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Susan Frank
Vice President and Chief Regulatory Officer
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BY EMAIL

September 2, 2014

Ms. Kirsten Walli
Secretary
Ontario Energy Board
Suite 2700, 2300 Yonge Street
P.O. Box 2319
Toronto, ON.
M4P 1E4

Dear Ms. Walli:

EB-2013-0416 Hydro One Networks' 2015 - 2019 Distribution Custom Rate Application – Compelled Disclosure, Undertaking Response, Amended Interrogatory Response

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Reference is made to the Board's Decision and Order on Confidentiality and Motion dated August 25, 2014 in the above-noted proceeding. In response to the Board's Decision and Order, please find enclosed the following documents:

- internal in-service additions budget information for years 2012, 2013 and 2014 as requested in interrogatory 3.2 SEC 25; and
- summaries of the internal audit reports requested in Interrogatories 4.2 SEC 35 and 6.1 SEC 84, as described in Hydro One's submission of August 8, 2014.

Also enclosed are:

(a) in satisfaction of Undertaking TCJ1.13, a modified Table 1 for Exhibit C1, Tab 2, Schedule 1 which includes a column for 2014 actuals to-date;

(b) an amended response for Exhibit I, Tab 7.1, Schedule 8, FOCA 6;

(c) the Hydro One Inc. 2013 Annual Report (Attachment 2 to Exhibit A, Tab 13, Schedule 1);

(d) the 2014 Second Quarter MD&A (Attachment 2 to Exhibit A, Tab 13, Schedule 2); and

(e) an updated Exhibit A, Tab 1, Schedule 1 (Exhibit List) to reflect (c) and (d).

Confidential materials will be filed under a separate cover letter.

Hydro One will file a completed version of the OEB Smart Meter Model, List of Witnesses, and their CVs by September 4, 2014.

Sincerely,

ORIGINAL SIGNED BY SUSAN FRANK

Susan Frank

cc. Intervenors

Encls.

Table 1
In-Service Capital Additions 2010-2014 ($ M): OEB Approved and Actual/Forecast

	Historic												Bridge
	2010			2011			2012			2013			2014
	OEB Approved	Actual	Variance	OEB Approved	Actual	Variance	Budget	Actual	Variance	Budget	Actual	Variance	Forecast
Sustaining	175.8	171.6	-4.2	195.5	203.3	7.8	220.6	195.6	-24.9	240.6	277.1	36.5	286.6
Development	166.1	171.6	5.6	168.3	159.0	-9.3	169.6	141.9	-27.7	160.8	185.3	24.5	155.4
Operations	6.8	2.3	-4.5	9.0	0.8	-8.2	2.2	2.3	0.1	3.0	1.4	-1.6	4.0
Common & Other	114.5	93.0	-21.6	50.3	89.5	39.2	89.1	74.4	-14.7	155.1	223.4	68.3	108.6
Total	**463.2**	**438.5**	**-24.7**	**423.1**	**452.5**	**29.4**	**481.4**	**414.2**	**-67.2**	**559.5**	**687.2**	**127.7**	**554.6**

SUMMARIES OF INTERNAL AUDIT REPORTS OF OM&A AND CAPITAL EXPENDITURES (2010-2013)

Included in this Attachment:

- 2010 Audit Reports Summary
- 2011 Audit Reports Summary
- 2012 Audit Reports Summary
- 2013 Audit Reports Summary

Note: Risk Levels – Definitions

DEFINITION	MATERIALITY
H = High – Controls are Ineffective	>$5,000,000 potential risk or equivalent
M = Medium – Controls Need Some Improvement	>$500,000 & <$5,000,000 potential risk or equivalent
L = Low – Controls are Good	<$500,000 potential risk or equivalent

Audit	Recommendation	Action Plan	Risk	Status of Action Plan
Audit of Purchasing #2010-03 May 28, 2010	**3. Personnel Risk Assessment for Contractors**			
	We recommend that Management coordinate with Corporate Security to: a. Review the process for contractor PRAs to refine it to ensure that PRAs are timely and are completed in all instances when they are required. b. Implement enhancements to ensure that there is timely follow-up with contractors to provide PRA forms promptly when required. c. Establish a log for tracking PRA requests initiated, followed-up, actioned, completed, etc. d. Update the process to advise Corporate Security of the need for the PRA in all instances when it is required.	To streamline the PRA process, Corporate Security has suspended PRAs, outside of those required under NERC Cyber security standards. The only PRAs that will be processed during this suspension period will be for persons who need unescorted access to Critical Cyber Assets (CCA). Based on analysis of the PRA program to date, this poses little if any risk to the Corporation.	M	**COMPLETE** – Time of Audit – Q2, 2010 The revised process has been rolled out. The PRA program will be continually assessed based on any identified risks or legislation.
Audit of Purchasing #2010-03 May 28, 2010	**4. Vendor Payments**			
	We recommend that Management: a. Co-ordinate with Corporate Security to perform an additional check to ensure that for EFT payments made to vendors, vendor bank accounts are compared to employee bank accounts to provide added assurance that no inappropriate payments are processed. b. Use results of such testing, once completed, to determine whether there is a need for periodic/ongoing testing of this nature.	Corporate Security will compare bank accounts used for vendor payments against payroll bank accounts used for employee pay deposits. Based on results of the comparison, a determination will be made on the necessity for ongoing testing.	M	**COMPLETE** – Q2, 2010 The EFT vendor bank accounts (1005 in number) were compared to all employee bank accounts. This resulted in one match which is being further examined to see if there was any wrongdoing. Based on the results of the scan the risk to Hydro One is very low. It is further recommended that this scan be done every two years.

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Audit	Recommendation	Action Plan	Risk	Status of Action Plan
Audit of Purchasing #2010-03 May 28, 2010	**5. Timeliness of Procurement**			
	We recommend that Management: a. Request appropriate reports to help track the turnaround time for issuing POs. b. Use the reports developed to: • Establish whether the turnaround time is appropriate. • Determine whether particular purchasing staffs are not processing orders on a timely basis. • Address delays with these staff through training, etc.	As part of Inergi contract extension negotiations, service levels have been agreed to regarding a number of minimum and target processing turnaround times. Reporting will be developed and in place for Q2. In addition, the Supply Chain Enhancement Project will be recommending enhanced performance reporting as part of proposed Phase 2 recommendations.	M	**COMPLETE** – Q2, 2010 New Inergi SLA's implemented which incorporate processing times for both simple and complex PO's Targets have been set, which continuously improved year over year, and have been established as Critical Performance Indicators. Results are reported, reviewed, assessed, and actions to be identified as necessary, through the monthly governance process with Inergi SMS.
Audit of Purchasing #2010-03 May 28, 2010	**6. Sole Source Purchases**			
	We recommend that Management engage with LoBs to: a. Assess the risks of not receiving critical materials, supplies and equipment from sole source suppliers. b. Develop mitigation strategies where required after assessing the risk.	Supply Chain has placed a Sole Source aid on our website to support individuals in completing this form and rolled out the process through issue of a corporate-wide communication. This aid includes the direction for the requisitioner to assess the risk of a sole source provider not being able to provide the material, and if it is assessed as a risk, then highlight it on the sole source request. Supply Chain then will develop a mitigation strategy with the LOB on an as needed basis. As well as placing this request on the website aid, this particular direction has also been issued to Grid Operations directly, as they are the significant users for the OEM sole sources.	H	**COMPLETE** – Time of Audit

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Audit	Recommendation	Action Plan	Risk	Status of Action Plan
Audit of Purchasing #2010-03 May 28, 2010	**7. Service Quality**			
	We recommend that Management consider: a. Strengthening the outcomes of the surveys done by Inergi by following-up to ensure any shortcomings identified by clients are addressed.	a. Metrics have been developed on meeting service level performance. New governance has been incorporated into the Inergi Contract Extension. This will result in actions plans being developed, and implementation of results being reported to the Joint Executive Committee.	L	
	b. Developing and implementing an independent survey to determine what's important for clients as well as the level of client satisfaction with the quality of service received for sourcing and procurement.	b. The need for an additional survey will be considered on an annual basis as part of a supply chain strategy development process.		
Audit of Purchasing #2010-03 May 28, 2010	**8. Follow-up of Previously Reported**			
	While Management actions have addressed most previously reported higher risk audit observations, we recommend that the remaining medium risk items be addressed as part of the Supply Chain Enhancement Project.	a. This item is being incorporated into and requirements will be assessed as part of the Supply Chain Enhancement project, and will be implemented as agreed subsequent to business case review and approvals, as appropriate.	M	**COMPLETE** – Q3, 2010
		b. This item is being incorporated into and requirements will be assessed as part of the Supply Chain Enhancement project, and will be implemented as agreed subsequent to business case review and approvals, as appropriate.		**COMPLETE** – Q3, 2010 A process has been established with Inergi, on a monthly basis, to provide base data used in calculating SLA performance results, to allow us to validate its accuracy with our own calculations.
		c. The status of the previous observation on Early Payment Discounts is currently being tracked in the quarterly audit reporting process.		**COMPLETE** – Q3, 2010 A process has been established with Inergi, on a monthly basis, to provide base data used in calculating SLA performance results, to allow us to validate accuracy of extraction criteria used for calculations.

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Audit	Recommendation	Action Plan	Risk	Status of Action Plan
Facility Management #2010-15 Dec. 15, 2010	**Facility Management**			
	1. Leverage the existing documentation (Accommodation and Facilities Strategy (Building our Facilities Foundation), CSA Workshop Report) to develop a plan to establish a Corporate level Managed System for facilities to drive sustainable performance. System to include (but not be limited to): a. Strategy/Objectives i. Mission Statement ii. Relationships/Stakeholder requirements iii. Inventory iv. Measurable Goals b. Plans/Programs i. Lifecycle Management Programs ii. Inspection iii. Maintenance iv. Operations v. Trouble Response vi. Accommodation Services c. Roles and Responsibilities i. Structure, and Authority (across LOBs) ii. Operational Processes iii. Information Management d. Performance Assessment and Improvement i. Performance Monitoring (KPIs) ii. Compliance Monitoring iii. Quality Assurance iv. Records Management e. Management Review i. Scorecard	1. Management will review existing documentation and develop a plan to establish a Corporate level Managed System for facilities. System will include the following elements: a) Strategy/Objectives b) Plans/Programs c) Roles and Responsibilities d) Performance Assessment and Improvement e) Management Review	M	**COMPLETE** – Q2, 2011 A Facilities Managed System document has been prepared and reviewed by the Facilities department. Minor modifications have been incorporated into the document and the revised document circulated March 3, 2011 for comment by the Facilities Committee. No comments/ objections were received as of March 18, 2011 as requested.

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Audit	Recommendation	Action Plan	Risk	Status of Action Plan
Facility Management #2010-15 Dec. 15, 2010	2. Stakeholder the plan with Senior Management and gain approval of EVP Operations.	2. The plan will be stakeholdered with Senior Management and be approved by the EVP Operations.	M	**COMPLETE** – Q3, 2011 By action plan as outlined below: March 3, 2011 the Facilities Managed system document was circulated for comment to the Director Stations, Director Provincial Lines, Director Forestry, Director Asset Management, Director OGCC, Director Equipment Services, and Director Work Management. In all cases no objections were received as of March 18, 2011 as requested and the document has therefore been finalized and will be sent to the EVP Operations for review/approval March 22 2011. May 13, 2011 the Facilities Managed System Document was presented/reviewed with the Operations Department VP team (SVP Cust Op's, SVP Grid Op's, SVP E&CS, VP HS&E, VP Supply Chain, VP F&RE< EVP Operations). Minor clarifications/additions were made to the document as requested by the Senior Team and the finalized document was approved and signed by EVP Operations on June 17, 2011

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Hydro One Networks Inc.
2010 Audit Reports
Action Items
Status as of June 30, 2014

Audit	Recommendation	Action Plan	Risk	Status of Action Plan
Cost of Power #2010-19 Jan. 14, 2011	**1. Set-up/Revision of Wholesale Delivery Points**			
	1. Meter upgrades as planned to meet IESO requirements.	1. Complete remaining upgrades as soon as possible.	M	**COMPLETE** – Q4, 2011 The upgrade for 1 Meter point from 2007 is complete.
	2. Renewal of meter seals and review and approval of associated documents on a timely basis.	2. Complete remainder of 2010 meter reseals. Complete all 2011 meter reseals.	M	**COMPLETE** – Q4, 2011 All 2010 Meter Seals complete
	3. Annual Inspection of ITs in accordance with Hydro One's policy and procedures, or determine whether there is a need to revise the policy and procedures to do away with this requirement after considering the benefits.	3. We will determine the risk/cost-benefit of not performing the annual inspections and discuss with Asset Management to revise the policy or to eliminate the requirement altogether. If Asset Management still require the annual inspections to be completed, we will re-establish the process to perform these inspections.	L	**COMPLETE** – Q4, 2011 Risk/Benefit analysis complete No IT Annual inspections to be performed in 2011. This will be reviewed in Q4 2011 for 2012.
Cost of Power #2010-19 Jan. 14, 2011	**2. Transmission and Settlement Activities**			
	Management should ensure that the updated version of the procedure documents are finalized, circulated, and also posted on the HODS.	Finalize and post the procedure documents on HODS	L	

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Hydro One Networks Inc.
2011 Audit Reports
Action Items
Status as of June 30, 2014

Audit	Recommendation	Action Plan	Risk	Status of Action Plan
DX Programs and Projects (Provincial Lines) #2011-01 June 8, 2011	**2. Estimating and Work Releases**			
	2.1			
	Determine a realistic price for unique pole replacements and adjust the 2011, 2012, and 2013 multi year release to reflect the amounts required to complete the unique poles.	The 2011 program will be reforecast and will include and estimate of the cost of the unique pole portion of the pole replacement program. The 2012 and 2013 programs will be reviewed and reforecast to include the cost of the unique pole program.	L	
DX Programs and Projects (Provincial Lines) #2011-01 June 8, 2011	**2.2**			
	Determine a realistic price for regular wood pole replacements and adjust the 2011, 2012, and 2013 multi year release to reflect the amounts required to complete the poles	The pole replacement program unit prices will be reviewed and adjustments will be made to include changes that have occurred since they were last priced. Technician labour hours required to complete the program will be specifically reviewed and adjusted as required. Changes will be reflected in new dollar forecasts for the 2011, 2012 and 2013 programs as required.	L	
DX Programs and Projects (Provincial Lines) #2011-01 June 8, 2011	**3.1**			
	Document the full process for managing and planning project work and roll out the procedures to staff. The revitalized planning process should integrate effectively with the increasing role of SAP for recording assets, generating orders and reporting on results.	In 2010 a team was established to review the Planning and Scheduling work in the FBC's. Recommendations have been presented and action plans are being prepared to address the key issues. Implementation of all actions will require full documentation of the processes and appropriate roll-out and training to staff.	M	**COMPLETE** – Q3, 2012 • Initiative required to be reassessed to ensure compatibility with SAP scheduling and project management tools. • Expected report by Q1 2013 on moving initiatives forward.
DX Programs and Projects (Provincial Lines) #2011-01 June 8, 2011	**3.2**			
	The use of P3e should be standardized. Over the next few years Lines should consider replacing P3e with SAP for planning Lines programs and projects. This would reduce interfaces, improve control, standardize and streamline the activities. A cost benefit analysis should be conducted to evaluate this potential change.	As above, the replacement of P3e was recommended by the Planning & Scheduling Team. Further review is underway to determine appropriate replacement and then define associated processes. This may be impacted by potential reorganizations.	L	

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Audit	Recommendation	Action Plan	Risk	Status of Action Plan
DX Programs and Projects (Provincial Lines) #2011-01 June 8, 2011	**3.3**			
	The responsibility for scheduling outage requests should be reassessed.	A dedicated knowledgeable resource for all Outage Planning is required in each Territory. A business case is being prepared for these new positions.	L	
DX Programs and Projects (Provincial Lines) #2011-01 June 8, 2011	**4.1**			
	The approach for setting up single project work orders for each feeder line is standardized across all zones and BI reports requested that can report project cost versus budget. These reports should be shared with Operations Managers.	BI reports are currently available to Customer Operations Managers, but they are not trained in how to access and analyze. Training is currently underway.	L	
DX Programs and Projects (Provincial Lines) #2011-01 June 8, 2011	**4.2**			
	The approach for setting up work orders for unique poles be reinforced across all zones.	The need to set up individual work orders for unique poles is being reviewed. It appears preferable to correct unit pricing to accommodate for these unique poles, rather than create large numbers of work orders.	L	
DX Programs and Projects (Provincial Lines) #2011-01 June 8, 2011	**4.3**			
	a) For ORMS trouble calls, management should ensure that they review queues and receive weekly exception reports for all outstanding orders and the old orders should be completed.	The existing process will be reviewed and enforced to ensure weekly clean-up of old orders.	M	**COMPLETE** – Q3, 2011 • Completed review with FBC's and supervisors. • Audit of process will be undertaken in Q1 2012
	b) For field orders with RTC status, it should be clarified who will monitor and disposition the various orders with RTC status and then the old orders should be cleaned up.	Training will be provided to the Field Business Centre's to monitor the RTC queue on a daily basis. In the case of the Call Centre setting an order RTC – a Work Flow Manager (WFM) will be sent to advise them to complete the order. In the case of the BASC setting orders RTC, a reminder will go to the BASC to ensure these are completed. QABS to document work instructions.	M	**COMPLETE** – Q3, 2011 • BASC staff were reminded to ensure RTC orders are completed. • FBC's were issued work instructions on July 25, 2011 advising them or the process for handling Dispatched and RTC orders.

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Audit	Recommendation	Action Plan	Risk	Status of Action Plan
DX Programs and Projects (Provincial Lines) #2011-01 June 8, 2011	**4.4**			
	Management should review and close all old prior year work orders that are currently open. Going forward management should run SAP listings of open work orders to ensure that work orders are closed when projects are complete.	Open work orders from 2009 are being reviewed and will be closed. Procedures for reviewing all work orders to ensure timely closure will be reviewed with all FBCs. This may be impacted by potential reorganizations.	L	
DX Programs and Projects (Provincial Lines) #2011-01 June 8, 2011	**4.5**			
	a) The nine FBC Managers and Supervisors should share their practices and techniques for monitoring the status of controls within the zone offices. The best practices should be implemented in all zone offices.	In 2010 a team was established to review the Planning and Scheduling work in the FBC's. Recommendations have been presented and action plans are being prepared to address the key issues. Implementation of all actions will require full documentation of the processes and appropriate roll-out and training to staff. This may be impacted by potential reorganizations.	L	
	b) Reporting requirements for management monitoring should be developed and fed into the SAP development team so that good management control is possible when SAP is implemented.	In 2010 a team was established to review the Planning and Scheduling work in the FBC's. Recommendations have been presented and action plans are being prepared to address the key issues. Implementation of all actions will require full documentation of the processes and appropriate roll-out and training to staff.	L	
DX Programs and Projects (Provincial Lines) #2011-01 June 8, 2011	**5.1**			
	SKF reporting requirements for unique poles be followed.	This requirement has been reconfirmed by the Planning and Scheduling team. All Business Managers are dedicating time to ensure existing procedures are followed.	L	

Audit	Recommendation	Action Plan	Risk	Status of Action Plan
Audit of Treasury #2011-07 July 15, 2011	**5. Authorizations, Confirmations and Settlement of Treasury Transaction**			
	1. Assess the risk of unauthorized settlement of Treasury transactions through CIBC Mellon Bank, revise settlement authorities where necessary, and clarify the procedure for settlement with CIBC Mellon.	1. On June 29 we amended our standing instructions to CIBC Mellon so that all settlement and cash transfer instructions from Hydro One now requires two signatures, one from Group I and one from Group 2.	M	**COMPLETE** – Q3, 2011 Implemented as per action plan on June 29, 2011
	2. Consider whether authorization limits for the Assistant Treasurer in Integra should be brought in line with the OAR, or whether there is a need to monitor transactions executed by the Assistant Treasurer for exercise of inappropriate authorization privileges.	2. We have received SunGard's (Integrity system owner) instructions on how to amend the Assistant Treasurer's rights in Integra re bond tickets and will request an amendment if the cost is nominal.	L	
	3. Request the system administrator to update the Transaction Security Report in Integra to remove former Treasury staff.	3. We have received SunGard's instructions on how to remove former Treasury staff from the Transaction Security Report in Integra and will request the system administrator to implement it.	L	
Audit of Treasury #2011-07 July 15, 2011	**6. Accounting for Treasury Transactions**			
	1. Review and revise as appropriate, Treasury Bank Reconciliation Templates referred to in SP 0715 RO, the "Procedure on Bank Accounts and Bank Account Reconciliations" (The Procedure) to facilitate monitoring and clearing of outstanding reconciling items on the monthly bank account reconciliations.	1. Treasury will request Inergi Accounts Payable to include a line for stale-dated cheques not reversed in their monthly reconciliations, as was the case with earlier templates. However, current cheque clearing rules have changed such that banks will continue to clear cheques older than 6 months making the definition of "stale dated' cheques unclear. We will adjust our procedures and reports accordingly.	L	
	2. Establish target dates for Inergi to review and clear the old outstanding cheques on the AP Clearing Account reconciliation as soon as possible, including journal entries if necessary.	2. Treasury will coordinate with Inergi Accounts Payable on the actions required to resolve this system conversion issue.		

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Audit	Recommendation	Action Plan	Risk	Status of Action Plan
Audit of Treasury #2011-07 July 15, 2011	**8. Treasury Contingency and Business Continuity Plan**			
	1. Update the draft Business Continuity Plan including differentiating between a contingency plan and a business continuity plan. 2. Approve the Business Continuity Plan once updated. 3. Develop test procedures to confirm the plan is workable. 4. Test the plan to confirm that it can be invoked.	We have met with the Manager, Business Continuity, regarding a revised Business Continuity Plan. This issue has also been included as part of Treasury's Performance Agreement with the CFO. The Manager, Business Continuity, will be providing Treasury with draft templates for developing a new Business Continuity Plan, as there will be a Corporate-wide initiative during 2012 to develop new Business Continuity Plans based on new guidelines. Treasury will discuss this matter with TD Bank and create a Draft Treasury Business Continuity Plan identifying the possible scenarios and the steps that will be taken to address these scenarios. The draft plan will then be submitted to the CFO for review and approval.	M	**COMPLETE** – Q4, 2011 Ahead of Corporate Initiative Treasury continues to work with the Manager, Business Continuity providing the necessary input to the Corporate Initiative in developing a Plan. In the absence of the Corporate Business Continuity Plan which is consistent with the corporate guidelines and requirements, Treasury has developed an interim plan that would be sufficient for current purposes. The EVP & CFO has been provided with the interim plan and is satisfied with its adequacy while work continues on the Corporate Initiative. In 2012 the interim plan will be embellished, consistent with corporate requirements once finalized.

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Audit	Recommendation	Action Plan	Risk	Status of Action Plan
Inventory and In-Transit (Provincial Lines) #2011-19 Dec. 21, 2011	**1. Accountabilities for Inventory Management**			
	Supply Chain and Lines prepare and agree upon an accountability matrix for inventory management.	Management will update the accountabilities matrix for inventory related elements, update the matrix and provide training to accountable staff	M	**COMPLETE** – Q1, 2012 Accountabilities documented, discussed and issued to accountable Operations staff.
Inventory and In-Transit (Provincial Lines) #2011-19 Dec. 21, 2011	**2. Inventory Management Practices**			
	Review all related work instructions and update where appropriate to ensure consistency in practices	Review of work instructions and updates have commenced as part of the materials initiative committee. Sixteen work processes being reviewed at present are attached in Appendix C. The majority of these processes did exist however some need to be updated to reflect changes that came about with SAP and to cover off project work and the new N to L ordering process.	M	**COMPLETE** – Q4, 2012 October 8, 2012
Inventory and In-Transit (Provincial Lines) #2011-19 Dec. 21, 2011	**3. Old Inventory Reservations in SAP**			
	Once the accountabilities and work instructions are clear, then old inventory reservations currently in SAP be reviewed and the material unreserved if the work has been completed, cancelled or deferred.	Work instructions and the process are developed for demand type activities to control the old reservations. New processes being developed for project type activities where material is taken from the yard on days when the stockkeeper is not present and where the material is staged and is constructed over long periods of time. There will be a new template form for material leaving yard and material returned after the job is complete. The planning department in each Field Business Centre (FBC) will monitor old inventory reservations as part of work order cleanup. The scheduling and planning group in the FBC will also monitor need dates and construction start dates on an ongoing basis and adjust the delivery dates as required	L	

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Audit	Recommendation	Action Plan	Risk	Status of Action Plan
Inventory and In-Transit (Provincial Lines) #2011-19 Dec. 21, 2011	**4. Safety Stock Levels**			
	Once the accountabilities and work instructions are clear, then: a) Inventory usage at each operations centre be carefully re-evaluated and new safety stock levels calculated and implemented to meet Corporate objectives.	a) Safety Stock evaluations will be performed for each operations centre. These will be re-established to improve efficiency while maintaining effectiveness. Customer Operations will undertake to manage the need dates of materials associated with work that is delayed, so as to reduce the amount of reserved stock for work that is delayed.	M	**COMPLETE** – Q4, 2012 Inventory alogorithm has been developed. HYD1 uses a report generated from SAP of actual monthly usage for trouble and customer reservations per SLOC and uses the average of this usage to determine the SS levels for each SLOC. Customer Operations has implemented an ongoing assessment of material needs for delayed projects, and assesses the need to reduce inventory levels. A review of the material codes for seasonal demand items was completed HYD1 safety stock has been reduced for December through March (4 months), and will increase again in April. This resulted in a safety stock reduction of approximately $1 million dollars.
	b) Some products that have high seasonal demand, e.g., 25 kva poletop transformers, should have the safety stock changed twice a year to optimize inventory levels in different seasons.	b) Safety Stock levels for seasonal demand items will be evaluated and adjusted as appropriate		
Inventory and In-Transit (Provincial Lines) #2011-19 Dec. 21, 2011	**5. Plan for Strategic Spares and Emergency Material**			
	When accountabilities and work instructions for safety stock levels are clarified (see previous recommendation) then accountabilities and work instructions for spare inventory should also be completed. Once the accountabilities and work instructions are clear, then a formal strategy for spare inventory be developed that identifies what strategic spares are needed for each zone and where they should be located.	Management will review the definitions of emergency stock as well as strategic spares, to ensure consistency, since this report has shown a gap in understanding. Management will undertake the following actions: - Local normal or moving stock will be managed through the use of safety stock and reorder points at the operations centres. These levels will be adequate to provide local crews with the ability to respond to emergency response, through the use of available or reserved stock held locally. Barrie will ensure that there is adequate stock to respond to larger demands. The stock levels locally will be established to supply local crews with adequate	M	**COMPLETE** – Q4, 2012 Discussions and workshops to examine the overall approach have been implemented by Provincial Lines. Almost all inventory, whether strategic or emergency is also normal use. These items have stocking strategy in place involving both the Barrie warehouse and field locations. Material initiative completed end of October. New Job Aids and processes were created and rolled out through the province. Crews are now informing stockkeepers when they remove inventory material from the field locations so the stockkeeper can

Audit	Recommendation	Action Plan	Risk	Status of Action Plan
		consigned materials to cover short term needs. Barrie will position itself to respond within an agreed upon time to supply larger demands (i.e. 6 hours after the need is communicated from the local operations centre). - Between Customer Operations and Logistics, managed by the Inventory Specialist, equipment and parts that are rarely used will be identified, and stock levels set to support emergency situations. These items typically are non-standard non-moving materials and equipment.		issue the material to the appropriate work order/reservation. This has resulted in less write offs/write ons during their monthly cycle counts. Should continue to improve as more crews get familiar with the new material movement forms. Need dates are being changed as projects/programs are delayed to reflect new date. This will un reserve material already shipped to locations and reserve to the next required demand. System will replenish again two weeks before need date. Inventory has reduced approximately $250,000.00 since the end of July. A process has been put in place to identify emergency materials not normally used any longer, and to reassess its stocking and location strategy. This is an ongoing process across each zone that will be constantly reviewed. We have completed zone 6 re two transformers. MM: 30004809 qty 1 and MM: 30004862 qty 1 in location 6KLL (Kirkland Lake).
Inventory and In-Transit (Provincial Lines) #2011-19 Dec. 21, 2011	**6. Inventory Adjustments**			
	Accountabilities be clarified and work instructions written to clarify how inventory adjustments and related inventory movements should be calculated, recorded and by whom.	The current cycle counts and steps required by the stockkeeper prior to counting inventory are being reviewed by all stakeholders and will be adjusted where required. We are looking into a work order or account where any thefts of material can be recorded and distributed versus wrote off. Procedure for clearly keeping certain project type jobs separated from regular count will be reviewed	L	

Audit	Recommendation	Action Plan	Risk	Status of Action Plan
		and communicated. A template for returns from a project type job will be developed and communicated to stockkeeper, crews, and planning department in the FBC. These new processes will be communicated and rolled out with the planning groups in each FBC, all stockkeepers and all Customer Operations manager. Some that are just minor changes will be emailed and others that are new or detailed with significant changes will be via webcast.		
Inventory and In-Transit (Provincial Lines) #2011-19 Dec. 21, 2011	**7. Surplus Inventory**			
	Estimate how much surplus inventory is in the field, conduct a cost benefit analysis to determine if any action is needed and then implement action as needed.	Surplus material outside of our work centre yards (Temporary Work Headquarters, DS and TS sites) is an unknown as discussed. Next spring after the snow melts we will do an analysis of how much we have and then determine whether we keep it local on the books, return to warehouse or scrap. Realistically we will not get to this before winter. The templates being developed in #3 will help eliminate the surplus that exists is as it will be returned to whatever job it was for and the decision will be made based on quantity whether to add it back into our stock or send to the warehouse.	L	

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Audit	Recommendation	Action Plan	Risk	Status of Action Plan
Corporate Charge Card Review – Follow-up Audit #2012-19 January 8, 2013	**1. Expense Review and Approval Process**			
	We recommend that management consider: 1. Supplementing the compliance testing program with data analysis to help identify other contraventions.	The compliance program will continue going forward with the following changes: 1. The sampling methodology will be reassessed to consider both random selection, data analytical reports and to also consider sample size.	M	**<u>COMPLETE</u>** – Q1, 2013 Implemented. Results will be reported in Q2 2013.
	2. Continuing re-enforcement of policy and procedure requirements through inclusion of exceptions identified on future monthly emails to "Hydro One All Staff" on the subject of "Corporate Controller: Helpful Reminders".	2. Continue reinforcing requirements through reminders.		**<u>COMPLETE</u>** – Q1, 2013 Communications are ongoing.
	3. We also recommend that management consider: a) Relying on BASC who perform the test for statement approval within 60 days as the Corporate Controller's Department reports a very high rate of compliance over a long period of time and this test does not require the expertise of the Corporate Controller staff. This will reduce duplicated effort as the BASC already reports on timely receipt of signed and approved CCC statements to management b) Reducing the sample size for compliance testing because of the low level of contraventions reported by the Corporate Controller's Department, and redirecting efforts to more analysis and to areas not currently tested, e.g., cash withdrawals incorrectly accounted for.	3. Cash withdrawals reported on the Cash Use Report will be included in the compliance test program.		**<u>COMPLETE</u>** – Q1, 2013 Implemented

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		4. Co-op students are currently used for the compliance testing. As the BASC is being reorganized, consideration will be given to reassigning compliance testing.		4. **COMPLETE** – Q1, 2013 a) BASC is assigned with other tasks and reporting to Bob Brown. b) Ongoing
Corporate Charge Card Review – Follow-up Audit #2012-19 January 8, 2013	**2. Local Purchases**			
	1. Management should determine whether there are opportunities for identifying significant local purchases through the CCC where POs should be established, or where POs exist but local purchases are processed through the CCC without reference to the PO, resulting in additional cost. This can be achieved through computerized data analysis.	1. The compliance program will be reassessed to consider reporting as recommended items.	M	**COMPLETE** – Q1, 2013 Assessment completed and action implemented.
	2. Management should re-enforce policy and procedure requirements for local purchasing through inclusion of reminders on future monthly emails to "Hydro One All Staff" on the subject of "Corporate Controller: Helpful Reminders".	2. Continue to reinforce concepts through monthly reminders.		**COMPLETE** – Q1, 2013 Communication sent out Nov.1, 2012.
Corporate Charge Card Review – Follow-up Audit #2012-19 January 8, 2013	**4. Charge Card Issue, Monitoring and Cancellation**			
	We recommend that management consider testing as part of the Corporate Controller's compliance test program.	Management agrees to periodically test whether credit cards are being cancelled in a timely manner.	L	

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Audit	Recommendation	Action Plan	Risk	Status of Action Plan
Supply Chain Management Controls #2012-20 January 8, 2013	**1. Procurement – Purchase Requisitions**			
	We recommend that: 1. Ensure effective communication of policies and procedures is issued on a regular basis.	1. Include in the Corporate Controller's Reminder, a message that Requisitioners are to ensure that the related business cases (if required) and the PREQ for each PO has the scope of work accurately described as staff augmentation or consulting services per the Consultants Policy (HODS SP0707). This communication will be issued on an annual basis.	M	**COMPLETE** – Q1, 2013 Communication sent out on February 8, 2013.
	2. Specifically include a sample of PREQs for Consultants in the FCAT testing program.	2. N/A		
	3. Look for opportunities to improve the efficiency of completing the quarterly Supply Chain Consultants report.	3. Investigations will be conducted in Q1, 2013 to identify opportunities to improve the efficiency of the completion of the Quarterly Consultants report.		**COMPLETE** – Q1, 2013 An in-depth analysis of the current state report process was conducted and a number of areas were identified where efficiencies could be gained. The new process has been approved and will be implemented and used for the preparation of the Q1 2013 Consultants report. It is expected that an overall reduction in work effort of approx. 25% will be achieved (6 hours/quarter).
	4. Investigate potential SAP solutions to highlight the requirement for additional approvals of Consultant requirements during the PREQ approval process.	4. Assessments will be conducted in Q1, 2013 to identify potential, cost effective SAP solutions to highlight to Requisitioners, the requirement for additional approvals for Consulting requirements. These assessments will be submitted to ISD for discussion and prioritization.		**COMPLETE** – Q1, 2013 SIR 2495(system investigation report) was submitted to ISD for consideration (effort, cost, and prioritization). This SIR recommends implementing a 'soft stop' in the requisitioning process in SAP whereby a message window would remind the Requisitioner that additional OAR approvals are required for Consulting requirements. The Requisitioner is required to acknowledge the message in order to proceed with submitting the PReq for

