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Oded Hubert
Vice President
Regulatory Affairs

BY COURIER

March 31, 2017

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

Dear Ms. Walli,

EB-2017-0049 – Hydro One Networks Inc.'s 2018-2022 Distribution Custom IR Application and Evidence Filing

Hydro One Networks Inc.'s ("Hydro One") five-year Distribution Custom IR Application for the period 2018-2022 and prefiled evidence in support of the Application has been submitted using the Ontario Energy Board's ("OEB") Regulatory Electronic Submission System. The Application includes Hydro One's distribution business plan and rate information needed to support the issuance of notice by the Ontario Energy Board.

Hydro One intends to post electronic copies of the Application and supporting evidence on its website for public access. A text-searchable Adobe Acrobat electronic version and two paper copies of the Application will be sent to the OEB shortly. In addition, Hydro One will make a copy of the Application and supporting evidence available for public access at the following Hydro One offices:

- Head Office, 7th Floor, South Tower, 483 Bay Street, Toronto, Ontario;
- Barrie Field Business Centre, 45 Sarjeant Drive, Barrie, Ontario;
- Peterborough Field Business Centre, 913 Crawford Drive, Peterborough, Ontario;
- Sudbury Field Business Centre, 957 Falconbridge Road, Sudbury, Ontario;
- Merivale Service Centre, 31 Woodfield Drive, Ottawa, Ontario;
- Dundas Field Business Centre, 40 Olympic Drive, Dundas, Ontario;

- Beachville Field Business Centre, 56 Embro Street, Beachville, Ontario; and
- Thunder Bay Field Business Centre, 255 Burwood Road, Thunder Bay, Ontario.

Hydro One's points of contact for service of documents associated with the Application are listed in Exhibit A, Tab 2 Schedule 1.

Sincerely,

ORIGINAL SIGNED BY ODED HUBERT

Oded Hubert

Encls.

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<u>ONTARIO ENERGY BOARD</u>

IN THE MATTER OF *the Ontario Energy Board Act, 1998,* s. 78;

AND IN THE MATTER OF an Application by Hydro One Networks Inc. for an order approving just and reasonable rates and other charges for electricity distribution to be effective January 1, 2018 to December 31, 2022.

<u>APPLICATION</u>

<u>THE APPLICANT AND THE ORDERS REQUESTED</u>

1. Hydro One Networks Inc. (referred to in this application as the “Applicant” or “Hydro One”), is a corporation incorporated under the *Ontario Business Corporations Act*, (Ontario), and is licensed by the Ontario Energy Board (“OEB”) under licence number ED-2003-0043 to distribute electricity.

2. Hydro One hereby applies to the OEB pursuant to s. 78 of the *Ontario Energy Board Act, 1998* (the “OEB Act”) as amended, for orders approving its proposed:

   a. Electricity distribution rates as identified in the proposed Tariff of Rates and Charges in Exhibit H1, Tab 2, Schedule 2 to be effective January 1, 2018. These rates are calculated to support Hydro One’s 2018 base revenue requirement and incorporate Hydro One’s proposed Retail Transmission Service Charge;

   b. Custom Incentive Regulation Model as a framework to set distribution rates for the period effective January 1, 2019 to December 31, 2022 as described in Exhibit A, Tab 3, Schedule 2 and the related rates, charges and conditions of services;

c. Specific Service Charges described in H1, Tab 2, Schedule 3;

d. Rate Riders as described in Exhibit H1, Tab 3, Schedule 2;

e. Continuation, creation, and disposition of specified regulatory accounts as described in Exhibit F1, Tab 1, Schedule 1;

f. Creation of new customer classes as described in Exhibit G1, Tab 2, Schedule 1; and

g. Other items or amounts that may be requested by the Applicant in the course of this proceeding, and as may be granted by the OEB.

3. This Application is prepared in accordance with the OEB's *Filing Requirements for Electricity Distribution Rate Applications* dated July 14, 2016 and the OEB's *Report on the Renewed Regulatory Framework for Electricity Distributors* dated October 18, 2012.

4. The Application is supported by pre-filed written evidence which may be amended from time to time. For the reasons set out in this Application, Hydro One submits that the proposed distribution rates and other charges are just and reasonable.

FORM OF HEARING REQUESTED

5. The Applicant requests that this Application be heard by way of an oral hearing.

PROPOSED EFFECTIVE DATE

6. The Applicant requests that the OEB's rate orders be effective January 1, 2018. In order to address the possibility that the requested rate orders cannot be made effective by that time,

the Applicant hereby requests an interim Order making the Applicant's current distribution rates and charges effective on an interim basis as of January 1, 2018 and establishing an account to recover any differences between the interim rates and the final rates effective January 1, 2018 based on the OEB's Decision and Order herein.

7. The persons affected by this Application are the distribution ratepayers of Hydro One. It is impractical to set out their names and addresses because they are too numerous.

8. Hydro One requests that a copy of all documents filed with the OEB by each party to this Application be served on the Applicant and the Applicant's counsel as follows:

a) The Applicant:

Erin Henderson
Senior Regulatory Coordinator
Hydro One Networks Inc.

Address:
483 Bay Street
7th Floor, South Tower
Toronto, ON M5G 2P5

Telephone:	(416) 345-5444
Fax:	(416) 345-5866
Electronic access:	Regulatory@HydroOne.com

b) The Applicant's counsel:

Mr. Gordon M. Nettleton
Mr. George Vegh
McCarthy Tétrault LLP
66 Wellington Street West
Suite 5300, P.O. Box 48
Toronto, ON
M5K 1E6

Telephone:	(403) 260-3622
Fax:	(403) 260-3501
Electronic access:	gnettleton@mccarthy.ca gvegh@mccarthy.ca

DATED at Toronto, Ontario, this 31st day of March, 2017.

Hydro One

By its counsel,

Gordon M Nettleton

George Vegh

CERTIFICATION OF EVIDENCE

TO: ONTARIO ENERGY BOARD

The undersigned, being Hydro One's Vice-President of Regulatory Affairs, Oded Hubert hereby certifies for and on behalf of Hydro One that:

1. I am a senior officer of Hydro One;
2. This certificate is given pursuant to the Ontario Energy Board's *Filing Requirements for Electricity Distribution Rate Applications* (last revised on July 14, 2016)*;* and
3. The evidence submitted in support of Hydro One's 2018-2022 distribution application (EB-2017-0049) filed with the OEB is accurate, consistent and complete to the best of my knowledge.

DATED this 31st day of March, 2017.

ODED HUBERT

COMPLYING WITH PAST OEB DECISIONS

Table 1 below lists OEB directions issued to Hydro One in its EB-2013-0416 Decision and the Exhibit references in this Application that respond to them. There are no other outstanding OEB directives or undertakings from prior proceedings that are relevant to this Application.

