several of Hydro One's key enterprise information systems as they reach their 'end of life'. The Cornerstone Project is also a major business process transformation initiative that provides a platform for further effectiveness and efficiency gains at Hydro One. The Cornerstone Project is being carried out in four phases as summarized below:

Phase 1 (Completed June 2008): Replaced end of life Passport application and functionality associated with work management, supply chain, procurement, accounts payable and asset registry with a modern Enterprise Asset Management ("EAM") solution using SAP.

Phase 2 (Majority Completed August 2009, minor items completed in 2010): Replaced end of life PeopleSoft application for Finance / Human Resources / Payroll processing with functionality provided by SAP Enterprise Resource Planning ("ERP") that is integrated with the EAM solution installed in Phase 1. The Phase 2 implementation also addressed the analytical and reporting business needs for work management, finance, investment management, HR and Pay using SAP's Business Intelligence ("BI") platform.

Phase 3 (In-Service 2011-2014): Enhance integrated planning, Enterprise Asset Management / Enterprise Resource Planning / Business Intelligence systems, tools and processes by expanding Hydro One's SAP solution and integrating key systems/technologies and specialized packaged point solutions to drive additional business value, improve end-to-end process efficiency and improve asset lifecycle management analytics/decisions. This includes adding and enhancing SAP functionality

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

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

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

Table 1
Cornerstone Capital 2009 – 2014 ($ Millions)

	Historic			Bridge	Test		TX Allocated	
	2009	2010	2011	2012	2013	2014	2013	2014
Minor Fixed Assets	0.2	0.3	11.0	1.2	-	-	-	-
Development Projects	90.7	18.9	59.7	108.4 *	44.9*	10.0	15.2	5.7
Total Capital Cost	90.9	19.2	70.7	109.6 *	44.9*	10.0	15.2	5.7

* 2012 - $85.7M and 2013 – 18.1M is directly allocated to DX only for Cornerstone Phase 4 (CIS)

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

Cornerstone Value Realization (Benefits):

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

- Productivity, Cost Effectiveness and Process Efficiency

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

- Better Decisions

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

- Compliance

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

- Employee Engagement

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

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

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

	Realized – Total Program			Planned – Total Program		
	Historic			Bridge	Test	Test
	2009	2010	2011	2012	2013	2014
TX OM&A	6.3	13.1	15.7	15.7	17.4	18.4
TX Capital	4.5	9.7	12.4	12.4	18.7	24.0
Total TX	10.8	22.8	28.1	28.1	36.1	42.4
DX OM&A	4.2	6.7	7.2	7.2	13.9	20.7
DX Capital	3.1	4.1	6.0	6.0	12.3	16.3
Total DX	7.3	10.8	13.2	13.2	26.2	37.0
Total	**18.1**	**33.6**	**41.3**	**41.3**	**62.3**	**79.4**

2.0 BACKGROUND

The capital work program for Cornerstone commenced in 2007. Phase 1 of the project was successfully completed in June 2008. The majority of Phase 2 was completed in August 2009. Work is well underway for both Phase 3 and Phase 4. The first three phases of the Cornerstone Project are discussed below:

Phase 1 – Enterprise Asset Management ("EAM") Core Functionality (Completed June 2008)

The EAM initiative replaced the existing Passport applications with a modern EAM solution in June 2008. The result is an integrated EAM application that has enabled more effective information transfer within the Company and provided the basis for connectivity with other core systems as they are replaced or upgraded. Phase 1 savings (both Transmission and Distribution) total $200 million over a seven year period beginning in 2009. Total savings of $62.2M are expected in the test years 2013 and 2014 as shown in Table 3 and have been incorporated into the current business plan.

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

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

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

Strategic Sourcing and Discount Capture:

Through improved collaboration across the business units and better visibility through SAP, the supply chain organization is able to execute a go-to-market strategy consisting of an approved set of standardized ratings with firm volume commitments resulting in significant reductions in the unit pricing with the vendors. The net result is a reduced material cost for projects and programs within the work program. In addition, through

better analysis and management of contractual terms, the supply chain organization is better able to define payment terms and achieve discounts through timely approvals. These reduced material costs are reflected in the in-year actuals as well as for the test years. Graph 1 represents the value realized from the strategic sourcing value area.

Process Efficiencies enabling Headcount Reductions:

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

Application Rationalization:

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

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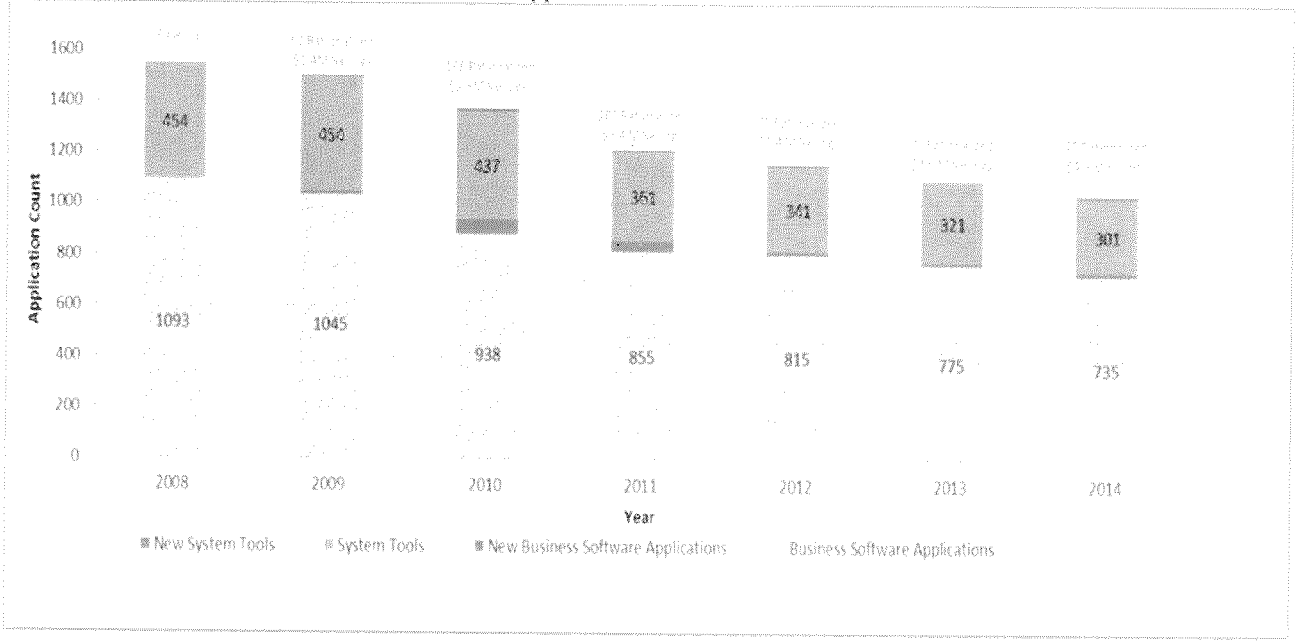
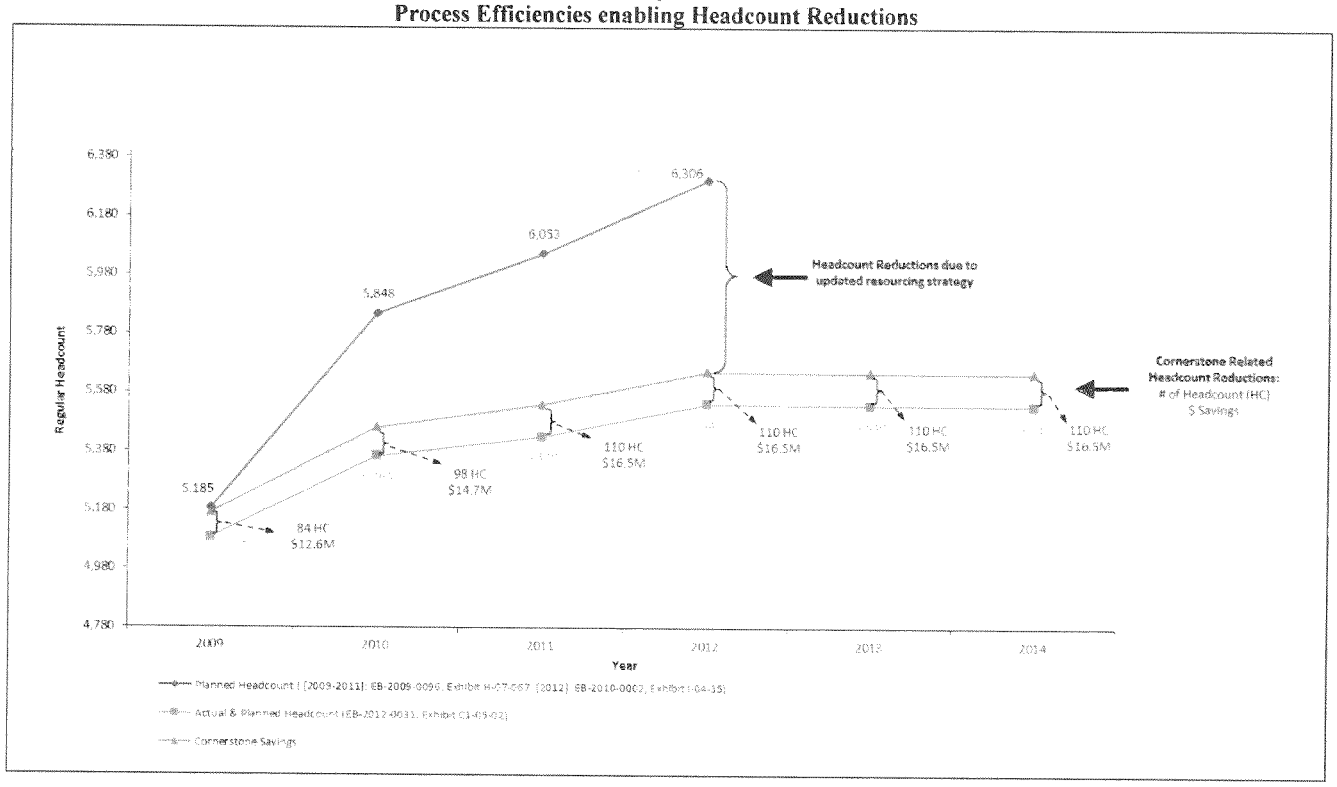
Graph 3
Application Rationalization



Graph 2
Process Efficiencies enabling Headcount Reductions



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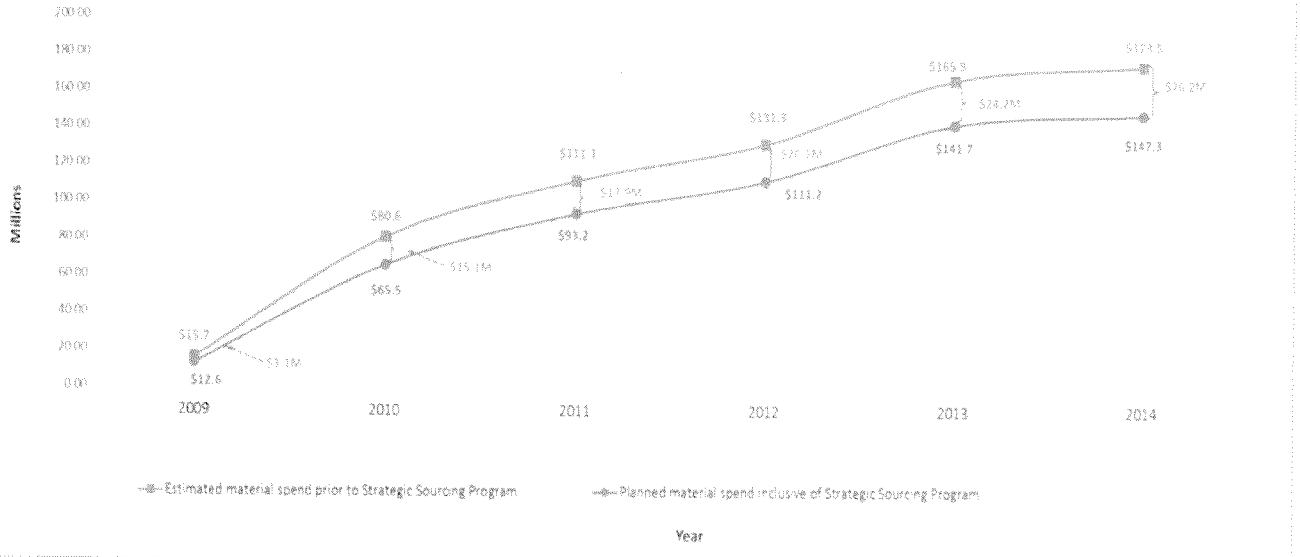
Graph 1
Strategic Sourcing and Discount Capture