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				approval. SIR will be implemented consistent with Corporate prioritization process.
Supply Chain Management Controls #2012-20 January 8, 2013	**4. Single/Sole Source Purchases**			
	1. Re-enforce the requirement for risk assessments for Sole Source requirements. 2. Review and monitor forms for compliance. 3. Consider including single/sole source risk assessments in FCAT testing.	1. The Requisitioner's Procedure (HODS SP1233) will be revised to highlight the importance of completing the risk assessment section of the Single/Sole Source Approval Form for Sole Source situations. A corporate communication and HODS bulletin will be issued to reinforce these requirements. 2. N/A 3. N/A	M	**COMPLETE** – Q1, 2013 Revision 1 to SP 1233 (Requisitioner's Procedure) was published to HODS on January 23, 2013. Section 4.8 Single / Sole Source was updated to include the following: "Requisitioner's requesting a Sole Source must complete the risk assessment section of this form." Further, a corporate communication was issued to employees on March 8, 2013 advising of the procedural revision and specifically highlighted the necessity to complete the sole source risk assessment component of the approval form. A HODS bulletin was also issued delivering the same message.
Supply Chain Management Controls #2012-20 January 8, 2013	**5. Data Management -Vendor and Material Master Data**			
	Management should establish a process to review and update the Vendor Master Database on a regular basis.	Supply Chain will document its process to review Vendor Masters, to be performed periodically, commencing in 2013.	L	
Supply Chain Management Controls #2012-20 January 8, 2013	**6. Vendor Management**			
	Management should ensure that a formal database is maintained to track suppliers' performance and to facilitate future contracting work. If this requirement is no longer considered appropriate in all cases, then management should revise the procedure accordingly.	1. Supply Chain will reinforce the requirement for post contract evaluations in a revision to the Requisitioner's Procedure (HODS SP1233) in Q1, 2013. The revision will be communicated via a corporate communication and HODS bulletin.	L	

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		2. Due to the legal issues associated with this item, confirmation by Hydro One Law will be sought in Q2, 2013 as to the appropriate use of performance feedback in future services contracting awards. Subsequent to obtaining Law's advice, the process will be updated to reflect their input.		
		3. Finally, Supply Chain will solicit advice on Vendor Management from its' Outsourcing Services Advisor for consideration and possible inclusion in the RFP for a future S2P service provider's scope of work in Q2, 2013.		
Supply Chain Management Controls #2012-20 January 8, 2013	**8. Management of Statement of Work (SOW) with Inergi**			
	1. Include language in the Scope of Work of the upcoming RFP for Outsourcing Services, a requirement that SLA reporting be independently accessible by Hydro One.	1. Supply Chain will develop language concerning independently accessed SLA reporting with input from our Outsourcing Services Advisor for inclusion in the SOW of the upcoming RFP for outsourcing services in Q2, 2013.	L	
	2. Use best practices and advise of Outsourcing Services Advisor to ensure the set of SLAs for the next Supply Chain outsourcing contract best represent the key performance areas that should be reported on.	2. Supply Chain will utilize the upcoming RFPQ for outsourcing services as well as the advice of our Outsourcing Services Advisor, to draft best in class SLAs for S2P that best fit Hydro One Supply Chain's needs in our next outsourcing contract.		
	3. Implement the Scorecard to report on the operational effectiveness of key Supply Chain processes.	3. N/A		

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Supply Chain Management Controls #2012-20 January 8, 2013	**9. Process Risk Assessment and Monitoring**			
	1. A formal risk assessment is completed and documented. Management should consider including the identification of all risks for Supply Chain whether the risks pertain to the activities managed by Hydro One or by Inergi.	1. Risks will continue to be assessed at least annually, as part of the Business Planning process.	M	**ONGOING**
	2. Appropriate controls are developed and monitoring is in place to mitigate risks associated with processing by all service providers whether they are external or internal to Hydro One.	2. As risks are identified, mitigating controls will continue to be put in place.		**ONGOING**

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Audit	Recommendation	Action Plan	Risk	Status of Action Plan
Vegetation Management #2013-07 May 16, 2013	**2. Vegetation Management Planning**			
	2.1 Dx Maintenance Cycle			
	Revisit the funding reflected in the business planning Accomplishment File to determine if it should be adjusted to reflect an 8 year Dx line clearing cycle as reflected in the Five Year Dx Vegetation Management plan.	Dx Asset Management will put forward an eight year proposed plan, as done in previous years. We will propose no increase in funding for next year, but then increase funding for four years to clear the backlog of work and attain an eight year maintenance cycle. The funding will then start declining in subsequent years as the benefits of being on cycle accrue and unit costs fall. However, this proposal may not be approved due to other constraints.	H	**COMPLETE** – Q2, 2013 An 8-year scenario was proposed in the business plan and the draft accomplishment file reflects an acceptance of this plan.
Vegetation Management #2013-07 May 16, 2013	**2.2 Resource Constraints for Proposed Budget Timelines**			
	Asset Management should confirm Forestry Services resources for planning purposes and take steps to prepare for budget increases in the future.	Dx Asset Management will work with Forestry Services at Business Planning time to ensure the plan being put forward has been reviewed and agreed prior to having the business plan approved.	H	**COMPLETE** – Q2, 2013 Forestry Services was consulted prior to submitting the business plan and they are able to provide resources to execute the proposed plan once the funding has been approved.
Vegetation Management #2013-07 May 16, 2013	**2.3 Annual Budget and Detailed Feeder Plan**			
	Develop a detailed long range (e.g.10 year) feeder plan with input from the service provider showing when each feeder will be cleared, and how much it will cost.	Dx Asset Management will work with Forestry Services to produce a ten year list along with a feeder level pricing methodology.	M	**COMPLETE** – Q3, 2013 6 year plan has been completed; this aligns with the Custom IR 2015-2019 Plan.
Vegetation Management #2013-07 May 16, 2013	**2.4 Lack of Coordinated Planning with Lines**			
	A process should be put in place to coordinate Forestry planning with Lines planning when preparing long range, annual and short range plans.	Forestry Services will take a lead role in developing an annual plan for regular interaction with Provincial Lines to review work plans and identify opportunities for coordination of execution.	M	**COMPLETE** – Q4, 2013 Forestry Services conducted meetings with all of the Provincial Lines Business Managers. Meetings were very positive & productive resulting in a Work Instruction (still in draft) process agreement between PL & FS that planned/schedule meetings will occur twice a year to review programs.

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Vegetation Management #2013-07 May 16, 2013	**2.5 Procedures**			
	Develop process flowcharts for key activities in Asset Management pertaining to Vegetation Management.	a) Tx AM - The process documentation for AM activities will be developed as part of the asset analytics project.	L	
		b) Dx AM – Asset Management planners looking after forestry programs will document the process currently used within AM with regards to Vegetation Management programs.	L	
Vegetation Management #2013-07 May 16, 2013	**3. Forestry Program Execution**			
	3.1 Forestry Services Input to Feeder Selection Process			
	Document the process for the collection of local knowledge regarding feeder condition and ensure that it is utilized when developing the feeder list. Include a mechanism for communicating to the Territory Crews, the rationale for the choice of feeders annually.	Will conduct a review of the present process for the collection of local knowledge regarding feeder condition and document the selection process including the requirement to review with Territory Staff in the Core Training conducted each year.	L	
Vegetation Management #2013-07 May 16, 2013	**3.2 Forestry Technician Services**			
	3.2.1 Forestry Technician Development			
	Develop and implement a strategy for Forestry Technician training and development, giving consideration to other Technician programs at Hydro One.	Will undertake a review of current Forestry Technician training and make recommendations to the Forestry Leadership Team for the development and implementation of a structured Forestry Technician development program.	M	**COMPLETE** – Q4, 2013 New training program curriculum reviewed and agreed to by Leadership. First session of training scheduled for Q2 of 2014.
Vegetation Management #2013-07 May 16, 2013	**3.2.2 Consistency**			
	Develop a formal process to verify consistency amongst Forestry Technicians.	Coincident with the development of the Forestry Technician training program (Action 3.2.1) develop a procedure for ensuring consistent performance amongst Forestry Technicians.	M	**COMPLETE** – Q4, 2013 Consistency issue addressed via formal training program. Oversight of Tech development & performance tasked to Supervisors & Managers and part of training/field type assessments.

Audit	Recommendation	Action Plan	Risk	Status of Action Plan
Vegetation Management #2013-07 May 16, 2013	**3.3 Field Audit Observations**			
	3.3.1 Application of Standards and Execution			
	1. Continue to work with Asset Management, to develop and deliver training on both the new Distribution Standards and the existing Transmission Standards, providing clear direction for Forestry Technicians and Forestry Maintainers to use when negotiating with property owners or when conducting vegetation management activities.	Forestry Services will develop and deliver training to staff on the new Distribution Standards and existing Transmission Standards in such a way as to establish consistent interpretation.	H	**<u>COMPLETE</u> -** Q4, 2013 All 2014 work is teched to new Dx Standards & Specs. Training for all RMF's & EF's consisting of slide deck will be delivered to all staff @ core training 2014.
	2. Develop and implement a process to verify consistent application of the Standards by Forestry Technicians in negotiation with Property Owners and in Work Packages.	See Action 3.2.2- above, e.g. Coincident with the development of the Forestry Technician training program (Action 3.2.1) develop a procedure for ensuring consistent performance amongst Forestry Technicians.	M	**<u>COMPLETE</u> -** Q4, 2013 same as above 3.2.2 Consistency issue addressed via formal training program. Oversight of Tech development & performance tasked to Supervisors & Managers and part of training/field type assessments.
	3. Reinforce with supervisory staff the expectation that Forestry Vegetation Management Activities are to be monitored for compliance to Work Packages and Vegetation Management Standards at every opportunity.	Review and reinforce with Forestry Supervisory staff the importance of the requirement to check and respond appropriately to adherence to the Standards at every possible opportunity in order to drive consistency.	H	**<u>COMPLETE</u> -** Q4, 2013 Supervisory staff review of accountabilities with regards to adherence to standards & specs are part of the training package.
Vegetation Management #2013-07 May 16, 2013	**4.1 Quality Assurance Audits**			
	4.1.1 Field Auditor Independence and Objectivity			
	Define requirements for the QA/QC Assessment function that address independence and objectivity.	a) Tx AM - Define a high level requirements document for the QA/QC audits.	M	**<u>COMPLETE</u>** – Q3, 2013 Currently under development and will be stakeholdered with the service provider. Once finalized, will be included as part of the scope of work for the QA/QC Audits. No concerns with schedule.

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		b) Dx AM – Dx Asset Management will implement an effective plan for the oversight of the QA/QC activities for Vegetation Management programs, the plan will include a detailed scope of what is required from the Auditors.	M	**COMPLETE** – Q3, 2013 Audit scope has been completed and updated in SAP.
Vegetation Management #2013-07 May 16, 2013	**4.1.2 Resources**			
	Review the resources required and plan for the continuity of trained QA personnel performing the review.	QA/QC will design and implement an appropriate process that clearly defines strategy and approach.	M	**COMPLETE** – Q1, 2014 Engaged Corporate Audit and developed draft audit protocol for both TX and DX 2014 program. -Engaged System Investment to review and finalize audit scope and protocol. -Trained auditor to execute 2014 program start Q3. -Forestry and Technical Service will continue to work together to refine program throughout 2014.
Vegetation Management #2013-07 May 16, 2013	**4.1.3 No Process to Monitor Management Action Plans**			
	Asset Management should establish a formal, documented follow-up process to assess action plans and monitor completion of the action plans resulting from the QA/QC report.	a) Tx AM - Develop a process that will include meeting with the forestry leadership following the development of the audit report, to discuss any deficiencies and develop an acceptable action plan to address. The resulting actions will be tracked to ensure completion. The tracking will happen through the formal "Transmission Asset Management Corrective Action Plan" Process that is currently being developed and is planned to be completed by end of year.	M	**COMPLETE** – Q1, 2014 Jan 10th – Forestry Services and TX Asset Management met and discussed the findings of the QA/QC audit. Forestry Services subsequently took a number of actions to begin root cause analysis for a number of the deficiencies and would report back by Feb 28, 2014. They have since reported back and have indicated completion of these root cause analysis to be completed and shared no later than Q2 2014

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		b) Dx AM – Dx Asset Management and Forestry services will establish a process to ensure that QA audit findings are cleared up. Will also put in place a process to make sure lessons learned are shared with all involved.	M	**COMPLETE** – Q4, 2013 The Dx vegetation program audit scope of work was updated and sent to forestry services through SAP workflow on December 19th 2013. The updated scope of work summarizes and formalizes the discussions had with forestry services pertaining to the QA findings. The scope of work includes an annual audit program summary report due by November 1st 2014 and a requirement for forestry planning staff to facilitate a continuous improvement workshop by year end 2014. The workshop will address audit findings and program execution lessons learned. The workshop will yield action items to address gaps in program management and execution.
Vegetation Management #2013-07 May 16, 2013	**4.1.4 Statistical Reporting of QA Testing Results**			
	Management should enhance the QA/QC report and report an error rate which is calculated using the number of non-compliances in the total population tested.	QAOS will design and implement an appropriate process that clearly defines strategy and approach including error rate calculations.	L	

Audit	Recommendation	Action Plan	Risk	Status of Action Plan
Management of Personal Computers #2013-09 Sept.11, 2013	**1. Ability to Account for Purchased Personal Computers**			
	1.1 Receipting controls are deficient			
	1. Create Material Master codes and use these for the procurement of personal computers.	ISD will work with the contractor (Inergi –IT and Supply Chain), vendors and Hydro One stakeholders to ensure that adequate received goods records are in place and that inventories are periodically reconciled to purchases. Inventory will include all personal computers purchased by Hydro One, including those that are held at vendor facilities.	M	**COMPLETE** – Q1, 2014 Eric Jylha ; April 1, 2014 Via discussions with Supply Chain it has been determined that creation of MM codes for client computers is not feasible. Rapid change in computer types and specs as well as bundling of computer objects to meet MFA materiality requirements.
	2. Include the correct number of material items in the Purchase Order (as had been done previous to 2012).			**COMPLETE** – Q1, 2014 Eric Jylha ; April 1, 2014 The processes and OPAs are being changed to reflect this requirement. See 1.1.3
	3. Rectify Goods Receipting to Purchase Order in SAP. Also, partial shipments of items need to be tracked against the full quantity of the items included in the PO.			**COMPLETE** – Q1, 2014 Eric Jylha ; April 1, 2014 The BOM will be included in SAP so that the number of items can be reflected in orders and receipting.
	4. Personal Computers purchased by Hydro One which are "receipted" at the Virtual Warehouse (vendor's warehouse) need to be included in the inventory database (CMDB) and properly receipted in SAP (along with required documentation – see 1.1.3 above).			**COMPLETE** – Q1, 2014 Eric Jylha ; April 1, 2014 Process is in place to ensure proper inventories are being kept at our Virtual Warehouse.
Management of Personal Computers #2013-09 Sept.11, 2013	**1.2 Inventory processes to enable comprehensive tracking of personal computers purchased by Hydro One requires further improvement**			
	1. Additional controls are required to reinforce alignment between purchases in SAP and inventory in CMDB. These controls include storing serial numbers of purchased units and the existing shipment scan-upon-receipt	ISD will continue implementation efforts to improve inventory tracking of personal computers and the ability to physically verify their existence required by Hydro One Minor Fixed Asset Accounting Procedure.	M	**COMPLETE** – Q1, 2014 Eric Jylha ; April 1, 2014 Inergi has implemented new processes and have improved the CMDB to track inventories and ownership of the assets.

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	spreadsheet files (receipt of new personal computers) directly within SAP as "Attached File" associated with the Goods Received record in SAP. These purchase records should be reconciled on a periodic basis with the inventory in CMDB to ensure that purchased personal computers are continually tracked within the inventory database. Establish controls to ensure a complete and accurate inventory database.			BOM attached in SAP but SAP is being used for financial control of purchase and bulk use of computers. CMDB is used to establish a complete and accurate asset inventory.
	2. Implement asset-to-user tracking for recording and ongoing monitoring within the existing inventory database (CMDB).			**COMPLETE** – Q1, 2014 Eric Jylha ; April 1, 2014 The CMDB and processes have been enhanced to improve the asset-to-user tracking.
	3. Hydro One and Inergi should determine the effectiveness of the Eracent Discovery Tool to detect the personal computers (desktops, laptops and tablets) on the Hydro One network. Implementation of additional mechanisms may be required to supplement this approach to comply with the need for annual operational status of Hydro One's minor fixed assets.			**COMPLETE** – Q1, 2014 Eric Jylha, April 1, 2014 Hydro One and Inergi have implemented changes in the use of tools (including Eracent) and processes for keeping the CMDB up to date with the asset-to-user inventories.
Management of Personal Computers #2013-09 Sept.11, 2013	**1.3 Management Oversight requires improvement**			
	1. Conduct and document regular periodic meetings between Hydro One and Inergi that includes physical and information security of personal computers along with inventory tracking.	1. Include physical and information security of personal computers along with inventory tracking as part of regular periodic meetings between Hydro One and Inergi. Hydro One ISD to retain documentation pertaining any specific instructions to Inergi (beyond the contract) for reference by Inergi and Hydro One.	M	**COMPLETE** – Q4, 2013 Rob Hosford ; Oct. 24, 2013 Regular Asset Management Meetings have been scheduled and conducted to review the end to end management of personal computers. There has been a review of the Operational Procedure Manuals and continuous improvement initiatives are being scheduled and conducting to improve the processes.

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	2. Create documentation of risk assessments consistent with Hydro One's Enterprise Risk Management Policy.	2. A risk assessment will be undertaken and documented for the management of personal computers according to the Hydro One Enterprise Risk Management Policy.	M	**COMPLETE** – Q4, 2013 Rob Hosford ; Dec. 15, 2013 The review and governance of the Asset Management Practice is now assessed on the Risk Consequence Reference Table. Also via this process ISD worked with the Bill 198 team to conduct an audit of the external warehouse for personal computer assets and have achieved 100% inventory accuracy.
Management of Personal Computers #2013-09 Sept.11, 2013	**2. Ability to Account for Purchased Personal Computers**			
	2.1 Disposal of Personal Computers is not adequately controlled and recorded			
	Inergi should receive the Bill of Lading records from Abtron that includes the list of units and serial numbers transferred to and from Hydro One for the purpose of disposal. This list should then be cross-referenced to the existing ITSM ticket indicating change of status of the items to dispose. These records from Abtron should be electronically stored at a secure designated location for retrieval by Inergi and Hydro One staff involved in the management of personal computers.	ISD will improve administrative coordination among Hydro One ISD and various 3rd party vendors for the decommissioning of client assets with a goal of more effective asset inventory controls.	L	
Management of Personal Computers #2013-09 Sept.11, 2013	**3. Information Protection of Personal Computers**			
	3.1 Conformance to the Hydro One information security policy is not being sufficiently monitored			
	Establish monitoring to detect and ensure that sensitive corporate information is being handled in accordance with the Hydro One's Information Security Policy and Information Classification and Handling Standard.	A Data Loss Pilot project is presently underway with scheduled completion by Q3 of 2013. Security Operations will provide an assessment of the pilot project outcome and future plan for Implementation and/or alternative solutions. This proof of concept project will determine the effectiveness of a proposed solution to detect the classification and handling of sensitive information by Q4, 2013.	M	**BEHIND SCHEDULE** – Q2, 2014 In Progress, Susan Greenough ; June 30, 2014 The change request has been put in to push this out to the employees. Expect to be fully rolled out by Q4.

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Fleet Services and Utilization #2013-12 Oct.4, 2013	**1. Fleet Inventory – Acquisition, Disposal and Surplus**			
	1.1 Record Keeping			
	1. Put a process in place to prepare a formal and documented reconciliation of the vehicle lists generated from SAP and ARI periodically. 2. Consider feasibility of conducting physical inventory of Hydro One's vehicles.	Fleet Services will examine a process that will reconcile vehicle lists between ARI and SAP. Physical inventory at one date is feasible but not practical. Fleet Services maintains an inventory through the day to day operations including scheduled maintenance cycles. Units that are not being used show up as such and are referred to LoBs for justification.	M (See note below)[1]	**COMPLETE** – Q4, 2013 Process of examining and reconciling the vehicle lists between ARI and SAP is in progress and will be completed quarterly going forward. Fleet Requisition Clerk also conducts ongoing monthly reviews by reconciling all new unit acquisitions from ARI to SAP. Ongoing annual MFA certification of 25% physical inventory also ensures reconciliation of vehicle lists between ARI and SAP. Complete 100% verification at any point in time is not feasible at this time.
Fleet Services and Utilization #2013-12 Oct.4, 2013	**1.2 Parts Inventory**			
	We recommend that management assess the feasibility of a centralized parts inventory tracking system and implement such a process should the cost /benefit analysis indicate its economic viability.	Fleet Services will follow up with ISD and with other organizations within Hydro One to examine what systems are available and will conduct a cost analysis. Discussion previously held with BC Hydro, indicated that the cost benefits to track the inventory were not realized and that the system costs to track and manage the inventory exceeded the realized benefits.	L	

[1] **Management commented:** *This risk seems high. This appears to be a record keeping / reconciliation issue vice a risk of lost vehicles and equipment. All active units (with affiliated ARI credit card for fuel and maintenance) are tracked regularly through ARI and Fleet Services. Units not tracked accurately are surplus and scrap equipment that has not come off the records.*

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Fleet Services and Utilization #2013-12 Oct.4, 2013	**1.3 Disposal of Road Vehicles**			
	1. We recommend that management ensure that all forms are completed with the required information. 2. The required fields should be marked as N/A (Not Applicable) if appropriate.	Fleet Services will issue direction that appropriate sign-off will occur for all T&WE Condition Report & Surplus Declarations. Fleet Services will also review the current format and implement changes as required.	M	**COMPLETE** – Q4, 2013 Direction has been issued and revised form sent to all Fleet maintenance Supervisors.
Fleet Services and Utilization #2013-12 Oct.4, 2013	**1.4 List of Vehicles Sent for Disposal**			
	We recommend that management put a process in place to reconcile: 1. The Fleet Services list of vehicles sent to LVG Auctions to the list of vehicles provided by LVG Auctions. 2. The proceeds received from LVG Auctions with (1) above.	Hydro One is currently tendering a new RFP for auction services which includes vehicles as part of the greater mandate. The new contract is being structured to place increased emphasis on the vendor to provide reports. Fleet Asset Management, will provide lists of vehicles to be sent to the auction vendor, and will reconcile this with lists provided by the vendor on vehicles received. Once sale of the vehicle is completed by the vendor, this value will be entered against the vehicle inventory.	L	
Fleet Services and Utilization #2013-12 Oct.4, 2013	**1.5 Validation of Sales Prices Declared by LVG Auctions**			
	We recommend that management establish a process to validate the reported sales price for vehicles sold by LVG Auctions.	As indicated in the above comment, there is a RFP for auction services that will be released soon that will be overseen by Hydro One Logistics. Fleet Services will oversee disposal of vehicles and other Fleet assets within this contract. This issue has been discussed with Logistics and they believe that this is low risk, which can be mitigated by a QA process of a sample of the sales to verify accuracy.	L	
Fleet Services and Utilization #2013-12 Oct.4, 2013	**Adequacy of Vehicle Availability to LoBs**			
	Management should consider: 1. Re-examining the methodology used for vehicle allocation. 2. Whether a consistent methodology for	Fleet Services will work with LoBs through quarterly Fleet Prime meetings and with annual reviews with LoB leadership to try to create a consistent methodology (ratio criteria). This	M	**COMPLETE** – Q4, 2013 Ongoing. Initial discussions have occurred with Fleet Primes. Methodology will be reviewed during requirements gathering with

Audit	Recommendation	Action Plan	Risk	Status of Action Plan
	allocation of vehicles within and between LoBs is feasible. 3. Determining why some locations are able to operate successfully with fewer vehicles. 4. Introducing lessons learned regarding best practices for vehicle allocation at Hydro One locations.	methodology will be based on each trade class as they have different demands. The methodology will consider use of floating vehicles and examine whether dedicated vehicles are required. There is also a significant demand from the field for spare vehicles which need to be calculated outside of the crew to vehicle ratios.		LoBs during 2014.
Fleet Services and Utilization #2013-12 Oct.4, 2013	**3. Vehicle Utilization, Downtime, and Productivity**			
	3.1 Monitoring Process for Downtime			
	We recommend that LoB management implement a system to monitor loss of vehicle availability due to maintenance.	Fleet Services is pursuing the above recommendation, and will work with LoBs to deliver them an interim tool that provides better downtime tracking. This tool will be further refined after the telematics rollout when we have a better understanding of what reports the technology can provide.	L	
Fleet Services and Utilization #2013-12 Oct.4, 2013	**3.2 Downtime Reporting**			
	We recommend that management consider establishing a process to identify and track idle time through a separate charge code for vehicles that are: 1. In transit to the garage. 2. Awaiting attention at the garage. 3. Not collected promptly after maintenance work. 4. In transit to the LoBs.	We will develop a tool using best practices from other members in the transportation and fleet industry.	M	**BEHIND SCHEDULE** – Q2, 2014 Telematics has been delayed …trial starting end of Q3 …if all goes well a larger implementation will begin in Q4 2014.
Fleet Services and Utilization #2013-12 Oct.4, 2013	**3.3 Vehicle Utilization**			
	Management should consider: 1. Determining why some locations are able to operate successfully with fewer vehicles. 2. Re-examining the methodology used for vehicle allocation with a close cooperation from the LoBs to reduce/eliminate under-utilized vehicles.	Fleet Services will work cooperatively with LoB management to highlight opportunities where reductions in fleet size can occur without negatively impacting their operations.	H	**COMPLETE** – Q4, 2013 Action has been initiated with LoB Fleet Primes. This action will be ongoing for vehicle replacement cycles. Furthermore all new growth now requires approval from the applicable LoB Vice President.

*COMPLETE means that that the risks identified by Audit or management have been substantially mitigated. Where additional actions are required these have been added to the action plan.

Audit	Recommendation	Action Plan	Risk	Status of Action Plan
Fleet Services and Utilization #2013-12 Oct.4, 2013	**3.4 Fuel Efficiency Analysis**			
	We recommend that management ensure the use of the appropriate data for productivity analysis.	This will be a continuous improvement path as we refine the information retrieved from Telematics, as actual data (ie, kilometers driven) by vehicle is made available. This development impacts the fuel efficiency analysis only on the Fleet Productivity Tool. The current method of calculating mileage has been accepted across multiple fleets as an accepted practice when difficulties obtaining accurate, timely mileage reports are experienced.	L	
Fleet Services and Utilization #2013-12 Oct.4, 2013	**3.5 Documentation of Productivity Analysis**			
	We recommend that management ensure that the process for productivity analysis is formally documented in an official Hydro One procedure.	Fleet will formalize the procedures, after the initial process has been Tested out/operationalized (designed and evaluated) for a minimum of three reporting periods.	L	
Fleet Services and Utilization #2013-12 Oct.4, 2013	**4. Vehicle Time and Mileage Reporting**			
	4.1 Time Reporting			
	We recommend that management consider: 1. Send out periodic reminders to the users to ensure vehicle usage is properly reported. 2. Perform a data analysis to monitor consistent reporting of vehicle utilization. 3. Determine whether system enhancements can be introduced to notify timesheet approvers of vehicle time that is not being reported.	Fleet Services current sends out utilization reports on a monthly basis. We will work with the LoBs to determine if further reminders are required. It is a LoB accountability to ensure accurate data entry. Fleet Services does not have any ability to control the time entry. Fleet is examining options to accurately capture all costs for vehicle usage and a better utilization method that includes telematics.	M	**ON SCHEDULE** – Q2, 2014 Initial implementation of Telematics is scheduled to be complete prior to end of Q3, 2014. Data used on the first part of Phase 1 will be used to define how well usage can be indicated. Implementation of telematics will not be complete for the initial project numbers till Q4, 2015. Telematics has been delayed …trial starting end of Q3 …if all goes well a larger implementation will begin in Q4 2014.

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Audit	Recommendation	Action Plan	Risk	Status of Action Plan
Fleet Services and Utilization #2013-12 Oct.4, 2013	**4.2 Vehicle Time Charge out Method**			
	We recommend that management should pursue their plan considering the feasibility of such a plan from technology point of view, specifically SAP.	Fleet Services will review current usage data, correlated against telematics information, as the project is rolled out. This will allow Fleet to examine a revised costing model that uses daily costs vice the current model using hourly costs. The proposed revision model is more consistent with how rental organizations charge for vehicles and may allow for better benchmarking opportunities.	L	
Fleet Services and Utilization #2013-12 Oct.4, 2013	**5.1 Inspection, Maintenance and Supervisory Monitoring**			
	We recommend that management ensure: 1. Monthly inspection for each vehicle is performed and a report is generated and reviewed by the supervisors. 2. Blue Books are completed meaningfully if required; otherwise, reconsider the use of the Blue Books and the value they provide.	Fleet Services fully supports this recommendation and will provide assistance as required for Audit Services to make this recommendation to the Lines of Business to whom the operators are accountable.	M	**<u>ON SCHEDULE</u>** – Q2, 2014 Telematics has been delayed …trial starting end of Q3 …if all goes well a larger implementation will begin in Q4 2014 Mike P will look into this further rand update by Q4 2014.
Fleet Services and Utilization #2013-12 Oct. 4, 2013	**5.2 Fleet Services' SLA (Service Level Agreement) with LoBs**			
	We recommend that management consider: 1. Establishing formal SLAs with all LoBs. 2. Monitoring and reporting quality and timeliness of services provided. 3. Periodic surveying users to ensure appropriate provision of services.	Continued dialogue with ARI, to develop the existing tools, and with supported LoBs to ensure that tools being developed meet their needs.	L	

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Audit	Recommendation	Action Plan	Risk	Status of Action Plan
Central Tools Services #2013-13 Oct. 25, 2013	**1. The Central Tools Services (CTS) business function lacks a documented business mandate.**			
	a) Document and Approve the CTS Business Function and Mandate	a) Management will establish a formal document that specifies the business mandate for the CTS business that includes purpose, scope, role, accountabilities and governance.	M	**COMPLETE** – Q1, 2014 Charter/Mandate is 100% complete.
	b) Complete and document a Risk Assessment of the CTS business function	b) Management will complete and document a Risk Assessment of the Central Tools Services business with a plan for subsequent annual review consistent with Hydro One's Enterprise Risk Management Policy.		**BEHIND SCHEDULE** – Q2, 2014 Reviewed Risk Assessment Document for CTS modeling the Hydro One "Enterprise Risk Management Policy" HODS Doc. #SP 0736 R2. Formal Risk Assessment to be completed by Maja Shkolnik, meeting set up with LoB in early July. Risk Assessment group reviewing CTS Audit Report. 70% Complete
Central Tools Services #2013-13 Oct. 25, 2013	**2. There is a lack of clarity in management roles / accountabilities and details in staff job description documents.**			
	a) Clarify CTS Management Roles and Accountabilities	a) The CoM Role Definition Form for the Central Tools Services business manager will be updated to (i) include the role of managing the Central Tools Services business and (ii) clarify the accountabilities pertaining to the CTS business *[recommend first stage to implement performance measures consistent with standard inventory and tool rental practices so that these can be tracked and trended and ultimately benchmarked with external businesses]*	M	**COMPLETE** – Q1, 2014 Item a) (i), Completed. - Craft of Management. Item a) (ii), Accountability Matrix is 100% complete.
	b) Update CTS Job Description Documents to include required skill set for roles necessary in order to meet the business function and mandate.	b) The Job Description documents associated with the CTS business staff roles will be updated to reflect skill set required by the CTS business function Q1/2014.	M	**COMPLETE** – Q1, 2014 Office staff completed. Technical and warehouse staff 100% complete.
	c) Establish Succession Plans for CTS FLM Role	c) A succession plan for the CTS FLM role will be developed.		**COMPLETE** – Q1, 2014 100% complete, Succession plans created for all supervisor positions at CTS.

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Audit	Recommendation	Action Plan	Risk	Status of Action Plan
	d) Establish Systematic Staff Training and Certification Records Database	d) CTS Staff training and certification accreditation will be implemented into HOLMS.		**COMPLETE** – Q4, 2013 All external training completed by shop staff has been submitted for input into the HOLMS system with expiry dates, these external training courses will be flagged for completion the same way all HONI training is. All the forms were submitted to Work Methods and Training on October 23, 2013.
	e) Establish a Security Alarm Response Plan	e) A security risk assessment according to the Hydro One Policy SP 0842 R2 Security Risk Management Directive will be conducted and documented. The initial assessment will include response to security alarms. A plan and schedule to review annually will be established.		**COMPLETE** – Q4, 2013 Effective November 01, 2013 if the alarm at CTS is deployed "SECURITAS CANADA" will be the first to respond with myself. Myself or my delegate will meet the security company at the gate on Lockport Ave. to open the gates and give them site access, Securitas will check the building and the yard before myself or my delegate will enter the premises. If the site is not clear, Securitas will contact local Police.
Central Tools Services #2013-13 Oct. 25, 2013	**3. CTS has not established consistent processes to identify present and future tool requirements of its LoB customers**			
	Establish Communication Channels between CTS and HONI Lines of Business	CTS management will (i) plan formal communication / presentation of the CTS business at LoB (CTS customer) meetings,	M	**COMPLETE** – Q4, 2013 PowerPoint presentation created illustrating services provided.
		(ii) formally arrange for CTS management and/or frontline management staff to participate in upcoming project meetings (e.g. large construction, lines and stations projects),		**COMPLETE** – Q4, 2013 Meetings with Construction Services late in 2013 & Jan. 2014 and Station in Feb. 2014.