Table 1

#	**OEB Direction**	**Exhibit Reference**
1	File a total factor productivity study of Hydro One's own productivity, including data from 2002 and following years at a minimum.	Exhibit A, Tab 3, Schedule 2
2	File a compensation study similar to the study Hydro One filed in EB-2013-0416 to allow benchmarking to comparable companies.	Exhibit C1, Tab 2, Schedule 1
3	File a comprehensive trend analysis of the vegetation management program showing year over year comparisons in unit costs.	Exhibit B1, Tab 1, Schedule 1
4	File a best practices study, if undertaken, for vegetation management similar to the CN Utility study filed in EB-2009-0096.	Exhibit B1, Tab 1, Schedule 1
5	File an updated depreciation study.	Exhibit C1, Tab 6, Schedule 1
6	File a consolidated Distribution System Plan, with either an independent third-party review of the Plan if conducted, or an explanation of the decision not to conduct such a review.	Exhibit B1, Tab 1, Schedule 1
7	File annual capital in-service additions, with explanations of any variance from approved levels (as required by the OEB Filing Requirements).	Exhibit D1, Tab 1, Schedule 2
8	File an external benchmarking study on the unit cost of the pole replacement program.	Exhibit B1, Tab 1, Schedule 1
9	File an internal trend analysis to show the variability of the unit costs of the pole replacement program year over year.	Exhibit B1, Tab 1, Schedule 1
10	File an external benchmarking study on the unit cost of the station refurbishment program.	Exhibit B1, Tab 1, Schedule 1
11	File an internal trend analysis to show the variability of the unit costs of the station refurbishment program year over year.	Exhibit B1, Tab 1, Schedule 1

Witness: Oded Hubert

#	**OEB Direction**	**Exhibit Reference**
12	Report on an updated customer classification review.	Exhibit G1, Tab 2, Schedule 1
13	File a study on Hydro One’s miscellaneous service charges, assessing whether the charges reflect underlying costs.	Attachment 1 to Exhibit H1, Tab 2, Schedule 3.

EXECUTIVE SUMMARY

This Exhibit describes the scope of Hydro One's Application and its proposed Custom IR approach to setting Distribution Rates for the period 2018 to 2022. It also provides an overview of Hydro One's Distribution business and explains how Hydro One developed the business plan that underpins this Application, in consideration of customer needs and preferences, the condition of the Distribution System, and resulting bill impacts.

Also included in this Exhibit is a Summary of the Application. The Exhibit addresses the requirements of Sections 2.1.2 and 2.1.5 in Chapter 2 of the Ontario Energy Board's (the "OEB") *Filing Requirements for Electricity Distribution Rate Applications*, issued on July 14, 2016.

1. SCOPE AND KEY CONSIDERATIONS OF THIS APPLICATION

Hydro One Networks Inc. ("Hydro One") is applying for an Order approving its Distribution revenue requirement, cost allocation and rates as determined by its Custom IR approach for the period 2018 to 2022 (in this Exhibit, the "Term") under the assigned docket number EB-2017-0049.

In this Application, Hydro One is requesting the OEB's approval of the following:

- The *rates revenue requirement* of $1,452.1 million for 2018, the underlying calculation of which is provided in Section 5.1 of this Exhibit;
- The *proposed Custom IR rate model* to determine the revenue requirements for each subsequent year of the Term, as described in Section 2 of this Exhibit, and further described in Exhibit A, Tab 3, Schedule 2;
- The OEB's mandatory *scorecard* for electricity distributors (the "Electricity Distributor Scorecard") and the proposed supplemental scorecard (the "Distribution

OEB Scorecard"), as set out in Exhibit A, Tab 5, Schedule 1 and Section 1.4 of Exhibit B1, Tab 1, Schedule 1, respectively;

- The continuation or creation of the various *regulatory accounts* discussed in Section 10 of this Exhibit;
- The *disposition of regulatory accounts* with a forecast net debit balance of $115.3 million effective January 1, 2018, to be collected over a five-year period, at $23.1 million per year;
- The proposed *specific service charges* detailed in Exhibit H1, Tab 2, Schedule 3;
- The creation of *new customer classes* discussed in Section 9 of this Exhibit; and
- *2018 rate schedules,* including terms and conditions of service, effective January 1, 2018, as set out in Exhibit H1, Tab 2, Schedule 1, which incorporate Hydro One Distribution's proposed retail transmission service charge.

The requested 2018 revenue requirement reflects an increase of 3.5% over 2017 OEB-approved levels. The increase is largely attributable to rate base growth including associated increases in depreciation, return on capital and income tax expenses as described in Exhibit E1, Tab 1, Schedule 1. The increase is partially offset by a lower cost of debt and lower OM&A expense. After adjustment for a reduced load forecast (3.0%), the resulting average impact on distribution rates is an increase of 6.5% in 2018, and an average of 3.7% per annum over the Term.

In preparing this Application, Hydro One was acutely aware of the impact on customer rates arising from investments in the electricity system, an impact that is further exacerbated by a reduced load forecast, and of the clear preference of its customers for low electricity costs. As a result, the Application reflects the level of capital investment required to avoid degradation in overall system asset condition, to meet regulatory requirements and maintain current reliability levels. Further, OM&A reflects efficiency improvements and cost reductions to control the extent to which OM&A contributes to the increase in customer rates. The proposed level of 2018 OM&A reflects a small decline from 2017 OEB-approved levels. The planning process followed by Hydro One also resulted in significant reductions in investments in 2018, to mitigate customer rate impacts in that year. As a result, the Application is responsive to Hydro One's customers' needs and preferences.

Investments during the Term include:

- maintenance of the population of poles and distribution stations at materially the same condition level, without significant improvement in overall condition;
- investments in lines sustainment and lifecycle optimization;
- investments to comply with regulatory requirements such as PCB line equipment replacements;
- investment in an Integrated System Operations Centre, which replaces the existing backup power system control and telecommunication centres; and
- later in the term, some investments to begin replacement of smart meters that are reaching end-of-life.

The components of the increased revenue requirement, and their individual contributions, are noted in Table 1 below. These components comprise certain factors that impact 2018 rates, but which were outside of Hydro One's immediate control in developing its 2018-2022 distribution business plan (the "Dx Business Plan"). They include legacy rate base (resulting from necessary prior-year in-service additions), the need to clear regulatory deferral and variance accounts, and planned 2018 in-service additions that are to a large extent non-discretionary (e.g., accommodating the connection of load and generation customers, responding to storms damage and trouble calls, and complying with regulations and other requirements). As a result, to mitigate these effects, Hydro One has planned very few incremental system improvement or end-of-life capital investments in 2018.

Table 1: Impact of Individual Components on Revenue Requirement

Description	**2018 vs. 2017 OEB-approved (M$)**	**2018 vs. 2017 OEB-approved (%)**
OM&A	(1.0)	-0.1
Rate Base Growth	33.2	2.3
Cost of debt	(4.4)	-0.3
Tax	9.3	0.7
External Revenue	0.1	0
Regulatory Deferral and Variance Accounts Disposition	12.0	0.8
Total Change	**49.2**	**3.5**

Exhibit Reference: E1-1-1.

In a formal Customer Engagement that it conducted in the summer of 2016, Hydro One received customer feedback that Hydro One must control costs better and demonstrate greater fiscal management and operational efficiency before considering rate increases. Customers also stated that electricity costs are their primary concern, with system reliability being a second priority.

This Application reflects these views, concerns and customers' needs and preferences regarding rates and reliability. In developing the Dx Business Plan, following the Customer Engagement, Hydro One studied three alternative investment plans, differentiated by varying outcomes, spending profiles, and rate impacts. The plan that informs this Application is a modified version of one of those three original investment plans. It is designed to limit rate impacts while still addressing minimum system needs by focusing investment on deteriorated infrastructure and by managing and controlling costs through investments that maintain reliability, but are insufficient to improve the overall reliability of the aging distribution system.

This Application reflects a reduction in 2018 capital expenditures from OEB-approved 2017 levels, and 2018 OM&A that is slightly lower than the OEB-approved level for 2017. Specifically, Hydro One's capital expenditures are reduced by approximately

4.2%, and OM&A expenditures are lower by approximately 0.2%. This is due to investment pacing decisions and productivity stretch targets that management has adopted. Hydro One has developed several approaches and initiatives to manage costs within its control. This includes greater use of benchmarking studies to inform the Distribution System Plan ("DSP") and to help manage resources and costs incurred throughout the Term. (See Section 1.6 of the DSP for further discussion.) The Application also describes Hydro One's focus on performance management and the measures that the Company is adopting to ensure that targets are met over the Term. A detailed discussion of performance management and measures is found in Section 1.4 of the DSP.