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

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

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

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

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

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

Phase 3 will enhance integrated planning, Enterprise Asset Management / Enterprise Resource Planning / Business Intelligence systems, tools and processes by expanding Hydro One's SAP solution and integrating key systems/technologies and specialized packaged point solutions to drive additional business value, improve end-to-end process efficiency and improve asset lifecycle management analytics/decisions. This includes

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

Supply Chain Optimization Project:

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

Asset Analytics:

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

date of January 2013 and will achieve value associated with maintenance cost reductions, process efficiencies for asset management staff and improved prioritization of the asset needs to optimize investments.

Business Planning and Consolidation Project:

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

Asset Investment Planning ("AIP"):

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

Engineering Design Transformation ("EDT"):

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

Planning, Scheduling and Dispatch:

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

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

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

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

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

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

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

Hydro One expects Distribution Business savings from the CIS implementation to total $172 million over a 7 year time horizon. Total savings of $24.0 million are expected in the test years 2013 and 2014 as shown in Table 6 and these savings have been incorporated into the current business plan.

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

	2009	2010	2011	2012	2013	2014
OM&A	-	-	-	-	3.3 *	9.2 *
Capital	-	-	-	-	4.3 *	7.2 *
Total	-	-	-	-	**7.6 ***	**16.4 ***

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

This is Exhibit "I" referred to in the Affidavit of M. Lilly Iannacito sworn April 13, 2016

Commissioner for Taking Affidavits (or as may be)

LISA S. LUTWAK

NON-TYPICAL CAPITAL - CUSTOMER INFORMATION SYSTEM

1.0 NEED

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

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

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

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

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

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

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

2.0 CURRENT CUSTOMER INFORMATION SYSTEM

The CIS project will replace Hydro One's end of life Customer Information System including customer/account services, billing, settlements, and open market systems. The CSS (Customer Service System) or Customer/1 application was purchased from Andersen Consulting (now Accenture). The application has undergone significant modifications in order to address the changes in the Ontario regulatory environment and to meet Ontario Energy Board requirements. This is an extensively customized product

which is very costly to maintain and very costly to modify to meet new regulatory and business needs. Accenture no longer develops or supports the application.

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

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

3.0 PROJECT OVERVIEW

The CIS project is replacing the legacy CIS systems with a unified platform based primarily on SAP's industry leading billing application – Customer Relationship and Billing ("CRB"). For Meter Data management, Itron's Enterprise Edition application will use out-of-the-box integration with the SAP core to facilitate integration to and from

the IESO for billing of Time Of Use residential customers as well as perform meter data management for interval billed commercial and industrial customers.

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

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

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

Table 1

CIS Project Costs by Phase and Item

($ Millions)

Item	Discovery	Blueprint Phase	Realization	Final Prep	Verification & Stabilization	TOTAL ($ million)
Implementation Effort (discovery, labour/services, commissioning and other support)	$9.1	$21.0	$49.5	$38.0	$21.3	$138.90
Hardware						$10.0
Software						$13.4
Interest and Overhead						$17.5
Total						$179.8

Table 2 identifies the CIS capital expenditures for the period 2011 to 2013.

Table 2

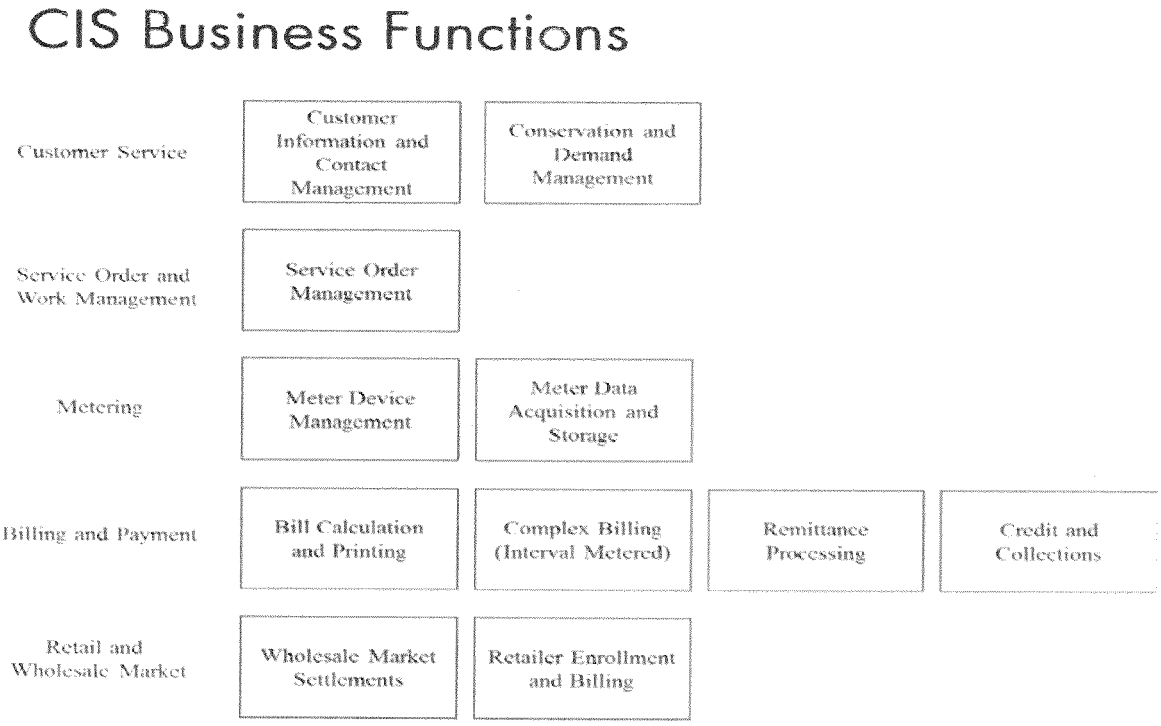
CIS Capital 2011– 2013 ($ Millions)