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Audit	Recommendation	Action Plan	Risk	Status of Action Plan
		(iii) create and schedule regular/formal service level and needs assessment survey - *[recommend engaging internal or external 3rd party to conduct and report survey results.]*		**COMPLETE** – Q2, 2014 (iii) Created an SLA and Need Assessment Survey Form. Survey sent to customers in 2013 and survey questionnaire will be on the CTS Web Site for continuous customer feedback by July 6. On-going meetings with all CTS customers. 100% Completed.
Central Tools Services #2013-13 Oct. 25, 2013	**4. There is a lack of Business Performance Monitoring and Reporting.**			
	Establish Performance Monitoring and Reporting	CTS management will plan and participate in the design and implementation of performance monitoring and reporting. Make a formal request to IT Business (ISD) to establish BI reporting. *[recommend engaging internal or external 3rd party to design and implement performance monitoring and reporting – may require CTS staff and/or sequestered HONI staff to assist.]*	M	**ON SCHEDULE** – Q2, 2014 50% Completed.
Central Tools Services #2013-13 Oct. 25, 2013	**5. Not all tool purchases are tracked in the CTS inventory.**			
	Establish Controls to Ensure that Equipment Purchased by CTS are Entered and Tracked in the CTS Inventory	a) Establish controls to ensure that equipment purchased by CTS are entered and tracked in the CTS Inventory	M	**COMPLETE** – Q4, 2013 All new tools are entered into SAP with Make, Model & Serial Number.
		b) Implement a solution to reconcile CTS inventory records with CTS purchases.		**COMPLETE** – Q4, 2013 All reconciling is done during ongoing cycle counting. Tracked through SAP.

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Audit	Recommendation	Action Plan	Risk	Status of Action Plan
Central Tools Services #2013-13 Oct. 25, 2013	**6. CTS purchase tools and test equipment for LoB specific work locations that are not used for rental purposes but charged against the CTS account.**			
	Provide clear mandate and criteria for CTS purchase of MFA tools and test equipment for LoB specific work locations that are not used for rental purposes	Establish and document a guideline for purchase of equipment and tools for other Lines of Business (other than for the purpose of tool rental services). This guideline will be referenced by the CTS business mandate document. CTS will work with finance to establish the means to account for equipment and tools purchases for CTS tool rentals separately from equipment purchased for other Lines of Business. e.g. establish a separate WBS in SAP.	L	

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UNDERTAKING - TCJ1.13

Undertaking

To provide year-to-date actuals for 2014, as they become available.

Response

Table 1
Summary of Distribution OM&A Budget
($ Millions)

Description	Historical Years						Bridge Year	Actuals	Test Years				
	2010	2010 Approved	2011	2011 Approved	2012	2013	2014	Q2 2014	2015	2016	2017	2018	2019
Sustaining	305.9	315.2	317.1	337.5	307.9	335.7	320.4	157.6	329.5	374.4	380.1	363.2	358.1
Development	12.3	11.7	15.8	12	14.7	11.1	18.4	6.1	15.4	17.7	17	17.4	17.8
Operations	18.5	20.2	18.1	20.9	21	22.0	30.4	13.9	30.2	34.4	34.8	42.2	41
Customer Services	114.7	117.2	113.3	113.4	116.7	148.6	133.7	114.5	117.9	116.3	114.7	113.5	115.4
Common Corporate Costs and Other OM&A	94.9	50.9	85.5	46.5*	88.6	88.8	73.8	65.3	66.7	62.5	62.4	62.4	62.3
Property Taxes & Rights Payments	4.6	4.7	4.6	4.8	4.5	4.4	4.6	2.3	4.7	4.9	5	5.2	5.4
TOTAL	**550.9**	**520**	**554.4**	**535**	**553.4**	**610.6**	**581.3**	**359.7**	**564.3**	**610.2**	**614**	**603.9**	**600**

Federation of Ontario Cottager's Association (FOCA) INTERROGATORY #6

Issue 7.1 Are the rate classes and their definitions proposed by Hydro One appropriate?

Interrogatory

Please advise the 2015 revenue requirement and resulting fixed and variable dx rates for the UR, R1 & R2 and Seasonal classes based on leaving the 11,000 high use customers in the seasonal class.

Response

The requested information is provided below.

Rate Class	2015 Rates Revenue Requirement	Fixed Distribution Rate	Variable Distribution Rate
UR	$86,965,324	$20.42	0.0178
R1	$302,434,596	$28.09	0.0314
R2	$484,750,562	$67.58	0.0452
Seasonal	$107,480,207	$30.08	0.0771

HYDRO ONE NETWORKS INC.
2013 ANNUAL REPORT

hydroOne

ANNUAL REPORT 2013

Every day Hydro One employees go to extraordinary lengths to take care of our customers and each other. During the December 2013 ice storm, 1,400 employees answered the call and gave up time with their families to get the lights back on.






We are committed to providing Ontarians with safe, reliable and affordable power 24/7, 365 days a year.

Ontarians rely on us and we deliver. Each and every day.

Serving our customers isn't just about answering the phone and driving a truck. It's about climbing a pole in freezing temperatures to restore power. It's about stopping at the side of the road to help our customers. It's any time we interact with anyone outside our Company.

81%

Customer Satisfaction (Transmission Customers)

87%

Customer Satisfaction (Distribution Customers)

Cover photo courtesy of CTV News Barrie.

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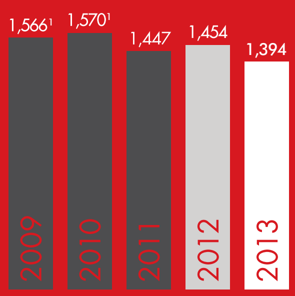
CONSOLIDATED FINANCIAL HIGHLIGHTS AND STATISTICS

CAPITAL INVESTMENTS

(CAD $ millions)

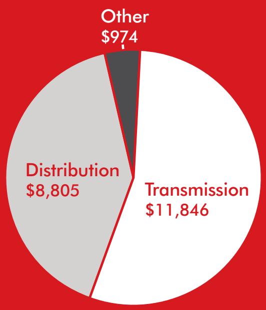


[1] based on Canadian GAAP

TOTAL ASSETS

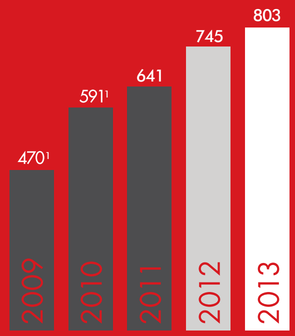
December 31, 2013

(CAD $ millions)



NET INCOME

(CAD $ millions)



[1] based on Canadian GAAP

Year ended December 31, 2013

(CAD $ millions, except as otherwise noted)	**2013**	2012	$ Change	% Change
Revenues	**6,074**	5,728	346	6
Purchased power	**3,020**	2,774	246	9
Operating costs	**1,782**	1,730	52	3
Net income	**803**	745	58	8
Net cash from operating activities	**1,404**	1,294	110	9
Average annual Ontario 60-minute peak demand *(MW)*[1]	**21,493**	21,132	361	2
Distribution – units distributed to customers *(TWh)*[1]	**29.8**	29.2	0.6	2

[1] System-related statistics are preliminary.

LETTER FROM THE CHAIR

"The Company continued its investments in the province's electricity system for the benefit of all Ontarians, as well as strengthening its commitment to provide a firm business model to its sole shareholder, the Province of Ontario."

Hydro One's commitment to delivering safe, reliable and affordable electricity to the people of Ontario remained foremost in our minds in 2013.

The Company continued its investments in the province's electricity system for the benefit of all Ontarians, as well as strengthening its commitment to provide a firm business model to its sole shareholder, the Province of Ontario.

From a financial standpoint, the year was a great success. Hydro One's net income reached $803 million for the year, compared to $745 million in 2012.

The 8 per cent increase was mainly due to efforts to reduce operating, maintenance and administrative costs. Additionally, the Company experienced higher revenues largely due to an increase in the Ontario Energy Board's regulated price plan rate-setting process and the Independent Electricity System Operator's spot market. Higher energy consumption and peak demand in the summer and winter months also contributed to higher revenues.

The Company's capital investments reached $1,394 million in 2013 due to the severe summer and winter storms, as well as investments in several infrastructure projects, including the completion of the Commerce Way Transformer Station and the Summerhaven 230 kV Switching Station.

Hydro One paid dividends of $218 million to the Province in 2013, and recorded a provision of $109 million for payments in lieu of corporate income taxes.

Our Company's response to the severe storms in 2013, particularly Toronto's July flood and December ice storm, is something of which we can all be proud.

While we continued to demonstrate our ability to deliver safe and reliable electricity and to provide excellent returns to our shareholder, affordability for our customers is a cause for concern. The Province's 2013 Long-Term Energy Plan (LTEP) indicates that electricity prices will continue to rise. While this increase will be caused more by the cost of the electricity itself rather than by our delivery charges, we will have to be even more vigilant as to our costs going forward.

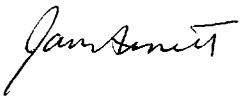
There were important strategic successes during the year:

1. The LTEP designated our Company to develop and seek approval for the Northwest Bulk Transmission Line Project, a significant reinforcement of the transmission system in the area west of Thunder Bay.

2. The Board of Directors approved a robust, but prudent, local distribution company (LDC) consolidation strategy to facilitate consolidation of Ontario's distribution sector. The agreement reached by our Company in 2013 to acquire Norfolk Power was an important first step in pursuing this strategy.

There was, however, a serious disappointment. In May 2013, our Company transitioned to a new customer billing system, a project over which the Board had detailed oversight. Some of our distribution customers experienced prolonged billing and related service issues as a result of the transition to the new system to a degree that was surprising and, indeed, unacceptable. This has led to an investigation by the provincial Ombudsman. However, the Board is confident that senior management is entirely focused on resolving these issues and delivering the service that our customers have a right to expect. Board oversight on this matter will remain a priority in 2014.

I would like to thank all Hydro One employees and my colleagues on the Board for their dedication and commitment to the Company and to the people of Ontario.



James Arnett
Chair of the Board of Directors

LETTER FROM THE PRESIDENT AND CEO

"During the December ice storm, more than 585,000 customers were affected, with 1,400 Hydro One employees working around the clock to repair the damage caused by freezing rain and to restore electricity service to our customers."

Our Company's success is determined by how well we serve the people of Ontario. Every employee who wears the Hydro One logo goes to work every day knowing that people count on us to make sure that electricity travels safely and reliably from where it's generated to where it's used to power life.

In 2013, we focused on improving our customer service and demonstrating excellence in running our business.

Serving our customers well often means responding in times of emergency. In a year of unprecedented storms, Hydro One employees worked quickly and safely to restore power to 2,556,000 customers affected by nine large storms that brought record rainfall, high winds and severe ice conditions.

During the December ice storm, more than 585,000 customers were affected, with 1,400 Hydro One employees working around the clock to repair the damage caused by freezing rain and to restore electricity service to our customers.

In May, we launched our new Customer Information System to replace a system that was no longer supported and had reached the end of its useful life. For 95 per cent of our customers, the move to the new system was seamless. But for about five per cent of our customers, the new system caused errors and we did not move quickly enough to solve their problems. These service issues will ultimately be resolved and Hydro One will continue to work to restore the confidence of these customers.

We are also measured by how well we perform as a commercial business, an important part of our mandate from the Province. Hydro One continued to demonstrate its value to the Province, exceeding its financial targets and working to control costs by improving the efficiency of our work programs and negotiating increased pension contribution ratios with two of our unions and our management employees.

During 2013, we made capital investments of $1,394 million to improve system reliability, to address our aging power system so we can improve service to our customers and to facilitate the connection of new generation.

I would like to thank our Board of Directors for their support, my leadership team for their dedication to improving our Company and our employees for their commitment to working safely in the service of our customers.

Carmine Marcello
President and Chief Executive Officer

SAFETY

EVERY DAY RESPONSIBILITY: FOR OUR SAFETY AND YOURS

Safety each and every day means a commitment to a workplace where all employees work together to ensure a safe work environment for all. It means looking out for one another just as much as it means staying alert and focused on the job at hand. We work safely to deliver the ultimate value to our customers. Power.

Hydro One was certified in the internationally recognized Occupational Health and Safety Assessment Series (OHSAS) 18001 standard on June 28, 2013 after an 18-month effort.

We have nothing without safety.

INJURY-FREE WORKPLACE

2.5 medical attentions per 200,000 hours worked in 2013

The electricity industry is an unforgiving, potentially hazardous environment where a single wrong move could result in a series of dangerous events.

To make sure every employee goes home safe and sound, Hydro One is committed to fostering a work environment where health and safety are the top priorities each and every day. This work culture guarantees that the right people are trained for the right jobs. It also maintains the safety of all Hydro One employees and Ontarians.

OHSAS 18001 CERTIFICATION

In June 2013, Hydro One was certified in the internationally recognized Occupational Health and Safety Assessment Series (OHSAS) 18001 standard. This prestigious certification further enforces the Company's commitment to creating a culture of zero workplace injuries. It is also a significant milestone in our history in sustaining our world-class Health and Safety management system.

HEALTH AND SAFETY PERFORMANCE RECOGNITION

The aim of the 2013 Health and Safety Performance Recognition program was to celebrate individual and team safety milestone achievements throughout the Company, as well as to improve the employee health and safety performance recognition process.

INJURY-FREE WORKPLACE

Hydro One has seen a steady decrease in both "near misses" (high Maximum Reasonable Potential for Harm incidents) and the number of preventable motor vehicle accidents year-over-year. As in previous years, Hydro One used medical attentions as a performance indicator to measure its injury-free workplace goal in 2013. This is in line with the Company's strategic objectives and its Journey to Zero initiatives.

Medical attentions are defined as injuries that require treatment by a medical practitioner and are reported to the Workplace Safety and Insurance Board. The indicator is calculated as the number of attentions per 200,000 hours worked. In 2013, Hydro One reported 2.5 incidents per 200,000 hours worked.

RELIABILITY

EVERY DAY RELIABILITY: BUILDING AND MAINTAINING OUR INFRASTRUCTURE

We bring knowledge, commitment and dedication to the work that we do. We work through holidays to get the power back on. We stop at the side of a road to talk to customers. We do more than just keep the lights on.

On April 2, 2013, our Company reached an agreement with Norfolk County to acquire Norfolk Power.

12.9
(minutes/delivery point)

Duration of customer unplanned interruptions on 115/230 kV network transmission system per all multi-circuit supplied delivery points

6.9
(hours per customer)

Duration of customer interruptions on the distribution system

The word “reliability” has been important every year in our history. This past year was proof. From wind storms and torrential rain to an ice storm at the end of December, Mother Nature tested our emergency response efforts in 2013.

PURCHASE OF NORFOLK POWER

In April, we reached an agreement with Norfolk County to purchase Norfolk Power.

POLE REPLACEMENT PROGRAM

In 2013, we replaced 11,000 wood poles across our 123,000-kilometre distribution system in an effort to maintain system reliability and promote public safety. The $82 million program is an investment in Ontario’s energy future.

SUMMERHAVEN 230 KV SWITCHING STATION

In June 2013, our Summerhaven 230 kV Switching Station was energized in Haldimand County. Work began in 2012 and involved the construction of a greenfield station to connect the Summerhaven Wind Farm Centre under Ontario’s Green Energy Act. At maximum generating capacity, the 124 MW centre can produce enough clean energy to power approximately 32,000 homes.

STORM RESTORATION

Ontario was hit with an onslaught of severe storms throughout 2013, causing power disruptions and at times, lengthy outages. We worked 24/7 to restore power to our customers.

Storm highlights include:

- In January, crews restored power to 48,000 customers after winter storms caused a number of outages.
- In April, crews restored power to more than 150,000 customers after high winds and freezing rain caused widespread damage.
- In July, crews restored power to more than 400,000 Toronto homes and businesses after heavy rains caused severe flooding at our Richview and Manby transmission stations.
- In November, crews worked for three days straight to restore power to more than 315,000 customers after a wind storm caused significant damage to our distribution system.
- In December, an ice storm that hit parts of Ontario downed power lines and caused widespread power outages. Between December 21 and December 29, approximately 585,000 customers were without power. We worked with local utilities to get customers back on line and by December 27, 98 per cent of affected customers had their power restored.

MODERNIZING THE GRID

Our focus continues on the Advanced Distribution System (ADS) – smart grid initiatives that consist of a wireless communication network and various intelligent electronic devices (IEDs) – to improve reliability and operations, renewable energy integration and provide timely information to help customers better manage their electricity costs.

In terms of our micro-fit initiatives and distributed generation, we connected 1,414 projects in 2013. The 2013 projects calculate to about 12,904 kW. Since December 2010, we’ve connected 11,329 projects, which calculates to about 109 MW in renewable power, through our clean and renewable energy programming.

Another key step in grid modernization is the reinforcement of our transmission system. Ontario’s Long-Term Energy Plan announcement that we will develop and seek approval for the Northwest Bulk Transmission Line Project, west of Thunder Bay, demonstrates the Province’s trust in our ability to improve reliability in the north.

INNOVATION & PRODUCTIVITY

EVERY DAY INNOVATION: COMMITTED TO THE FUTURE

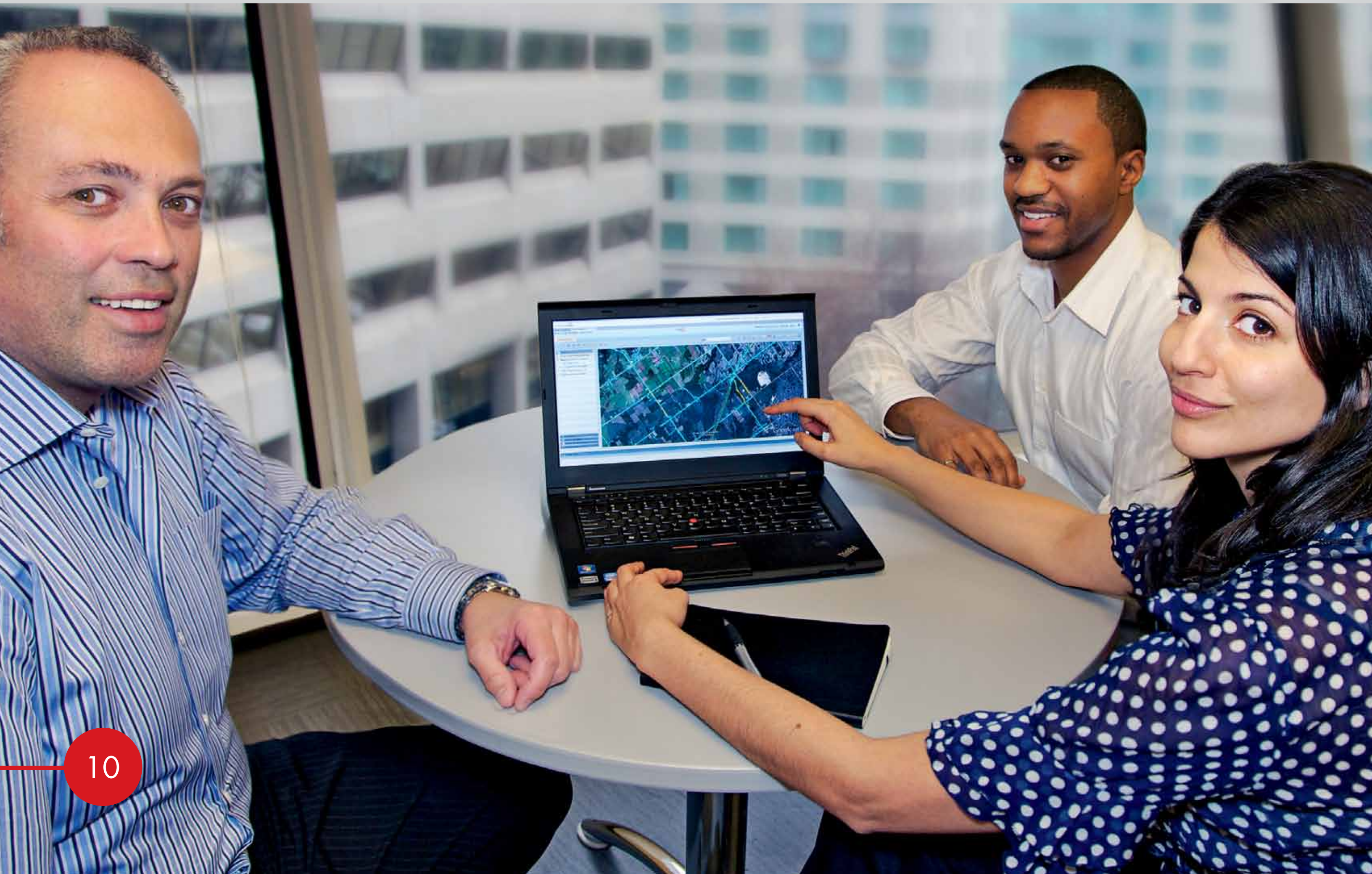
From our sustainment planning tool to our free mobile app, we are constantly looking for innovative and creative ways to better serve the electricity needs of Ontarians today, tomorrow and well into the future.

On December 22, 2013, at the peak of the ice storm, our free mobile app was downloaded 27,047 times.

The new Asset Analytics tool uses a combination of mapping, asset inventory and risk assessment to help make the best investment decisions and address the challenges planners and asset managers face when deciding what to replace and when to replace it.

BY THE NUMBERS

- **1.7 million** distribution wood poles
- **500,000** pole top transformers
- **50,000** steel transmission structures
- **42,000** transmission wood pole structures
- **1,002** distribution stations
- **29,000** kilometres of transmission line conductor
- **1,400** transformers
- **1,200** distribution power transformers
- **285** transmission stations
- **123,000-** kilometre low-voltage distribution system



We own and operate Ontario's 29,000-kilometre high-voltage transmission network that delivers electricity to municipal utilities and large industrial customers, and a 123,000-kilometre low-voltage distribution system that serves approximately 1.3 million end-use customers.

Ontarians rely on us each and every day to provide them with the power they need to go about their daily lives. We are committed to providing safe, reliable and affordable electricity to the people of Ontario through the advancement of new technologies, programs and procedures.

LAUNCH OF CUSTOMER INFORMATION SYSTEM

With a commitment to improving our customers' experiences and satisfying their needs, we launched our new Customer Information System (CIS) in May 2013.

The new system replaces an outdated, unsupported and unreliable system, and builds on our customer-first, customer-driven approach to providing value to our customers.

As is the case with any new system, the implementation of the CIS is part of a learning curve. Once it stabilizes, the benefits to our customers include improved call centre experiences, increased accuracy and timeliness of our billing system, and improved ability to address customers' concerns with up-to-date information.

MOBILE APP

The popularity of our free mobile app grew in 2013. The app connects users to Hydro One's interactive online outage mapping system and allows them to receive detailed power outage information from anywhere in our service area.

Between January 1 and December 31, 2013, the app received 125,133 downloads, an average of 343 downloads per day. On December 22, 2013, at the peak of the ice storm, the app received 27,047 downloads.

ASSET ANALYTICS

Asset Analytics is our sustainment planning tool created as a way for planners to manage and monitor assets in Hydro One's transmission and distribution systems. The first phase of Asset Analytics was launched in 2012 and work on the second phase began in 2013.

The Asset Analytics tool uses SAP data, Google Earth maps and sustainment planning information to map and list Hydro One's assets. It also has the ability to display risk information about their condition, which allows us to manage our assets so that we get the most out of them.

COMMUNITY

EVERY DAY COMMITMENT: ONE EMPLOYEE AT A TIME

We wouldn't be who we are without our employees. Hydro One is a diverse Company of like-minded and talented individuals who are committed to serving the people of Ontario. We are a Company where new ideas and original initiatives are fostered. We are dedicated, knowledgeable and reliable.

On March 23, 2013, during Earth Hour, Hydro One customers contributed to an overall reduction of 448 MW of energy consumption in the province. This demonstrated our commitment to educating our customers through programs and initiatives on ways to reduce energy consumption.

ELECTRICITY DISCOVERY CENTRE

Our Electricity Discovery Centre (EDC) travels across Ontario, broadening Ontarians' understanding about electrical safety, energy conservation and how we invest in the province's electricity system.

- **In 2013, the EDC visited:**
  1. The International Plowing Match
  2. The Norfolk County Fair
  3. The Royal Agricultural Winter Fair
  4. Queen's Park
  5. The Association of Municipalities of Ontario's Energy Connections Conference
  6. Alight at Night

- **More than 10,000** visitors toured the EDC between September and December 2013.
- **More than 3,700** visitors toured the EDC during its launch at the International Plowing Match in Perth County between September 17 and 21, 2013.

- Internet connected
- Handicap accessible
- Solar smartphone charging station
- Electric vehicle charging station

Our success relies heavily on our people. From the crews in the field to those in head office, Hydro One employees represent many cultures, backgrounds and skills. We are as diverse as Ontario, and we work together to provide Ontarians with a level of customer service they so richly deserve.

Just as we are committed to investing in educating and training our current and future workforce, we are also committed to building our corporate reputation by investing in Ontario and its communities through the development of partnerships and initiatives.

A number of key partnerships and initiatives were launched in 2013 to continue Hydro One's culture of putting Ontarians first.

ELECTRICITY DISCOVERY CENTRE

We broadened our longstanding commitment to electricity education and consumer engagement with the September 2013, launch of our Electricity Discovery Centre (EDC). The 1,000-square-foot, fully accessible mobile centre features hands-on exhibits about electrical safety, energy conservation and how we invest in Ontario's electricity system.

The EDC features a solar charging station, the Kids' Electricity Safety Team Headquarters, the Time-of-Use game and videos on Ontario's power system. The EDC travels across the province to engage and educate our customers.

The EDC visited a number of community fairs and events throughout Ontario in 2013, including the International Plowing Match in Mitchell in September, The Association of Municipalities Conference in Toronto in December, and Alight at Night in Morrisburg, also in December.

WOMEN IN ENGINEERING UNIVERSITY PARTNERSHIP

In March, we announced a partnership with Ryerson University, the University of Ontario Institute of Technology, the University of Waterloo and Western University to increase the number of female students pursuing careers in the Science, Mathematics, Technology and Engineering fields.

The main goal of the Women in Engineering University Partnership is to increase the number of female engineering students and graduates over the next four years.

LIGHTNING TRAIL RETREAT

In August, we partnered with Northern College and the District School Board Ontario North East to host a week-long retreat in Timmins for 29 Aboriginal youth between the ages of 12 and 18. As part of Hydro One's College Consortium, Lightning Trail provided the youth with opportunities to explore several trades and technology programs related to the electricity industry. Each student received a Certificate of Completion from Northern College, with three participants awarded Northern College Hydro One Aboriginal Leadership Entrance Bursaries.

FIRST NATIONS, MÉTIS AND INUIT SCHOLARSHIP

In June, we held our second annual First Nations, Métis and Inuit awards ceremony in Toronto to recognize the achievements of First Nations and Métis youth in the energy sector. The award honours youth who are attending a post-secondary program with a focus on the electricity industry, and who have demonstrated that they are leaders in the communities we serve.

WILLIAM PEYTON HUBBARD AWARD

Hydro One also sponsors two academic awards for outstanding black students attending an Ontario college or university through our William Peyton Hubbard Award.

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 & Culture

Rick Stevens
Vice President,
Customer Service

Sandy Struthers
Chief Administration Officer
and Chief Financial Officer

MANAGEMENT'S DISCUSSION AND ANALYSIS

For the years ended December 31, 2013 and 2012

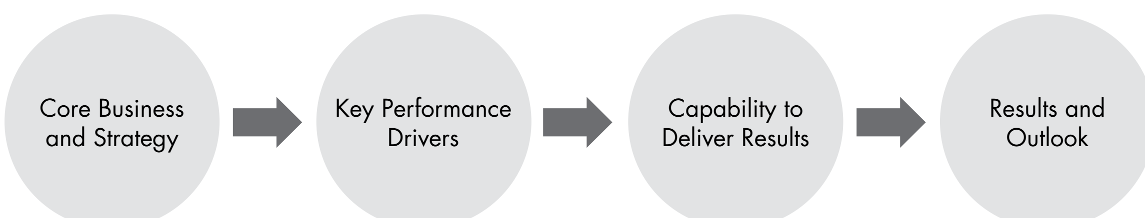
The following Management's Discussion and Analysis (MD&A) of the financial condition and results of operations should be read together with the consolidated financial statements and accompanying notes (the Consolidated Financial Statements) of Hydro One Inc. (the Company) for the year ended December 31, 2013. The Consolidated Financial Statements are presented in Canadian dollars and have been prepared in accordance with United States (US) Generally Accepted Accounting Principles (GAAP). All financial information in this MD&A is presented in Canadian dollars, unless otherwise indicated.

The Company has prepared this MD&A with reference to National Instrument 51-102 – Continuous Disclosure Obligations of the Canadian Securities Administrators. Under the US/Canada Multijurisdictional Disclosure System, the Company is permitted to prepare this MD&A in accordance with the disclosure requirements of Canada, which are different from those of the US. This MD&A provides information for the year ended December 31, 2013.

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 reflects 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 2013, 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 objectives, 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 objectives. We establish specific performance targets for each driver aimed at measuring the achievement of our strategic objectives 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 the 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 2013, we set nine stretch targets and we met or exceeded five of them. In 2012, we also met or exceeded five of nine stretch targets. We met our target for minimizing the duration of unplanned customer interruptions within our Distribution Business. We also met our targets of satisfying our transmission and distribution customers with the service they receive from our company. Our targets, and our 2013 performance relating to these targets, are discussed in the section "Performance Measures and Targets." 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 2013, our financial fundamentals remained strong with net income of $803 million. In 2013, we issued $1,185 million of long-term debt, the proceeds of which were used to fund the retirement of $600 million of long-term debt, 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 "Annual Results of Operations" and "Liquidity and Capital Resources."

In 2013, we made capital investments totaling $1,394 million to improve our transmission and distribution systems' reliability and performance, address our aging power system infrastructure, facilitate new generation, and improve service to our customers. Capital investments for the next few years will include expenditures 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 our aging power system infrastructure. Our future capital expenditures are more fully described in the section "Future Capital Investments."

OVERVIEW

Our Businesses

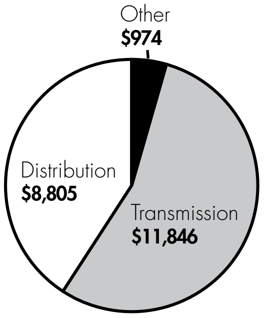
Our company has three reportable segments:

- Our Transmission Business, which comprises the core business of providing electricity transportation and connection services, is responsible for transmitting electricity throughout the Ontario electricity grid;
- Our 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 our telecommunications business.

Transmission

Our Transmission Business includes the transmission business of our subsidiary Hydro One Networks, which owns and operates substantially all of Ontario's electricity transmission system. 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 2013, we earned total transmission revenues of $1,529 million, primarily by transmitting approximately 140.7 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 electricity imports of up to 6,510 MW in the summer and 6,390 MW in the winter, and electricity exports of up to 6,070 MW in the summer and 6,270 MW in the winter. In terms of assets, our Transmission Business is our largest business segment, representing approximately 55% of our total assets at December 31, 2013.

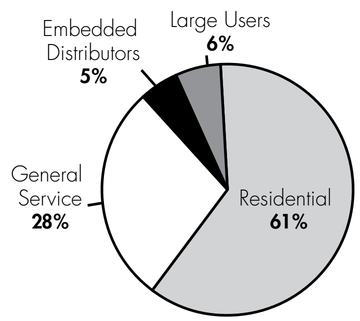
Total Assets
December 31, 2013
(millions of Canadian dollars)



Distribution

Our consolidated Distribution Business includes the distribution business of our subsidiary Hydro One Networks, as well as our subsidiaries Hydro One Brampton Networks Inc. (Hydro One Brampton Networks) and Hydro One Remote Communities Inc. (Hydro One Remote Communities). Our consolidated distribution system is the largest in Ontario and spans roughly 75% of the province. We serve approximately 1.4 million rural and urban customers. 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 2013, we earned total distribution revenues of $4,484 million, and over half of our distribution revenues were earned from our residential customers. At December 31, 2013, our Distribution Business assets represented approximately 41% of our total assets.

2013 Distribution Revenues



Other

Our Other business segment primarily represents the operations of our subsidiary, Hydro One Telecom Inc. (Hydro One Telecom), 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. In 2013, our Other business segment contributed revenues of $61 million, and had assets of $974 million at December 31, 2013, representing 4% of our total assets.

Our Strategy

Our corporate strategy builds on our strong commitment to the Province and is shaped by our values. It lays out a set of objectives to position our company to achieve our mission and vision, which 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 affordable 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 and ensure we remain focused on achieving our corporate goal of providing safe, reliable and affordable service to our customers, today and tomorrow, while increasing enterprise value for our shareholder.

- *Creating an injury-free workplace and maintaining public safety.* Health and safety must be integrated into all that we do as we continue to reinforce that nothing is more important than the health and safety of our employees. We will continue to create a passion for preventing injury, staying safe and keeping each other safe. We will invest in building a culture of accountability to continue our drive to zero injuries in the workplace. In addition, we will continue to strengthen our already strong safety culture through our Journey to Zero initiative and our successful certification to the Occupational Health and Safety Assessment Series (OHSAS) 18001 standard.
- *Satisfying our customers.* We exist to serve our customers, and serving our customers means reducing costs, improving customer service and meeting their expectations regarding reliable power supply. We will continue to focus our efforts to improve our relationship with customers and to improve our customers' satisfaction with us. We will meet our commitments, make customers our focus in all planning discussions, communicate effectively, coordinate across our company, and maximize opportunities to improve our corporate image and every customer interaction. We will develop and deliver targeted customer segment strategies, products and delivery channels that will respond to their unique needs.