In developing the revenue requirement for the period beyond 2018, Hydro One has adopted the highest stretch factor applicable under the OEB's existing incentive regulation regime. Hydro One did so after reviewing the results of a total cost benchmarking study (completed by Power Systems Engineering Inc.) for the period 2013 to 2015. The study will be refreshed once 2016 audited actuals become available. Based on the results, Hydro One will update its proposed stretch factor, if appropriate.

The estimated increase in the total bill for Hydro One General Service Energy customers consuming 2000 kWh/month is 1.9% in 2018, and the average annual estimated total bill increase over the Term is 1.2%. For Hydro One medium density residential customers consuming 750 kWh/month, the estimated increase is 2.9% in 2018 and the average annual estimated total bill increase over the Term is 1.6%. Bill impacts are addressed in greater detail in Section 11 of this Exhibit.

2. THE CUSTOM IR PROPOSAL

Hydro One's Application is based on a Custom Incentive Rate-Setting approach for a five-year period. The revenue requirement for the first year (2018) is determined using a cost of service, forward test year approach. To establish the annual revenue requirements from 2019 to 2022, Hydro One is proposing a Revenue Cap IR, whereby the revenue for the test year t+1 is equal to the revenue in year t adjusted annually by the revenue cap index (RCI)**.**

The custom RCI is expressed as:

$$RCI = I - X + C$$

Where:

- "I" is the inflation factor, as determined annually by the OEB.
- "X" is the productivity factor that is equal to the sum of Hydro One's Custom Industry Total Factor Productivity measure and Hydro One's Custom Productivity Stretch Factor.
- "C" is Hydro One's Custom Capital Factor, determined to recover the incremental revenue in each test year necessary to support Hydro One's proposed Distribution System Plan, beyond the amount of revenue recovered in rates.

A detailed discussion of these components is found in Exhibit A, Tab 3, Schedule 2.

The proposed Revenue Cap IR model has several advantages over a Price Cap IR model. Specifically, the Revenue Cap IR:

- provides the needed flexibility to introduce new rate classes in 2021 to fully integrate Norfolk Power Distribution Inc., Haldimand County Hydro Inc., and Woodstock Hydro Services Inc. (together the "Acquired Utilities"), as described in Exhibit A, Tab 7, Schedule 1;

- permits the continued transition to fully-fixed rates for residential customers (EB-2014-0416);
- provides adequate flexibility to reset customer rates should the OEB proceed with the elimination of the seasonal rate class over the Term (EB-2013-0416/EB-2016-0315);
- provides adequate flexibility to reset customer rates as the OEB advances its initiative relating to rate design for commercial and industrial electricity customers (EB-2015-0043); and
- allows Hydro One to update its billing determinants and cost of capital parameters in 2021 to reflect estimated changes in the industry and load forecast over the Term, consistent with its proposal to integrate the Acquired Utilities.

A summary of the capital- and OM&A-related revenue requirement components is set out in Table 2.

Table 2: Summary of Revenue Requirement Components ($ Million)

Line		Reference	2018	2019	2020	2021	2022
1	Rate Base	D1-1-1	7,672.3	8,049.1	8,476.8	9,035.4	9,434.7
2	Return on Debt	E1-1-1	190.9	200.3	211.0	224.9	234.8
3	Return on Equity	E1-1-1	269.5	282.7	297.7	317.3	331.3
4	Depreciation	C1-6-2	394.4	414.4	428.7	448.1	464.7
5	Income Taxes	C1-7-2	58.0	61.3	62.6	68.7	69.6
6	Capital Related Revenue Requirement		912.8	958.7	1,000.0	1,059.0	1,100.5
7	Less Productivity Factor (0.60%)			(5.8)	(6.0)	(6.4)	(6.6)
8	**Total Capital Related Revenue Requirement**		**912.8**	**953.0**	**994.0**	**1,052.6**	**1,093.9**
9	OM&A	C1-1-1	591.9	599.6	607.4	615.3	634.2
10	Integration of Acquired Utilities	A-7-1				10.7	
11	**Total Revenue Requirement**		**1,504.7**	**1,552.6**	**1,601.4**	**1,678.7**	**1,728.1**
12	Increase in Capital Related Revenue Requirement			40.2	41.0	58.6	41.3
13	Increase in Capital Related Revenue Requirement as a percentage of Previous Year Total Revenue Requirement			2.67%	2.64%	3.66%	2.46%
14	Less Capital Related Revenue Requirement in I-X			0.79%	0.80%	0.81%	0.82%
15	**Capital Factor**			**1.88%**	**1.84%**	**2.86%**	**1.64%**

Exhibit Reference: A-3-2

To align Hydro One's business interests with those of customers and provide an additional element of protection for customers, Hydro One is also proposing the following features:

- An earnings sharing mechanism that will permit customers to share 50% of any earnings that exceed the regulatory ROE by more than 100 basis points in any year of the Term;
- A capital in-service variance account to track the cumulative difference over the Term between: (a) the revenue requirement associated with actual in-service capital additions during a rate year; and (b) the revenue requirement associated with the OEB-approved forecast for in-service capital additions for that year; for any capital in-service additions that are 98% or lower than the OEB- approved level; and
- Z-factor and off-ramp mechanisms that apply OEB-approved criteria.

Hydro One's proposed custom IR components, therefore, contain both OEB-approved components and other mechanisms that are designed to align the utility's and the customers' interests.

The other rate adjustment during the Term will address the integration of the Acquired Utilities. As outlined in Exhibit A, Tab 7, Schedule 1, Hydro One proposes to integrate the Acquired Utilities effective January 1, 2021. As set out in Exhibit G1, Tab 2, Schedule 1, Hydro One will introduce six new rate classes at that time. The OM&A costs associated with the Acquired Utilities will be incorporated into the revenue requirement for 2021, and the capital costs associated with the Acquired Utilities will also be incorporated into the Custom Capital Factor at that time.

3. OVERVIEW OF THE HYDRO ONE DISTRIBUTION BUSINESS

Hydro One serves approximately 1.3 million distribution customers across a vast service area that is 99% rural and through a system that is largely radial in design. This design is cost-effective for Hydro One's service area, where the average customer density is fewer than three customers per square kilometre, although the lack of redundancy does have reliability impacts on customers. Most of Hydro One's distribution system was built in the 1950s and the 1960s, and many assets are approaching or are beyond their expected service lives, resulting in an ongoing need to replace or refurbish assets at an increasing rate if system reliability and safety are to be maintained. Any material improvement in reliability or system condition requires significantly more investment, which would impact customer bills in a manner inconsistent with the feedback that Hydro One received in its customer engagement process. An overview of Hydro One's distribution system and a detailed discussion of its key components are provided in Sections 2.2 and 2.3 of the DSP in Exhibit B1, Tab 1, Schedule 1.

Hydro One was established in 1999 as a company wholly-owned by the Province of Ontario. In 2015, Hydro One's parent company transitioned from being solely government-owned to being publicly-traded, and a new Board of Directors was appointed to enhance the customer-centric, commercial orientation of the organization. Specifically, management and the new Board of Directors intend to increase Hydro One's focus on customers, create greater corporate accountability for performance outcomes and drive continuous company-wide improvements in efficiency and productivity.

4. DEVELOPMENT OF HYDRO ONE'S DISTRIBUTION BUSINESS PLAN

This Section provides an overview of the development of the Dx Business Plan, which underpins Hydro One's Application and especially the Distribution System Plan, which is set out in Exhibit B1, Tab 1, Schedule 1 of this Application.