	2011	2012	2013	Total In-service 2013
Minor Fixed Assets	10.1	0		10.1
Development Project	41.5	85.7	18.1	145.3
Total Capital Cost	51.6	85.7	18.1	155.4

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

Functional Overview:

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



Customer Service:

Customer Information & Contact Management

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

Conservation and Demand Management

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

Service Order and Work Management:

Service Order Processing

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

Metering:

Meter Device Management

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

Meter Data Acquisition and Storage

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

Billing and Payment:

Bill Calculation and Printing

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

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

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

Complex Billing

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

Remittance Processing

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

Credit & Collections

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

Retail and Wholesale Market:

Wholesale Settlements

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

Retailer Enrolment & Billing

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

The Ontario market rules support a bill-ready retailer billing model, in which the LDCs inform electricity retailers of the amount of electricity consumed by each of their customers, and the retailers inform the LDCs of the commodity charge to add to their customer's bills. In a bill-ready market, the retailers are required to calculate the

commodity charge based on the customer's consumption. This market supports both distributor consolidated billing ("DCB") and retailer consolidated billing ("RCB"). For a DCB customer, the bill is issued by Hydro One to the customer using the commodity charge ($) provided by the retailer and all other charges as calculated by Hydro One. For a RCB customer, all of the charges normally billed to the customer (including the commodity charge) are billed by the retailer. The retailer decides which bill option they will use. CIS functionality in this area also automates the calculation and processing of settlement payments between Hydro One and the retailers who do business within Hydro One's service territory.

Data and Reporting Improvements:

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

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

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

4.0 CUSTOMER CARE/CIS COSTS AND BENEFITS

4.1 Costs

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

1

Table 3

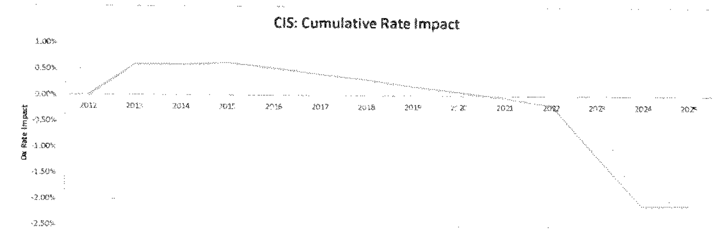
CORNERSTONE

CIS Cost Template

#	Category of Cost	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2009 - 2024 Total
	LEGACY CIS COSTS																	
1	License Fees	$1,108,600	$1,108,600	$1,108,600	$1,108,600	$461,917												$4,896,317
2	CIS Hosting & Support	$15,134,259	$15,134,259	$15,134,259	$14,636,716	$6,098,632												$66,138,123
3	CIS Backoffice	$3,907,408	$3,962,116	$3,843,227	$3,843,227	$1,601,345												$17,157,323
	LEGACY CIS COSTS SUBTOTAL	$20,150,267	$20,204,974	$20,086,086	$19,588,543	$8,161,893												$88,191,763
	NEW CIS COSTS																	
4	License Fees					$1,801,243	$2,421,685	$2,421,685	$2,421,685	$2,421,685	$2,421,685	$2,421,685	$2,421,685	$2,421,685	$2,421,685	$2,421,685	$2,421,685	$28,439,778
5	CIS Hosting & Support					$7,926,108	$9,958,897	$7,133,131	$7,133,131	$7,133,131	$7,133,131	$7,133,131	$7,133,131	$7,133,131	$7,133,131	$7,133,131	$7,133,131	$89,216,313
6	CIS Backoffice					$2,442,603	$4,110,577	$2,793,227	$2,793,227	$2,793,227	$2,793,227	$2,793,227	$2,793,227	$2,793,227	$2,793,227	$2,793,227	$2,793,227	$34,485,455
	NEW CIS COSTS SUBTOTAL					$12,169,954	$16,491,158	$12,348,043	$12,348,043	$12,348,043	$12,348,043	$12,348,043	$12,348,043	$12,348,043	$12,348,043	$12,348,043	$12,348,043	$152,141,545
7	CIS Project Costs @ 40% Equity					$6,798,917	$8,798,917	$30,955,707	$29,973,306	$28,668,294	$27,398,770	$26,106,948	$24,807,888	$23,495,209	$22,185,898	$10,781,240	$0	$237,951,098
	TOTAL CIS COSTS:	$20,150,267	$20,204,974	$20,083,085	$19,528,533	$27,130,704	$23,290,076	$43,303,750	$42,321,349	$41,016,337	$39,746,819	$38,454,991	$37,155,930	$35,843,252	$34,533,941	$23,109,283	$12,348,043	$479,284,456
	Number of Customers	1,189,183	1,201,196	1,210,889	1,220,514	1,231,476	1,243,713	1,256,331	1,268,421	1,280,511	1,292,600	1,304,689	1,316,779	1,328,868	1,340,958	1,353,048	1,366,579	20,405,755
	CIS Cost per Customer	$16.94	$16.82	$16.59	$16.06	$22.03	$18.73	$34.47	$33.37	$32.03	$30.75	$29.47	$28.22	$26.97	$25.75	$17.08	$9.04	$23.44
	CIS Cost per Customer Annual Change			-1.4%	-3.2%	37.3%	-15.0%	84.1%	-3.2%	-4.0%	-4.0%	-4.1%	-4.3%	-4.4%	-4.5%	-33.7%	-47.1%	