- *Continuous innovation.* Innovation represents one of our values and is critical to achieving our mission and vision. We have been using innovation and technology to build the foundation of our company as the utility of the future. Over the next two decades, we will continue to build on that foundation to improve the reliability and efficiency of our transmission and distribution systems and provide our customers with more capability to manage their power costs. The development of the Advanced Distribution System (ADS) is a key element in our investment in innovation, as are the investments we have made, through our Cornerstone project, in next generation business tools to enable us to implement leading industry practices and increase productivity.
- *Building and maintaining reliable, affordable 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 continuing to meet the challenge of providing reliable, affordable service to our customers in a wide range of geographical regions and climate zones; incorporating ADS technology to provide greater visibility; and increased control and improved customer service. We will meet customer expectations regarding reliability, in part through our investment planning process, which starts with the identification of asset and customer needs.
- *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.
- *Championing people and culture.* We believe our primary strength is the capability of our people. In order to sustain this advantage, we will continue to address the issues of corporate culture, labour demographics, diversity, development of critical core competencies, and skill and knowledge retention. We will continue to develop a culture of accountability and trust as a key component to fostering employee engagement. Our labour strategy is to consolidate and clarify our collective agreements, increase flexibility and reduce costs, and maintain a progressive relationship with our unions.
- *Maintaining a commercial culture that increases value for our shareholder.* For the delivery component of a customer bill, we are committed to maintaining total annual bill impacts for an average residential customer at or below the rate of inflation, and delivering income and dividends to our shareholder. We will pursue growth opportunities through local distribution company (LDC) consolidation to increase the enterprise value of our company by leveraging our existing assets, technologies, capabilities, unparalleled experience in LDC acquisitions and our distribution and transmission footprint.
- *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.

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 2013, 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 2013 were transmission unit cost and distribution unit cost. For transmission unit cost, we measured 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 9.8%, and we met this target. The distribution unit cost target was set at $9,800 per kilometre of line. We did not meet 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 2013, 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 2013 was 9 minutes per delivery point. We did not meet this target.

For the duration of unplanned customer interruptions within our distribution business, the target for 2013 was set at 6.7 hours per customer. While we did not meet this target, our Board of Directors noted that the impact of storms in January and February of 2013 would require our company to change work practices and alter resource levels to simply meet the target and that the cost to do so would be prohibitive and not in the best interests of the ratepayer. Considering the storm impacts and the positive results over the balance of the year, our Board of Directors, in the exercise of its discretion, determined that this target was met.

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 2013, for transmission customers we targeted a customer satisfaction rate of 82%. The survey was given to three major groups of transmission customers. Our Board of Directors determined that there was significant improvement in two of the three groups which comprise the survey members and accordingly, in the exercise of its discretion, considered this target met. 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 employee engagement survey is 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 2013 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 2013 target was $702 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 2013, 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 Insurance Board and is calculated as the number of attentions per 200,000 hours worked. In 2013, we set a target of no higher than 1.9 attentions per 200,000 hours worked. We did not meet this target.

REGULATION

Our electricity transmission and distribution businesses are licensed and regulated by the OEB. 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. 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.

The OEB approved the use of US GAAP for rate setting and regulatory accounting and reporting by Hydro One Networks' Transmission and Distribution Businesses, as well as by Hydro One Remote Communities, beginning with the year 2012. Hydro One Brampton Networks currently uses Canadian GAAP for its distribution rate-setting purposes.

Renewed Regulatory Framework

In December 2010, the OEB initiated a coordinated consultation process for the development of a Renewed Regulatory Framework for Electricity. In October 2012, the OEB issued its report *A Renewed Regulatory Framework for Electricity Distributors: A Performance Based Approach*. The report identified three rate-setting models available to provide choices suitable for distributors having varying capital requirements: a fourth generation Incentive Regulation Mechanism (IRM); a custom rate setting; and an Annual Incentive Rate-setting Index method. The report also provided information on performance measurement, continuous improvement and implementation of the new framework.

In late 2013, the OEB issued its *Report of the Board on Rate-Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors*. This report sets out the OEB's policies and approaches to the rate adjustment parameters for incentive rate setting for electricity distributors and the benchmarking of electricity distributor total cost performance. It also includes the OEB's determination on rate adjustment parameter values for 2014 incentive rate setting, which were used to adjust Hydro One Networks' 2014 distribution rates.

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. Substantially all of our RPP customers are now on TOU billing. We received an exemption from the OEB, effective until December 31, 2014, from implementing mandatory TOU pricing for approximately 122,000 customers that are currently out of reach of our smart meter telecommunications infrastructure. Unexpected shortfalls or overpayments associated with the RPP are temporarily financed by the OPA. RPP 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.

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. The following is a summary of the RPP for the reporting and comparative periods:

RPP	**Tier Threshold (kWh/month)**		**Tier Rates (cents/kWh)**	
Effective Date	**Residential**	**Non-Residential**	**Lower Tier**	**Upper Tier**
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
May 1, 2013	600	750	7.8	9.1
November 1, 2013	1,000	750	8.3	9.7

RPP TOU	**Rates (cents/kWh)**		
Effective Date	**On Peak**	**Mid Peak**	**Off Peak**
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
May 1, 2013	12.4	10.4	6.7
November 1, 2013	12.9	10.9	7.2

Transmission Rates

In May 2010, we filed a cost-of-service application with the OEB for 2011 and 2012 transmission rates, seeking 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 for our company 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 UTRs, with an effective date of January 1, 2012. The new rates resulted in an approximate 8% transmission rate increase, or 0.6% when considering total bill impact, for a typical residential customer consuming 800 kWh per month. The adoption of US GAAP in lieu of modified IFRS as a basis for rate setting decreased the approved rates by approximately 15%.

In May 2012, we filed a cost-of-service application with the OEB for our 2013 and 2014 transmission rates. The application sought OEB approval for revenue requirement increases of approximately 0.6% in 2013 and 9.1% in 2014, or estimated increases of 0% in 2013 and 0.7% in 2014 on an average customer's total bill. In November 2012, we submitted a draft Rate Order, which included 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. For a typical residential customer consuming 800 kWh per month, this represents increases of nil for 2013 and 0.5% for 2014. In December 2012, the OEB approved the 2013 and 2014 transmission revenue requirements of $1,438 million and $1,528 million, respectively, and the 2013 Ontario UTRs, which remained unchanged at the 2012 levels.

On December 6, 2013, we submitted a draft Rate Order for our 2014 transmission rates. The 2014 revenue requirement has been increased to $1,535 million from the originally-approved revenue requirement of $1,528 million, primarily due to changes in the cost of capital parameters for 2014 released by the OEB in November 2013. On January 9, 2014, the OEB approved the draft Rate Order for 2014 transmission rates as filed. For the transmission portion of a customer's bill, this represents an increase of 6.3% in 2014, or 0.5% when considering total bill impact, for a typical residential customer consuming 800 kWh per month.

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.

- **Hydro One Networks**

  Hydro One Networks elected to retain the same distribution rates for 2012 as approved by the OEB for 2011, with a revenue requirement of $1,218 million.

  In June 2012, Hydro One Networks filed an IRM rate application with the OEB for 2013 distribution rates, to be effective January 1, 2013. In December 2012, the OEB issued a final Rate Order, which resulted in an increase in distribution rates of approximately 1.3% in 2013, or 0.4% when considering total bill impact, for a typical residential customer consuming 800 kWh per month.

  On April 26, 2013, Hydro One Networks filed an IRM rate application with the OEB for 2014 distribution rates, to be effective January 1, 2014. On September 26, 2013, the OEB issued a partial decision, approving a rate rider to recover a 2014 revenue requirement of $29.3 million for operation, maintenance and administration expenses and in-service capital costs of the ADS Project, which will modernize our distribution system. On December 5, 2013, the OEB issued its final decision, which resulted in an increase of distribution rates of approximately 2.4% in 2014, or 0.85% when considering total bill impact, for a typical residential customer consuming 800 kWh per month.

  On December 19, 2013, Hydro One Networks filed a 2015–2019 distribution custom rate application with the OEB, for rates effective January 1 of each test year. This application is a five-year custom rate application which is being submitted under the OEB's Renewed Regulatory Framework for Electricity Distributors. It has been customized to fit Hydro One Networks' specific circumstances, which necessitate significant multi-year investments. The submitted evidence includes the overall business plan, revenue requirements, and rate information necessary to support the issuance of a notice by the OEB. We are seeking OEB approvals for revenue requirements of $1,411 million for 2015, $1,515 million for 2016, $1,571 million for 2017, $1,615 million for 2018, and $1,666 million for 2019. If the application is approved as filed, the resulting change to the distribution portion of the average customer bill will be approximately a 1.3% decrease in 2015, 4.2% increase in 2016, 2.6% increase in 2017, 1.9% increase in 2018, and 2.9% increase in 2019, for a typical residential customer consuming 800 kWh per month. When considering total bill impact, the resulting change will be approximately a 1.1% decrease in 2015, 1.5% increase in 2016, 0.9% increase in 2017, 0.7% increase in 2018, and 1.1% increase in 2019.

- **Hydro One Brampton Networks**

  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, or a 1.7% reduction on the average customer's total bill, for a typical residential customer consuming 800 kWh per month. These rate reductions were primarily due to OEB-approved adjustments to depreciation rates.

  In August 2012, Hydro One Brampton Networks filed an IRM application with the OEB for 2013 distribution rates, to be effective January 1, 2013. In December 2012, the OEB released a decision that resulted in an increase in distribution rates of approximately 0.3% for 2013, or less than 0.1% on the average customer's total bill, for a typical residential customer consuming 800 kWh per month.

  In August 2013, Hydro One Brampton Networks filed an IRM application with the OEB for 2014 distribution rates, to be effective January 1, 2014. On December 5, 2013, the OEB released a decision that resulted in a reduction in distribution rates of approximately 2.5% for 2014, or a 0.5% reduction on the average customer's total bill, for a typical residential customer consuming 800 kWh per month.

- **Hydro One Remote Communities**

  In November 2011, Hydro One Remote Communities filed an IRM application with the OEB for 2012 distribution rates. In March 2012, the OEB approved an increase of approximately 1.08% to basic rates for the distribution and generation of electricity, with an effective date of May 1, 2012, representing an increase of approximately $1 on the average residential customer's total bill.

  In September 2012, Hydro One Remote Communities filed a cost-of-service application with the OEB for 2013 distribution rates, seeking approval for a 2013 revenue requirement of $53 million. In August 2013, the OEB issued a final decision approving a revenue requirement of $51 million and rate increase of approximately 3.45%, with an effective date of May 1, 2013.

  In October 2013, Hydro One Remote Communities filed an IRM application with the OEB for 2014 distribution, seeking approval for a rate increase of approximately 0.48%, to be effective May 1, 2014.

Recent Industry Developments

Long-Term Energy Plan

In 2010, the Ministry of Energy released Ontario's LTEP, which set out the province's expected electricity needs until 2030 and supported the continued procurement of new, cleaner generation. The 2010 LTEP addressed seven key areas: demand, supply, conservation, transmission, Aboriginal communities, capital investments, and electricity prices.

On December 2, 2013, the Province released its updated LTEP, *Achieving Balance*, which sets out the Province's plan of action for the energy sector, including strategies for mitigating increases in electricity rates; increased renewable energy procurement; nuclear refurbishment; enhanced regional planning with respect to energy infrastructure; transmission enhancements; encouraging Aboriginal participation in energy development, transmission and conservation projects; and the expansion of natural gas infrastructure. The plans are guided by the goal of balancing five core principles: cost-effectiveness, reliability, clean energy, community engagement, and conservation and demand management (CDM). Pursuant to the updated LTEP, the Province "will encourage Ontario Power Generation Inc. (OPG) and Hydro One to explore new business lines and opportunities inside and outside Ontario. These opportunities will help leverage existing areas of expertise and grow revenues for the benefit of Ontarians." We will continue to work with the Province to develop business plans and efficiency targets that will reduce costs and result in significant ratepayer savings.

In November 2013, the Minister of Energy issued a directive to the OEB, which in turn issued a decision and order on January 9, 2014, to amend the transmission licence of Hydro One Networks to develop and seek approval for the Northwest Bulk Transmission Line Project, an expansion or reinforcement of the transmission system in the area west of Thunder Bay. The scope and timing of the Northwest Bulk Transmission Line Project shall be in accordance with the recommendations of the OPA.

Distribution Sector Consolidation

In April 2012, the Province announced it was launching a comprehensive review of Ontario's electricity sector to explore options to improve efficiencies, including LDC consolidation. As a result, the Province created the Ontario Distribution Sector Review Panel (Panel). In December 2012, the Panel released its report, "Renewing Ontario's Electricity Distribution Sector: Putting the Consumer First" with recommendations for electricity sector consolidation. This report recommended 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 recommended 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 recommended 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. The Minister of Energy subsequently indicated he was supportive of voluntary consolidation and expects all LDCs to pursue innovative partnerships and transformative initiatives that will result in electricity ratepayer savings.

On April 2, 2013, we reached an agreement with Norfolk County to acquire the outstanding shares of Norfolk Power Inc. (Norfolk Power) for $93 million, subject to final closing adjustments. We will pay Norfolk County approximately $66 million net after assuming Norfolk Power's existing debt of approximately $27 million. Norfolk Power is a holding company that owns Norfolk Power Distribution Inc., a local distribution company, and Norfolk Energy Inc., a non-rate regulated energy services company. The selection of our company as successful bidder followed a comprehensive competitive sales process initiated by Norfolk Power. The acquisition is pending a regulatory decision from the OEB, which is anticipated in 2014.

We will continue to pursue growth opportunities through LDC consolidation by leveraging our existing assets, technologies, capabilities, unparalleled experience in LDC acquisitions, and our distribution footprint.

Procurement of New Generation

In 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. The FIT program is currently divided into three streams: Micro FIT (projects up to 10 kW), Small FIT (projects between 10 kW and 500 kW) and regular FIT (projects greater than 500 kW), all of which may result in connections to our distribution system. Under the FIT program, the OPA has entered into contracts or conditional contracts with generation proponents pursuant to which the OPA will pay a fixed rate for power produced over a specified period of time. We continue to connect projects for which there are firm contracts.

On May 30, 2013, the Province announced that it would make 900 MW of new capacity available between 2013 and 2018 for the Small FIT and Micro FIT programs. The Province has set annual procurement targets, from 2014 onwards, of 150 MW for Small FIT generation and 50 MW for Micro FIT generation. The Province is working with the OPA to develop a competitive process for renewable energy generation projects above 500 kW. The new process will replace the existing large project stream of the FIT program. As at December 31, 2013, our company has connected more than 370 FIT and 11,000 Micro FIT projects.

Conservation and Demand Management

In April 2012, the OEB issued its CDM guidelines for all electricity distributors. These guidelines provide guidance on certain provisions in the CDM Code and the type of evidence that should be filed by distributors in support of an application for OEB-approved CDM programs. The guidelines also provide details on the Lost Revenue Adjustment Mechanism (LRAM) related to CDM programs implemented under the CDM Code. LRAM is the mechanism by which LDCs are compensated for lost revenues associated with their respective load reductions resulting from CDM programs. In addition, the guidelines state that savings associated with TOU pricing are eligible to be counted towards the 2011–2014 CDM targets.

In December 2012, the Minister of Energy issued a directive to the OPA to extend funding for the OPA-contracted Ontario-wide CDM programs for one additional year, to December 31, 2015. This extension will provide an opportunity for the OPA and LDCs to collaboratively work to strengthen the current framework, and to keep customer programs in place for 2015.

On September 30, 2013, in accordance with the CDM Code, Hydro One Networks and Hydro One Brampton Networks each filed a 2012 Annual CDM Report with the OEB. The reports discussed CDM activities, energy and peak demand savings results achieved in 2012, and plans to reach CDM targets by the end of 2014. Hydro One Networks reported that it expects to reach 100% of its demand target and 80% of its cumulative energy target by 2014. Hydro One Brampton Networks reported that it expects to reach 68% of its demand target and 100% of its cumulative energy target by 2014. The OEB has indicated that there are several LDCs that have a similar issue. The OEB is aware of our situation.

ANNUAL RESULTS OF OPERATIONS

Year ended December 31 *(millions of Canadian dollars)*	**2013**	2012	$ Change	% Change
Revenues	**6,074**	5,728	346	6
Purchased power	**3,020**	2,774	246	9
Operation, maintenance and administration	**1,106**	1,071	35	3
Depreciation and amortization	**676**	659	17	3
	4,802	4,504	298	7
Income before financing charges and provision for payments in lieu of corporate income taxes	**1,272**	1,224	48	4
Financing charges	**360**	358	2	1
Income before provision for payments in lieu of corporate income taxes	**912**	866	46	5
Provision for payments in lieu of corporate income taxes	**109**	121	(12)	(10)
Net income	**803**	745	58	8

Revenues

Year ended December 31 *(millions of Canadian dollars)*	**2013**	2012	$ Change	% Change
Transmission	**1,529**	1,482	47	3
Distribution	**4,484**	4,184	300	7
Other	**61**	62	(1)	(2)
	6,074	5,728	346	6
Average annual Ontario 60-minute peak demand (MW)[1]	**21,493**	21,132	361	2
Distribution – units distributed to customers (TWh)[1]	**29.8**	29.2	0.6	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, ancillary revenues primarily attributable to maintenance services provided to generators, and secondary use of our land rights.

Our 2013 transmission revenues were higher by $47 million, or 3%, compared to 2012. The average Ontario 60-minute peak demand was higher in 2013, resulting in an increase in transmission revenues of $26 million, compared to 2012. The higher energy consumption in 2013 mainly resulted from a warmer summer and a colder winter, as compared to 2012. In addition, we experienced higher revenues of $21 million in 2013, associated with the OEB's approval of export service revenues and ancillary services.

Distribution

Distribution revenues include our distribution tariff and amounts to recover the cost of purchased power used by the customers of our 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 service 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 charges for late payments.

Our 2013 distribution revenues were higher by $300 million, or 7%, compared to 2012. The increase was primarily due to the recovery of higher purchased power costs of $246 million, as described below under "Purchased Power." In addition, energy consumption was higher by $29 million in 2013, mainly resulting from a warmer summer and a colder winter, as compared to 2012. Distribution revenues also increased by $15 million as a result of our placement in service of new smart grid and smart meter investments, which are currently being recovered through separate rate mechanisms.

In December 2012, the OEB approved new tariff rates effective January 1, 2013, based on its third generation IRM process. As part of the IRM decision, the OEB approved our application for an additional rate rider related to an incremental capital module (ICM) adjustment to our rates, reflecting our placement in service of certain specific capital investments. This ICM approval resulted in an increase of $13 million, compared to 2012. In addition, the OEB's IRM decision resulted in higher distribution revenues of $10 million, which will support the maintenance and investment requirements of our distribution system and enable the safe and reliable delivery of electricity to our customers throughout Ontario. The 2013 distribution revenue increases were partially offset by lower 2013 ancillary distribution revenues of $13 million, primarily associated with OEB-approved regulatory accounts.

Purchased Power

Purchased power costs are incurred by our Distribution Business and represent the cost of purchased electricity delivered to customers within our distribution service territory. These costs comprise the wholesale commodity cost of energy, the IESO wholesale market service charges, and transmission charges levied by the IESO. The commodity cost of energy is based on the OEB's RPP, as described above under "Regulation."

Our 2013 purchased power costs increased by $246 million, or 9%, to $3,020 million, compared to 2012. The increase in our 2013 purchased power costs was mainly due to a $104 million increase resulting from higher purchased power costs for customers who are not eligible for the RPP, an $85 million increase resulting from the impact of changes in the OEB's RPP rates for residential and other eligible customers, a $44 million increase due to higher electricity demand, a $9 million increase resulting from the IESO's Smart Metering Entity charge effective May 1, 2013, and a $4 million reduction in wholesale market service charges levied by the IESO.

Operation, Maintenance and Administration

Our operation, maintenance and administration costs consist of labour, materials, 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 our transmission and distribution lines, stations and buildings. Our transmission operation, maintenance and administration costs are incurred to sustain our high-voltage transmission stations, lines and rights-of-way. Our distribution operation, maintenance and administration costs are required to maintain our low-voltage distribution system. Our company continues to focus on managing its costs, while continuing to substantially complete our planned work programs for both our Transmission and Distribution Businesses.

Year ended December 31 *(millions of Canadian dollars)*	**2013**	2012	$ Change	% Change
Transmission	**375**	402	(27)	(7)
Distribution	**672**	608	64	11
Other	**59**	61	(2)	(3)
	1,106	1,071	35	3

Transmission
Our 2013 transmission operation, maintenance and administration costs decreased by $27 million, or 7%, to $375 million, compared to 2012. Within our work programs, we continued to invest in the safe and reliable operation of our transmission system.

Expenditures in support of our transmission system decreased by $33 million in 2013, compared to 2012, primarily due to a reduction to our provision for payments in lieu of property taxes related to transmission stations for the years 1999 to 2012, inclusive, following the finalization of the related regulations and receipt of a final assessment of our property tax returns. The decrease in our transmission system support costs was partially offset by an increase of $6 million in our work program costs, compared to 2012. This increase was primarily due to higher expenditures related to our forestry work program on our transmission rights-of-way resulting from heavy tree densities, power equipment preventive and corrective maintenance, and emergency restoration requirements as a result of severe flooding at our Richview and Manby transmission stations caused by a major rainstorm in July 2013. We also experienced increased cyber security and internal compliance program requirements related to the reliability standards and criteria mandated by the North American Electric Reliability Corporation (NERC). These increases in work program costs were partially offset by lower expenditures related to the OPA's recommendation to increase short circuit and/or transformer capacity at ten of our transmission stations to enable the connection of small renewable projects, as this work was substantially completed by the end of 2012. Expenditures for these station upgrades were recorded within operation, maintenance and administration rather than as capital expenditures, given that recovery was restricted pursuant to a shareholder declaration made in April 2011. No such declarations were issued in 2013. In addition, we experienced lower expenditures within our overhead lines program.

Distribution
Our 2013 distribution operation, maintenance and administration costs increased by $64 million, or 11%, to $672 million, compared to 2012. Our work program expenditures increased by $63 million compared to 2012, mainly as a result of increased power restoration expenditures following major storms in 2013, increased customer-driven work related to trouble calls and cable locates in support of the new One Call Program, higher requirements within the line patrol program, higher expenditures on our customer care programs, higher Information Technology (IT) improvements and enhancements, and continued work on the ADS Project. These impacts were partially offset by lower station corrective and preventive maintenance expenditures, as well as lower line clearing expenditures, compared to 2012. Our expenditures in support of our distribution system increased marginally by $1 million, compared to 2012.

Depreciation and Amortization
Our 2013 depreciation and amortization costs increased by $17 million, or 3%, compared to 2012. This increase was attributable to higher 2013 depreciation expense, primarily related to our placement of new assets in service consistent with our ongoing capital work program, as well as higher asset removal costs in 2013.

Financing Charges
Financing charges increased by $2 million, or 1%, to $360 million for 2013, compared to 2012. Higher financing costs in 2013 were mainly due to a decrease in interest capitalized, partially offset by a decrease in interest expense on long-term debt due to lower average interest rates.

Provision for Payments in Lieu of Corporate Income Taxes
The provision for payments in lieu of corporate income taxes (PILs) decreased by $12 million, or 10%, to $109 million in 2013, compared to 2012. This decrease primarily resulted from changes in net temporary differences, and a true-up relating to the 2012 research and development tax credits. This reduction was partially offset by the impact of higher levels of pre-tax income in 2013, compared to 2012.

Net Income
Our 2013 net income increased by $58 million, or 8%, to $803 million, compared to 2012. We experienced higher distribution revenues in 2013 mainly reflecting increased purchased power costs, primarily related to the OEB's RPP rate-setting process and the IESO's spot market. We also experienced increased transmission revenues in 2013 reflecting a higher peak demand due to intermittent periods of hot weather in the summer of 2013, as well as extreme cold winter weather. Our 2013 net income was also positively impacted by a lower provision for PILs and by a reduction to our provision for payments in lieu of transmission station property taxes, following the finalization of the assessment of certain prior years' property tax returns. This reduction was partially offset by power restoration expenditures following several major storms in 2013.

QUARTERLY RESULTS OF OPERATIONS

The following table sets forth unaudited quarterly information for each of the eight quarters, from the quarter ended March 31, 2012 through December 31, 2013. 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 Canadian dollars)		**2013**				2012		
Quarter ended	**Dec. 31**	**Sept. 30**	**Jun. 30**	**Mar. 31**	Dec. 31	Sept. 30	Jun. 30	Mar. 31
Total revenue	**1,557**	**1,542**	**1,403**	**1,572**	1,435	1,466	1,359	1,468
Net income	**160**	**218**	**168**	**257**	165	201	169	210
Net income to common shareholder	**155**	**214**	**163**	**253**	160	197	164	206

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 Canadian dollars)*	**2013**	2012
Operating activities	**1,404**	1,294
Financing activities		
Long-term debt issued	**1,185**	1,085
Long-term debt retired	**(600)**	(600)
Dividends paid	**(218)**	(370)
Investing activities		
Capital expenditures	**(1,412)**	(1,463)
Other financing and investing activities	**11**	21
Net change in cash and cash equivalents	**370**	(33)

Operating Activities

Net cash from operating activities increased by $110 million to $1,404 million in 2013, compared to 2012. The increase was primarily due to higher 2013 net income, compared to 2012, as well as changes in accrual balances, mainly related to timing of tax payments and to capital projects. The increase was partially offset by growth in accounts receivable balances, resulting from higher revenues and lower collections in the period.

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 our holding of Province of Ontario Floating-Rate Notes.

Our Commercial Paper Program is supported by our $1,500 million committed revolving credit facility with a syndicate of banks, which matures in June 2018. In addition, our investment in Province of Ontario Floating-Rate Notes of $250 million (with a fair value of $251 million at December 31, 2013) maturing on November 19, 2014 also provides temporary liquidity. 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, 2013, we had $9,045 million in long-term debt outstanding, including the current portion. Our notes and debentures mature between 2014 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, 2013, $1,815 million remained available until October 2015.

Cash generated from operations, after payment of expected dividends, will not be sufficient to fund capital expenditures, fund the repayment of our existing indebtedness, and meet other liquidity requirements. We rely on debt financing through our MTN Program and our Commercial Paper Program to repay our existing indebtedness and fund a portion of our capital expenditures.

The credit ratings assigned to our debt securities by external rating agencies are important to our ability to raise capital and funding to support our business operations. Maintaining strong credit ratings allows us to access capital markets on competitive terms. A material downgrade of our credit ratings would likely increase our cost of funding significantly, and our ability to access funding and capital through the capital markets could be reduced. Our corporate credit ratings from approved rating organizations are as follows:

	Rating	
Rating Agency	**Short-term Debt**	**Long-term Debt**
DBRS Limited	R-1 (middle)	A (high)
Moody's Investors Service Inc.	Prime-1	A1
Standard & Poor's Rating Services Inc. (S&P)[1]	A-1	A+

[1] 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 cannot exceed 10% of the total book value of our assets. We were in compliance with all these covenants and limitations as at December 31, 2013.

In 2013, we issued $1,185 million of long-term debt under our MTN Program, compared to $1,085 million of long-term debt issued in 2012. In 2013, we also repaid $600 million in maturing long-term debt, compared to $600 million of long-term debt called and redeemed in 2012, prior to its maturity date of November 15, 2012. We had no short-term notes outstanding at December 31, 2013 or 2012.

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 following quarter.

In 2013, we paid dividends to the Province in the amount of $218 million, consisting of $200 million in common dividends and $18 million in preferred dividends. 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 2013, cash dividends per common share were $2,000, compared to $3,523 per common share in 2012. Cash dividends per preferred share were $1.375 in each of 2013 and 2012.

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

Capital investments consist of cash capital expenditures and related accruals. Capital investments primarily relate to enhancing and reinforcing of our transmission and distribution infrastructure.

Year ended December 31 *(millions of Canadian dollars)*	**2013**	2012	$ Change	% Change
Transmission	**714**	776	(62)	(8)
Distribution	**673**	671	2	–
Other	**7**	7	–	–
Total capital investments	**1,394**	1,454	(60)	(4)

Transmission

Our 2013 transmission capital investments decreased by $62 million, or 8%, to $714 million, compared to 2012. Investments to expand and reinforce our transmission system were $170 million in 2013, representing a decrease of $143 million, compared to 2012. The decrease was mainly due to the completion of our Bruce to Milton Transmission Reinforcement Project to connect refurbished nuclear and new wind generation sources in the Huron-Grey-Bruce area. This project was placed in-service in May 2012. In addition, we experienced lower expenditures as a result of completing our Commerce Way Transmission Station, a new load supply station in the City of Woodstock to address load growth issues in the Woodstock area, and the Switchyard Reconstruction Project at our Burlington Transmission Station, where two new 115 kV switchyards were constructed to increase the load supply capacity and to ensure reliability of supply to customers in the area. These projects were placed in-service in February 2013 and December 2012, respectively.

During 2013, we continued to invest in inter-area network projects to support the Province's supply mix objectives for generation, and in load customer connections and local area supply projects to address growing loads. Our local area supply project expenditures include investments in our Midtown Transmission Reinforcement Project, which will provide additional supply capability to meet future load growth in midtown Toronto as well as areas to the west. Work at our Hearn Switching Station was partially completed in December 2013, where we rebuilt an existing switchyard that had reached its end-of-life. This project will also increase short circuit capability to accommodate future connection of renewable generation in central and downtown Toronto. We are also constructing our Lambton to Longwood Transmission Upgrade to increase transmission capability between our Lambton (Sarnia) and Longwood (London) transmission stations. This project is needed to satisfy government policy relating to the incorporation of 10,700 MW of non-hydroelectric renewable generation resources by 2021.

Investments to sustain our existing transmission system were $481 million in 2013, representing an increase of $89 million, compared to 2012. In 2013, we made significant investments in the refurbishment and replacement of end-of-life equipment for overhead lines and system re-investments in order to improve reliability, as well as replacement of circuit breakers. In addition, we have experienced higher expenditures associated with the timing of work related to the replacement of end-of-life power transformers. We continued work on replacing end-of-life underground transmission cables between our Strachan Transmission Station and Riverside Junction. These new underground cables will maintain a reliable supply of electricity to downtown Toronto. These increases were partially offset by lower expenditures related to the replacement of protection and control equipment.

Our other transmission capital investments were $63 million in 2013, representing a decrease of $8 million, compared to 2012. The decrease was mainly due to lower requirements associated with IT initiatives, including our entity-wide SAP information system replacement and improvement project, and timing of field facilities improvements. These reductions were partially offset by increased fleet acquisitions and emergency flood restoration work at our Richview transmission station caused by a major rainstorm in July 2013.

Distribution

Our 2013 distribution capital investments increased by $2 million, or less than 1%, to $673 million, compared to 2012. Investments to expand and reinforce our distribution network were $235 million in 2013, representing a decrease of $49 million, compared to 2012. We experienced reduced expenditures related to some of our major projects, including the ADS Project, as we completed the deployment of our Distribution Management System within our Owen Sound pilot area in 2012, and the Smart Metering Project, as most of the network expansion work was completed in 2012. In 2013, we also experienced a lower demand for new customer connections and upgrades. These decreases were partially offset by increased work on upgrading and adding capacity to our system to enable new customer connections and timing of generation connection projects. Given that the OEB has assessed the prudency of the ADS Project, the next phase of this project is anticipated in 2014.

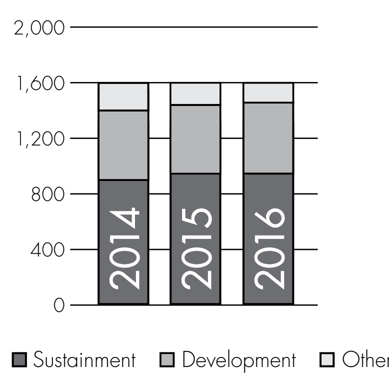
Investments to sustain our distribution system were $324 million in 2013, representing an increase of $79 million, compared to 2012. The increase was primarily due to increased expenditures for replacements related to storm restoration work caused by major storms in 2013. We also experienced increased work within our wood pole replacement program and station refurbishment projects. Investments were also impacted by the timing of customer contribution payments received in 2012 relating to work for joint use and relocation of our lines. These increases were partially offset by lower work within our lines programs.

Our other distribution capital investments were $114 million in 2013, representing a decrease of $28 million, compared to 2012. The majority of these expenditures were related to the Customer Information System (CIS) phase of our entity-wide information system replacement and improvement project, which was placed into service in May 2013. 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 also anticipated to result from performance improvements, consolidation and/or decommissioning of legacy IT systems. In addition, we experienced decreased expenditures associated with IT initiatives, including our entity-wide SAP information system replacement and improvement project, and the timing of field facilities improvements, partially offset by an increase in fleet acquisitions and emergency flood restoration work at our Richview Transmission Station.

Future Capital Investments

Our capital investments for 2014 are budgeted at approximately $1,600 million. Our 2014 capital budgets for our Transmission and Distribution Businesses are approximately $950 million and $650 million, respectively. Consolidated capital investments are expected to be approximately $1,600 million in each of 2015 and 2016. These investment levels reflect the sustainment requirements of our aging infrastructure. Our sustainment program capital investments are expected to be approximately $900 million in each of 2014, 2015, and 2016. Our development capital investments are expected to be approximately $450 million in 2014, $500 million in 2015, and $500 million in 2016. Our development projects include the inter-area network upgrades that reflect supply mix policies, local area supply improvements, the ADS, new load and generation connections and requirements to enable Distributed Generation (DG), and customer demand work. Other capital investments are expected to be $250 million in 2014, $200 million in 2015, and $200 million in 2016. This includes investments in operating infrastructure integration, IT, fleet services and facilities, and real estate. Our future capital investments amounts do not include future LDC acquisitions.

Future Capital Investments
(millions of Canadian dollars)



Transmission

Transmission capital investments are incurred 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 sustainment program future capital investments include the replacement of air blast circuit breakers and switchgear, high-voltage underground cables, and power transformers. These investments are necessary to ensure that we maintain our current levels of supply to our customers and continue to meet all regulatory, compliance, safety and environmental objectives.

Our development future capital investments include the Clarington Transmission Station Project to install additional auto-transformer capacity in east Greater Toronto Area; the Guelph Area Transmission Refurbishment Project, an upgrade of a transmission line and transmission stations in south-central Guelph; investments in ADS; requirements to enable DG; and up to four other transmission station upgrades, which when combined with the new Hearn Switching Station, will collectively enable up to 600 MW of new generation capacity in the Niagara, Toronto and Ottawa areas.