The Dx Business Plan reflects Hydro One's core values and business objectives and attempts to align three competing but equally important factors: (i) customer needs and preferences; (ii) responsible stewardship of the distribution system; and (iii) customer bill impacts. The Dx Business Plan has been shaped by: (i) Hydro One's commitment to reduce costs and increase productivity and efficiency before asking customers to pay more; (ii) directing investment to address specifically identified customer needs and preferences; (iii) reducing or deferring investment where trade-offs with respect to reliability can reasonably be justified by lower rates; and (iv) evaluating the resulting rates profile for the Term in the context of the customer feedback referred to in Section 1.3 of the DSP.

The Dx Business Plan seeks to meet customers' needs regarding reliability and power quality and responsible asset management in a manner that controls costs, recognizing the sensitivities that customers have to the total price of power. The Dx Business Plan includes significant productivity initiatives, cost reduction initiatives, and the minimum level of capital required to responsibly manage the electricity distribution system.

The Dx Business Plan is provided as Attachment 1 to this Exhibit, and excerpts from Hydro One's consolidated business plan on strategy, customer, and common corporate costs are provided in Attachment 2.

4.1 CORE VALUES AND BUSINESS OBJECTIVES

Management expects Hydro One to be a best-in-class, customer-centric commercial utility that is easy to do business with, has a presence in the communities it serves, and consistently meets the needs and preferences of its customers.

Hydro One's core values are:

- caring for customers;
- maintaining a safe workplace;
- operating as one company;
- being people-powered; and
- executing with excellence.

Hydro One's executive leadership and Board of Directors are focused on delivering the service expected by customers while managing costs and improving operational efficiencies. The ability to measure and track Hydro One's performance is essential to this vision.

Table 3 describes Hydro One's business objectives and the metrics that Hydro One uses to measure its progress, and shows how these business objectives align with the OEB's *Renewed Regulatory Framework* ("RRF").

Table 3: Alignment of RRF Outcomes with Hydro One's Business Objectives and Performance Measures

RRF Outcomes	Hydro One Business Objectives	Performance Measures
Customer Focus Services are provided in a manner that responds to identified customer preferences	Consistently improve customer satisfaction	• Handling Unplanned Outages Satisfaction % • Call Centre Customer Satisfaction % • My Account Customer Satisfaction % • New Residential/Small Business Services Connected on Time • Scheduled Appointments Met On Time • Telephone Calls Answered On Time • First Contact Resolution • Billing Accuracy • Customer Satisfaction Survey Results
	Engage with our customers consistently and proactively	• Used to inform outcomes
	Ensure our investment plan reflects our customers' needs and desired outcomes	• Used to inform outcomes

RRF Outcomes	Hydro One Business Objectives	Performance Measures
Operational Effectiveness Continuous improvement in productivity and cost performance is achieved; and distributors deliver on system reliability and quality objectives	Actively control and lower costs through OM&A and capital efficiencies	• Total Cost per Customer • Total Cost per km • OM&A per Customer • OM&A per km of Line • Pole Replacement –Cost per Unit • Vegetation Management – Cost per km Line Clearing • Station Refurbishments – Cost per MVA
	Achieve and maintain employee engagement	• Drives company culture leading to improved Operational Effectiveness
	Drive towards achieving an injury - free workplace for employees and the public	• Drives company culture leading to improved Operational Effectiveness • Level of Public Awareness • Level of Compliance with Reg. 22/04 • Number of General Public Incidents
	Provide reliability consistent with customer requirements	• Average Number of Times that Power to a Customer is Interrupted • Average Number of Hours that Power to a Customer is Interrupted. • Rural and Urban SAIFI • Rural and Urban SAIDI • Large Customer Interruption Frequency • Number of Substation Caused Interruptions • Number of Vegetation Caused Interruptions • Number of Line Equipment Caused Interruptions • In-Service Additions (Capital Work Program Completion)
Public Policy Responsiveness Distributors deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements	Ensure compliance with all codes, standards, and regulations	• Monitored by the applicable business unit(s)
	Partner in the economic success of Ontario	• Monitored by the applicable business unit(s)

RRF Outcomes	Hydro One Business Objectives	Performance Measures
imposed further to Ministerial directives to the Board).	Sustainably manage our environmental footprint	• Net cumulative energy savings • Renewable CIAs completed on time • Micro embedded facilities connected on time
Financial Performance Financial viability is maintained; and savings from operational effectiveness are sustainable.	Achieve the ROE allowed by the OEB	• Current Ratio (Current Assets/Current Liabilities) • Return on Equity (deemed) • Return on Equity (achieved) • Total Debt to Equity

Exhibit Reference: B1-1-1

4.2 CUSTOMER NEEDS AND PREFERENCES

In June and July of 2016, Hydro One undertook a formal customer engagement initiative to obtain customer feedback to inform its planning decisions. The initiative was designed to reach as many customers as possible. Hydro One adopted a comprehensive consultation methodology, which included both qualitative approaches (such as focus groups and workshops) and quantitative approaches (such as surveys and online workbooks). The methodology and process are detailed in Section 1.3 of the DSP.

Customers were presented with three illustrative investment scenarios. Each scenario was differentiated by varying OM&A and capital investment levels, the corresponding directional impacts on distribution system reliability and customer service, and rate impacts. The engagement materials were tailored for each of Hydro One’s five customer segments, namely, Residential and Small Business, Commercial and Industrial, Large Distribution Accounts, Local Distribution Companies, and Distribution-connected Generators.

Based on the results of this formal initiative, and consistent with the customer feedback that Hydro One receives in its day-to-day operations, Hydro One believes that keeping costs as low as possible is the top priority of its customers. Specifically, the results indicated that:[1]

- controlling cost is the top priority for customers;
- customers want to see Hydro One demonstrate greater fiscal management and operational efficiency before considering rate increases;
- maintaining reliable electricity service is consistently second, after cost control, in terms of priority;
- large customers are more concerned than other customers are with reliability and capacity; and
- customers are generally unwilling to accept a rate increase, except in the context of potentially degrading reliability.

4.3 ADDRESSING CUSTOMER FEEDBACK AND STRIKING THE RIGHT BALANCE: "PLAN B MODIFIED"

Following the formal customer engagement initiative, Hydro One developed three alternative candidate investment plans for consideration by its senior leadership team and were reviewed by the Board of Directors. In developing these alternative investment plans, Hydro One assessed the reliability impacts of varying investment levels for rights-of-way (vegetation management), pole replacement and stations. Based on Hydro One's data, these three investment areas are the most significant, predictable drivers of reliability. The alternative investment plans and their estimated projected rate impacts are discussed below:

[1] Attachment 1 of DSP, Ipsos, *Distribution Customer Engagement Report: Development of Distribution Investment Plan August 2016*, pp. 146-147 (Section 1.3).

- Plan A, recommended by the Company's asset managers, would improve reliability and the overall condition of the system, and would result in a 7.1% rate increase in 2018 over 2017 and an average annual rate increase of 3.8% over the Term.
- Plan B, prepared to reflect an option that offered a smaller reliability improvement and marginal improvements in the overall asset condition of the system, would have resulted in a 6.2% rate increase in 2018 over 2017 and an average annual rate increase of 3.5% over the Term.
- Plan C would achieve the lowest possible 2018 rate increase while ensuring continued compliance with Hydro One's regulatory obligations, but would likely result in significantly reduced reliability and further deterioration in the overall condition of the system. Plan C would have resulted in a 5.0% rate increase in 2018 over 2017, and an average annual rate increase of 2.8% over the Term, and was not supported by the Company's asset managers because of the risk to the system.

More detail on Plans A, B, and C is provided in Section 2.4 of the DSP and in Tables 4 and 5 of this Exhibit.

The 2018 rate increases associated with all three of these investment plans reflects some factors that were not entirely within the company's immediate control in developing those plans. Approximately half of the rate increase is caused by changes in the load forecast (due to external factors such as conservation and demand management, and economic conditions) and the settlement of existing regulatory accounts. The large non-controllable component of the rate increase required Hydro One to consider aggressive deferrals of certain investments and significant efficiency initiatives in order to prepare investment plans that are consistent with the outcome of the customer engagement process, which highlighted the importance to customers of keeping cost increases to a minimum.