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

#		2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2009 - 2024 Total
8	CIS Revenue Requirement					$6,798,917	$6,798,917	$7,248,911	$6,069,530	$4,761,761	$3,459,279	$2,046,071	$924,253	($488,987)	($1,852,916)	($13,279,389)	($24,147,489)	[illegible]
9	2011 OEB Approved Revenue Requirement					$1,148,885,481	$1,148,885,481	$1,148,885,481	$1,148,885,481	$1,148,885,481	$1,148,885,481	$1,148,885,481	$1,148,885,481	$1,148,885,421	$1,148,885,481	$1,148,885,481	$1,140,885,481	
10	Dx Rate Impact (Cumulative)					0.59%	0.59%	0.63%	0.53%	0.41%	0.30%	0.18%	0.07%	-0.04%	-0.16%	-1.16%	-2.10%	



2

4.2 Table 3 Cost Descriptions

Rows 1 and 4 – License fees

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

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

Rows 2 and 5 - CIS Hosting and Support

This row represents the charges from Inergi for:

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

With the implementation of the new CIS, which is based on commercial off-the-shelf software, and which is configurable instead of requiring expensive time consuming code changes, it is

anticipated that the service provider costs will reduce considerably once the new CIS application has been stabilized. The new CIS application will also allow the existing mainframe computers to be retired, which will provide further savings. These savings will be fully realized via the re-tendering of IT services which will occur prior to 2015 when the current Inergi contract expires.

Rows 3 and 6 - CIS Backoffice

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

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

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

Row 7 – New CIS project capital costs

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

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

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

4.3 Savings and Benefits Summary

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

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

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

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

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

Customer Care

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

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

Finance

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

IT

Benefits will be realized through operational and capital savings from the decommissioning of mainframe. Rationalization of the hardware environment on which SAP runs will reduce infrastructure management and support costs as well as facility costs and hardware refresh. A common SAP platform for CIS enhances productivity in the area of application maintenance

support and enhancement work program across Hydro One and Hydro One's outsourced service provider.

5.0 STAKEHOLDER INFORMATION REQUESTS

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

5.1 Cost for Hydro One staff working on CIS Project

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

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

Table 4
Costs for Hydro One staff on CIS Project

($M)	2011	2012	2013	TOTAL
Hydro One	4.7 *	6.8 *	4.7 *	16.2

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

In very large projects such as CIS, it is typical that significant numbers of key staff are seconded to the project for a number of months / years, leaving a resource gap in the home base organization. The intent of the cost treatment applied to this project is to provide funding for the home base organizations to bring in backfill resources through either temporary employees or

external contract staff. It should be noted, however, that in some circumstances staff have been moved from another capital project in which case their costs would not impact OM&A.

5.2 Project Contingency

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

In very large projects such as CIS, Hydro One includes a portion of funding in contingency to cover any project issues such as clarification on requirements, system issues, technology performance and external factors unknown to the project at the time the business case is approved. Due to the complexity of the CIS project, Hydro One expects to use the contingency, and the Board of Directors has approved the release of these funds.

5.3 Ontario Clean Energy Benefit implementation

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

Ontario Clean Energy Benefit study:

The implementation of the Ontario Clean Energy Benefit is representative of the type of change to customer charges that Hydro One has to implement from time to time. Implementing this change in the existing CIS system – CSS – was performed by Inergi late in 2010, on a very aggressive timeline. As with all billing changes there was considerable detail to be worked through in design to determine:

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

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

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

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

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

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

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

5.4 Hydro One Board Approval document

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

This is Exhibit "J" referred to in the Affidavit of M. Lilly Iannacito sworn April 13, 2016

Lisa Lutwak

Commissioner for Taking Affidavits (or as may be)

LISA S. LUTWAK

Ontario Energy Board (Board Staff) INTERROGATORY #18 List 1

Issue 4 **Is Hydro One's proposal with respect to the treatment of the CIS project for 2013 and 2014 appropriate?**

Interrogatory

Ref: Exhibit B/Tab3/Sch1/pages 2-3

Hydro One indicates that its current CIS system, installed in 1998, is now at end of life. Can Hydro One provide examples of CIS systems for similar distributors in Ontario or other jurisdictions and compare their CIS systems in terms of costs and end of life considerations?

Response

Hydro One's current CIS (Customer/1) was purchased from Andersen Consulting, now doing business as Accenture. Accenture no longer develops or supports the Customer/1 application. In contrast to modern, vendor-supported applications like SAP, Customer/1 is not configurable software. Any required changes are therefore custom modifications to the software programs that make up Customer/1, and are made at Hydro One's expense and risk. In addition, Customer/1 requires mainframe hardware which is itself costly to maintain and operate.

Based on the information gathered from the public record, among the larger Ontario electric utilities, Toronto Hydro, Enersource, Hydro Ottawa, London Hydro, EnWin and Powerstream have all recently replaced or are replacing their CIS systems, indicating similar concerns with attempting to fulfill Ontario distributor business requirements based on their legacy CIS systems. The legacy CIS systems that they replaced mostly date from the late 1990s or later. Similarly, Enbridge Gas Distribution replaced their legacy CIS systems with SAP in 2009. The legacy CIS system was implemented in the late 1990s. See the table below for a summary.

In other Canadian jurisdictions, BC Hydro, Fortis BC, Hydro Quebec and SaskPower have all either moved or are moving to an SAP-based CIS in the last 10 years.