In 2011, the OPA provided the scope and timing to increase short circuit and/or transformer capacity at ten of 15 transmission stations. Seven of these station upgrades have now been completed, and alternate solutions have been determined for the remaining three projects. The Lambton to Longwood Transmission Upgrade has a required in-service date of December 2014, and is included in our budgeted future capital investments. This project is needed to satisfy government policy relating to the incorporation of 10,700 MW of non-hydroelectric renewable generation resources by 2021. In August 2013, the OPA requested us to terminate work related to the Southwestern Ontario Reactive Compensation Priority Project, and an OPA recommendation regarding the third priority specified transmission project, which was not included in the most recent LTEP, is not expected in the foreseeable future. Therefore, these two projects are not included in our budgeted future capital investments.

Based on the OEB's framework for competitive designation for the development of eligible transmission projects, we did not include in our budgeted future capital investments any projects that could meet the definition of expansions. We do not plan to undertake large capital investments without a reasonable expectation of recovering them through our rates.

The actual timing and investments of many development projects are uncertain as they are dependent upon various regulatory approvals, negotiations with customers, neighbouring utilities and other stakeholders, and consultations with First Nations and Métis communities. Projects are also dependent upon the timing and level of generator contributions for enabling facilities.

Distribution

Distribution capital investments include the sustainment of our infrastructure. Our core work will continue to focus on maintaining the performance of our aging distribution asset base through renewal and refurbishment activities. Planned capital investments include the continued replacements of equipment and components that are beyond their expected service life, as well as increased wood pole replacements and distribution station refurbishments. Sustainment capital investments in the Smart Metering project will decrease through 2016.

Distribution development capital investments are expected to be relatively stable through 2016, with the exception of capital contributions for capacity improvements at the Orleans Transmission Station in 2015 and the Hanmer Transmission Station in 2016. We will continue to make investments required to connect new load and DG customers, as well as investments to ensure the system is capable of supplying customer needs. During 2014 to 2016, a number of our projects will address local load growth issues. Generation connection investments will decrease as the volume of connections is expected to decrease. The budgeted capital expenditures only reflect projects with FIT and Micro FIT Program contracts from the OPA that are expected to connect to our distribution system.

In 2014 and 2015, the ADS Project will continue to pilot various technologies and related capital investments will begin to decrease in 2016. Pilot technologies include improvements to outage response management through more effective resource dispatch, automation to isolate faults where needed, and the dynamic regulation of voltage to reduce losses.

Off-Balance Sheet Arrangements

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.

Summary of Contractual Obligations and Other Commercial Commitments

The following table presents a summary of our debt and other major contractual obligations, as well as other major commercial commitments:

December 31, 2013 *(millions of Canadian dollars)*	Total	2014	2015/2016	2017/2018	After 2018
Contractual obligations *(due by year)*					
Long-term debt – principal repayments[1]	9,045	750	1,050	1,350	5,895
Long-term debt – interest payments[1]	7,634	422	770	691	5,751
Pension[2]	172	160	12	–	–
Environmental and asset retirement obligations[3]	329	32	63	46	188
Inergi LP (Inergi) outsourcing agreement[4]	152	130	22	–	–
Operating lease commitments	48	11	14	14	9
Total contractual obligations	17,380	1,505	1,931	2,101	11,843
Other commercial commitments (*by year of expiry*)					
Bank line[5]	1,500	–	–	1,500	–
Letters of credit[6]	149	149	–	–	–
Guarantees[6]	326	326	–	–	–
Total other commercial commitments	1,975	475	–	1,500	–

1 The "long-term debt – principal repayments" amounts 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 the long-term debt is recorded in financing charges on our Consolidated Statements of Operations and Comprehensive Income or as a cost of our capital programs.

2 Contributions to the Hydro One Pension Fund are generally made one month in arrears. The 2014 minimum pension contributions are based on an actuarial valuation effective December 31, 2011. Minimum pension 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. On January 30, 2014, we made contributions of $140 million.

3 We record a liability for the estimated future expenditures associated with the removal and destruction of polychlorinated biphenyl (PCB)-contaminated insulating oils and related electrical equipment, and for the assessment and remediation of chemically-contaminated lands. We also record a liability for asset retirement obligations associated with the removal and disposal of asbestos-containing materials installed in some of our facilities, as well as the future decommissioning and removal of two of our switching stations. The forecast expenditure pattern reflects our planned work programs for the periods.

4 In 2002, Inergi began providing services to our company, including business processing and IT outsourcing services. The current agreement with Inergi will expire in February 2015. We have begun developing a plan of action for end-of-term and issued a request for proposal on November 7, 2013. Based on the September 2013 Shareholder Resolution, the Province requires us to contract only with parties who are employed and physically located in Ontario when providing services to our company. The amounts disclosed include an estimated contractual annual inflation adjustment in the range of 1.5% to 3.0%. Payments in respect of our agreement with Inergi are recorded in operation, maintenance and administration costs on our Consolidated Statements of Operations and Comprehensive Income or as a cost of our capital programs.

5 On May 31, 2013, we increased the size of the revolving standby credit facility used to support our liquidity requirements from $1,250 million to $1,500 million, and extended the maturity date from June 2017 to June 2018.

6 We currently have outstanding bank letters of credit of $127 million relating to retirement compensation arrangements. We provide prudential support to the IESO in the form of letters of credit, the amount of which is calculated based on forecasted monthly power consumption. At December 31, 2013, we have provided letters of credit to the IESO in the amount of $21 million to meet our current prudential requirement. In addition, we have approximately $1 million pertaining 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 approximately $1 million.

RELATED PARTY TRANSACTIONS

We are owned by the Province. The OEFC, IESO, OPA, OPG and the OEB are related parties to our company because they are controlled or significantly influenced by the Province.

Related party transactions primarily consist of our transmission revenues received from, and our power purchases payments made to the IESO. 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 payments in lieu of property taxes, which are paid to the OEFC. In addition, 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.

Our company receives revenues for transmission services from the IESO, based on OEB-approved UTRs. Transmission revenues include $1,509 million (2012 – $1,474 million) related to these services. Our company receives amounts for rural rate protection from the IESO. Distribution revenues include $127 million (2012 – $127 million) related to this program. Our company also receives revenues related to the supply of electricity to remote northern communities from the IESO. Distribution revenues include $33 million (2012 – $28 million) related to these services.

In 2013, our company purchased power in the amount of $2,477 million (2012 – $2,392 million) from the IESO-administered electricity market; $15 million (2012 – $10 million) from OPG; and $8 million (2012 – $7 million) from power contracts administered by 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 2013, our company incurred $12 million (2012 – $11 million) in OEB fees.

Our company has service level agreements with OPG. These services include field, engineering, logistics and telecommunications services. In 2013, revenues related to the provision of construction and equipment maintenance services with respect to these service level agreements were $9 million (2012 – $10 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 $1 million in 2013 (2012 – $2 million).

The OPA funds substantially all of the Company's CDM programs. The funding includes program costs, incentives, and management fees. In 2013, our company received $34 million (2012 – $39 million) from the OPA related to these programs.

Our company pays a $5 million annual fee to the OEFC for indemnification against adverse claims in excess of $10 million paid by the OEFC with respect to certain of Ontario Hydro's businesses transferred to our company on April 1, 1999.

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.

The amounts due to and from related parties as a result of the transactions referred to above are as follows:

December 31 *(millions of Canadian dollars)*	**2013**	2012
Due from related parties	**197**	154
Due to related parties[1]	**(230)**	(261)
Long-term investment	**251**	251

[1] Included in "due to related parties" at December 31, 2013 are amounts owing to the IESO in respect of power purchases of $217 million (2012 – $199 million).

CONSIDERATIONS OF CURRENT ECONOMIC CONDITIONS

Effect of Load on Revenue

Our load, based on normal weather patterns, is expected to decline in 2014 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 1.6%, 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 0.4% and 3.5%, respectively. On the whole, our load is expected to decline by about 2.3% in 2014. Our approved revenue requirement for 2014 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 return on equity (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' 2014 results of operations by approximately $20 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.

Pension Plan

In 2013, we contributed approximately $160 million to our pension plan and incurred $287 million in net periodic pension benefit costs, based on an actuarial valuation effective December 31, 2011. 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 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 an actuarial valuation effective no later than December 31, 2014. Our pension plan experienced positive returns of approximately 17.91% in 2013. Our pension obligation is impacted by interest rates. The 0.5% increase in the discount rate, from 4.25% at December 31, 2012 to 4.75% at December 31, 2013, resulted in a decrease in the pension obligation of $443 million and an increase to our post-retirement and post-employment benefit obligation of $126 million. Our pension obligation is also impacted by mortality assumptions. The changes in mortality assumptions at December 31, 2013, compared to December 31, 2012, resulted in an increase in the pension obligation of $380 million and an increase to our post-retirement and post-employment benefit obligation of $136 million. Contribution increases are being implemented for all segments of our company's active 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, and represents the greatest threats to meeting our strategic objectives. The Board of Directors' committees review risks relevant to their mandate at every meeting. 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 ERM 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, 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 Inergi Agreement. In 2011, the Province made a declaration preventing our company from seeking cost recovery through the regulatory process for the cost of upgrades required for either Micro FIT or Small FIT generators for costs related to investment and expenditures made. Effective September 30, 2013, the Province made a declaration regarding the outsourcing of services covered by the Inergi Agreement.

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 our company'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 OPG, 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.

The OEB's new Renewed Regulatory Framework requires that the term of a custom rate application (distribution business) is a five-year period. There are risks associated with forecasting over a longer period. Changes in the industry may alter the investment needs or require changes to rate setting that could result in a significant impact on our capability to execute its plan. To mitigate the risk of externally driven factors that may impact its plan, Hydro One Networks proposed a number of adjustment mechanisms in the design of its recent custom application to reflect plan changes outside the normal course of business in order for the Company to avoid a regulatory review by the OEB during the five-year custom application period. Hydro One Networks also proposed a set of outcome measures to track its performance and delivery of the plan. There can be no assurance that the OEB will accept these mechanisms or that they will be sufficient to protect our company from unforeseen changes to its plan.

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 NERC and Northeast Power Coordinating Council. As a result, we will be required to comply with the Federal Energy Regulatory Commission's definition of the Bulk Electric System unless we are granted an exception which will allow the application of the new definition in a cost-effective manner. We plan to submit exception applications and will look for recovery for costs incurred in meeting the definition in our rates; however, an adverse decision on an exception or recovery of costs could have an 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.

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, including $750 million maturing in 2014 and $550 million maturing in 2015. We plan to incur capital expenditures of approximately $1,600 million in each of 2014 and 2015. 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.

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 communities 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 Associated with Outsourcing Arrangement

Consistent with our strategy of reducing operating costs, we amended and extended our agreement with Inergi, effectively renewing the arrangement until February 28, 2015. If our agreement with Inergi is terminated for any reason or expires before a new supplier is selected, 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 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 to 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 communities. Obtaining OEB and/or environmental 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 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 recoverable only 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 upon 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 2013, approximately 16% of our employees were eligible for retirement, and by the end of 2014, 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.

Labour Relations Risk

The substantial majority of our employees are represented by either the Power Workers Union (PWU) or the Society of Professional Energy Workers (Society). 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 and increased pension contributions for PWU and Society staff, we may not be able to achieve further improvement. The existing collective agreement with the PWU will expire on March 31, 2015, and the existing Society collective agreement will expire on March 31, 2016. 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.

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 minimally required to be 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 approximately $160 million in respect of 2012 and approximately $160 million in respect of 2013 to its pension plan to satisfy minimum funding requirements. Contributions beyond 2013 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 increases.

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. However, given the territory that our system encompasses and the amount of equipment that we own, we cannot guarantee 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.

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 price 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 in a deemed regulatory capital structure of 40% common equity and 60% debt 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' 2014 net income by approximately $20 million and our Hydro One Networks distribution business' 2014 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.

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. Where the agreement and permit are for transmission assets, we must negotiate rental terms. 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. In 2013, we paid approximately $2 million to First Nations in respect of these agreements. 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. In either case, 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 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. We have identified the following critical accounting estimates used in the preparation of our Consolidated Financial Statements:

Revenues

Our monthly distribution revenue is estimated based on wholesale electricity purchases. At the end of each month, the electricity delivered to customers, but not billed, is estimated and revenue is recognized. The newly implemented CIS phase of our entity-wide system improvement project will allow us to use historical trends at a customer level to better estimate our unbilled revenue each period. This change in methodology for estimating revenue is anticipated to be implemented in 2014. Any changes in estimate will be accounted for prospectively.

Regulatory Assets and Liabilities

Our 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. Our regulatory assets mainly include costs related to the pension benefit liability, deferred income tax liabilities, post-retirement and post-employment benefit liability, and environmental liabilities. Our regulatory liabilities represent certain amounts that are refundable to future electricity customers, and pertain primarily to OEB deferral and variance accounts. The regulatory assets and liabilities can be recognized for rate-setting and financial reporting purposes only if the amounts have been approved for inclusion in the rates 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 allow the inclusion of a regulatory asset or liability in future rates, the applicable carrying amount of the regulatory asset or liability will be reflected in results of operations in the period that the judgement is made by management.

Environmental Liabilities

We record a liability for the estimated future expenditures for the contaminated LAR and for the phase-out and destruction of PCB-contaminated mineral oil removed from electrical equipment. 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. 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. All factors used in estimating the Company's environmental liabilities represent management's best estimates of the present value of 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. Environmental liabilities are reviewed annually or more frequently if significant changes in regulations or other relevant factors occur. Estimate changes are accounted for prospectively.

In June 2013, Environment Canada issued Canada Gazette I, which included a proposed amendment to the existing PCB regulations. The proposed amendment would extend the end-of-use deadline for our company's PCBs in concentrations of 500 parts per million or more from December 31, 2014 to December 31, 2025. The proposed amendment is subject to final approvals before the enacted regulation is published in Canada Gazette II. Canada Gazette II is anticipated to be issued in the first half of 2014. An environmental liability is recorded based on regulations as currently enacted, and as such, our environmental liability as at December 31, 2013 is based on the current compliance date of December 31, 2014.

Employee Future Benefits

We provide future benefits to our current and retired employees, including pension, group life insurance, health care and long-term disability.

The discount rate used to calculate the accrued benefit obligation is determined each year end by referring to the most recently available market interest rates based on "AA"-rated corporate bond yields reflecting the duration of the applicable employee future benefit plan. The discount rates at December 31, 2013 increased to 4.75% from 4.25% used at December 31, 2012, in conjunction with increases in bond yields over this period. The increase in discount rates has resulted in a corresponding decrease in liabilities for accounting purposes. 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 assumed return on pension plan assets 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 pension plan's investment policy. Returns on the respective portfolios are determined with reference to published Canadian and US 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.

Further, based on differences between long-term Government of Canada nominal bonds and real return bonds, the implied inflation rate has decreased from 1.9% per annum as at December 31, 2012 to approximately 1.2% per annum as at December 31, 2013. 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, 2013.

Our pension and post-retirement and post-employment obligations are also impacted by changes in life expectancies used in mortality assumptions. Increases in life expectancies of plan members result in increases in pension and post-retirement and post-employment benefit obligations.

The costs of post-retirement and post-employment benefits 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 approximately $21 million per year and an increase in the year-end obligation of about $258 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 property, plant and equipment 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 property, plant and equipment and intangible assets.

Asset Impairment

Within our regulated businesses, the carrying costs of most of our 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. We regularly monitor the assets of our unregulated Hydro One Telecom subsidiary for indications of impairment. As at December 31, 2013, no asset impairment had been recorded for assets within our regulated or unregulated businesses.

Goodwill represents the cost of acquired LDCs that is in excess of the fair value of the net identifiable assets acquired at the acquisition date. Goodwill is evaluated for impairment on an annual basis, or more frequently if circumstances require. We have concluded that goodwill was not impaired at December 31, 2013.

DISCLOSURE CONTROLS AND INTERNAL CONTROLS OVER FINANCIAL REPORTING

To optimize our customer service operations, we implemented the CIS module of SAP. This new system replaced multiple legacy applications which provided service to our distribution customers and key constituents for billing, customer contacts, field services, settlements, and customer choice administration. Internal controls have been documented and tested for adequacy and effectiveness, and continue to be refined.

In compliance with the requirements of National Instrument 52-109, our Certifying Officers have reviewed and certified the Consolidated Financial Statements for the year ended December 31, 2013, together with other financial information included in our 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. Further, our Certifying Officers have certified that internal controls over financial reporting (ICFR) have been designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the Consolidated Financial Statements. Based on the evaluation of the design and operating effectiveness of our company's DC&P and ICFR, our Certifying Officers concluded that our company's DC&P and ICFR were effective as at December 31, 2013.

SELECTED ANNUAL INFORMATION

Consolidated Statements of Operations and Comprehensive Income

Year ended December 31 *(millions of Canadian dollars, except amounts per share)*	**2013**	2012	2011
Revenue	**6,074**	5,728	5,471
Net income	**803**	745	641
Basic and fully diluted earnings per common share	**7,850**	7,280	6,228
Cash dividends per common share	**2,000**	3,523	1,500
Cash dividends per preferred share	**1.375**	1.375	1.375

Consolidated Balance Sheets

December 31 *(millions of Canadian dollars)*	**2013**	2012	2011
Total assets	**21,625**	20,811	18,836
Total long-term debt	**9,057**	8,479	8,008
Preferred shares	**323**	323	323

Other

Year ended December 31 *(millions of Canadian dollars)*	**2013**	2012	2011
Total capital investments	**1,394**	1,454	1,447

NEW ACCOUNTING PRONOUNCEMENTS

Recently Adopted Accounting Pronouncements

In December 2011, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) 2011-11, Balance Sheet (Topic 210): Disclosures about Offsetting Assets and Liabilities. This ASU requires an 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 was required to be applied retrospectively and was effective for fiscal years, and interim periods within those years, beginning on or after January 1, 2013. The adoption of this ASU did not have an impact on our Consolidated Financial Statements.

In February 2013, the FASB issued ASU 2013-02, Comprehensive Income (Topic 220): Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income. This ASU requires an entity to provide information about the amounts reclassified out of accumulated other comprehensive income by component. In addition, an entity is required to present, either on the face of the statement where net income is presented or in the notes, significant amounts reclassified out of accumulated other comprehensive income by the respective line items of net income, but only if the amount reclassified is required under US GAAP to be reclassified to net income in its entirety in the same reporting period. For other amounts that are not required under US GAAP to be reclassified in their entirety to net income, an entity is required to cross-reference to other disclosures required under US GAAP that provide additional detail about those amounts. This ASU was required to be applied prospectively and was effective for fiscal years, and interim periods within those years, beginning after December 15, 2012. The adoption of this ASU did not have a significant impact on our Consolidated Financial Statements.

Recent Accounting Guidance Not Yet Adopted

In July 2013, the FASB issued ASU 2013-11, Income Taxes (Topic 740): Presentation of an Unrecognized Tax Benefit When a Net Operating Loss Carryforward, a Similar Tax Loss, or a Tax Credit Carryforward Exists. This ASU provides guidance on the presentation of unrecognized tax benefits. This ASU is effective for fiscal years, and interim periods within those years, beginning after December 15, 2013, and should be applied prospectively to all unrecognized tax benefits that exist at the effective date. Retrospective application is permitted. The adoption of this ASU is not anticipated to have a significant impact on our Consolidated Financial Statements.

OUTLOOK

We will achieve our mission and vision and remain focused on achieving our corporate goal of providing safe, reliable and affordable service to our customers, today and tomorrow, while increasing enterprise value for our shareholder. We will do this by continuing to concentrate on our strategic objectives of safety, customer satisfaction, continuous innovation, reliability, protection of the environment, championing people and culture, 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, including maintaining our OHSAS 18001 standing.

We are focused on achieving our long-term vision of improving customer satisfaction, maintaining affordable rates for the portion of the customers' bill within our control and building a trusted partner relationship with our customers. Our plan has taken into account discussions with our customers and reflects the planned development and delivery of targeted customer segment strategies, products and services which respond to our customers' unique needs. This includes realizing value from our new customer information system, simplifying and shortening timeframes for the delivery of services, enhancing accessibility in person, by phone or through our web portal and/or our mobile application to ensure effective self-service for simple transactions and delivering programs which help customers better manage their energy consumption.

We will continue to focus on driving our transformation to a culture that is accountability-based. All of our management staff received training under our Craft of Management program. This program will serve as the foundation for establishing that culture of accountability. Investments in this program, coupled with existing programs which enhance employee skills and ability, will help us deliver best-in-class service to our customers, continue the drive to zero workplace injuries and create a great workplace that will lead to improved employee engagement. We remain focused on managing the resourcing requirements of an increasing work program through appropriate compensation policies, labour negotiations, use of outsourced multi-skilled staff and support of internal and external college and university training programs. Aging workforce demographics provide opportunities, through retirements, to restructure and transform the workforce.

Our assets are in the midst of a demographic change with an increasing proportion of assets reaching the end of their expected service life and an increasing average asset age. To ensure the electricity system's reliability in the public interest, we have planned for significant investments in transmission and distribution infrastructure. Our plan includes targeted, risk-based investments to maintain, refurbish and replace existing assets that are in poor condition and beyond their expected service life, within the policy set by the OEB. Investments in technology, such as the successful implementation of Asset Analytics, has provided 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.

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.

We continue to seek to strike the right balance between making prudent risk-based reliability investments and keeping customers' rates low. Effectively and efficiently managing costs is an important part of achieving this balance. Over the last five years, we have replaced most of our core IT systems with an enterprise-wide IT system. Further development of the existing IT platform will provide tools which are being developed to allow us to effectively plan and reprioritize work and integrate customers' needs into multi-year investment plans. This outcome is consistent with the OEB's direction in its new Outcomes-Based Approach to regulation.

Our plan is focused on delivering integrated asset-to-work planning, optimized scheduling and dispatch as well as field mobility. Through our investment in our Workflow of the Future initiative we will bring together data, analytics and mobility to allow our employees, especially those in the field, to do more at the job site with their mobile devices.

Significant opportunity resides with smart meters and the proliferation of an ADS including energy efficiency, demand response and distributed-resource technologies. We will continue to 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 we will receive customer capital contributions. There is little flexibility to reduce this work as most of it is customer demand driven.

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.

Consistent with our corporate strategy, we will pursue an LDC consolidation approach that is robust but prudent, to facilitate the consolidation of Ontario's distribution sector. This is consistent with the Ontario Distribution Sector Panel's assessment that there are substantial efficiencies to be found through consolidation of Ontario LDCs and we are key to the solution. 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 CEO, effective January 1, 2013. Mr. Marcello assumed his responsibilities following the planned retirement of outgoing President and CEO Laura Formusa. Mr. Marcello has over 25 years of experience with our company as a senior executive, strategic planner and advisor on transmission and distribution utility processes in the electric utility industry.

CHANGES TO OUR BOARD OF DIRECTORS

On November 20, 2013, Sandra Pupatello was appointed to our Board of Directors. Ms. Pupatello is the Director of Business Development and Global Markets at PricewaterhouseCoopers Canada. She is also the Chief Executive Officer of the WindsorEssex Economic Development Corporation.

On November 27, 2013, Catherine Karakatsanis was appointed to our Board of Directors. Ms. Karakatsanis is the Chief Operating Officer of Morrison Hershfield Group Inc. and also serves as Director and Secretary of the Toronto-based consulting engineering firm.

On August 12, 2013, Janet Holder resigned from our Board of Directors. Ms. Holder has been a member of our Board of Directors since July 2010.

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: expectations regarding energy-related revenues and profit and their trend; statements regarding our transmission and distribution rates and customer bills resulting from our rate applications; statements related to the FIT program; statements about CDM; statements about our strategy, including our strategic objectives; statements regarding considerations of current economic conditions; statements related to employee future benefits; expectations regarding First Nation involvement in competitive bids; 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 (including productivity savings, process improvements, and customer satisfaction) and their completion dates; expectations regarding the recoverability of large capital investments; expectations regarding generation connection investments; statements regarding expected future capital and development investments, the timing of these expenditures and our investment plans; expectations regarding OPA recommendations; statements regarding contractual obligations and other commercial commitments; statements related to the OEB; statements regarding future pension contributions, our pension plan and actuarial valuation; statements about our outsourcing arrangement with Inergi and such future outsourcing arrangements; expectations regarding work and costs of compliance with environmental and health and safety regulations; statements related to the LTEP; and statements related to LDC consolidation including our acquisition of Norfolk Power. 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 the required approvals; no unforeseen changes in rate orders or rate structures for our distribution and transmission businesses; continued use of US GAAP; 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 risk that unexpected capital investments may be needed to support renewable generation or resolve unforeseen technical issues;
- the risk that previously granted regulatory approvals may be subsequently challenged, appealed or overturned;
- the inability to prepare financial statements in US GAAP;
- the impact of the 2010 LTEP and the 2013 LTEP on our company and the costs and expenses arising therefrom;
- the risk that future environmental expenditures are not recoverable in future electricity rates;
- the risk that the presence of release of hazardous or harmful substances could lead to claims by third parties and/or governmental orders;
- the risk that assumptions that form the basis of our recorded environmental liabilities and related regulatory assets may change;
- the risks associated with information system security, with maintaining a complex information technology system infrastructure, and with transitioning most of our financial and business processes to an integrated business and financial reporting system;
- the risks associated with changes in the forecast long-term Government of Canada bond yield;
- the risks related to our workforce demographic and our potential inability to attract and retain qualified personnel;
- 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, including regulatory decisions regarding our revenue requirements, cost recovery, rates, acquisitions and divestitures;
- 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 investments 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 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, changes in benefits and changes in actuarial assumptions;
- 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 Reserves (as defined in the *Indian Act* (Canada));
- 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 or expires before a new service provider is selected;
- the impact of the ownership by the Province of lands underlying our transmission system; and
- the ability to negotiate appropriate collective agreements.

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 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 potential 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.

Additional information about the Company, including the Company's Annual Information Form, can be found on SEDAR at www.sedar.com and on the US Securities and Exchange Commission's website at www.sec.gov.

MANAGEMENT'S REPORT

The Consolidated Financial Statements, Management's Discussion and Analysis (MD&A) and related financial information 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 13, 2014.

Management is responsible for establishing and maintaining adequate internal control over financial reporting for the Company. 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, management has assessed the design and operating effectiveness of the Company's internal control over financial reporting in accordance with the criteria set forth in Internal Control – Integrated Framework (1992), issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, management concluded that the Company maintained effective internal control over financial reporting as of December 31, 2013. The effectiveness of these internal controls and findings is reported to 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 Shareholder. 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 findings.

The President and Chief Executive Officer and the Chief Administration Officer and Chief Financial Officer have certified Hydro One's annual Consolidated Financial Statements and annual MD&A, related disclosure controls and procedures and the design and effectiveness of related internal controls over financial reporting.

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, 2013 and December 31, 2012, the consolidated statements of operations and comprehensive income, changes in shareholder's equity and cash flows for the years then ended, 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 judgement, 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, 2013 and December 31, 2012, and its consolidated results of operations and its consolidated cash flows for the years then ended in accordance with United States Generally Accepted Accounting Principles.

KPMG LLP

Chartered Professional Accountants, Licensed Public Accountants

Toronto, Canada
February 13, 2014

CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME

For the years ended December 31, 2013 and 2012

Year ended December 31 (millions of Canadian dollars, except per share amounts)	**2013**	2012
Revenues		
Distribution (includes $160 related party revenues; 2012 – $155) *(Note 20)*	**4,484**	4,184
Transmission (includes $1,517 related party revenues; 2012 – $1,482) *(Note 20)*	**1,529**	1,482
Other	**61**	62
	6,074	5,728
Costs		
Purchased power (includes $2,500 related party costs; 2012 – $2,409) *(Note 20)*	**3,020**	2,774
Operation, maintenance and administration *(Note 20)*	**1,106**	1,071
Depreciation and amortization *(Note 5)*	**676**	659
	4,802	4,504
Income before financing charges and provision for payments in lieu of corporate income taxes	**1,272**	1,224
Financing charges *(Note 6)*	**360**	358
Income before provision for payments in lieu of corporate income taxes	**912**	866
Provision for payments in lieu of corporate income taxes *(Notes 7, 20)*	**109**	121
Net income	**803**	745
Other comprehensive income	**–**	1
Comprehensive income	**803**	746
Basic and fully diluted earnings per common share *(dollars) (Note 18)*	**7,850**	7,280
Dividends per common share declared *(dollars) (Note 19)*	**2,000**	3,523

See accompanying notes to Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS

At December 31, 2013 and 2012

December 31 (millions of Canadian dollars)	**2013**	2012
Assets		
Current assets:		
Cash and cash equivalents *(Note 13)*	**565**	195
Accounts receivable (net of allowance for doubtful accounts – $36; 2012 – $23) *(Note 8)*	**923**	845
Due from related parties *(Note 20)*	**197**	154
Regulatory assets *(Note 11)*	**47**	29
Materials and supplies	**23**	23
Deferred income tax assets *(Note 7)*	**18**	18
Derivative instruments *(Note 13)*	**6**	–
Investment *(Notes 13, 20)*	**251**	–
Other	**28**	22
	2,058	1,286
Property, plant and equipment *(Note 9)*:		
Property, plant and equipment in service	**23,820**	22,650
Less: accumulated depreciation	**8,615**	8,145
	15,205	14,505
Construction in progress	**1,078**	1,055
Future use land, components and spares	**148**	147
	16,431	15,707
Other long-term assets:		
Regulatory assets *(Note 11)*	**2,636**	3,098
Investment *(Notes 13, 20)*	**–**	251
Intangible assets (net of accumulated amortization – $252; 2012 – $305) *(Note 10)*	**313**	267
Goodwill	**133**	133
Deferred debt costs	**36**	34
Derivative instruments *(Note 13)*	**6**	19
Deferred income tax assets *(Note 7)*	**11**	14
Other	**1**	2
	3,136	3,818
Total assets	**21,625**	20,811

See accompanying notes to Consolidated Financial Statements.

CONSOLIDATED BALANCE SHEETS (continued)

At December 31, 2013 and 2012

December 31 (millions of Canadian dollars, except number of shares)	**2013**	2012
Liabilities		
Current liabilities:		
Bank indebtedness *(Note 13)*	**31**	42
Accounts payable	**62**	140
Accrued liabilities *(Notes 7, 15, 16)*	**733**	578
Due to related parties *(Note 20)*	**230**	261
Accrued interest	**100**	95
Regulatory liabilities *(Note 11)*	**85**	40
Long-term debt payable within one year (includes $506 measured at fair value; 2012 – $0) *(Notes 12, 13)*	**756**	600
	1,997	1,756
Long-term debt (includes $256 measured at fair value; 2012 – $769) *(Notes 12, 13)*	**8,301**	7,879
Other long-term liabilities:		
Post-retirement and post-employment benefit liability *(Note 15)*	**1,488**	1,416
Deferred income tax liabilities *(Note 7)*	**1,129**	944
Pension benefit liability *(Note 15)*	**845**	1,515
Environmental liabilities *(Note 16)*	**239**	227
Regulatory liabilities *(Note 11)*	**163**	181
Net unamortized debt premiums	**20**	23
Asset retirement obligations *(Note 17)*	**14**	15
Long-term accounts payable and other liabilities	**14**	25
	3,912	4,346
Total liabilities	**14,210**	13,981
Contingencies and commitments (Notes 22, 23)		
Preferred shares (authorized: unlimited; issued: 12,920,000) *(Notes 18, 19)*	**323**	323
Shareholder's equity		
Common shares (authorized: unlimited; issued: 100,000) *(Notes 18, 19)*	**3,314**	3,314
Retained earnings	**3,787**	3,202
Accumulated other comprehensive loss	**(9)**	(9)
Total shareholder's equity	**7,092**	6,507
Total liabilities, preferred shares and shareholder's equity	**21,625**	20,811

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

For the years ended December 31, 2013 and 2012

Year ended December 31, 2013 *(millions of Canadian dollars)*	**Common Shares**	**Retained Earnings**	**Accumulated Other Comprehensive Loss**	**Total Shareholder's Equity**
January 1, 2013	**3,314**	**3,202**	**(9)**	**6,507**
Net income	**–**	**803**	**–**	**803**
Other comprehensive income	**–**	**–**	**–**	**–**
Dividends on preferred shares	**–**	**(18)**	**–**	**(18)**
Dividends on common shares	**–**	**(200)**	**–**	**(200)**
December 31, 2013	**3,314**	**3,787**	**(9)**	**7,092**

Year ended December 31, 2012 *(millions of Canadian 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

See accompanying notes to Consolidated Financial Statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

For the years ended December 31, 2013 and 2012

Year ended December 31 (millions of Canadian dollars)	**2013**	2012
Operating activities		
Net income	**803**	745
Environmental expenditures	**(16)**	(18)
Adjustments for non-cash items:		
Depreciation and amortization (excluding removal costs)	**597**	589
Regulatory assets and liabilities	**3**	12
Deferred income taxes	**(2)**	(9)
Other	**8**	6
Changes in non-cash balances related to operations *(Note 21)*	**11**	(31)
Net cash from operating activities	**1,404**	1,294
Financing activities		
Long-term debt issued	**1,185**	1,085
Long-term debt retired	**(600)**	(600)
Dividends paid	**(218)**	(370)
Change in bank indebtedness	**(11)**	3
Other	**(5)**	(1)
Net cash from financing activities	**351**	117
Investing activities		
Capital expenditures *(Note 21)*		
Property, plant and equipment	**(1,333)**	(1,373)
Intangible assets	**(79)**	(90)
Other	**27**	19
Net cash used in investing activities	**(1,385)**	(1,444)
Net change in cash and cash equivalents	**370**	(33)
Cash and cash equivalents, beginning of year	**195**	228
Cash and cash equivalents, end of year	**565**	195

See accompanying notes to Consolidated Financial Statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

For the years ended December 31, 2013 and 2012

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. The electricity rates of 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. Certain comparative figures have been reclassified to conform to the presentation of these Consolidated Financial Statements (see Note 21 – Consolidated Statements of Cash Flows). In the opinion of management, these Consolidated Financial Statements include all adjustments that are necessary to fairly state the financial position and results of operations of Hydro One as at, and for the year ended December 31, 2013.