Hydro One's management, in discussion with the Board of Directors, determined that Plan B would still result in bill impacts that were too high for customers, particularly in 2018 and with the effects of the reduced load forecast. Senior management therefore challenged planners to continue to investigate a plan that would further mitigate cost increases but still reflect responsible stewardship of the assets and no degradation in reliability over the full Term. In particular, managers were challenged to consider how to mitigate the significant rate increase in 2018.

As a result, an adjusted investment portfolio with a forecasted 2018 rate impact of 5.4%, "Plan B – Modified", was developed that would maintain overall forecasted system reliability at current levels, while continuing to offer discrete power quality and reliability improvements for certain segments of the network. Tables 4 and 5 summarize the assumptions that defined Plans A, B, C and B - Modified.

Table 4: SAIDI Projection for Investment Plan Options

SAIDI[1]:	**Avg. 2013-15: 7.3 hours/year**	**Average Number of Hours that a Customer is Interrupted**					
	Assumptions			**Forecasted Impact on SAIDI [2]**			
	Failure Rate/Impact	**Contribution to SAIDI**	**SAIDI Contribution (based on 2013-15)**	**Plan A**	**Plan B**	**Plan C**	**Plan B-M**
Poles	• 345 outages/year • 180 customers/outage • 10 hours/outage	3%	0.2	20%	15%	(15)%	7%
Stations	• 16 failures (outages) /year • 1200 customers/outage • 24 hours/outage	4%	0.2	14%	5%	(4)%	0%
Other Line Components	• 2070 outages/year • 180 customers/outage • 4 hours/outage	23%	1.5	10%	0%	(10)%	(5%)
Vegetation	• 15,530 outages/year	27%	1.8	8%	8%	4%	8%
Estimated Impact to SAIDI				**6%**	**3%**	**(2)%**	**0%**
Forecasted SAIDI (hours)				**6.9**	**7.1**	**7.4**	**7.3**

Exhibit Reference: B1-1-1

1- Excludes force majeure and loss of supply events

2 – These columns reflect the forecasted impact on SAIDI by the end of 2022. Estimated performance improvement is expressed as a positive value; performance deterioration is expressed as a negative value.

Table 5: SAIFI Projection for Investment Plan Options

SAIFI [1]:	**Avg. 2013-15: 2.6 outages/year**	**Average Number of Times a Customer is Interrupted**					
	Assumptions			**Forecasted Impact on SAIFI[2]**			
	Failure Rate/Impact	**Contribution to SAIFI**	**SAIFI Contribution (based on 2013-15)**	**Plan A**	**Plan B**	**Plan C**	**Plan B-M**
Poles	• 345 outages/year • 180 customers/outage • 10 hours/outage	2%	0.1	20%	15%	(15)%	7%
Stations	• 16 failures (outages) /year • 1200 customers/outage • 24 hours/outage	3%	0.1	14%	5%	(4)%	0%
Other Line Components	• 2070 outages/year • 180 customers/outage • 4 hours/outage	18%	0.5	10%	0%	(10)%	(5%)
Vegetation	• 15,530 outages/year	16%	0.4	8%	8%	4%	8%
Estimated Impact to SAIFI				**4%**	**2%**	**(2)%**	**0%**
Forecasted SAIFI (instances)				**2.5**	**2.6**	**2.6**	**2.6**

Exhibit Reference: B1-1-1
1-Excludes force majeure and loss of supply events
2 – These columns reflect the forecasted impact on SAIFI by the end of 2022. Estimated performance improvement is expressed as a positive value; performance deterioration is expressed as a negative value.

Plan B - Modified included the following adjustments compared to original Plan B:

- A deferral of some 2018 capital spending on wood pole replacements, station refurbishments, component replacements, system capability reinforcement, information technology and facilities and real estate to minimize rate impacts and offset the effects of a reduced load forecast, accepting short-term, small-scale reliability impacts where appropriate;
- The acceleration of productivity initiatives to reduce unit and operational costs and associated rate impacts, which are described in Section 1.5 of the DSP and summarized in Table 6 of this Exhibit;
- To sustain reliability, continued investment in certain System Renewal projects and programs based on asset condition and poor performance; and
- The establishment of OM&A and capital programs to investigate power quality issues, install power quality meters and surge arresters, and improve grounding where needed.

These initiatives reduced the total Term projected capital expenditures by $51 million or approximately 7.5% when compared to original Plan B.

Plan B - Modified reflects an optimized investment portfolio that is designed to maintain current reliability within the proposed envelope for the period 2018 to 2022 by:

- implementing a vegetation management plan that is expected to result in improved reliability, at a spending level consistent with past OEB-approved levels, by using lower cost temporary workers to complete low-skilled work and by better aligning clearing frequency with reliability performance;
- outsourcing cable location work at lower cost;
- replacing poles at a rate that will maintain or slightly reduce by 2022 the population of poles that are in poor condition;
- refurbishing stations at a rate where station condition and reliability will remain stable over the forecast period;
- implementing a worst performing feeder initiative, which will deploy enhanced communication and automation capability to targeted lines to improve reliability by reducing outage duration;
- improved targeting of lines sustainment investments based on performance and focused on the root causes of poor performance;
- targeting OM&A and capital investments to address industrial customer power quality and reliability outliers; and
- ensuring continued compliance with regulatory, environmental and reliability standards.

The investments are described in more detail in Sections 3.1 to 3.8 of the DSP and in Exhibit C1, Tab 1, Schedules 1 to 10.

Hydro One believes that Plan B-Modified is the investment plan that most effectively aligns customer needs and preferences, responsible asset management, and bill impacts. Plan B-Modified maintains system health and reliability at current levels without further degradation, albeit without material improvement to the overall system.

4.4 EXECUTING THE BUSINESS PLAN

Hydro One is focused on delivering service expected by customers while managing costs and improving operational efficiencies, all within the revenue requirement envelope set by the Custom IR approach described in Section 2 of this Exhibit. To ensure Hydro One meets the Dx Business Plan's objectives within the OEB-approved envelope, Hydro One is cultivating a performance management culture that tracks and motivates the desired behaviours and adopting productivity incentives.

4.4.1 PERFORMANCE MANAGEMENT

4.4.1.1 SCORECARDS

As illustrated in Figure 1 below, Hydro One is tracking its performance through (i) the (mandatory) Electricity Distributor Scorecard; (ii) Hydro One's proposed Distribution OEB Scorecard, which is intended to provide greater transparency on outcome measures and areas targeted for improvement; and (iii) its Team Scorecard which is used to award annual short-term incentive payments to management employees.

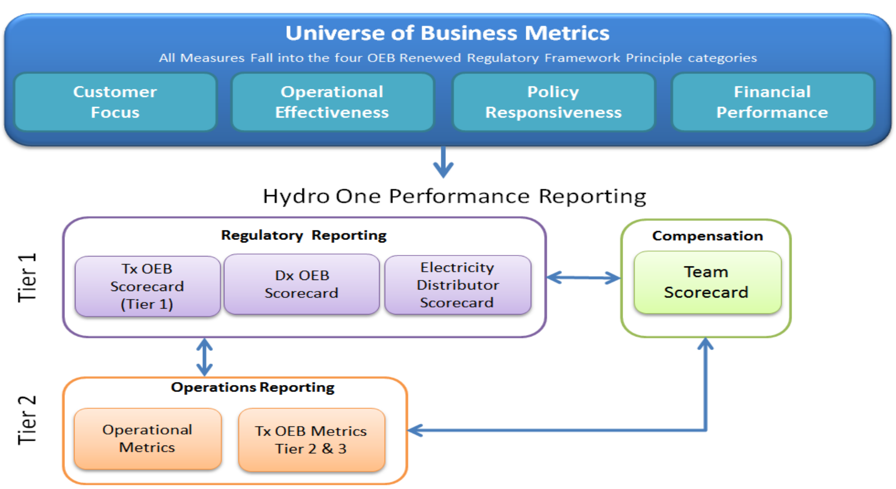

Exhibit Reference: B1-1-1

Figure 1: Performance Reporting Tools

The metrics contained in these scorecards align with the RRF objectives and are expected to drive continuous improvement in asset management, work execution and in customer-oriented performance in support of Hydro One's business objectives. Managers throughout the business are required to include these measures where appropriate in their personal performance goals. As part of Hydro One's performance management system, they are intended to provide transparency to Hydro One's Board of Directors, management, customers, and the OEB, and provide business drivers to ensure that targeted work is completed in an efficient manner, while delivering the stated outcomes for Hydro One's customers.