Utility & Rank in Ontario by # customers (for Electric Utilities)	Date of implementation of legacy CIS	Current CIS Status
Toronto Hydro (2)	SCT Banner implemented 1999/2000	SCT Banner was replaced in 2011 with Oracle CC&B
Hydro Ottawa (4)	CIS Replacement in 2004 (Advanced Utility Systems to SPL)	CIS Upgrade from SPL to CC&B is underway with a planned in-service date of Q4 2013
Enersource (6)	Legacy CIS implemented 1999	Legacy CIS replaced with Oracle CC&B in 2009
London Hydro (7)	CISOntario implemented in 2000/2001	SAP implementation 2008/2009
EnWin (10)	SPL system implemented in 2004.	Currently planning to replace
Enbridge Gas Distribution (n/a)	Legacy CIS implemented in 1998/99	Legacy CIS replaced with SAP in 2009

With respect to costs, it is generally difficult to compare Hydro One's CIS costs with other Ontario utilities using publicly available information. However, for Enbridge's CIS replacement the costs were filed in a template in EB-2011-0226 Exhibit A, Tab 2, Schedule 1 in a form which Hydro One followed in this filing, so the costs can be compared. Per EB-2011-0226 Exhibit N1, Tab 1, Schedule 1 EGD's capital cost of the CIS project was $118.7M, which was subsequently updated to $127.2M. Hydro One's capital cost is $155.4M.

With respect to the capital costs of EGD's CIS project compared to Hydro One's CIS project, there are significant differences in the requirements of an Ontario electric distribution utility compared to a gas utility, for example, requirements to:

- interact with the IESO's meter data management repository for smart metered customers who are on TOU pricing
- process time of use meter data and calculate interval bills and TOU bills
- process the EBTs associated with the interactions with Retailers.

On a per customer basis EGD's costs are lower given the considerably larger customer base at EGD. Hydro One believes that once a CIS project reaches this magnitude and complexity, the number of customers served is not a significant driver of the overall project cost. The differences between the capital costs of the two projects can be explained by the increased complexity associated with the requirements associated with Ontario electric utilities related to Smart Metering, TOU pricing, and open market interactions via EBTs.

Ontario Energy Board (Board Staff) INTERROGATORY #20 List 1

Issue 4 **Is Hydro One's proposal with respect to the treatment of the CIS project for 2013 and 2014 appropriate?**

Interrogatory

Ref: Exhibit B/Tab3/Sch1/page 16

Hydro One indicates that it continues to explore opportunities with other Ontario LDCs to look for project cost savings but has insufficient information to quantify the amount of the potential savings. Please provide more detail on these opportunities: What is the progress so far on this initiative? How many LDCs have been approached or have shown interest in the new system? Please provide an estimate of the potential savings or provide a range.

Response

Hydro One and EnWin discussed the possibility of EnWin leveraging Hydro One's CIS implementation or a portion of the development deliverables for its CIS replacement, given that EnWin was considering an SAP-based CIS implementation. The two utilities met on a number of occasions to compare requirements, to consider which aspects of Hydro One's implementation could be leveraged by EnWin, and to discuss cost sharing mechanisms. These discussions concluded with EnWin determining that their needs were better served by approaching their CIS requirements differently, and have subsequently decided to pursue other vendors' CIS software solutions.

Hydro One leveraged the experience of London Hydro's SAP and Itron CIS installation to provide cost effective knowledge transfer and implementation experience. Hydro One has worked with London Hydro to provide resources for expert advisors to assist with testing of the CIS system with the IESO systems and interfaces. London Hydro is the only utility in the Ontario Energy Market that has installed an SAP & Itron based system with interfaces to the IESO similar to those being installed at Hydro One. The estimated saving associated with this partnership is approximately $180,000, when compared to the estimated cost of completing this work with our outsourcing provider.

Hydro One has also signed a Memorandum of Understanding (MOU) with London Hydro. The objective of the MOU is to formalize ongoing collaboration efforts between the two organizations to reduce project development, testing, training and on-going operational costs associated with the common systems. The collaboration efforts will minimize risks to achieve project timelines, influence vendors and improve the quality of solutions. Collaboration may further help in influencing major project vendors such as SAP & Itron in developing meaningful and reasonable product changes in their core solutions/offerings.

Ontario Energy Board (Board Staff) INTERROGATORY #21 List 1

Issue 4 **Is Hydro One's proposal with respect to the treatment of the CIS project for 2013 and 2014 appropriate?**

Interrogatory

Ref: Exhibit B/Tab3/Sch1/page 19

Hydro One indicates that due to the complexity of the CIS project, it expects to use the project contingency funds. What were the primary reasons that contingency funds were required? Please provide a table that summarizes the use of the contingency funds by major category.

Response

As the project entered the realization phase of the project, the complexity in certain areas was greater than anticipated. As a result, additional resources were required to help complete the design and build of the system. As the build increased in complexity, other aspects of the project such as data conversion and testing were subject to corresponding increases in resources as required. Specifically:

- The meter data acquisition area of the solution saw a significant increase in complexity based on the requirement to interface with the provincial MDM/R and with HONI's existing Smart Meter Infrastructure. As the detailed solution design associated with these requirements was developed, there was more than a one hundred percent increase in the number of developments required for this aspect of the solution.
- Similarly, the complexity of the solution associated with processing Ontario Electronic Business Transactions increased. In this area the solution requires integrating a new piece of SAP's CIS solution with Hydro One's existing applications. In this area there was an overall fifty percent increase in the number of developments required.
- Other areas of increases included complex billing and settlements, where Hydro One has unique requirements associated with its role as both a transmitter and distributor in Ontario.

The additional complexity in these areas impacted the various project development phases spanning system and interface design, build, test, data conversion, and final preparation. Taken together, the items detailed above have resulted in the in-service date of the project being shifted from Q1 2013 to Q2 2013. The table below shows the breakdown of spend by the above categories.

Table 1: CIS Project Costs (Contingency Spend by Category)

Item	Meter Data Acquisition/Meter Device Management	Ontario Deregulation	Other	TOTAL ($M)
Implementation Effort (discovery, labour/services, commissioning and other support)	**$17.2**	**$5.2**	**$3.1**	**$25.50**

Energy Probe (EP) INTERROGATORY #17 List 1

Issue 4 **Is Hydro One's proposal with respect to the treatment of the CIS project for 2013 and 2014 appropriate?**

Interrogatory

Ref: Exhibit B, Tab 3, Page 16 &
Exhibit B, Tab 3, Schedule 1, Table 3 Updated-CIS Benefits

a) Please expand on the details of the Benefits Realization Plan for the new CIS. If this is documented, please file a copy.

b) Please list all areas of the Business that will benefit from the new CIS and provide short descriptions/examples of these.

c) Please list by year and Functional Area the Quantitative Benefits that underlie the claimed benefit of $172 million over seven years for the new CIS.

d) Please quantify the benefit reductions that have been netted out from the net revenue requirement on Line 8 of the second reference.

e) How will actual benefits be tracked and how will these, together with variances from Plan, be reported to the Board and Ratepayers? Please provide detailed proposal(s)

Response

a) and e)

Within the project methodology, financial benefits are identified up front as part of the discovery and business case process. Benefits are associated with the CIS requirements so that the relationship between the benefits and the system design is maintained throughout the project.