Hydro One performed an evaluation of subsequent events through to February 13, 2014, the date these Consolidated Financial Statements were issued, to determine whether any events or transactions warranted recognition and disclosure in these Consolidated Financial Statements. See Note 25 – Subsequent Event.

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 Transmission Business includes the separately regulated transmission business of Hydro One Networks. The Company's consolidated Distribution Business includes Hydro One Brampton Networks, Hydro One Remote Communities, as well as the separately regulated distribution business of Hydro One Networks.

The OEB has approved the use of US GAAP for rate setting and regulatory accounting and reporting by Hydro One Networks' transmission and distribution businesses, as well as by Hydro One Remote Communities, beginning with the year 2012. Hydro One Brampton Networks currently uses Canadian GAAP for its distribution rate-setting purposes.

Transmission
In May 2010, Hydro One Networks filed a cost-of-service application with the OEB for 2012 transmission rates. 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. In May 2012, Hydro One Networks filed a cost-of-service application with the OEB for 2013 transmission rates, seeking approval for a 2013 revenue requirement of $1,465 million. In December 2012, the OEB approved a revenue requirement of $1,438 million for 2013. The reduced approved revenue requirement included reductions to proposed operation, maintenance and administration costs, and capital expenditures.

Distribution
In 2010, the OEB approved a revised 2011 revenue requirement of $1,218 million and 2011 distribution rates. Hydro One Networks elected to retain the same distribution rates for 2012 as approved by the OEB for the 2011 rate year. In June 2012, Hydro One Networks filed an Incentive Regulation Mechanism (IRM) application with the OEB for 2013 distribution rates. In December 2012, the OEB approved an increase in average distribution rates of approximately 1.3%, with an effective date of January 1, 2013.

In September 2011, Hydro One Brampton Networks filed an IRM application with the OEB for 2012 distribution rates. In January 2012, the OEB approved a reduction in distribution rates of approximately 13.2%, with an effective date of January 1, 2012. These rate reductions were primarily due to OEB-approved adjustments to depreciation rates. In August 2012, Hydro One Brampton Networks filed an IRM application with the OEB for 2013 distribution rates. In December 2012, the OEB approved an increase in average distribution rates of approximately 0.3%, with an effective date of January 1, 2013.

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. In September 2012, Hydro One Remote Communities filed a cost-of-service application with the OEB for 2013 rates, seeking approval for a 2013 revenue requirement of $53 million. In June 2013, the OEB approved a revenue requirement of $51 million for 2013.

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 been 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 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 with 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

Billed accounts receivable are recorded at the invoiced amount, net of allowance for doubtful accounts. Unbilled accounts receivable are estimated and recorded based on wholesale electricity purchases. 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 billed 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 110 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 non-refundable 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, 2013. A summary of average service lives and depreciation and amortization rates for the various classes of assets is included below:

	Average	Rate (%)	
	Service Life	Range	Average
Transmission	57 years	1% – 2%	2%
Distribution	42 years	1% – 20%	2%
Communication	19 years	1% – 15%	5%
Administration and service	15 years	3% – 20%	6%

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 10%.

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. 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, 2013, based on the qualitative assessment performed as at September 30, 2013, 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 at December 31, 2013.

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, 2013, 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 discontinued 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 13 – Fair Value of Financial Instruments and Risk Management.

The Company's 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, 2013 or 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 on 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 on the Consolidated Balance Sheets. The post-retirement and post-employment benefit plans are unfunded because there are no related plan assets.

Pension benefits

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 recorded 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.

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.

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

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.

Hydro One records a regulatory asset equal to the incremental net unfunded projected benefit obligation for post-retirement and post-employment plans recorded 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.

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 the 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. At December 31, 2012, OMERS had approximately 429,000 members, with approximately 283 members being current employees of Hydro One Brampton Networks.

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.

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. 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 December 2011, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) 2011-11, Balance Sheet (Topic 210): Disclosures about Offsetting Assets and Liabilities. This ASU requires an 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 was required to be applied retrospectively and was effective for fiscal years, and interim periods within those years, beginning on or after January 1, 2013. The adoption of this ASU did not have an impact on the Company's Consolidated Financial Statements.

In February 2013, the FASB issued ASU 2013-02, Comprehensive Income (Topic 220): Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income. This ASU requires an entity to provide information about the amounts reclassified out of accumulated other comprehensive income by component. In addition, an entity is required to present, either on the face of the statement where net income is presented or in the notes, significant amounts reclassified out of accumulated other comprehensive income by the respective line items of net income, but only if the amount reclassified is required under US GAAP to be reclassified to net income in its entirety in the same reporting period. For other amounts that are not required under US GAAP to be reclassified in their entirety to net income, an entity is required to cross-reference to other disclosures required under US GAAP that provide additional detail about those amounts. This ASU was required to be applied prospectively and was effective for fiscal years, and interim periods within those years, beginning after December 15, 2012. 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 July 2013, the FASB issued ASU 2013-11, Income Taxes (Topic 740): Presentation of an Unrecognized Tax Benefit When a Net Operating Loss Carryforward, a Similar Tax Loss, or a Tax Credit Carryforward Exists. This ASU provides guidance on the presentation of unrecognized tax benefits. This ASU is effective for fiscal years, and interim periods within those years, beginning after December 15, 2013, and should be applied prospectively to all unrecognized tax benefits that exist at the effective date. Retrospective application is permitted. The adoption of this ASU is not anticipated to have a significant impact on the Company's Consolidated Financial Statements.

4. BUSINESS ACQUISITION

Norfolk Power Purchase Agreement

On April 2, 2013, Hydro One reached an agreement with The Corporation of Norfolk County to acquire 100% of the common shares of Norfolk Power Inc. (Norfolk Power), an electricity distribution and telecom company located in southwestern Ontario. The acquisition is pending a regulatory decision from the OEB. The purchase price for Norfolk Power will be approximately $93 million, subject to final closing adjustments. The transaction is anticipated to be completed in 2014. In anticipation of the Norfolk Power acquisition, the Company made a refundable deposit totaling $5 million, which was recorded in other current assets on the interim Consolidated Balance Sheet.

5. DEPRECIATION AND AMORTIZATION

Year ended December 31 (millions of Canadian dollars)	**2013**	2012
Depreciation of property, plant and equipment	**533**	522
Amortization of intangible assets	**48**	48
Asset removal costs	**79**	70
Amortization of regulatory assets	**16**	19
	676	659

6. FINANCING CHARGES

Year ended December 31 (millions of Canadian dollars)	**2013**	2012
Interest on long-term debt	**416**	421
Other	**9**	12
Less: Interest capitalized on construction and development in progress	**(51)**	(59)
Gain on interest-rate swap agreements	**(11)**	(12)
Interest earned on investments	**(3)**	(4)
	360	358

7. PROVISION FOR PAYMENTS IN LIEU OF CORPORATE INCOME TAXES

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 Canadian dollars)	**2013**	2012
Income before provision for PILs	**912**	866
Canadian federal and Ontario statutory income tax rate	**26.50%**	26.50%
Provision for PILs at statutory rate	**242**	230
Increase (decrease) resulting from:		
Net temporary differences included in amounts charged to customers:		
Capital cost allowance in excess of depreciation and amortization	**(72)**	(42)
Pension contributions in excess of pension expense	**(23)**	(23)
Interest capitalized for accounting but deducted for tax purposes	**(13)**	(15)
Overheads capitalized for accounting but deducted for tax purposes	**(14)**	(14)
Prior year's adjustments	**(8)**	(2)
Non-refundable investment tax credits	**(4)**	(8)
Environmental expenditures	**(4)**	(5)
Post-retirement and post-employment benefit expense in excess of cash payments	**4**	–
Other	**(1)**	(1)
Net temporary differences	**(135)**	(110)
Net permanent differences	**2**	1
Total provision for PILs	**109**	121

The major components of income tax expense are as follows:

Year ended December 31 (millions of Canadian dollars)	**2013**	2012
Current provision for PILs	**111**	130
Deferred recovery of PILs	**(2)**	(9)
Total provision for PILs	**109**	121
Effective income tax rate	**11.98%**	13.96%

The current provision for PILs is remitted to, or received from, the Ontario Electricity Financial Corporation (OEFC). At December 31, 2013, $29 million due from the OEFC was included in due from related parties on the Consolidated Balance Sheet (December 31, 2012 – $10 million included in due to related parties).

The total provision for PILs includes deferred recovery of PILs of $2 million (2012 – $9 million) that is not included in the rate-setting process, using the 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, 2013 and 2012, deferred income tax assets and liabilities consisted of the following:

December 31 (millions of Canadian dollars)	**2013**	2012
Deferred income tax assets		
Post-retirement and post-employment benefits expense in excess of cash payments	**7**	7
Environmental expenditures	**5**	4
Depreciation and amortization in excess of capital cost allowance	**–**	3
Other	**(1)**	–
Total deferred income tax assets	**11**	14
Less: current portion	**–**	–
	11	14

December 31 (millions of Canadian dollars)	**2013**	2012
Deferred income tax liabilities		
Capital cost allowance in excess of depreciation and amortization	**(1,556)**	(1,344)
Post-retirement and post-employment benefits expense in excess of cash payments	**542**	519
Environmental expenditures	**66**	62
Regulatory amounts that are not recognized for tax purposes	**(144)**	(147)
Goodwill	**(20)**	(19)
Other	**1**	3
Total deferred income tax liabilities	**(1,111)**	(926)
Less: current portion	**18**	18
	(1,129)	(944)

During 2013, there was no change in the rate applicable to future taxes (2012 – a change in rate applicable to future rates generated a $60 million increase).

8. ACCOUNTS RECEIVABLE

December 31 (millions of Canadian dollars)	**2013**	2012
Accounts receivable – billed	**268**	224
Accounts receivable – unbilled	**691**	644
Accounts receivable, gross	**959**	868
Allowance for doubtful accounts	**(36)**	(23)
Accounts receivable, net	**923**	845

The following table shows the movements in the allowance for doubtful accounts for the years ended December 31, 2013 and 2012:

Year ended December 31 (millions of Canadian dollars)	**2013**	2012
Allowance for doubtful accounts – January 1	**(23)**	(18)
Write-offs	**24**	17
Additions to allowance for doubtful accounts	**(37)**	(22)
Allowance for doubtful accounts – December 31	**(36)**	(23)

9. PROPERTY, PLANT AND EQUIPMENT

December 31, 2013 (millions of Canadian dollars)	**Property, Plant and Equipment**	**Accumulated Depreciation**	**Construction in Progress**	**Total**
Transmission	**12,413**	**4,215**	**671**	**8,869**
Distribution	**8,498**	**3,046**	**316**	**5,768**
Communication	**1,060**	**560**	**53**	**553**
Administration and Service	**1,380**	**716**	**38**	**702**
Easements	**617**	**78**	**–**	**539**
	23,968	**8,615**	**1,078**	**16,431**

December 31, 2012 (millions of Canadian dollars)	Property, Plant and Equipment	Accumulated Depreciation	Construction in Progress	Total
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

Financing charges capitalized on property, plant and equipment under construction were $48 million in 2013 (2012 – $56 million).

10. INTANGIBLE ASSETS

December 31, 2013 (millions of Canadian dollars)	**Intangible Assets**	**Accumulated Amortization**	**Development in Progress**	**Total**
Computer applications software	**557**	**249**	**3**	**311**
Other	**5**	**3**	**–**	**2**
	562	**252**	**3**	**313**

December 31, 2012 (millions of Canadian dollars)	Intangible Assets	Accumulated Amortization	Development in Progress	Total
Computer applications software	451	301	116	266
Other	5	4	–	1
	456	305	116	267

Financing charges capitalized on intangible assets under development were $3 million in 2013 (2012 – $3 million). The estimated annual amortization expense for intangible assets is as follows: 2014 – $52 million; 2015 – $52 million; 2016 – $52 million; 2017 – $52 million; and 2018 – $44 million.

11. 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 Canadian dollars)	**2013**	2012
Regulatory assets:		
Deferred income tax regulatory asset	**1,145**	954
Pension benefit regulatory asset	**845**	1,515
Post-retirement and post-employment benefits	**308**	320
Environmental	**266**	249
Pension cost variance	**80**	61
OEB cost assessment differential	**9**	6
DSC exemption	**7**	2
Long-term project development costs	**5**	5
Rider 2	**–**	10
Other	**18**	5
Total regulatory assets	**2,683**	3,127
Less: current portion	**47**	29
	2,636	3,098
Regulatory liabilities:		
External revenue variance	**81**	61
Rider 8	**55**	45
Retail settlement variance accounts	**35**	54
Deferred income tax regulatory liability	**19**	16
Rider 9	**19**	–
PST savings deferral	**17**	13
Hydro One Brampton Networks rider	**8**	–
Rider 3	**–**	9
Rural and remote rate protection variance	**–**	6
Other	**14**	17
Total regulatory liabilities	**248**	221
Less: current portion	**85**	40
	163	181

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 2013 provision for PILs would have been higher by approximately $139 million (2012 – $136 million).

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, 2013 OCI would have been higher by $670 million (2012 – lower by $736 million).

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, 2013 OCI would have been higher by $12 million (2012 – lower by $197 million).

Environmental
Hydro One records a liability for the estimated future expenditures required to remediate environmental contamination. Because such expenditures are expected to be recoverable in future rates, the Company has recorded an equivalent amount as a regulatory asset. In 2013, the environmental regulatory asset decreased by $3 million (2012 – $3 million) to reflect related changes in the Company's PCB liability, and increased by $26 million (2012 – $2 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, 2013 operation, maintenance and administration expenses would have been higher by $23 million (2012 – lower by $1 million). In addition, 2013 amortization expense would have been lower by $16 million (2012 – $18 million), and 2013 financing charges would have been higher by $10 million (2012 – $11 million).

Pension Cost Variance
A pension cost variance account was established for 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 regulatory account reflects the excess of pension costs paid as compared to OEB-approved amounts. In the absence of rate-regulated accounting, 2013 revenue would have been lower by $19 million (2012 – $18 million).

OEB Cost Assessment Differential
In April 2010, the OEB announced its decision regarding the Company's rate application in respect of Hydro One Networks' distribution business for 2010 and 2011. As part of this decision, the OEB also approved the distribution-related OEB Cost Assessment Differential Account to record the difference between the amounts approved in rates and actual expenditures with respect to the OEB's cost assessments.

DSC Exemption
In June 2010, Hydro One Networks filed an application with the OEB regarding the OEB's new cost responsibility rules contained in the OEB's October 2009 Notice of Amendment to the Distribution System Code (DSC), with respect to the connection of certain renewable generators that were already connected or that had received a connection impact assessment prior to October 21, 2009. The application sought approval to record and defer the unanticipated costs incurred by Hydro One Networks that resulted from the connection of certain renewable generation facilities. The OEB ruled that expenditures for identified specific expenditures can be recorded in a deferral account, subject to the OEB's review at a future date.

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 2012, the OEB approved the recovery of the December 31, 2012 balance, including accrued interest, to be recovered over a one-year period from January 1, 2014 to December 31, 2014.

Rider 2
In April 2006, the OEB approved Hydro One Networks' distribution-related deferral account balances. The Rider 2 regulatory asset includes retail settlement and cost variance amounts and distribution low-voltage service amounts, plus accrued interest. In December 2012, as part of Hydro One Networks' 2013 IRM distribution rate application, the OEB approved the balance of the Rider 2 regulatory account for disposition as part of Rider 9, including accrued interest, to be disposed over a 24-month period from January 1, 2013 to December 31, 2014.

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. In November 2012, the OEB again approved forecasted amounts related to these revenue categories and extended the scope to encompass all other external revenues. The external revenue variance account balance reflects the excess of actual external revenues compared to the OEB-approved forecasted amounts.

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.

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 December 2012, the OEB approved the disposition of the total RSVA balance accumulated from January 2010 to December 2011, including accrued interest, to be disposed over a 24-month period from January 1, 2013 to December 31, 2014. Hydro One has continued to accumulate a net liability in its RSVAs since December 31, 2011.

Rider 9
In December 2012, as part of Hydro One Networks' 2013 IRM distribution rate application, the OEB approved for disposition certain distribution-related deferral account balances, including RSVA amounts and balances of Rider 2 and Rider 3, accumulated up to December 2011, including accrued interest, to be disposed over a 24-month period from January 1, 2013 to December 31, 2014.

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 administration 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 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 Hydro One Networks' distribution revenue requirement, PST was included between July 1, 2010 and December 31, 2013 and recorded in a deferral account, per direction from the OEB.

Hydro One Brampton Networks Rider
In December 2013, the OEB issued a decision for Hydro One Brampton Networks' 2014 distribution rates. Included in the OEB's decision was the approval of certain deferral account balances, primarily RSVAs. 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 January 1, 2014 to December 31, 2015.

Rider 3
In December 2008, the OEB approved certain distribution-related deferral account balances, 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. In December 2012, as part of Hydro One Networks' 2013 IRM distribution rate application, the OEB approved the balance of Rider 2 for disposition as part of Rider 9.

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. At December 31, 2013, the RRRP variance account had a $2 million debit balance, which is included in Other regulatory assets.

12. 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 which has a maximum authorized 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, 2013 and 2012.

Hydro One has a $1,500 million committed and unused revolving standby credit facility with a syndicate of banks, maturing in June 2018. If used, interest on the facility would apply based on Canadian benchmark rates. This credit facility is unsecured and 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.

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, 2013, $1,815 million remained available for issuance until October 2015.

The following table presents the outstanding long-term debt at December 31, 2013 and 2012:

December 31 (millions of Canadian dollars)	**2013**	2012
5.00% Series 15 notes due 2013	**–**	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**	50
5.18% Series 13 notes due 2017	**600**	600
2.78% Series 28 notes due 2018	**750**	–
4.40% Series 20 notes due 2020	**300**	300
3.20% Series 25 notes due 2022	**600**	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
4.59% Series 29 notes due 2043	**435**	–
5.00% Series 11 notes due 2046	**325**	325
4.00% Series 24 notes due 2051	**225**	225
3.79% Series 26 notes due 2062	**310**	310
	9,045	8,460
Add: Unrealized marked-to-market loss[1]	**12**	19
Less: Long-term debt payable within one year	**(756)**	(600)
Long-term debt	**8,301**	7,879

[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 $12 million (2012 – $19 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 13 – 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 2013, Hydro One issued $1,185 million (2012 – $1,085 million) of long-term debt under the MTN Program, and repaid the $600 million MTN Series 15 notes (2012 – redeemed $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 13 – Fair Value of Financial Instruments and Risk Management.

13. 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, 2013 and 2012, the Company's carrying amounts of accounts receivable, due from related parties, cash and cash equivalents, bank indebtedness, accounts payable, 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, 2013 and 2012 are as follows:

December 31 (millions of Canadian dollars)	**2013 Carrying Value**	**2013 Fair Value**	2012 Carrying Value	2012 Fair Value
Long-term debt				
$500 million of MTN Series 19 notes[1]	**506**	**506**	512	512
$250 million of MTN Series 21 notes[2]	**256**	**256**	257	257
Other notes and debentures[3]	**8,295**	**9,018**	7,710	9,188
	9,057	**9,780**	8,479	9,957

[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, 2013, the Company had interest-rate swaps totaling $750 million (2012 – $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 8% (2012 – 9%) of its total long-term debt of $9,057 million (2012 – $8,479 million). At December 31, 2013, 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, 2013, the Company also had interest-rate swaps with a total notional value of $900 million (2012 – $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, 2013 to December 11, 2014, from February 19, 2013 to February 19, 2014, and from February 19, 2014 to November 19, 2014;

(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, 2013 to January 24, 2014, and from January 24, 2014 to January 24, 2015; 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 December 3, 2013 to December 3, 2014.

Fair Value Hierarchy

The fair value hierarchy of financial assets and liabilities at December 31, 2013 and 2012 is as follows:

December 31, 2013 (millions of Canadian dollars)	Carrying Value	Fair Value	Level 1	Level 2	Level 3
Assets:					
Cash and cash equivalents	**565**	**565**	**565**	**–**	**–**
Investment	**251**	**251**	**–**	**251**	**–**
Derivative instruments					
Fair value hedges – interest-rate swaps	**12**	**12**	**–**	**12**	**–**
	828	**828**	**565**	**263**	**–**
Liabilities:					
Bank indebtedness	**31**	**31**	**31**	**–**	**–**
Long-term debt	**9,057**	**9,780**	**–**	**9,780**	**–**
	9,088	**9,811**	**31**	**9,780**	**–**

December 31, 2012 (millions of Canadian dollars)	Carrying Value	Fair Value	Level 1	Level 2	Level 3
Assets:					
Cash and cash equivalents	195	195	195	–	–
Investment	251	251	–	251	–
Derivative instruments					
Fair value hedges – interest-rate swaps	19	19	–	19	–
	465	465	195	270	–
Liabilities:					
Bank indebtedness	42	42	42	–	–
Long-term debt	8,479	9,957	–	9,957	–
	8,521	9,999	42	9,957	–

Cash and cash equivalents include cash and short-term investments. At December 31, 2013, short-term investments consisted of bankers' acceptances and money market funds totaling $515 million (2012 – $195 million). The carrying values are representative of fair value because of the short-term nature of these instruments.

The investment represents the Province of Ontario Floating-Rate Notes maturing in November 2014. The fair value of the 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 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 inputs 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 fair value levels during the years ended December 31, 2013 and 2012.

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' annual results of operations by approximately $19 million (2012 – $18 million) and Hydro One Networks' distribution business' annual results of operations by approximately $10 million (2012 – $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 in existence as at December 31, 2013 or 2012.

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, 2013 or 2012.

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, 2013 and 2012 are included in financing charges as follows:

Year ended December 31 (millions of Canadian dollars)	**2013**	2012
Unrealized loss (gain) on hedged debt	**(8)**	(14)
Unrealized loss (gain) on fair value interest-rate swaps	**8**	14
Net unrealized loss (gain)	**–**	–

At December 31, 2013, Hydro One had $750 million (2012 – $750 million) of notional amounts of fair value hedges outstanding related to interest-rate swaps, with assets at fair value of $12 million (2012 – $19 million). During the years ended December 31, 2013 and 2012, 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, 2013 and 2012, 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 single customer. At December 31, 2013 and 2012, there was no significant accounts receivable balance due from any single customer.

At December 31, 2013, the Company's provision for bad debts was $36 million (2012 – $23 million). Adjustments and write-offs were determined on the basis of a review of overdue accounts, taking into consideration historical experience. At December 31, 2013, approximately 4% of the Company's net accounts receivable were aged more than 60 days (2012 – 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 marked-to-market position on the measurement date. The Company would offset the positive market values against negative values with the same counterparty only 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 an 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, 2013, the counterparty credit risk exposure on the fair value of these interest-rate swap contracts was $14 million (2012 – $22 million). At December 31, 2013, 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 three of the four counterparties accounted for more than 10% of the total credit exposure of derivative contracts.

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 of $1,500 million, and by holding Province of Ontario Floating-Rate Notes. The short-term liquidity under the Commercial Paper Program, the holding of Province of Ontario Floating-Rate Notes and anticipated levels of funds from operations should be sufficient to fund normal operating requirements.

At December 31, 2013, accounts payable and accrued liabilities in the amount of $795 million (2012 – $722 million) were expected to be settled in cash at their carrying amounts within the next 12 months.

At December 31, 2013, Hydro One had issued long-term debt in the principal amount of $9,045 million (2012 – $8,460 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 Canadian dollars)*	**Interest Payments** *(millions of Canadian dollars)*	**Weighted Average Interest Rate** *(%)*
1 year	750	422	3.1
2 years	550	398	2.8
3 years	500	372	4.3
4 years	600	361	5.2
5 years	750	330	2.8
	3,150	1,883	3.6
6 – 10 years	900	1,470	3.6
Over 10 years	4,995	4,281	5.5
	9,045	7,634	4.7

14. 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, 2013 and 2012, the Company's capital structure was as follows:

December 31 (millions of Canadian dollars)	**2013**	2012
Long-term debt payable within one year	**756**	600
Less: cash and cash equivalents	**565**	195
	191	405
Long-term debt	**8,301**	7,879
Preferred shares	**323**	323
Common shares	**3,314**	3,314
Retained earnings	**3,787**	3,202
	7,101	6,516
Total capital	**15,916**	15,123

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, 2013 and 2012, Hydro One was in compliance with all of these covenants and limitations.

15. 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, 2013 were \$2 million (2012 – \$2 million). Company contributions payable at December 31, 2013 and included in accrued liabilities on the Consolidated Balance Sheets were \$0.2 million (2012 – \$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, 2012.

At December 31, 2012, the OMERS plan was 85.6% funded, with an unfunded liability of $9,924 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 employee contributions to the Pension Plan are based on actuarial valuations performed at least every three years. Annual Pension Plan contributions for 2013 of $160 million (2012 – $163 million) were based on an actuarial valuation effective December 31, 2011 and the level of 2013 pensionable earnings. Estimated annual Pension Plan contributions for 2014 are approximately $160 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 benefit 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. The measurement date for the Plans is December 31.

	Pension Benefits		Post-Retirement and Post-Employment Benefits	
Year ended December 31 (millions of Canadian dollars)	**2013**	2012	**2013**	2012
Change in projected benefit obligation				
Projected benefit obligation, beginning of year	**6,507**	5,461	**1,459**	1,206
Current service cost	**170**	123	**40**	29
Interest cost	**278**	285	**63**	63
Reciprocal transfers	**1**	1	**–**	–
Benefits paid	**(317)**	(291)	**(44)**	(42)
Net actuarial loss (gain)	**(63)**	928	**13**	203
Projected benefit obligation, end of year	**6,576**	6,507	**1,531**	1,459
Change in plan assets				
Fair value of plan assets, beginning of year	**4,992**	4,682	**–**	–
Actual return on plan assets	**887**	425	**–**	–
Reciprocal transfers	**1**	1	**–**	–
Benefits paid	**(317)**	(291)	**–**	–
Employer contributions	**160**	163	**–**	–
Employee contributions	**30**	27	**–**	–
Administrative expenses	**(22)**	(15)	**–**	–
Fair value of plan assets, end of year	**5,731**	4,992	**–**	–
Unfunded status	**845**	1,515	**1,531**	1,459

Hydro One presents its benefit obligations and plan assets net on its Consolidated Balance Sheets within the following line items:

	Pension Benefits		Post-Retirement and Post-Employment Benefits	
December 31 (millions of Canadian dollars)	**2013**	2012	**2013**	2012
Accrued liabilities	**–**	–	**43**	43
Pension benefit liability	**845**	1,515	**–**	–
Post-retirement and post-employment benefit liability	**–**	–	**1,488**	1,416
Unfunded status	**845**	1,515	**1,531**	1,459

The funded or 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 Canadian dollars)	**2013**	2012
PBO	**6,576**	6,507
ABO	**5,998**	6,074
Fair value of plan assets	**5,731**	4,992

On an ABO basis, the Pension Plan was funded at 96% at December 31, 2013 (2012 – 82%). On a PBO basis, the Pension Plan was funded at 87% at December 31, 2013 (2012 – 77%). 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, 2013 and 2012 for the Pension Plan:

Year ended December 31 (millions of Canadian dollars)	**2013**	2012
Current service cost, net of employee contributions	**141**	96
Interest cost	**278**	285
Expected return on plan assets, net of expenses	**(309)**	(289)
Actuarial loss amortization	**175**	112
Prior service cost amortization	**2**	3
Net periodic benefit costs	**287**	207
Charged to results of operations[1]	**72**	76

[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, 2013, pension costs of $160 million (2012 – $163 million) were attributed to labour, of which $72 million (2012 – $76 million) was charged to operations, and $88 million (2012 – $87 million) was capitalized as part of the cost of property, plant and equipment and intangible assets.

The following table provides the components of the net periodic benefit costs for the years ended December 31, 2013 and 2012 for the post-retirement and post-employment plans:

Year ended December 31 (millions of Canadian dollars)	**2013**	2012
Current service cost, net of employee contributions	**40**	30
Interest cost	**63**	63
Actuarial loss amortization	**27**	8
Prior service cost amortization	**3**	3
Net periodic benefit costs	**133**	104
Charged to results of operations	**58**	48

Assumptions

The measurement of the obligations of the Plans and the costs of providing benefits under the 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 at December 31, 2013 and 2012:

	Pension Benefits		Post-Retirement and Post-Employment Benefits	
Year ended December 31	**2013**	2012	**2013**	2012
Significant assumptions:				
Weighted average discount rate	**4.75%**	4.25%	**4.75%**	4.25%
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[1]	**–**	–	**4.39%**	4.39%

[1] 6.81% per annum in 2014, grading down to 4.39% per annum in and after 2031 (2012 – 6.91% in 2013, grading down to 4.39% per annum in and after 2031)

The following weighted average assumptions were used to determine the net periodic benefit costs for the years ended December 31, 2013 and 2012. 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	**2013**	2012
Pension Benefits:		
Weighted average expected rate of return on plan assets	**6.25%**	6.25%
Weighted average discount rate	**4.25%**	5.25%
Rate of compensation scale escalation (without merit)	**2.50%**	2.50%
Rate of cost of living increase	**2.00%**	2.00%
Average remaining service life of employees *(years)*	**11**	11
Post-Retirement and Post-Employment Benefits:		
Weighted average discount rate	**4.25%**	5.25%
Rate of compensation scale escalation (without merit)	**2.50%**	2.50%
Rate of cost of living increase	**2.00%**	2.00%
Average remaining service life of employees *(years)*	**11**	11
Rate of increase in health care cost trends[1]	**4.39%**	4.41%

[1] 6.91% per annum in 2013, grading down to 4.39% per annum in and after 2031 (2012 – 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 projected benefit obligation for the post-retirement and post-employment benefits at December 31, 2013 and 2012 is as follows:

December 31 (millions of Canadian dollars)	**2013**	2012
Projected benefit obligation:		
Effect of 1% increase in health care cost trends	**258**	246
Effect of 1% decrease in health care cost trends	**(200)**	(191)

The effect of 1% change in health care cost trends on the service cost and interest cost for the post-retirement and post-employment benefits for the years ended December 31, 2013 and 2012 is as follows:

Year ended December 31 (millions of Canadian dollars)	**2013**	2012
Service cost and interest cost:		
Effect of 1% increase in health care cost trends	**21**	17
Effect of 1% decrease in health care cost trends	**(16)**	(13)

The following approximate life expectancies were used in the mortality assumptions to determine the projected benefit obligations for the pension and post-retirement and post-employment plans at December 31, 2013 and 2012:

December 31, 2013				December 31, 2012			
Life expectancy at 65 for a member currently at				Life expectancy at 65 for a member currently at			
Age 65		**Age 45**		Age 65		Age 45	
Male	**Female**	**Male**	**Female**	Male	Female	Male	Female
23	**25**	**24**	**26**	20	22	21	23

Estimated Future Benefit Payments

At December 31, 2013, estimated future benefit payments by the Company to Plan participants were:

(millions of Canadian dollars)	Pension Benefits	Post-Retirement and Post-Employment Benefits
2014	310	54
2015	319	57
2016	327	59
2017	335	62
2018	343	65
2019 through to 2023	1,698	370
Total estimated future benefit payments through to 2023	3,332	667

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:

Year ended December 31 (millions of Canadian dollars)	**2013**	2012
Pension Benefits:		
Actuarial loss (gain) for the year	**(619)**	807
Actuarial loss amortization	**(175)**	(112)
Prior service cost amortization	**(2)**	(3)
	(796)	692
Post-Retirement and Post-Employment Benefits:		
Actuarial loss for the year	**13**	203
Actuarial loss amortization	**(27)**	(8)
Prior service cost amortization	**(3)**	(3)
	(17)	192

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, 2013 and 2012:

Year ended December 31 (millions of Canadian dollars)	**2013**	2012
Pension Benefits:		
Prior service cost	**3**	5
Actuarial loss	**842**	1,510
	845	1,515
Post-Retirement and Post-Employment Benefits:		
Prior service cost	**2**	5
Actuarial loss	**306**	315
	308	320

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	
December 31 (millions of Canadian dollars)	**2013**	2012	**2013**	2012
Prior service cost	**2**	2	**2**	3
Actuarial loss	**103**	175	**15**	17
	105	177	**17**	20

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, 2013, the Pension Plan target asset allocations and weighted average asset allocations were as follows:

	Target Allocation (%)	Pension Plan Assets (%)
Equity securities	60.0	67.8
Debt securities	35.0	32.2
Other [1]	5.0	0.0
	100.0	100.0

[1] Other investments include real estate and infrastructure investments.

At December 31, 2013, the Pension Plan held $15 million of Hydro One corporate bonds (2012 – $20 million) and $217 million of debt securities of the Province (2012 – $243 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, 2013 and 2012. 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, 2013 and 2012, 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 "A+" by Standard and Poor's, Dominion Bond Rating Service, and Fitch Ratings, and "A1" by Moody's Investors Service Inc., and also by utilizing exposure limits to each counterparty and ensuring that exposure is diversified across counterparties. 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 tables present 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, 2013 and 2012:

December 31, 2013 (millions of Canadian dollars)	**Level 1**	**Level 2**	**Level 3**	**Total**
Pooled funds	**1**	**16**	**117**	**134**
Cash and cash equivalents	**150**	**–**	**–**	**150**
Short-term securities	**–**	**180**	**–**	**180**
Real estate	**–**	**–**	**2**	**2**
Corporate shares – Canadian	**943**	**–**	**–**	**943**
Corporate shares – Foreign	**2,708**	**–**	**–**	**2,708**
Bonds and debentures – Canadian	**–**	**1,416**	**–**	**1,416**
Bonds and debentures – Foreign	**–**	**186**	**–**	**186**
Total fair value of plan assets[1]	**3,802**	**1,798**	**119**	**5,719**

[1] At December 31, 2013, the total fair value of Pension Plan assets excludes $19 million of interest and dividends receivable, and $7 million relating to accruals for pension administration expense.

December 31, 2012 (millions of Canadian 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.

See Note 13 – 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, 2013 and 2012. 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 Canadian dollars)	**2013**	2012
Fair value, beginning of year	**106**	167
Realized and unrealized gains	**23**	5
Purchases	**–**	6
Sales and disbursements	**(10)**	(72)
Fair value, end of year	**119**	106

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.