Exhibit A, Tab 5, Schedule 1 contains a discussion of Hydro One Distribution's performance and targets for the Electricity Distributor Scorecard. Section 1.4 of the DSP addresses the Distribution OEB Scorecard and the targets that Hydro One is proposing for the additional performance metrics described therein. Hydro One's Team Scorecard for 2016 is provided as Attachment 4 to Exhibit C1, Tab 2, Schedule 1.

4.4.1.2 BENCHMARKING

Since its last distribution rates application (EB-2013-0416), Hydro One has commissioned several benchmarking studies as directed by the OEB. The benchmarking reports are included in this Application and discussed in Section 1.6 of the DSP, Exhibit A, Tab 3, Schedule 2, and Exhibit C1, Tab 2, Schedule 1. These studies are focused on: (a) Hydro One Distribution's larger work programs, specifically, its pole replacement, station refurbishment, and vegetation management programs; (b) total compensation costs; and (c) total factor productivity and total cost performance. Hydro One also commissioned an additional benchmarking study focused on information technology spending.

The results of these studies have informed Hydro One's Custom IR approach and its investments and execution strategies. Based on these results, Hydro One continues to evaluate opportunities to further improve its operational efficiency to ensure that it can achieve its RRF-consistent business objectives. For example, Hydro One is investigating the feasibility and cost-benefit analysis of pole refurbishment recommendations, and the development of key performance indicators for station projects related to cost and system impact. More detail on Hydro One's responses to the benchmarking study results and recommendations is provided in Section 1.6 of the DSP.

4.4.2 PRODUCTIVITY INCENTIVES

In its proposed Custom IR model, Hydro One includes an external productivity incentive in the form of a stretch factor of 0.6%. This is the highest stretch factor applicable under the OEB's existing incentive regulation regime, which will apply to the entirety of the Hydro One Distribution revenue requirement over the Term. This stretch factor is meant to mitigate the impact of Hydro One's below-average total cost performance relative to its peer group, as evidenced by a total cost benchmarking study performed by Power System Engineering Inc., which is discussed in Exhibit A, Tab 5, Schedule 2. When Hydro One Distribution's audited 2016 actual financial results are available, Hydro One will update its total cost performance forecast in a Blue Page Update and change its proposed stretch factor, if warranted.

To ensure that Hydro One executes the Dx Business Plan within the allowed envelope, management has reflected significant efficiency savings targets in the DX Business Plan. These efficiencies are realized in both the capital and OM&A work programs as set out in Table 6. The values in Table 6 are stretch targets that reflect management's commitment to ensuring that all possible efficiencies and cost reductions are achieved before Hydro One asks customers for a rate increase, as expressed by customers during the engagement process. Specifically, the Company has taken targeted actions to implement productivity improvements as early as 2018, the rebasing year, and intends to achieve further efficiencies over the subsequent four years. While the OEB's RRF provides an incentive for utilities to achieve productivity gains during the Term, such efficiencies ultimately accrue to the benefit of ratepayers at the time of the next rebasing.

Table 6: Detailed Productivity Savings Forecast

$Millions	**2018**	**2019**	**2020**	**2021**	**2022**
Capital	25.5	26.8	32.2	33.7	34.6
OM&A	34.5	40.5	43.2	45.5	49.8
Corporate Common	3.2	3.3	3.3	3.3	3.3
Total Savings	**63.2**	**70.5**	**78.7**	**82.5**	**87.6**

Exhibit Reference: B1-1-1

There are additional features of the Custom IR model which align Hydro One's interests with those of its customers in reducing its costs and executing effectively against plan. Two features that provide customers with a measure of protection against excessive utility earnings are the proposed earnings sharing mechanism and asymmetrical capital in-service variance account. These mechanisms are discussed in Section 2 of this Exhibit.

5. SUMMARY OF THE APPLICATION

5.1 REVENUE REQUIREMENT

Table 7 provides a comparative profile of the annual rates revenue requirement build-up from 2017, the last OEB-approved rate year, to 2018, along with references to the Exhibits in the Application that discuss each cost component.

Table 7: Revenue Requirement ($ Millions)

Components	**2017**[1]	**2018**	**Reference**
OM&A	593.0	591.9	Exhibit C1, Tab 1, Schedule1
Depreciation and Amortization	390.2	394.4	Exhibit C1, Tab 6, Schedule 1
Income Taxes	48.7	58.0	Exhibit C1, Tab 7, Schedule 1
Return on Capital	435.8	460.4	Exhibit D1, Tab 2, Schedule 1
Total Revenue Requirement	**1,467.6**	**1,504.7**	Exhibit E2, Tab 1, Schedule 1
Deduct External Revenues and Other	(52.7)	(52.6)	Exhibit E1, Tab 1, Schedule 2
Rates Revenue Requirement	**1,414.9**	**1,452.1**	
Regulatory Deferral and Variance Accounts Disposition	11.1	23.1	Exhibit F1, Tab 2, Schedule 1, Attachment 1
Rates Revenue Requirement (with Deferral and Variance Accounts)	**1,426.0**	**1,475.2**	

Exhibit Reference: E1-1-1

Note 1: The 2017 revenue requirement is from the OEB approved Hydro One Distribution's 2015 to 2017 rate application in EB-2013-0416

The increase in revenue requirement is largely attributable to the impact of rate base growth, as reflected in the increase in depreciation, return on capital, income tax expenses and lower external revenue forecast as described in Exhibit E1, Tab 1, Schedule 2. These are partially offset by a lower cost of debt and lower OM&A costs.

5.1.1 BUDGETING ASSUMPTIONS

For 2018, Hydro One assumed 2.0% annual inflation and cost escalators for construction and OM&A expense growth of 2.5% and 2.2%, respectively. These assumptions are explained in further detail in Section 2.1.2 of the DSP. Hydro One adopted the US GAAP accounting standard for regulatory purposes, based on the OEB's Decision with Reasons in EB-2011-0268.

5.1.2 LOAD FORECAST SUMMARY

Table 8 sets out Hydro One's 2018-2022 distribution system load forecast, which includes the impact of conservation and demand management and embedded generation.

Table 8: Forecast Energy Deliveries and Customer Count

Year	Energy Delivery Forecast (GWh)	Change (%)	Distribution Customer Count	Change (%)
2018	36,019	-0.6	1,300,516	0.7
2019	35,680	-0.9	1,309,216	0.7
2020	35,673	0.0	1,317,967	0.7
2021*	36,363	1.9	1,386,522	5.2
2022*	36,373	0.0	1,395,578	0.7

Exhibit Reference: E1-2-1

** The figures include the impact of integrating Acquired Utilities into Hydro One Distribution. Without this, the GWh delivered would have changed by -0.3% in 2021 and 0% in 2022, and the number of customers would have changed by 0.7% in both 2021 and 2022*

The changes in the energy delivery forecast are distinct from the load impact on rates. The load impact on revenue requirement is a function of peak demand, energy delivery and customer count forecasts by rate class. It reflects changes since the last OEB-approved forecast. As set out in Section 1 of this Exhibit, the reduced load forecast contributes 3.0% of the resulting average increase in distribution rates of 6.5%.