The benefits are validated with the applicable business leads in each Hydro One Line of Business, and reflected in applicable business plans and budgets. Hence the realization of these benefits is committed via reduction of the applicable budgets. During the Realization and Final Preparation phases of the project, benefits are further validated, benefits reporting is defined, and the actions required to ensure the benefits are realized are identified. These activities are ongoing, and result in for example, documented business process changes, updates to work instructions and updates to relevant training materials.

Once the project is live and CIS is in service, benefits will be tracked by Hydro One staff. The Business Transformation Sub-Committee of Hydro One's Board of Directors will receive regular updates on the benefits realized by the CIS Project, and these benefits will be reported to the Board and ratepayers through Hydro One's cost of service rate applications. Benefits will be further validated by Hydro One's Internal Audit team.

b) The areas of the business that will benefit from the new CIS are Customer Care, IT, Finance.

Customer Care

An integrated CIS which provides a more integrated view of the customer profile with enhanced customer issue resolution capability will reduce handling time on calls and correspondences, improve billing timeliness and accuracy, increase first call resolution ("FCR") and improve customer satisfaction. In addition, the new CIS will improve collections and hence reduce bad debt expense by improving HONI's ability to track customers as they move within, or in and out of, HONI's service territory. This is expected to lead to improved ability to collect on receivables associated with premises that the customer has vacated.

Finally, the new CIS coupled with the Smart Meter network, will allow HONI to disconnect and reconnect service to a meter remotely, without a field technician making a visit to the property. This is expected to both reduce field support costs related to collections and special investigations, and to reduce bad debt.

Finance

Benefits will be realized through reducing the time required to issue bills which will result in cash flow savings. Accounting processes will also be streamlined in the new CIS due to the integrated nature of CIS with the existing SAP ECC platform. Finally, the new system will enable more accurate application of late payment charges to overdue arrears, which is expected to increase late payment revenues.

IT

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

c) The business benefits by LOB are shown in the table below.

CIS Business Benefit Breakdown by LOB ($M)								
Line of Business	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Customer Service	$2.3	$5.5	$9.3	$9.5	$9.5	$9.5	$9.5	$1.9
IT	$0.0	$2.9	$17.7	$15.2	$7.6	$7.7	$7.6	$1.5
Finance	$5.3	$8.0	$8.0	$8.0	$8.0	$8.0	$8.0	$1.6
TOTAL	$7.6	**$16.4**	**$35.0**	**$32.6**	**$25.0**	**$25.2**	**$25.1**	**$5.0**
CIS Project OM&A costs	($13.6)							

Note that for 2013, there are CIS Project OM&A costs of $13.6M which more than offset the business benefits forecast to be realized in that year.

d) Over the period covered in the model, Hydro One has netted out $239,717,209 of benefits from Line 6 (CIS Project Costs) to derive Line 8 (CIS Revenue Requirement).

Consumers Council of Canada (CCC) INTERROGATORY #12 List 1

Issue 4 **Is Hydro one's proposal with respect to the treatment of the CIS project for 2013 and 2014 appropriate?**

Interrogatory

EX. B/T3/S1/P. 4

The evidence states that Hydro One had planned the CIS in-service date for 2016. What was the expected cost for the 2016 CIS? Please explain how that differs from the current cost. How much has been spent to date in 2012 relative to the forecast of $103.8 million?

Response

The estimated cost of the 2016 CIS was $150M with projected benefits of $90M over seven years. This amount was a high-level estimate and subject to discovery, which involved detailed requirements gathering and RFP, confirmation of requirements, costs and benefits. After the discovery phase of the project, the costs and benefits were updated to the current values of $180M of cost and $172M of benefit.

During the recent update to the rate application, Hydro One reduced the projected 2012 capital expenditure from $103.8M to $85.7M. The updated table has been reinserted below for your reference. Actual spend to June 30 2012 is $21.5M

Table 2

CIS Capital 2011– 2013 ($ Millions)

	2011	2012	2013	Total In-service 2013
Minor Fixed Assets	10.1	0		10.1
Development Project	41.5	85.7	18.1	145.3
Total Capital Cost	51.6	85.7	18.1	155.4

School Energy Coalition (SEC) INTERROGATORY #30 List 1

Issue 4 **Is Hydro One's proposal with respect to the treatment of the CIS project for 2013 and 2014 appropriate?**

Interrogatory

[B/3/1/p.5] Please:

a. Provide the start and end dates for each of the phases listed in Table 1; and

b. Provide a detailed explanation of each change in cost between the June 15th filing and the August 29th update.

Response

a.

Project Phase	Start Date	End Date
Discovery	Feb-11	May-11
Blueprint	Jun-11	Oct-11
Realization	Nov-11	Dec-12
Final Preparation	Jan-13	May-13
Verification and Stabilization	Jun-13	Sep-13

b. Please Reference the response to Exhibit I, Tab 4, Schedule 1.05 Staff 21

School Energy Coalition (SEC) INTERROGATORY #35 List 1

Issue 4 **Is Hydro One's proposal with respect to the treatment of the CIS project for 2013 and 2014 appropriate?**

Interrogatory

[B/3/1/p.18] Please provide details of the incremental FTEs hired as a result of the CIS project, and the roles those incremental personnel filled in each of 2011 through 2013. Please confirm that all of those incremental personnel were temporary, and those FTEs will revert to normal levels in 2014 and beyond.