16. ENVIRONMENTAL LIABILITIES

The following tables show the movements in environmental liabilities for the years ended December 31, 2013 and 2012:

Year ended December 31, 2013 (millions of Canadian dollars)	**PCB**	**LAR**	**Total**
Environmental liabilities, January 1	**197**	**52**	**249**
Interest accretion	**9**	**1**	**10**
Expenditures	**(2)**	**(14)**	**(16)**
Revaluation adjustment	**(3)**	**26**	**23**
Environmental liabilities, December 31	**201**	**65**	**266**
Less: current portion	**15**	**12**	**27**
	186	**53**	**239**

Year ended December 31, 2012 (millions of Canadian dollars)	PCB	LAR	Total
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

The following tables show the reconciliation between the undiscounted basis of the environmental liabilities and the amount recognized on the Consolidated Balance Sheets after factoring in the discount rate:

December 31, 2013 (millions of Canadian dollars)	**PCB**	**LAR**	**Total**
Undiscounted environmental liabilities	**237**	**68**	**305**
Less: discounting accumulated liabilities to present value	**36**	**3**	**39**
Discounted environmental liabilities	**201**	**65**	**266**

December 31, 2012 (millions of Canadian dollars)	PCB	LAR	Total
Undiscounted environmental liabilities	233	54	287
Less: discounting accumulated liabilities to present value	36	2	38
Discounted environmental liabilities	197	52	249

At December 31, 2013, the estimated future environmental expenditures were as follows:

(millions of Canadian dollars)	
2014	27
2015	28
2016	35
2017	23
2018	22
Thereafter	170
	305

At December 31, 2013, of the total estimated future environmental expenditures, $237 million relates to PCBs (2012 – $233 million) and $68 million relates to LAR (2012 – $54 million).

Hydro One records a liability for the estimated future expenditures for the contaminated LAR and for the phase-out and destruction of PCB-contaminated mineral oil removed from electrical equipment. 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. 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 rate assumption of approximately 2% has been used to express these current cost estimates as estimated future expenditures. Future expenditures have been discounted using factors ranging from approximately 3.3% to 6.3%, depending on the appropriate rate for the period when expenditures are expected to be incurred. All factors used in estimating the Company's environmental liabilities represent management's best estimates of the present value of 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. 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. Environmental liabilities are reviewed annually or more frequently if significant changes in regulations or other relevant factors occur. Estimate changes are accounted for prospectively. The Company records a regulatory asset reflecting the expectation that future environmental costs will be recoverable in rates.

PCBs

In September 2008, Environment Canada published regulations governing the management, storage and disposal of PCBs, enacted under the *Canadian Environmental Protection Act, 1999*. The regulations impose timelines for disposal of PCBs based on certain criteria, including type of equipment, in-use status, and PCB-contamination thresholds. Under these regulations and Hydro One's approved end-of-use extension, PCBs in concentrations of 500 parts per million (ppm) or more have to be disposed of by the end of 2014, with the exception of specifically exempted equipment, and PCBs 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. Contaminated 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 $237 million. These expenditures are expected to be incurred over the period from 2014 to 2025. As a result of its annual review of environmental liabilities, the Company recorded a revaluation adjustment in 2013 to reduce the PCB environmental liability by $3 million (2012 – $3 million).

LAR

The Company's best estimate of the total estimated future expenditures to complete its LAR program is $68 million. These expenditures are expected to be incurred over the period from 2014 to 2022. As a result of its annual review of environmental liabilities, the Company recorded a revaluation adjustment in 2013 to increase the LAR environmental liability by $26 million (2012 – $2 million).

17. ASSET RETIREMENT OBLIGATIONS

Hydro One records a liability for the estimated future expenditures for the removal and disposal of asbestos-containing materials installed in some of its facilities and for the decommissioning of specific switching stations located on unowned sites. 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 reasonable 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 carrying 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 flows associated with the ARO, which can occur due to a number of factors including, but not limited to, cost escalation, changes in technology applicable to the assets to be retired, changes in legislation or 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.

In determining the amounts to be recorded as AROs, the Company estimates the current fair value for 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 expenditures have been discounted using factors ranging from approximately 3.0% to 5.0%, depending on the appropriate rate for the period when expenditures are expected to be incurred. All factors used in estimating the Company's AROs represent management's best estimates 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. AROs are reviewed annually or more frequently if significant changes in regulations or other relevant factors occur. Estimate changes are accounted for prospectively.

At December 31, 2013, Hydro One had recorded AROs of $14 million (2012 – $15 million), consisting of $7 million (2012 – $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 $7 million (2012 – $8 million) related to the future decommissioning and removal of two switching stations. The amount of interest recorded is nominal and there have been no significant expenditures associated with these obligations in 2013.

18. 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, 2013. 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.

19. DIVIDENDS

In 2013, preferred share dividends in the amount of $18 million (2012 – $18 million) and common share dividends in the amount of $200 million (2012 – $352 million) were declared.

20. 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.

Hydro One receives revenues for transmission services from the IESO, based on OEB-approved uniform transmission rates. Transmission revenues include $1,509 million (2012 – $1,474 million) related to these services. Hydro One receives amounts for rural rate protection from the IESO. Distribution revenues include $127 million (2012 – $127 million) related to this program. Hydro One also receives revenues related to the supply of electricity to remote northern communities from the IESO. Distribution revenues include $33 million (2012 – $28 million) related to these services.

In 2013, Hydro One purchased power in the amount of $2,477 million (2012 – $2,392 million) from the IESO-administered electricity market; $15 million (2012 – $10 million) from OPG; and $8 million (2012 – $7 million) from power contracts administered by 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 2013, Hydro One incurred $12 million (2012 – $11 million) in OEB fees.

Hydro One has service level agreements with OPG. These services include field, engineering, logistics and telecommunications services. In 2013, revenues related to the provision of construction and equipment maintenance services with respect to these service level agreements were $9 million (2012 – $10 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 $1 million in 2013 (2012 – $2 million).

The OPA funds substantially all of the Company's conservation and demand management programs. The funding includes program costs, incentives, and management fees. In 2013, Hydro One received $34 million (2012 – $39 million) from the OPA related to these programs.

Hydro One pays a $5 million annual fee to the OEFC for indemnification against adverse claims in excess of $10 million paid by the OEFC with respect to certain of Ontario Hydro's businesses transferred to Hydro One on April 1, 1999.

PILs and payments in lieu of property taxes are paid to the OEFC, and dividends are paid 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 interest free and settled in cash.

At December 31, 2013, the Company held $250 million in Province of Ontario Floating-Rate Notes with a fair value of $251 million (2012 – $251 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 Canadian dollars)	**2013**	2012
Due from related parties	**197**	154
Due to related parties[1]	**(230)**	(261)
Investment	**251**	251

[1] Included in due to related parties at December 31, 2013 are amounts owing to the IESO in respect of power purchases of $217 million (2012 – $199 million).

21. CONSOLIDATED STATEMENTS OF CASH FLOWS

The changes in non-cash balances related to operations consist of the following:

Year ended December 31 (millions of Canadian dollars)	**2013**	2012
Accounts receivable	**(78)**	(30)
Due from related parties	**(43)**	2
Materials and supplies	**–**	2
Other assets	**(5)**	(4)
Accounts payable	**(60)**	(5)
Accrued liabilities	**150**	10
Due to related parties	**(31)**	(85)
Accrued interest	**5**	10
Long-term accounts payable and other liabilities	**(11)**	13
Post-retirement and post-employment benefit liability	**84**	56
	11	(31)

Capital Expenditures

The following table illustrates the reconciliation between investments in property, plant and equipment and the amount presented in the Consolidated Statements of Cash Flows after factoring in the net change in related accruals:

Year ended December 31 (millions of Canadian dollars)	**2013**	2012
Capital investments in property, plant and equipment	**(1,312)**	(1,363)
Net change in accruals included in capital investments in property, plant and equipment	**(21)**	(10)
Capital expenditures – property, plant and equipment	**(1,333)**	(1,373)

The following table illustrates the reconciliation between investments in intangible assets and the amount presented in the Consolidated Statements of Cash Flows after factoring in the net change in related accruals:

Year ended December 31 (millions of Canadian dollars)	**2013**	2012
Capital investments in intangible assets	**(82)**	(91)
Net change in accruals included in capital investments in intangible assets	**3**	1
Capital expenditures – intangible assets	**(79)**	(90)

Supplementary Information

Year ended December 31 (millions of Canadian dollars)	**2013**	2012
Net interest paid	**395**	411
PILs	**138**	197

22. 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. In 2013, the Company paid approximately $2 million (2012 – $1 million) in respect of these consents. 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.

23. COMMITMENTS

Agreement with Inergi LP (Inergi)

In 2002, Inergi, an affiliate of Capgemini Canada Inc., began providing services to Hydro One, including business processing and information technology outsourcing services, as well as core system support related primarily to SAP implementation and optimization. The current agreement with Inergi will expire in February 2015.

At December 31, 2013, the annual commitments under the Inergi agreement are as follows: 2014 – $130 million; 2015 – $22 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, 2013, 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 (2012 – $325 million), and on behalf of two distributors using guarantees of $1 million (2012 – $1 million). In addition, as at December 31, 2013, the Company has provided letters of credit in the amount of $21 million (2012 – $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 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 eligible employees of Hydro One. 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, 2013, Hydro One had letters of credit of $127 million (2012 – $127 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 telecommunications 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, the future minimum lease payments under non-cancellable operating leases were as follows:

December 31 (millions of Canadian dollars)	**2013**	2012
Within one year	**11**	10
After one year but not more than five years	**28**	29
More than five years	**9**	14
	48	53

During the year ended December 31, 2013, the Company made lease payments totaling $11 million (2012 – $9 million).

24. 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 of the Company are determined based on information used by the chief operating decision maker in deciding how to allocate resources and evaluate the performance of 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, 2013 (millions of Canadian dollars)	**Transmission**	**Distribution**	**Other**	**Consolidated**
Revenues	**1,529**	**4,484**	**61**	**6,074**
Purchased power	**–**	**3,020**	**–**	**3,020**
Operation, maintenance and administration	**375**	**672**	**59**	**1,106**
Depreciation and amortization	**327**	**340**	**9**	**676**
Income (loss) before financing charges and provision for PILs	**827**	**452**	**(7)**	**1,272**
Financing charges				**360**
Income before provision for PILs				**912**
Capital investments	**714**	**673**	**7**	**1,394**

Year ended December 31, 2012 (millions of Canadian dollars)	Transmission	Distribution	Other	Consolidated
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 investments	776	671	7	1,454

Total Assets by Segment:

December 31 (millions of Canadian dollars)	**2013**	2012
Total assets		
Transmission	**11,846**	11,586
Distribution	**8,805**	8,621
Other	**974**	604
	21,625	20,811

All revenues, costs and assets, as the case may be, are earned, incurred or held in Canada.

25. SUBSEQUENT EVENT

On January 29, 2014, Hydro One issued $50 million notes under its MTN Program, with a maturity date of January 29, 2064 and a coupon rate of 4.29%.

BOARD OF DIRECTORS
(as at December 31, 2013)

James Arnett[2]
Chair of the
Board of Directors,
Hydro One Inc.

Kathryn A. Bouey[4,6,7]
President,
TBG Strategic
Services Inc.

Corporate Director

Catherine Karakatsanis[4,6]
Chief Operating Officer,
Morrison Hershfield
Group Inc.

Michael J. Mueller[1,2,4]
Corporate Director

Robert L. Pace[2,3,7]
President and CEO,
The Pace Group Ltd.

Sandra Pupatello[1,5]
Chief Executive Officer,
WindsorEssex Economic
Development Corporation

Director, Business
Development and
Global Markets, for
PwC Canada

Douglas E. Speers[3,4,6]
Corporate Director

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

George Cooke[1,5,7]
President, Martello
Associates Consulting

Chair of the Board of
Directors of OMERS
Administration Corporation

Don MacKinnon[5,6]
President,
Power Workers' Union

Walter Murray[1,3,7]
Corporate Director

Yezdi Pavri[1,4]
Corporate Director

Gale Rubenstein[2,3,5]
Partner,
Goodmans LLP

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. With the Company's SEC registration in 2013, the Audit and Finance Committee mandate was updated to ensure compliance with U.S. securities legislation. The committee met six times in 2013.

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 seven times in 2013.

3 *Human Resources Committee* The Human Resources Committee is responsible for reviewing the appropriateness of the Company's current and future organizational structure, succession plans for corporate and divisional officers, the code of business conduct, and the performance and remuneration of senior executives, including recommending to the Board the remuneration of the President and CEO. The committee met seven times in 2013.

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 seven times in 2013.

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 the Company. 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 five times in 2013.

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 2013.

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 five times in 2013.

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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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

FSC LOGO
TO COME

To learn more about what Hydro One is doing to deliver electricity, build for the future and keep the environment healthy, visit

www.HydroOne.com

HYDRO ONE INC.
MANAGEMENT'S DISCUSSION AND ANALYSIS
For the three and six months ended June 30, 2014 and 2013

The following Management's Discussion and Analysis (MD&A) of the financial condition and results of operations should be read together with the unaudited interim consolidated financial statements and accompanying notes (the Consolidated Financial Statements) of Hydro One Inc. (the Company) for the three and six months ended June 30, 2014, as well as the Company's audited consolidated financial statements and accompanying notes, and MD&A, for the year ended December 31, 2013. The Consolidated Financial Statements are presented in Canadian dollars and have been prepared in accordance with United States (US) Generally Accepted Accounting Principles (GAAP). All financial information in this MD&A is presented in Canadian dollars, unless otherwise indicated.

The Company has prepared this MD&A with reference to National Instrument 51-102 – Continuous Disclosure Obligations of the Canadian Securities Administrators. Under the US/Canada Multijurisdictional Disclosure System, the Company is permitted to prepare this MD&A in accordance with the disclosure requirements of Canada, which are different from those of the US. This MD&A provides information for the three and six months ended June 30, 2014, based on information available to management as of August 14, 2014.

EXECUTIVE SUMMARY

We are wholly owned by the Province of Ontario (Province or Shareholder), and our transmission and distribution businesses are regulated by the Ontario Energy Board (OEB). Our mission and vision reflects 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.

We have eight strategic objectives that drive the fulfillment of our mission and vision and ensure we remain focused on achieving our corporate goal of providing safe, reliable and affordable service to our customers, today and tomorrow, while increasing enterprise value for our shareholder:

- Creating an injury-free workplace and maintaining public safety;
- Satisfying our customers;
- Continuous innovation;
- Building and maintaining reliable, affordable transmission and distribution systems;
- Protecting and sustaining the environment for future generations;
- Championing people and culture;
- Maintaining a commercial culture that increases value for our shareholder; and
- Achieving productivity improvements and cost-effectiveness.

During the first six months of 2014, our financial fundamentals remained strong with net income of $355 million and revenues of $3,330 million. We issued $628 million of long-term debt, the proceeds of which were used to fund a portion of our capital expenditures and other corporate requirements. During the first six months of 2014, we made capital investments totaling $676 million to improve our transmission and distribution systems' reliability and performance, address our aging power system infrastructure, facilitate new generation, and improve service to our customers. We have focused tremendous energy on improving our customer service processes and policies. The rate of our customers now receiving timely bills based on actual consumption has increased from 95% to 98%. A full discussion of our results of operations, financing activities, and capital investments can be found in the sections "Results of Operations" and "Liquidity and Capital Resources."

OVERVIEW

Our company has three reportable segments:

- Our Transmission Business, which comprises the core business of providing electricity transportation and connection services, is responsible for transmitting electricity throughout the Ontario electricity grid;
- Our 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 our telecommunications business

Our Transmission Business includes the transmission business of our subsidiary Hydro One Networks Inc. (Hydro One Networks), which owns and operates substantially all of Ontario's electricity transmission system. 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. During the first six months of 2014, we earned total transmission revenues of $804 million. At June 30, 2014, our Transmission Business assets represented approximately 54% of our total assets.

Our consolidated Distribution Business includes the distribution business of our subsidiary Hydro One Networks, as well as our subsidiaries Hydro One Brampton Networks Inc. (Hydro One Brampton Networks) and Hydro One Remote Communities Inc. (Hydro One Remote Communities). Our consolidated distribution system is the largest in Ontario and spans roughly 75% of the province. During the first six months of 2014, we earned total distribution revenues of $2,497 million, including cost of purchased power of $1,746 million. At June 30, 2014, our Distribution Business assets represented approximately 41% of our total assets.

Our Other business segment primarily represents the operations of our 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. During the first six months of 2014, our Other business segment contributed revenues of $29 million. At June 30, 2014, the assets of our Other business segment represented approximately 5% of our total assets.

RESULTS OF OPERATIONS

As used in this section, references to increases and decreases, whether in terms of amounts or percentages, are made by comparison of the three and six months ended June 30, 2014 to the three and six months ended June 30, 2013, respectively.

	Three months ended June 30				**Six months ended June 30**			
(millions of Canadian dollars)	**2014**	**2013**	**$ Change**	**% Change**	**2014**	**2013**	**$ Change**	**% Change**
Revenues	1,566	1,403	163	12	3,330	2,975	355	12
Purchased power	824	684	140	20	1,746	1,482	264	18
Operation, maintenance and administration	334	291	43	15	645	524	121	23
Depreciation and amortization	181	160	21	13	348	321	27	8
	1,339	1,135	204	18	2,739	2,327	412	18
Income before financing charges and provision for payments in lieu of corporate income taxes	**227**	**268**	**(41)**	**(15)**	**591**	**648**	**(57)**	**(9)**
Financing charges	95	89	6	7	185	177	8	5
Income before provision for payments in lieu of corporate income taxes	**132**	**179**	**(47)**	**(26)**	**406**	**471**	**(65)**	**(14)**
Provision for payments in lieu of corporate income taxes	17	11	6	55	51	46	5	11
Net income	**115**	**168**	**(53)**	**(32)**	**355**	**425**	**(70)**	**(16)**

Revenues

	Three months ended June 30				Six months ended June 30			
(millions of Canadian dollars)	**2014**	**2013**	**$ Change**	**% Change**	**2014**	**2013**	**$ Change**	**% Change**
Transmission	382	368	14	4	804	741	63	9
Distribution	1,170	1,020	150	15	2,497	2,204	293	13
Other	14	15	(1)	(7)	29	30	(1)	(3)
	1,566	1,403	163	12	3,330	2,975	355	12
Average annual Ontario 60-minute peak demand (MW)[1]	19,403	20,668	(1,265)	(6)	20,757	20,977	(220)	(1)
Distribution – units distributed to customers (TWh)[1]	6.7	6.5	0.2	3	15.4	14.8	0.6	4

[1] System-related statistics are preliminary.

Electricity demand generally follows normal weather-related variations, and consequently, our energy-related revenues, all other things being equal, will tend to be higher in the first and third quarters than in the second and fourth quarters.

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. This reduces the risk of power interruptions during periods of high demand. Demand is primarily influenced by weather and economic conditions. Transmission revenues also include export revenues associated with transmitting excess generation to surrounding markets, ancillary revenues primarily attributable to maintenance services provided to generators, and secondary use of our land rights.

Our transmission revenues increased by $14 million, or 4%, in the second quarter of 2014, and by $63 million, or 9%, in the first six months of 2014, compared to the same periods in 2013. On January 9, 2014, the OEB approved new transmission rates effective January 1, 2014, which resulted in higher transmission revenues of $21 million and $44 million in the second quarter and the first six months of 2014, respectively, compared to the same periods in 2013. In addition, we experienced higher revenues of $9 million and $20 million in the second quarter and the first six months of 2014, respectively, associated with the OEB's approval of export service revenues, the disposition of certain OEB-approved transmission regulatory accounts, and ancillary services. The transmission revenue increases were partially offset by decreases in the average Ontario 60-minute peak demand in 2014. The average Ontario 60-minute peak demand was 1,265 MW and 220 MW lower in the second quarter and the first six months of 2014, respectively, resulting in a decrease in transmission revenues of $16 million and $1 million in the second quarter and the first six months of 2014, respectively, compared to the same periods in 2013, mainly due to a milder spring in 2014.

Distribution

Distribution revenues include our distribution tariff and amounts to recover the cost of purchased power, at rates set by the OEB, used by the customers of our 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 service 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 charges for late payments.

Our distribution revenues increased by $150 million, or 15%, in the second quarter of 2014, and by $293 million, or 13%, in the first six months of 2014, compared to the same periods in 2013. The increases were primarily due to the recovery of higher purchased power costs of $140 million and $264 million in the second quarter and the first six months of 2014, respectively, as described below under "Purchased Power." In addition, distribution revenues were higher by $6 million and $23 million in the second quarter and the first six months of 2014, respectively, due to increased energy consumption mainly resulting from the colder weather experienced in 2014. In December 2013, the OEB approved new distribution rates effective

January 1, 2014, which resulted in higher distribution revenues of $3 million and $5 million in the second quarter and the first six months of 2014, respectively, compared to the same periods in 2013. Distribution revenues also increased by $1 million in both the second quarter and the first six months of 2014, as a result of our placement in service of new smart grid and smart meter investments, which are currently being recovered through separate rate mechanisms, as well as ancillary distribution revenues, primarily associated with OEB-approved regulatory accounts and external revenues.

Purchased Power

Purchased power costs are incurred by our Distribution Business and represent the cost of purchased electricity delivered to customers within our distribution service territory. These costs comprise the wholesale commodity cost of energy, the Independent Electricity System Operator (IESO) wholesale market service charges, and transmission charges levied by the IESO. The commodity cost of energy is based on the OEB's Regulated Price Plan (RPP), as summarized below:

RPP	**Tier Threshold (kWh/month)**		**Tier Rates (cents/kWh)**	
Effective Date	**Residential**	**Non-Residential**	**Lower Tier**	**Upper Tier**
November 1, 2012	1,000	750	7.4	8.7
May 1, 2013	600	750	7.8	9.1
November 1, 2013	1,000	750	8.3	9.7
May 1, 2014	600	750	8.6	10.1

RPP Time of Use (TOU)	**Rates (cents/kWh)**		
Effective Date	**On Peak**	**Mid Peak**	**Off Peak**
November 1, 2012	11.8	9.9	6.3
May 1, 2013	12.4	10.4	6.7
November 1, 2013	12.9	10.9	7.2
May 1, 2014	13.5	11.2	7.5

Our purchased power costs increased by $140 million, or 20%, in the second quarter of 2014, and by $264 million, or 18%, in the first six months of 2014, compared to the same periods in 2013.

The increase in our second quarter purchased power costs was mainly due to a $103 million increase resulting from higher purchased power costs for customers who are not eligible for the RPP, an $18 million increase resulting from the impact of changes in the OEB's RPP rates for residential and other eligible customers as noted in the above tables, an $11 million increase due to higher demand for electricity, a $6 million increase resulting from the OEB transmission rate decision effective January 1, 2014, and a $2 million increase resulting from the IESO's wholesale market service charges and the Smart Metering Entity charge which was effective May 1, 2013.

The increase in our purchased power costs for the first six months of 2014 was mainly due to a $131 million increase resulting from higher purchased power costs for customers who are not eligible for the RPP, a $58 million increase due to higher demand for electricity, an increase of $30 million in wholesale market service charges levied by the IESO, a $28 million increase resulting from the impact of changes in the OEB's RPP rates for residential and other eligible customers as noted in the above tables, a $13 million increase resulting from the OEB transmission rate decision effective January 1, 2014, and a $4 million increase resulting from the IESO's Smart Metering Entity charge which was effective May 1, 2013.

Operation, Maintenance and Administration

Our operation, maintenance and administration costs consist of labour, which is substantially established under collective bargaining agreements, and materials, equipment and purchased services, which are subject to public tenders. These expenditure categories support the operation and maintenance of the transmission and distribution systems. Also included in these costs are payments in lieu of property taxes related to our transmission and distribution lines, stations and buildings. Our transmission operation, maintenance and administration costs are incurred to sustain our high-voltage transmission stations, lines and rights-of-way. Our distribution operation, maintenance and administration costs are required to maintain our low-voltage distribution system. Our company continues to focus on managing its costs, while continuing to complete our planned work programs for both our Transmission and Distribution Businesses.

	Three months ended June 30				Six months ended June 30			
(millions of Canadian dollars)	**2014**	**2013**	**$ Change**	**% Change**	**2014**	**2013**	**$ Change**	**% Change**
Transmission	105	105	–	–	220	177	43	24
Distribution	214	170	44	26	395	317	78	25
Other	15	16	(1)	(6)	30	30	–	–
	334	291	43	15	645	524	121	23

Transmission

Our transmission operation, maintenance and administration costs remained the same in the second quarter of 2014, and increased by $43 million, or 24%, in the first six months of 2014, compared to the same periods in 2013. The increase in the first six months of 2014 was primarily due to a reduction to our provision for payments in lieu of property taxes in 2013 related to transmission stations for the years 1999 to 2012, inclusive, following the finalization of the related regulations and receipt of a final assessment of our property tax returns. In 2014, we continued to invest in the safe and reliable operation of our transmission system. In the first six months of 2014, our transmission work program costs increased mainly due to increased sustainment expenditures, such as increased forestry expenditures related to brush control and line clearing on our transmission rights-of-way, a higher volume of corrective and preventive maintenance on power equipment, increased expenditures within our environmental management programs, and higher transmission site facilities maintenance requirements.

Distribution

Our distribution operation, maintenance and administration costs increased by $44 million, or 26%, in the second quarter of 2014, and by $78 million, or 25%, in the first six months of 2014, compared to the same periods in 2013. Our work program expenditures increased in the second quarter and in the first six months of 2014, compared to the same periods in 2013, mainly resulting from increased aging of accounts receivable as a result of a combination of the impact of cold winter weather on customer bills based on increased electricity consumption and prices, as well as our customer service recovery initiatives. The increases were also due to higher vegetation management expenditures for our line clearing program as a result of work expedited and brought forward in the second quarter, and higher line clearing costs related to higher tree densities. The increases in our work program expenditures were partially offset by decreased expenditures in support of our distribution system in the second quarter and in the first six months of 2014, compared to the same periods in 2013, primarily due to the CIS having been placed in service in May 2013.

Depreciation and Amortization

Our depreciation and amortization costs increased by $21 million, or 13%, in the second quarter of 2014, and by $27 million, or 8%, in the first six months of 2014, compared to the same periods in 2013. These increases were primarily attributable to higher property, plant and equipment depreciation expense in 2014, mainly related to the growth in capital assets as we continue to place new assets in service, consistent with our ongoing capital work program, as well as higher asset removal costs in 2014.

Financing Charges

Our financing charges increased by $6 million, or 7%, in the second quarter of 2014, and by $8 million, or 5%, in the first six months of 2014, compared to the same periods in 2013. Higher financing charges in 2014 primarily resulted from an increase in interest expense on our long-term debt due to a higher average level of debt, partially offset by a lower average interest rate.

Provision for Payments in Lieu of Corporate Income Taxes

The provision for payments in lieu of corporate income taxes (PILs) increased by $6 million, or 55%, in the second quarter of 2014, and by $5 million, or 11%, in the first six months of 2014, compared to the same periods in 2013. The increases are due to changes in temporary differences, such as capital cost allowance in excess of depreciation and amortization. The increases were partially offset by lower levels of pre-tax income in 2014, compared to the same periods in 2013.

Net Income

Our net income of $115 million for the second quarter and $355 million for the first six months of 2014 was lower by $53 million, or 32%, in the second quarter, and by $70 million, or 16%, in the first six months of 2014, compared to the same periods in 2013. The reductions in net income were primarily due to higher operation, maintenance and administration costs resulting from increased aging of accounts receivable as a result of a combination of the impact of cold winter weather on customer bills based on increased electricity consumption and prices, as well as our customer service recovery initiatives. The decrease in our net income for the first six months of 2014 was also due to a non-recurring reduction in operation, maintenance and administration costs in the first six months of 2013, due to a reduction to our provision for payments in lieu of property taxes related to transmission stations for the years 1999 to 2012. The increases in operation, maintenance and administration costs were partially offset by higher revenues, primarily due to new OEB-approved 2014 transmission rates and higher distribution energy consumption.

SELECTED QUARTERLY RESULTS

The following table sets forth unaudited quarterly information for each of the eight quarters, from the quarter ended September 30, 2012 through June 30, 2014. This information has been derived from our Consolidated Financial Statements and our annual audited 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 Canadian dollars)	**2014**		**2013**				**2012**	
Quarter ended	**Jun. 30**	**Mar. 31**	**Dec. 31**	**Sept. 30**	**Jun. 30**	**Mar. 31**	**Dec. 31**	**Sept. 30**
Total revenue	1,566	1,764	1,557	1,542	1,403	1,572	1,435	1,466
Net income	115	240	160	218	168	257	165	201
Net income to common shareholder	110	236	155	214	163	253	160	197

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

	Three months ended June 30		**Six months ended June 30**	
(millions of Canadian dollars)	**2014**	**2013**	**2014**	**2013**
Operating activities	185	325	334	486
Financing activities				
Long-term debt issued	453	–	628	–
Short-term notes payable	–	44		118
Dividends paid	(30)	(30)	(229)	(159)
Investing activities				
Capital expenditures	(367)	(337)	(659)	(619)
Other financing and investing activities	17	(11)	–	(21)
Net change in cash and cash equivalents	258	(9)	74	(195)

Operating Activities

Net cash from operating activities decreased by $140 million, to $185 million, in the second quarter of 2014, and by $152 million, to $334 million, in the first six months of 2014, compared to the same periods in 2013. The decreases in 2014 are primarily due to lower net income, changes in accrual balances mainly related to timing of capital projects, and changes in regulatory accounts, partially offset by timing of PILs paid to the Ontario Electricity Financial Corporation (OEFC). The first quarter decrease was also partially offset by changes in accounts receivable balances resulting from lower revenues in the second quarter of 2014 as compared to the first quarter of 2014.

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 our holding of Province of Ontario Floating-Rate Notes.

Our Commercial Paper Program is supported by our $1,500 million committed revolving credit facility with a syndicate of banks, which matures in June 2019. In addition, our investment in Province of Ontario Floating-Rate Notes of $250 million (with a fair value of $250 million at June 30, 2014) maturing on November 19, 2014 also provides temporary liquidity. The short-term liquidity under this program and anticipated levels of funds from operations should be sufficient to fund our normal operating requirements.

At June 30, 2014, we had $9,673 million in long-term debt outstanding, including the current portion. Our notes and debentures mature between 2014 and 2064. 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 June 30, 2014, $1,187 million remained available until October 2015.

We rely on debt financing through our MTN Program and our Commercial Paper Program to repay our existing indebtedness and fund a portion of our capital expenditures. The credit ratings assigned to our debt securities by external rating agencies are important to our ability to raise capital and funding to support our business operations. Maintaining strong credit ratings allows us to access capital markets on competitive terms. A material downgrade of our credit ratings would likely increase our cost of funding significantly, and our ability to access funding and capital through the capital markets could be reduced. Our corporate credit ratings from approved rating organizations are as follows:

	Rating	
Rating Agency	**Short-term Debt**	**Long-term Debt**
DBRS Limited	R-1 (middle)	A (high)
Moody's Investors Service Inc.	Prime-1	A1
Standard & Poor's Rating Services Inc.	A-1	A+

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 cannot exceed 10% of the total book value of our assets. We were in compliance with all these covenants and limitations as at June 30, 2014.

During the first and second quarters of 2014, we issued $175 million and $453 million of long-term debt, respectively, under our MTN Program, for a total of $628 million of long-term debt issued in the first six months of 2014, compared to no new long-term debt issued in the first six months of 2013. No long-term debt matured or was repaid during the first six months of 2014 or 2013. We had no short-term notes outstanding at June 30, 2014 or December 31, 2013.

Common share 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 share dividends pertaining to our quarterly financial results are generally declared and paid in the following quarter.

During the second quarter of 2014, we paid dividends to the Province in the amount of $30 million, consisting of $25 million in common share dividends and $5 million in preferred share dividends, compared to dividends of $30 million, consisting of $25 million of common share dividends and $5 million of preferred share dividends paid to the Province in the second quarter of 2013.

During the first six months of 2014, we paid dividends to the Province in the amount of $229 million, consisting of $220 million in common share dividends and $9 million in preferred share dividends, compared to dividends of $159 million, consisting of $150 million of common share dividends and $9 million of preferred share dividends, paid to the Province in the first six months of 2013.

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

Capital investments consist of cash capital expenditures and related accruals. Capital investments primarily relate to enhancing and reinforcing of our transmission and distribution infrastructure.

	Three months ended June 30				Six months ended June 30			
(millions of Canadian dollars)	**2014**	**2013**	**$ Change**	**% Change**	**2014**	**2013**	**$ Change**	**% Change**
Transmission	203	157	46	29	376	306	70	23
Distribution	175	192	(17)	(9)	298	312	(14)	(4)
Other	2	2	–	–	2	3	(1)	(33)
	380	351	29	8	676	621	55	9

Transmission

Our transmission capital investments increased by $46 million, or 29%, to $203 million in the second quarter of 2014, and by $70 million, or 23%, to $376 million in the first six months of 2014, compared to the same periods in 2013, primarily due to sustainment programs to address our aging infrastructure. Our capital investments to sustain our existing transmission system were $167 million in the second quarter, and $290 million in the first six months of 2014, representing increases of $63 million and $83 million, respectively, compared to the same periods in 2013. In 2014, we made significant station and lines investments in order to improve reliability. We accomplished several replacements of end-of-life power transformers, increased work within our station and lines refurbishment projects and programs, including a project to address the condition of the conductors on the 170 km 230 kV circuit from the Chats Falls Switching Station to the Havelock Transmission Station, and experienced increased expenditures related to addressing aging protection and control equipment. We also continued work on replacing end-of-life underground transmission cables between our Strachan Transmission Station and Riverside Junction, in order to maintain a reliable supply of electricity to downtown Toronto.