The forecast was developed using the econometric and end-use approaches described in Exhibit E1, Tab 3, Schedule 1. The forecast base year was corrected for abnormal weather conditions, and growth rates were applied to the normalized base year value. Consistent with the IESO’s approach, normal weather data is based on the average weather conditions experienced over the last 31 years.

Relative to 2017 figures, Hydro One forecasts a decrease of 0.6% in its load forecast and an increase of 0.7% over the customer count forecast for 2018. The small decrease in load is mainly due to the impact of conservation and demand management and economic factors.

6. THE DISTRIBUTION SYSTEM PLAN

The basis of Plan B – Modified is Hydro One's DSP, which is provided as Exhibit B1, Tab 1, Schedule 1. The DSP capital expenditure forecast for the Term and for historical years dating back to 2013 is set out in Table 9. A summary line for OM&A expenditures is also provided.

Table 9: Summary of Distribution Capital and OM&A Expenditures ($ Millions)

CATEGORY	Historical (previous plan and actual)											Forecast (planned)				
	2013 [1]	2014 [1]	2015			2016			2017 Bridge [2]			2018	2019	2020	2021	2022
	Plan	Plan	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Test	Test	Test	Test	Test
	$M	$M	$M		%	$M		%	$M		%	$M	$M	$M	$M	$M
System Access	159.5	199.4	183.3	188.1	2.6	182.6	179.0	(1.9)	176.1	168.3	(4.4)	154.6	157.6	160.9	165.9	170.0
System Renewal	265.7	262.7	250.7	308.4	23.0	265.4	291.2	9.7	285.0	252.2	(11.5)	248.6	318.7	336.7	362.5	451.1
System Service	96.5	85.5	120.1	71.6	(40.4)	103.3	76.8	(25.7)	110.1	66.6	(39.5)	81.8	93.4	85.6	78.8	69.5
General Plant	115.3	99.9	94.8	110.1	16.2	103.3	156.3	51.2	90.1	146.3	62.3	149.0	187.1	135.8	133.4	136.6
Total	637.0	647.5	648.9	678.3	4.5	654.7	703.2	7.4	661.4	633.5	(4.2)	633.9	756.8	719.0	740.7	827.2
System OM&A [3]	610.6	674.5	543.1	572.5	5.4	589.1	583.6	(0.9)	593.0	580.5	(2.1)	591.9	595.6	603.1	621.5	625.9

1) 2013 and 2014 were IRM years and therefore do not have Board-approved capital expenditure figures.

2) Bridge year 2017 is a forecast as of end of 2016

3) System OM&A values include all Operations, Maintenance and Administration expenses.

Exhibit Reference: B1-1-1

6.1 CAPITAL DRIVERS

System Renewal costs are expected to increase by an average of 12.3% annually from 2017 to 2022, reflecting an increase in pole replacements, station refurbishments, line sustainment and life cycle optimization investments to deal with assets at end of life. PCB line equipment replacements increase to meet Environment Canada's December 31, 2025 deadline. In 2021, there is a significant increase in spending as Hydro One begins replacing smart meters that will be at end of life. Higher General Plant investment levels are attributable to an investment in the Integrated System Operations Centre, which replaces the existing backup power system control and telecommunication centres. This investment is described in Investment Summary Document GP18 of the DSP.

Costs associated specifically with renewable energy connections/expansions, smart grid, and regional planning initiatives are summarized in Table 10 below.

Table 10: REG Connections/Expansions, Smart Grid and Regional Planning Investments

DSP ISD#	Investment Name	Total Cost ($M)				
		2018	2019	2020	2021	2022
SA5	Generation Connections	4.1	3.4	3.3	2.9	3.0
SS2	System Upgrades Driven by Load Growth* - Regional Planning Projects only	6.7	11.7	8.4	-	-
SS7	Advanced Distribution System	5.0	0.0	0.0	0.0	0.0
GP25	Leamington TS Capital Contribution	2.2	0.0	0.0	0.0	0.0
GP26	Hanmer TS Capital Contribution	3.4	0.3	0.0	0.0	0.0
GP27	Enfield TS - Capital contribution	2.0	1.0	0.0	0.0	0.0

Exhibit Reference: B1-1-1
*These amounts are included in the investment summary document ("ISD") which covers all investments due to load growth.

Investments have been paced to mitigate rate impacts and offset the effects of a reduced load forecast, which includes managing asset replacement rates and, where appropriate, accepting potentially increased risk, to reduce or defer capital spending requirements. Hydro One's leadership team is actively driving cost reductions and improving productivity to help offset the customer bill impacts of the proposed plan and reduced load forecast.

6.2 OPERATING, MAINTENANCE AND ADMINISTRATION DRIVERS

A summary of forecast OM&A expenses for 2018 is provided in Table 11. More detail is available in Exhibit C1, Tab 1, Schedule 1.

Table 11: Summary of Recoverable Distribution OM&A Expenses ($ Millions)

Description	Historic					Bridge		Test
	2014 IRM	2015	2015	2016	2016	2017	2017	2018
	Actual	Actual	Approved	Forecast	Approved	Forecast	Approved	Forecast
Sustainment	325.7	304.6	316.5	326.6	361.4	334.5	367.1	346.7
Development	11.0	10.9	15.4	12.1	17.8	13.2	17.0	11.0
Operations*	29.5	27.6	35.8	29.5	39.4	33.4	37.5	36.7
Customer Care*	209.3	155.4	111.7	129.3	110.9	132.6	111.6	131.6
Common Corporate	94.4	69.1	59.0	81.5	54.8	62.0	54.7	61.0
Property Taxes & Rights Payments	4.6	4.8	4.7	4.6	4.9	4.7	5.0	4.9
Total	**674.5**	**572.5**	**543.1**	**583.6**	**589.1**	**580.5**	**593.0**	**591.9**
% Change (year-over-year)		*-15%*	*-19%*	*2%*	*8%*	*-1%*	*1%*	*2%*
% Change (Test vs. 2016 Actual)								*1%*

Exhibit Reference: C1-1-1
*Costs associated with the Smart Grid pilot were moved from Customer Care to Operations in 2015.

Hydro One has identified and applied significant productivity and efficiency improvements that have resulted in an OM&A plan that reflects this Application's commitment to the top customer priority of keeping bills as low as possible. In 2018, Hydro One forecasts total OM&A expenditures of $591.9 million. This is an increase of $11.4 million or 2% compared with the 2017 forecast expenditures, which were $12.5 million below OEB-approved levels, as shown in Table 12. Despite inflation, the expansion of the Hydro One Distribution system, and expenditures that are required to address the increasing maintenance requirements of a deteriorating distribution system, Hydro One has planned for lower OM&A costs than the last level approved by the OEB in 2017.

Table 12 compares 2017 projected costs to the 2017 OM&A expenditures approved by the OEB in Hydro One's previous distribution application (EB-2013-0416).

Table 12: 2017 OEB-approved versus 2017 Projected OM&A Expenditures

	Bridge	
Description	**2017 Forecast**	**2017 Approved**
Sustainment	334.5	367.1
Development	13.2	17.0
Operations	33.4	37.5
Customer Service	132.6	111.6
Common Corporate	62.0	54.7
Property Taxes & Rights Payments	4.7	5.0
Total	**580.5**	**593.0**
% Variance	*-2.1%*	

Hydro One's projected 2017 OM&A costs are $12.5 million lower or 2.1% below OEB-approved levels, mostly due to lower Sustainment expenditures attributable to initiatives in the vegetation management program (described in Exhibit C1, Tab 1, Schedule 2) and cost reductions that new management has been driving and which are now benefiting the 2018 base year.