Response

There are approximately 35-40 Hydro One staff members supporting the CIS project at any given time, drawn primarily from Customer Care and IT. These staff are backfilled. The net effect of the backfilling is for incremental staff to be hired by the base organization, either on contract or temporary employment positions. Staffing will revert back to normal levels in late 2013, after all project activities have been completed.

School Energy Coalition (SEC) INTERROGATORY #36 List 1

Issue 4 **Is Hydro One's proposal with respect to the treatment of the CIS project for 2013 and 2014 appropriate?**

Interrogatory

[B/3/1/Attach. 2, p. 1 and 7] Please explain why the in-service date changed from October 2012. Please explain why there were cost overruns when HCL Axon was on a "fixed price arrangement".

Response

As discussed during the October 19, 2011 Stakeholder session (See Exhibit A, Tab 4, Schedule 1, Appendix D, Notes Page 19) from a regulatory perspective, the go live date may not be the date that the assets go into service. In the original June 15 2012 filing, the in-service date was assumed to be Q1 2013. For an explanation of why the in-service date changed from Q1 to Q2 2013, please refer to Exhibit I, Tab 4, Schedule 1.05 Staff 21.

Given that Hydro One has contracted with HCL Axon on a fixed price basis for the CIS project, the extension of the project has a limited impact on the cost of HCL Axon's work. However, the other parties engaged in the project – Hydro One staff and contractors, and Inergi staff – do not work on a fixed price basis. Hence the impact of the extension of the project is primarily associated with the effort from these other parties.

Association of Major Power Consumers in Ontario (AMPCO) INTERROGATORY #4
List 1

Issue 4 **Is Hydro One's proposal with respect to the treatment of the CIS project for 2013 and 2014 appropriate?**

Interrogatory

Reference: Exhibit B, Tab 3, Schedule 1

a) Page 4 – The project is expected to be in service in 2013. Please confirm the original start date of the project.

b) Page 5 Table 2 – Please reproduce Table 2 to show the breakdown of Board Approved and actual costs for the life of the project.

c) Page 5 Table 2 – Please provide the types of costs included under development costs.

d) Page 16 – Hydro One expects Distribution Business savings from the CIS implementation to total $172 million over a 7 year time horizon. Please provide a description of the savings and provide a breakdown of these savings by year.

e) Page 16 – Please identify the potential opportunities between HONI and other Ontario LDCs to look for project cost savings.

f) Page 18 Table 4 – Please confirm staff costs began in 2011.

g) Page 18 Table 4 - Please add additional rows to the Table to provide the number # temporary FTEs by year, number of # external contract staff by year and include other staff categories as required to match total costs for HONI staff on CIS project.

h) Please confirm the non-typical capital CIS project is non-discretionary.

i) Please confirm the amounts proposed in 2013 are outside of the base upon which rates are derived.

j) The Board's Guidelines state that the distributor's decision to incur the amounts must represent the most cost-effective option. Please discuss.

k) Please confirm that the incremental revenue requested will not be recovered through other means.

l) The Board's Filing Requirements (June 28, 2012) state on page 7 that the amounts must clearly have a significant influence on the operation of the distributor; otherwise they should be dealt with at rebasing. Please comment.

m) Please describe the actions HONI will take in the event that the Board does not approve the proposed non-typical capital CIS spending.

Response

a) The CIS project Discovery Phase began in February 2011.

b) The CIS project costs are broken down in Table 1 of Exhibit B, Tab 3, Schedule 1. There were no Board approved amounts for 2011 or 2012 for the CIS project.

c) Development costs as noted on Page 5 Table 2 include:
- Labour Costs (Hydro One, Inergi & system integrator)
- Expenditures on software (both licencing & maintenance)
- Third Party Support Costs (SAP, TD Bank, etc.)
- Overhead

d) Please refer to Exhibit I, Tab 4, Schedule 2.03 EP 17, part c).

e) Please refer to Exhibit I, Tab 4, Schedule 1.04 Staff 20.

f) Confirmed – staff costs began in 2011.

g) The number of Hydro One staff supporting the project varies from month to month and has also varied within individual years as various activities ramp up or down. Depending on the exact time of year, there were approximately 25-30 Hydro One staff members supporting the project in 2011 and 35-40 Hydro One staff members in 2012.

Table 4: Costs for HONI Resources on the Project

($M)	2011	2012	2013
Hydro One Labour Cost	$4.70	$6.80	$4.70
Min Number of HONI Employees on the Project	25	35	TBD
Max Number of HONI Employees on the Project	30	40	TBD

h) Yes the non-typical capital CIS project is non-discretionary. Please refer Exhibit I, Tab 2, Schedule 1.01 Staff 2.

i) Yes the amounts proposed in 2013 are outside the base upon which rates are derived.

j) As discussed in Exhibit B, Tab 3, Schedule 1 and in Exhibit I, Tab 2, Schedule 1.01 Staff 2, the project is non-discretionary and had to be undertaken now to replace an aging system which is not supported by the vendor. Having established the CIS requirements, the cost of the project was established through a competitive process to select both the software components upon which the CIS system is based, and the integrator costs. HCL Axon, the lowest cost bidder, was selected as the system integrator under a fixed price arrangement, and SAP and Itron were selected as the software providers through this competitive process. Based on the responses to the RFP that was issued Hydro One is confident that it obtained a cost-effective solution.

k) Confirmed. There is no other mechanism to recover the incremental revenue requested.

l) As discussed in Exhibit B, Tab 3, Schedule 1 and in response found in Exhibit I, Tab 2, Schedule 1.01 Staff 2, the project is non-discretionary and has to be undertaken now to replace an aging system which is not supported by the vendor. Furthermore, the CIS is a significant investment being brought to the Board's attention as soon as possible. Given the material impact on the Company, Hydro One cannot wait for rebasing to recover these costs.

m) Hydro One believes this project is in the best interest of customers and will be approved by the Board.

BILL BENNETT Plaintiff and **HYDRO ONE INC., ET AL.** Defendants Court File No.: CV-15-535019-00CP

ONTARIO
SUPERIOR COURT OF JUSTICE

Proceeding commenced at Toronto

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CERTIFICATION MOTION RECORD
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