Our capital investments to expand and reinforce our transmission system were $26 million in the second quarter, and $64 million in the first six months of 2014, representing decreases of $17 million and $19 million, respectively, compared to the same periods in 2013. We experienced reduced expenditures related to some of our major projects, including the Advanced Distribution System (ADS) Project, reduced transmission system upgrades to incorporate renewable energy into our transmission system, and decreases in some of our inter-area network projects. During the first six months of 2014, we continued to invest in local area supply projects to address growing loads and in inter-area network projects to support the Province's supply mix objectives for generation. Our local area supply project investments include our Toronto Midtown Transmission Reinforcement Project, which will provide additional supply capability to meet future load growth in midtown Toronto as well as areas to the west, and our Guelph Area Transmission Refurbishment Project to reinforce electricity supply to the Kitchener-Waterloo-Cambridge-Guelph area and minimize the impact of any major transmission outages on area customers. Inter-area network projects include our Lambton to Longwood Transmission Upgrade Project to increase transmission capability between our Lambton (Sarnia) and Longwood (London) transformer stations. This project is needed to satisfy government policy relating to the incorporation of 10,700 MW of non-hydroelectric renewable generation resources by 2021. We have also begun work on our new Clarington Transmission Station Project to install additional auto-transformer capacity in the Oshawa area to address supply reliability issues relating to the eventual closure of the Pickering generating station. These investments will maintain and improve power reliability for electricity customers throughout the province, including our residential and industrial consumers.

Our other transmission capital investments were $10 million in the second quarter, and $22 million in the first six months of 2014, representing no increase in the second quarter and an increase of $6 million in the first six months of 2014, compared to the same periods in 2013. The increase was mainly due to the development phase investment in our Network Management System Project, a critical operating tool used for monitoring and control of our transmission system.

Distribution

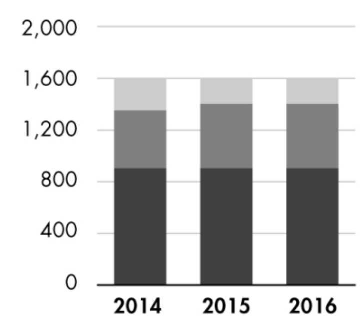
Our distribution capital investments decreased by $17 million, or 9%, to $175 million in the second quarter of 2014, and by $14 million, or 4%, to $298 million in the first six months of 2014, compared to the same periods in 2013. Our capital investments to sustain our distribution network were $96 million in the second quarter, and $154 million in the first six months of 2014, representing increases of $15 million and $22 million, respectively, compared to the same periods in 2013. The increases were primarily due to meter replacements, increased work within our Station Refurbishment Program, and the replacement of end-of-life wood poles, partially offset by lower storm restoration work in 2014.

Our capital investments to expand and reinforce our distribution network were $60 million in the second quarter, and $109 million in the first six months of 2014, representing decreases of $11 million and $5 million, respectively, compared to the same periods in 2013. The decreases were mainly due to lower lines and stations work related to upgrading and adding capacity to our distribution system, partially offset by the timing of capital contributions for new customer connections and upgrades. In the first six months of 2014, the decrease was also offset by the continued work on the ADS Project and the Smart Metering Project to tune and collect data for TOU meters, and the timing of customer driven work related to generation connections.

Our other distribution capital investments were $19 million in the second quarter, and $35 million in the first six months of 2014, representing decreases of $21 million and $31 million, respectively, compared to the same periods in 2013. The decreases were primarily due to the CIS phase of our entity-wide information system replacement and improvement project, which was placed into service in May 2013.

Future Capital Investments

Our capital investments for 2014 are budgeted at approximately $1,600 million. Our 2014 capital budgets for our Transmission and Distribution Businesses are approximately $950 million and $650 million, respectively. Consolidated capital investments are expected to be approximately $1,600 million in each of 2015 and 2016. These investment levels reflect the sustainment requirements of our aging infrastructure. Our sustainment program capital investments are expected to be approximately $900 million in each of 2014, 2015, and 2016. Our development capital investments are expected to be approximately $450 million in 2014, $500 million in 2015, and $500 million in 2016. Our development projects include the inter-area network upgrades that reflect supply mix policies, local area supply improvements, the ADS Project, new load and generation connections and requirements to enable Distributed Generation (DG), and customer demand work. Other capital investments are expected to be $250 million in 2014, $200 million in 2015, and $200 million in 2016. This includes investments in operating infrastructure integration, information technology (IT), fleet services and facilities, and real estate. Our future capital investments amounts do not include future local distribution companies (LDC) acquisitions.



Future Capital Investments
(millions of Canadian dollars)

Transmission

Transmission capital investments are incurred 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 sustainment program future capital investments include the replacement of end-of-life air blast circuit breakers and switchgear, high-voltage underground cables, and power transformers. These investments are necessary to ensure that we maintain our current levels of supply to our customers and continue to meet all regulatory, compliance, safety and environmental objectives.

Our future development capital investments include the Clarington Transmission Station Project to install additional auto-transformer capacity in the eastern Greater Toronto Area; the Guelph Area Transmission Refurbishment Project, an upgrade of a transmission line and transmission stations in south-central Guelph; the Lambton to Longwood Transmission Upgrade, a double circuit transmission line project that will enable renewable generation in the west of London area; investments in ADS; requirements to enable DG; the Supply to Essex County Transmission Reinforcement Project, a new transmission line in the Windsor-Essex region; and up to four other transmission station upgrades, which when combined with the new Hearn Switching Station, will collectively enable up to 600 MW of new generation capacity in the Niagara, Toronto and Ottawa areas.

Based on the OEB's framework for competitive designation for the development of eligible transmission projects, we did not include in our budgeted future capital investments any projects that could meet the definition of expansions. We do not plan to undertake large capital investments without a reasonable expectation of recovering them through our rates.

The actual timing and investments of many development projects are uncertain as they are dependent upon various regulatory approvals, negotiations with customers, neighbouring utilities and other stakeholders, and consultations with First Nations and Métis communities. Projects are also dependent upon the timing and level of generator contributions for enabling facilities.

Distribution

Distribution capital investments include the sustainment of our infrastructure. Our core work will continue to focus on maintaining the performance of our aging distribution asset base through renewal and refurbishment activities. Planned capital investments include the continued replacements of equipment and components that are beyond their expected service life, as well as increased wood pole replacements and distribution station refurbishments. Sustainment capital investments related to the Smart Metering project will decrease through 2016.

Distribution development capital investments are expected to be relatively stable through 2016, with the exception of capital contributions for capacity improvements at the Orleans Transmission Station on the Ottawa area in 2015 and the Hanmer Transmission Station in the Sudbury area in 2016. We will continue to make investments required to connect new load and DG customers, as well as investments to ensure the system is capable of supplying customer needs. During 2014 to 2016, a number of our projects will address local load growth issues. Generation connection investments will decrease as the volume of connections is expected to decrease. The budgeted capital expenditures only reflect projects with Feed-in Tariff (FIT) and Micro FIT Program contracts from the Ontario Power Authority (OPA) that are expected to connect to our distribution system.

In 2014 and 2015, the ADS Project will continue to pilot various technologies and related capital investments will begin to decrease in 2016. Pilot technologies include improvements to outage response management through more effective resource dispatch, automation to isolate faults where needed, and the dynamic regulation of voltage to reduce losses.

Off-Balance Sheet Arrangements

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.

Summary of Contractual Obligations and Other Commercial Commitments

The following table presents a summary of our debt and other major contractual obligations, as well as other major commercial commitments:

June 30, 2014 *(millions of Canadian dollars)*	**Total**	**2014[1]**	**2015/2016**	**2017/2018**	**After 2018**
Contractual obligations *(due by year)*					
Long-term debt – principal repayments[2]	9,673	750	1,050	1,350	6,523
Long-term debt – interest payments[2]	8,072	221	811	732	6,308
Pension[3]	361	–	349	12	–
Environmental and asset retirement obligations[4]	298	20	63	45	170
Inergi LP (Inergi) outsourcing agreement[5]	85	64	21	–	–
Operating lease commitments	43	5	14	15	9
Total contractual obligations	18,532	1,060	2,308	2,154	13,010
Other commercial commitments *(by year of expiry)*					
Bank line[6]	1,500	–	–	–	1,500
Letters of credit[7]	129	127	2	–	–
Guarantees[7]	326	326	–	–	–
Total other commercial commitments	1,955	453	2	–	1,500

[1] The amounts disclosed represent the amounts due over the period from July 1, 2014 to December 31, 2014.

[2] The "long-term debt – principal repayments" amounts 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 the long-term debt is recorded in financing charges on our Consolidated Statements of Operations and Comprehensive Income or as a cost of our capital programs.

[3] Contributions to the Hydro One Pension Fund were generally made one month in arrears. However, due to the interest rate environment, the annual contributions have been prepaid in each of the last two years. The 2014, 2015 and 2016 minimum pension contributions are based on an actuarial valuation as at December 31, 2013. Pension contributions totalling $174 million were made during the six months ended June 30, 2014. Minimum pension contributions beyond 2016 will be based on an actuarial valuation effective no later than December 31, 2016, and will depend on future investment returns, changes in benefits, or actuarial assumptions. Pension contributions beyond 2016 are not estimable at this time.

[4] We record a liability for the estimated future expenditures associated with the removal and destruction of polychlorinated biphenyl (PCB)-contaminated insulating oils and related electrical equipment, and for the assessment and remediation of chemically-contaminated lands. We also record a liability for asset retirement obligations associated with the removal and disposal of asbestos-containing materials installed in some of our facilities, as well as the future decommissioning and removal of two of our switching stations. The forecast expenditure pattern reflects our planned work programs for the periods.

[5] In 2002, Inergi began providing services to our company, including business processing and IT outsourcing services. The current agreement with Inergi will expire in February 2015. We have begun developing a plan of action for end-of-term and issued a request for proposal in November 2013. Based on the September 2013 Shareholder Resolution, the new agreement regarding these outsourcing services will be subject to the Shareholder Resolution whereby the Province requires us to contract only with parties who are employed and physically located in Ontario when providing services to our company. The amounts disclosed include an estimated contractual annual inflation adjustment in the range of 1.5% to 4.0%. Payments in respect of our agreement with Inergi are recorded in operation, maintenance and administration costs on our Consolidated Statements of Operations and Comprehensive Income or as a cost of our capital programs.

[6] In support of our liquidity requirements, we have a $1,500 million revolving standby credit facility with a syndicate of banks. On June 1, 2014, we extended the maturity date of the revolving standby credit facility from June 2018 to June 2019.

[7] We currently have outstanding bank letters of credit of $127 million relating to retirement compensation arrangements. We provide prudential support to the IESO in the form of letters of credit, the amount of which is calculated based on forecasted monthly power consumption. At June 30, 2014, we have provided letters of credit to the IESO in the amount of $2 million to meet our current prudential requirement. 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 $325 million, and on behalf of two distributors using total guarantees of $1 million.

RELATED PARTY TRANSACTIONS

We are owned by the Province. The OEFC, IESO, OPA, Ontario Power Generation Inc. (OPG), and the OEB are related parties to our company because they are controlled or significantly influenced by the Province. The following is a summary of our related party transactions during the three and six months ended June 30, 2014:

The Province

- During the three and six months ended June 30, 2014, we paid dividends to the Province totalling $30 million and $229 million, respectively, compared to $30 million and $159 million paid in the same periods in 2013.
- At June 30, 2014, our company held $250 million of Province of Ontario Floating-Rate Notes, with a fair market value of $250 million. This investment was purchased in January 2010 and matures on November 19, 2014.

OEFC

- During the three and six months ended June 30, 2014, we made payments in lieu of corporate income taxes to the OEFC totalling $21 million and $43 million, respectively, compared to payments of $31 million and $76 million made in the same periods in 2013.
- During the first six months of 2014, our company paid a $5 million annual fee to the OEFC, compared to $5 million paid in the same period in 2013, for indemnification against adverse claims in excess of $10 million paid by the OEFC with respect to certain of Ontario Hydro's businesses transferred to Hydro One on April 1, 1999.
- During the three and six months ended June 30, 2014, we purchased power in the amount of $2 million and $7 million, respectively, from power contracts administered by the OEFC, compared to $3 million and $5 million purchased in the same periods in 2013.

IESO

- During the three and six months ended June 30, 2014, we purchased power in the amount of $568 million and $1,343 million, respectively, from the IESO-administered electricity market, compared to $538 million and $1,244 million purchased in the same periods in 2013.
- We receive revenues for transmission services from the IESO, based on OEB-approved uniform transmission rates. Our transmission revenues for the three and six months ended June 30, 2014 include $368 million and $776 million, respectively, related to these services, compared to $363 million and $731 million in the same periods in 2013.
- We receive amounts for rural rate protection from the IESO. Our distribution revenues for the three and six months ended June 30, 2014 include $32 million and $64 million, respectively, related to this program, compared to $31 million and $63 million in the same periods in 2013.
- We receive revenues related to the supply of electricity to remote northern communities from the IESO. Our distribution revenues for the three and six months ended June 30, 2014 include $8 million and $16 million, respectively, related to these services, compared to $7 million and $14 million in the same periods in 2013.

OPG

- During the three and six months ended June 30, 2014, we purchased power in the amount of $4 million and $18 million, respectively, from the OPG, compared to $4 million and $9 million purchased in the same periods in 2013.
- Our company has service level agreements with OPG. These services include field, engineering, logistics and telecommunications services. Our other revenues for the three and six months ended June 30, 2014 include $3 million and $6 million, respectively, related to these service level agreements, compared to $3 million and $5 million in the same periods in 2013. Our operation, maintenance and administration costs for the three months ended June 30, 2014 and 2013 were insignificant, and $1 million for the six months ended June 30, 2014 and 2013.

OPA

- The OPA funds substantially all of our conservation and demand management programs. The funding includes program costs, incentives, and management fees. During the three and six months ended June 30, 2014, we received

$14 million and $21 million, respectively, from the OPA related to these programs, compared to $8 million and $15 million received in the same periods in 2013.

OEB

- 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. During the three and six months ended June 30, 2014, we incurred $3 million and $6 million, respectively, in OEB fees, compared to $3 million and $6 million incurred in the same periods in 2013.

At June 30, 2014, the amounts due from and to related parties as a result of the transactions referred to above were $206 million and $78 million, respectively, compared to $197 million and $230 million at December 31, 2013, respectively. At June 30, 2014, included in amounts due to related parties were amounts owing to the IESO in respect of power purchases of $67 million, compared to $217 million at December 31, 2013.

CONSIDERATIONS OF CURRENT ECONOMIC CONDITIONS

Pension Plan

During the first six months of 2014, we contributed approximately $174 million to our pension plan, compared to contributions of approximately $160 million made during the same period in 2013. We incurred $79 million in net periodic pension benefit costs, compared to $146 million incurred during the first six months of 2013. We currently estimate our total annual pension contributions to be approximately $174 million, $174 million and $175 million for 2014, 2015, and 2016, respectively, based on an actuarial valuation as at December 31, 2013 and projected levels of pensionable earnings. Actuarial valuations are required to be filed at least every three years. Future minimum contributions beyond 2016 will be based on an actuarial valuation effective no later than December 31, 2016. Our pension plan experienced positive returns of approximately 6.64% in the six months ended June 30, 2014, which is comparable to approximately 6.57% in the six months ended June 30, 2013.

DISCLOSURE CONTROLS AND INTERNAL CONTROLS OVER FINANCIAL REPORTING

Internal controls have been documented and tested for adequacy and effectiveness, and continue to be refined over all business processes, with emphasis on the implementation of the CIS module in SAP.

In compliance with the requirements of National Instrument 52-109, our Certifying Officers have reviewed and certified the Consolidated Financial Statements for the period ended June 30, 2014, together with other financial information included in our quarterly securities filings. Our Certifying Officers have also certified that disclosure controls and procedures have been designed to provide reasonable assurance that material information relating to our company is made known within our company. Further, our Certifying Officers have also certified that internal controls over financial reporting have been designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the Consolidated Financial Statements. There have been no changes in our internal controls over financial reporting during the first six months of 2014 that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

RECENT DEVELOPMENTS

LDC Acquisitions

Norfolk Power Acquisition

On April 2, 2013, we reached an agreement with The Corporation of Norfolk County to acquire the outstanding shares of Norfolk Power Inc. (Norfolk Power), pending a regulatory decision from the OEB. Norfolk Power is a holding company that owns Norfolk Power Distribution Inc. (NPDI), a local electricity distribution company, and Norfolk Energy Inc., a non-rate regulated energy services company, located in southwestern Ontario. The purchase price for Norfolk Power is approximately

$93 million, subject to final closing adjustments. Hydro One will pay Norfolk County approximately $66 million net after assuming Norfolk Power's existing debt of approximately $27 million, subject to final closing adjustments. The selection of our company as successful bidder followed a comprehensive competitive sales process initiated by Norfolk Power.

On July 3, 2014, the OEB issued its Decision and Order for our company to acquire all of the issued and outstanding common shares of Norfolk Power within 18 months from the date of this Decision and Order. In addition, among other items, the OEB's Decision and Order approved NPDI to transfer its distribution system to Hydro One Networks within 18 months from the date of this Decision and Order, and ordered that NPDI file with the OEB a draft Rate Order that includes a proposed Tariff of Rates and Changes reflecting the OEB's approval of a 1% reduction relative to NPDI's 2012 base electricity delivery rates. Once the NPDI distribution system transfer is completed, the OEB will transfer NPDI's electricity distribution licence and NDPI's Rate Order to Hydro One Networks.

The acquisition transaction is anticipated to be completed in the third quarter of 2014. Based on the timing of the completion of this acquisition transaction in relation to the date of issuance of the Consolidated Financial Statements and MD&A, the final closing adjustments to the purchase price of $93 million and the initial allocation of the consideration paid have not yet been completed.

Woodstock Hydro Purchase Agreement

On May 21, 2014, we reached an agreement with the City of Woodstock to acquire 100% of the common shares of Woodstock Hydro Holdings Inc. (Woodstock Hydro) for approximately $29 million, subject to final closing adjustments. Woodstock Hydro is an urban electricity distribution company located in southwestern Ontario. The transaction is the result of extensive discussions between Hydro One and the City of Woodstock looking at economic development opportunities and other benefits resulting from the sale of Woodstock Hydro. The acquisition is pending a regulatory decision from the OEB and is anticipated to be completed in 2015.

Haldimand Hydro Purchase Agreement

On June 10, 2014, we reached an agreement with the Haldimand County to acquire 100% of the common shares of Haldimand County Utilities Inc. (Haldimand Hydro) for approximately $65 million, subject to final closing adjustments. Haldimand Hydro is the largest electricity distribution and telecom company located in southwestern Ontario. The transaction is the result of extensive discussions between Hydro One and Haldimand County. The acquisition is pending a regulatory decision from the OEB and is anticipated to be completed in 2015.

Electricity Rates

Hydro One Brampton Networks

On April 23, 2014, Hydro One Brampton Networks filed a cost-of-service application with the OEB for 2015 distribution rates, to be effective January 1, 2015, seeking the approval of revenue requirement of approximately $74 million for 2015. In its application, Hydro One Brampton Networks also requested OEB approval for retail transmission service rates and the approval of rate riders to dispose of certain deferral and variance accounts. If the application is approved as filed, the resulting change to the distribution portion of the average customer bill will be an increase of approximately 5.6% in 2015, for a typical residential customer consuming 800 kWh per month. When considering total bill impact, the resulting change will be an increase of approximately 1.8% in 2015.

Hydro One Remote Communities

In October 2013, Hydro One Remote Communities filed an Incentive Regulation Mechanism (IRM) application with the OEB for 2014 distribution, seeking approval for a rate increase of approximately 0.48%. On March 13, 2014, the OEB approved an increase of approximately 1.7% to basic rates for the distribution and generation of electricity, with an effective date of May 1, 2014. The final rate increase was adjusted by the OEB's updated rate adjustment parameters and Hydro One Remote Communities' IRM stretch factor.

Major Projects

Supply to Essex County Transmission Reinforcement Project

On January 22, 2014, Hydro One Networks submitted a Leave to Construct application to the OEB under Section 92 of the *OEB Act* to construct a new 13-kilometre 230 kV double circuit transmission line in the Windsor-Essex region. The new transmission line will connect to a proposed transmission station in the Municipality of Leamington and an existing 230 kV transmission line in the Town of Lakeshore. The new transmission line and transmission station will address future growth in electricity demand and anticipated expansion in the local agricultural sector. They would also improve the reliability of electricity supply in the broader Windsor-Essex region. The planned in-service date for this project is March 2017.

Regulatory Developments

Revenue Decoupling for Distributors

In November 2012, the OEB initiated a project to coordinate revenue decoupling with the new rate-setting policies proposed in the renewed regulatory framework for electricity (RRFE). On April 3, 2014, the OEB released a Draft Report of the Board on Rate Design for Electricity Distributors (Report) to solicit stakeholder comments. The Report presents three proposals to achieve revenue decoupling: (1) a single monthly charge which is the same for all consumers within the rate class; (2) a fixed monthly charge with the size of the charge based on the size of the electrical connection; and (3) a fixed monthly charge where the size of the charge is based on use during peak hours.

Performance Measurement and Continuous Improvement

On March 5, 2014, the OEB issued its *Report of the Board on Performance Measurement for Electricity Distributors: A Scorecard Approach* (Report) under its Renewed Regulatory Framework. The Report sets out the OEB's policies on the measures that will be used by the OEB to assess a distributor's effectiveness and improvement in achieving customer focus, operational effectiveness, public policy responsiveness, and financial performance to the benefit of existing and future customers, as well as the form and implementation of a performance monitoring tool – a Scorecard. The Scorecard is designed to track and show an individual distributor's performance gains over a period of time and at a point in time. Most of the measures included on the Scorecard leverage measures and reporting requirements that are already in place. Five new measures are also included to underscore the OEB's renewed focus on value to customers and effective planning and asset management. These new measures are: First Contact Resolution; Billing Accuracy; Customer Satisfaction Survey Results; Public Safety; and Distribution System Plan Implementation Progress.

On March 7, 2014, the OEB issued amendments to its Reporting and Record Keeping Requirements (RRR). In addition to the Scorecard changes, the amended RRR requires the reporting of: capital additions and capital expenditures; the details on customers whose distribution revenues exceed certain revenue levels; when material loss of load is incurred or expected; and revised reporting on capital.

On July 15, 2014, the OEB issued a Staff Discussion Paper "Electricity Distribution System Reliability Measures and Targets" to establish specific performance targets for the existing system reliability measures, to develop customer specific reliability measures and to address the monitoring of momentary outages.

On July 17, 2014, the OEB issued a billing accuracy scorecard measure for all licensed electricity distributors, as well as a performance target of 98% for the new billing accuracy measure. Tracking of the performance target is effective October 1, 2014, with the first reporting period of October to December 2014 being due on April 30, 2015.

New 2015-2020 Conservation and Demand Management Framework

On March 31, 2014, the Minister of Energy issued a Directive to the OPA, directing the OPA to coordinate, support and fund the delivery of Conservation and Demand Management (CDM) programs through electricity distributors to achieve a total of 7 TWh of reductions in electricity consumption in the period 2015 to 2020. The funding source will be the global adjustment mechanism. The OPA will develop an allocation methodology to allocate the 7 TWh of reductions in electricity consumption among distributors. The OPA will also encourage distributors to aggregate CDM targets with neighbouring distributors to develop 21 regional CDM targets and to work cooperatively to develop regional CDM plans. As a result, consumers in

Ontario could see a 7 TWh reduction in electricity consumption from 2015 to 2020 as these programs are phased in by their LDCs, including Hydro One.

On March 26, 2014, the Minister of Energy issued a Directive to the OEB, directing the OEB to amend the licences of electricity distributors regarding CDM activities for the period 2015 to 2020, to establish CDM requirement guidelines for electricity distributors, and to develop a Demand Side Management (DSM) policy framework for natural gas distributors for the same period. The coordination and integration of CDM and DSM activities is aimed to achieve efficiencies and convenient integrated programs for electricity and natural gas customers.

Regional Plans

In August 2013, the OEB amended the Transmission System Code and Distribution System Code to implement a more formal and structured approach to regional planning in Ontario. The new regional planning approach consists of two main processes: the Regional Infrastructure Planning (RIP) to be led by transmitters, and the Integrated Regional Resource Planning (IRRP) to be led by the OPA. The RIP process focuses mainly on wires planning, both transmission and distribution, and the IRRP process focuses on resources planning (e.g. generation, conservation and demand management) and the integration of resources with the wires planning. The development of regional plans will involve close coordination of the two processes and active participation by the OPA, transmitters, distributors and other applicable agencies such as the IESO.

The regional plans are intended to support investments brought forward in transmitter and distributor rate submissions and transmitter Leave to Construct applications. Regional plans are to be reviewed or developed at least every 5 years. The OEB expects the first cycle of regional plans for all regions in Ontario to be completed in the next 3 to 4 years. For regional planning purposes, the province has been subdivided into 21 regions. Hydro One is the lead transmitter responsible for the RIP process for 19 of the 21 regions. Planning activities are underway and the regional plans are expected to be completed between 2015 and 2017.

Other

Environment Canada Regulations

In June 2013, Environment Canada issued Canada Gazette I, which included proposed amendments to the existing PCB regulations, including the extension of the end-of-use deadline beyond 2014 for equipment containing certain concentrations of PCBs. In April 2014, amendments to the PCB regulations were enacted and published in Canada Gazette II, with an effective date of January 1, 2015. The amendments will, among other things, extend the end-of-use deadline for our company's PCBs in concentrations of 500 parts per million or more from December 31, 2014 to December 31, 2025. We are currently assessing the impact of the PCB regulations amendments on our environmental liabilities and will make the necessary adjustments to our estimated environmental liability balances during the remainder of 2014.

Electricity Sector Pension Plans

On August 1, 2014, a Report on the Sustainability of Electricity Sector Pension Plans (Report) was released by Jim Leech, Special Advisor to the Minister of Finance for Ontario. As part of its fiscal 2013 budget, the Province announced its intention to establish a government-led industry Working Group (Working Group) to address pension issues associated with the single-employer pension plans at Hydro One, OPG, IESO and the Electrical Safety Authority (ESA). This Report is intended to inform and help frame the efforts of the Working Group. The Report noted that it is critically important for any pension plan of public-sector workers to be sustainable so that the retirement income of retirees and active members is secure. Management will continue to monitor the initiatives of this Working Group and potential impacts of any recommendations for Hydro One accordingly.

Advisory Council on Government Assets

On April 11, 2014, the Province announced the appointment of an advisory council on government assets (Council) to recommend ways to improve the efficiency and optimize the full value of Hydro One, OPG, and the Liquor Control Board of Ontario (LCBO). The announcement stated that, as part of its review, the Council will consider various options to generate better returns and revenues to maximize the value of our company, OPG and LCBO to the Province, including such measures as efficient governance, growth strategies, corporate reorganization, mergers, acquisitions, and public-private partnerships. The announcement also stated that the Council will give preference to owning rather than selling core assets. Our company welcomes the work of the Council and will fully participate in the process.

Changes to our Board of Directors

On March 7, 2014, our Shareholder, the Minister of Energy, on behalf of the Government of Ontario, announced that Sandra Pupatello would be appointed Chair of our Board of Directors, effective April 1, 2014, and on April 1, 2014, the Shareholder formally elected Ms. Pupatello as our new Chair. Ms. Pupatello is the Director of Business Development and Global Markets at PricewaterhouseCoopers Canada. She is also the Chief Executive Officer of the WindsorEssex Economic Development Corporation. Ms. Pupatello has been a member of our Board of Directors since November 2013.

On April 11, 2014, the following new members were added to our Board of Directors: William Limbrick, Tom Moss, and John Wiersma. William Limbrick was the Vice President of Information and Technology Services, Chief Information Officer of the IESO, and a Principal Consultant within the utilities practice of PricewaterhouseCoopers and Sun Life Assurance in the United Kingdom. Tom Moss is the former President and Chief Operating Officer of Telecom Ottawa, and has held strategic policy positions in the federal government at Treasury Board and Industry Canada. John Wiersma, P. Eng., is a former director of the ESA (Ontario) and IESO Board of Directors, and a former member of the Board of the Electrical and Utilities Safety Association and the Canadian Energy Efficiency Alliance.

On April 25, 2014, the following new members were added to our Board of Directors: Sally Daub, Maureen Sabia, and Carole Workman. Sally Daub is the President and Chief Executive Officer of ViXS Systems, a former chair of the Small Business Agency of Ontario, and a former board member of the Information Technology Association of Canada and the Global Semiconductor Association. Maureen Sabia is the Chair of the Board of Canadian Tire Corporation Limited, and has an extensive background with organizations at the provincial and federal levels. She has been named one of Canada's Most Powerful Women and is also an officer of the Order of Canada. Carole Workman is a member of the Board of Allstate Insurance of Canada (Toronto). She also served on the Board of the Ottawa Hospital and its affiliates since 2007, and is a former member of the Board of Hydro Ottawa Holding Inc.

On April 1, 2014, James Arnett resigned from our Board of Directors. Mr. Arnett has been a member and Chair of our Board of Directors since March 2008. The Board of Directors terms for Michael Mueller, Walter Murray, Robert Pace, and Douglas Speers expired on April 11, 2014.

SELECTED FINANCIAL HIGHLIGHTS AND RATIOS

	Three months ended June 30		**Six months ended June 30**	
(millions of Canadian dollars, except earnings per share and ratios)	**2014**	**2013**	**2014**	**2013**
Net income	115	168	355	425
Net cash from operating activities	185	325	334	486
Capital investments	380	351	676	621
Earnings per common share	1,099	1,633	3,456	4,158
Earnings coverage ratio[1]		2.81		2.94
Net assets coverage on long-term debt ratio[2]		1.78		1.82
Total debt to capitalization ratio[3]		56%		55%

[1] The earnings coverage ratio has been presented for the twelve months ended June 30, 2014 and June 30, 2013, and has been calculated as the sum of net income, provision for PILs and financing charges divided by the sum of financing charges, capitalized interest and cumulative preferred dividends.

[2] The net asset coverage on long-term debt ratio has been presented as at June 30, 2014 and December 31, 2013, and has been calculated as total assets minus total liabilities excluding long-term debt (including current portion) divided by long-term debt (including current portion).

[3] Total debt to capitalization ratio has been presented as at June 30, 2014 and December 31, 2013, and has been calculated as total long-term debt divided by total long-term debt plus total shareholder's equity and preferred shares.

NEW ACCOUNTING PRONOUNCEMENTS

Recently Adopted Accounting Pronouncements

In July 2013, the Financial Accounting Standards Board issued Accounting Standards Update (ASU) 2013-11, Income Taxes (Topic 740): Presentation of an Unrecognized Tax Benefit When a Net Operating Loss Carryforward, a Similar Tax Loss, or a Tax Credit Carryforward Exists. This ASU provides guidance on the presentation of unrecognized tax benefits, and was effective for fiscal years, and interim periods within those years, beginning after December 15, 2013. The adoption of this ASU did not have a significant impact on our consolidated financial statements.

Recent Accounting Guidance Not Yet Adopted

In May 2014, the FASB issued ASU 2014-09, Revenue from Contracts with Customers (Topic 606). This ASU provides guidance on revenue recognition that depicts the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods and services. This ASU is required to be applied retrospectively and is effective for fiscal years, and interim periods within those years, beginning after December 15, 2016. We are currently assessing the impact of adoption of ASU 2014-09 on our consolidated financial statements.

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: expectations regarding energy-related revenues and profit and their trend; statements about CDM; statements about our strategy, including our strategic objectives; statements regarding the new regional planning process; statements regarding our liquidity and capital resources and operational requirements; statements about our revolving credit facility; statements regarding our financing activities, including expectations related to our credit ratings; 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 (including productivity savings, process improvements, and customer satisfaction/impact) and their completion dates; expectations regarding the recoverability of large capital investments; statements regarding expected future capital and development investments, the timing of these expenditures and our investment plans; statements regarding contractual obligations and other commercial commitments; statements related to the OEB, including statements about the Report and Scorecard; statements regarding future pension contributions, our pension plan and actuarial valuation; statements about our outsourcing arrangement with Inergi and such future outsourcing arrangements; statements related to internal controls; statements regarding recent accounting-related guidance; expectations regarding costs of compliance with environmental regulations; statements related to the Council; statements related to the Working Group on electricity sector pension plans; and statements related to our acquisition of Norfolk Power, Woodstock Hydro, and Haldimand Hydro. 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 the required approvals; no unforeseen changes in rate orders or rate structures for our distribution and transmission businesses; continued use of US GAAP; a stable regulatory environment; the PCB regulations in effect as of June 30, 2014; 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 risk that unexpected capital investments may be needed to support renewable generation or resolve unforeseen technical issues;
- the risk that previously granted regulatory approvals may be subsequently challenged, appealed or overturned;
- the impact of the Province's Long-Term Energy Plan on our company and the costs and expenses arising therefrom;
- the risk that future environmental expenditures are not recoverable in future electricity rates;
- the risk that the presence of release of hazardous or harmful substances could lead to claims by third parties and/or governmental orders;
- the risk that assumptions that form the basis of our recorded environmental liabilities and related regulatory assets may change;
- the risks associated with information system security, with maintaining a complex IT system infrastructure, and with transitioning most of our financial and business processes to an integrated business and financial reporting system;
- 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, including regulatory decisions regarding our revenue requirements, cost recovery, rates, acquisitions and divestitures;
- 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 investments 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 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, changes in benefits and changes in actuarial assumptions;
- 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 Reserves (as defined in the *Indian Act* (Canada));
- 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 or expires before a new service provider is selected; 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 the 2013 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 potential future investments, is provided in order to give context to the nature of some of our future plans and may not be appropriate for other purposes.

Additional information about the Company, including the Company's Annual Information Form for the year ended December 31, 2013, can be found on SEDAR at www.sedar.com and on the US Securities and Exchange Commission's website at www.sec.gov.

EXHIBIT LIST

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A				**Administration**
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		2		Financial Summary
	4	1		Summary of Hydro One Custom Application Framework
		2		Annual Adjustments
		3		Adjustments Outside of Normal Course of Business
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	5	1		The Voice of the Customer
			Att.1	Results of the Transactional Satisfaction Surveys
			Att.2	Results of the Large Distribution and Commercial Customer Surveys
	6	1		Summary of Distribution Business
	7	1		Distribution System Plan
			App.A	OPA Letter of Comment on HONI Distribution System Plan
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	9	1		Compliance with OEB Filing Requirements for Electricity Distributors
	10	1		Service Area Map
			Att.1	Service Area Map