Details of Hydro One's corporate staffing and compensation are provided at Exhibit C1, Tab 4, Schedule 1.

7. RATE BASE

Exhibit D1, Tab 1, Schedule 1 provides the details of the derivation of the requested rate base figures for the Term. Table 13 summarizes this request.

Table 13: Distribution Rate Base ($ Millions)

Description		Test				
		2018	**2019**	**2020**	**2021**	**2022**
Mid-Year Gross Plant		11,948.7	12,541.0	13,219.8	14,082.3	14,783.5
Mid-Year Accumulated Depreciation		(4,601.7)	(4,833.1)	(5,097.7)	(5,431.3)	(5,749.7)
Mid-Year Net Plant		**7,347.0**	**7,708.0**	**8,122.0**	**8,651.0**	**9,033.8**
Cash Working Capital		321.2	335.7	348.3	378.5	395.3
Materials and Supplies Inventory		4.1	5.5	6.5	5.9	5.5
Distribution Rate Base		**7,672.3**	**8,049.1**	**8,476.8**	**9,035.4**	**9,434.7**

Table 14 compares 2017 forecast rate base to the 2017 rate base approved by the OEB in its Decision on Hydro One's previous distribution application EB-2013-0416.

Table 14: 2017 OEB-approved versus 2017 Bridge Year Forecast Rate Base

($ Millions)

Rate Base Component	2017 Bridge Year (Forecast)	2017 OEB-approved	Variance
Mid-Year Gross Plant	11,372.7	11,239.1	133.6
Less: Mid-Year Accumulated Depreciation	(4,335.6)	(4,311.7)	(23.9)
Mid-Year Net Utility Plant	7,037.1	6,927.4	109.7
Cash Working Capital*	310.2	255.7	54.5
Materials & Supplies Inventory	4.0	6.8	(2.7)
Total Rate Base	**7,351.3**	**7,189.9**	**161.5**

Total 2017 rate base is expected to be $161.5 million above the OEB-approved level. This variance of 2.2% is explained by higher in-service additions due to higher than forecast spending on trouble calls and storm damage, as well as joint use and relocation projects. This is partially offset by lower demand for distribution generation connections and more efficient completion of wood pole replacements. In addition, a higher cash working capital requirement also results in higher rate base.

8. COST OF CAPITAL

Table 15 summarizes the cost of capital parameters reflected in the Application, details of which can be found at Exhibit D2, Tab 2, Schedule 1.

Table 15: Cost of Capital

Comparison of Cost of Capital and Rate Base	OEB-approved 2017*	2018	Exhibit Reference
Cost of Debt	4.25%	4.15%	D2-2-1
Cost of Equity	8.78%	8.78%	D2-2-1
Total Debt ($ Millions)	4,313.94	4,603.39	D2-2-1
Total Equity ($ Millions)	2,875.96	3,068.92	D2-2-1
Rate Base ($ Millions)	**7,189.89**	**7,672.31**	D2-2-1
Weighted Average Cost of Capital	**6.1%**	**6.0%**	

*Source: Dx 2015-19 Rate Order Evidence

Hydro One's deemed capital structure for distribution ratemaking purposes is 60% debt and 40% common equity. The 60% deemed debt component comprises 4% short-term debt and 56% long-term debt. For the 2018 rebasing year, Hydro One intends to continue to use the OEB's cost of capital parameters for its deemed short-term debt rate and return on equity, consistent with the OEB's report on cost of capital. Hydro One's forecast 2018 cost of long-term debt is calculated as the weighted average cost rate of embedded debt, new debt issued after the last OEB-approved rate application and forecast debt to be issued in 2017 and 2018.

Hydro One's Application reflects a "placeholder" return on equity of 8.78% for the 2018 test year, based on the cost of capital parameters released by the OEB on October 27, 2016, for rates effective January 1, 2017. Hydro One will update the return on equity and the cost of short-term debt for the purpose of establishing the final revenue requirement for 2018, when those metrics are updated by the OEB later in 2017. Hydro One has applied to also update the cost of capital metrics in 2021 with the integration of the Acquired Utilities.

9. COST ALLOCATION AND RATE DESIGN

Hydro One has followed the OEB's cost allocation and rate design methodologies, with minor changes to address Hydro One's specific circumstances as previously reviewed and approved by the OEB. For the 2021 cost allocation model, Hydro One adopted six new customer classes for the Acquired Utilities and included some adjustment factors within the model to ensure that costs allocated to the six new classes appropriately reflect their cost to serve, as directed by the OEB. Details of these adjustments are discussed in Exhibit G1, Tab 3, Schedule 1.

Hydro One proposes to change only those revenue-to-cost ratios that fall outside the OEB-approved ranges for the Distributed Generation class from 2018 to 2020 and for some of the new Acquired Utilities' rate classes in 2021 and 2022. No changes to fixed/variable splits are proposed except with respect to the move to fully-fixed rates for all residential classes as required by the OEB under proceeding EB-2012-0410, and the transition to new customer classes for general service energy and demand customers of two of the Acquired Utilities. The details of these changes are discussed in Exhibit H1, Tab 1, Schedule 1.

Hydro One proposes bill impact mitigation by gradually phasing-in increases in revenue-to-cost ratios to within the OEB- approved ranges for the Distributed Generation class from 2018 to 2020, the new acquired urban general service energy and demand billed classes in 2021 and 2022, and the new acquired general service demand billed class in 2021. Bill impact mitigation in the form of bill credits will be applied to the streetlight, sentinel light and unmetered scattered load customers of the Acquired Utilities that are transitioning to Hydro One's existing classes. Details of these changes are discussed in Exhibit H1, Tab 1, Schedule 1.

10. DEFERRAL AND VARIANCE ACCOUNTS

Hydro One is seeking approval to continue or establish the following accounts:

- Pension Cost Differential Account;
- Tax Rate Changes Account;
- OEB Cost Differential Account;
- Smart Meter Entity Charge Variance Account;
- Lost Revenue Adjustment Mechanism Variance Account;
- Capital In-Service Additions Variance Account;
- Earning Sharing Mechanism Deferral Account; and
- Bill Impact Mitigation Variance Account.

Hydro One is seeking discontinuance of the following regulatory accounts:

- Rural and Remote Rate Protection Variance Account;
- Bill Impact Mitigation Variance Account;
- Revenue Offset Difference Account – Pole Attachment Charge; and
- Revenue Difference Account – Pole Attachment Charge.

Hydro One proposes disposing of its regulatory account balances as at December 31, 2016, plus interest improvement for 2017. Hydro One expects that the OEB's final decision will be based on the audited 2016 year end balances which Hydro One will provide in its planned Blue Page Update in June 2017.

It is expected that new distribution rates will be effective and implemented on January 1, 2018 and that the disposition of these accounts will commence on that date. Hydro One's requested recovery in 2018 to 2022 of a total $115.3 million is detailed in Table 16:

Table 16: Hydro One Distribution Regulatory Assets

Disposition of Regulatory Account Balances ($ Millions)		
Description	**US of A Account Ref.**	**Forecast Balance as at Dec. 31, 2017**
Retail Service Variance Accounts	1550 to 1589	115.1
Retail Cost Variance Accounts	1518/ 1548	0.0
Pension Cost Differential Account	2405	8.1
Tax Rate Changes Account	1592	(4.4)
OEB Cost Differential Account	1508	(1.3)
Smart Meter Entity Charge Variance Account	1551	0.3
Revenue Offset Difference Account – Pole Attachment Charge	2405	(2.3)
Bill Impact Mitigation Variance Account	1508	2.4
Microfit Connection Charge Variance Account	1508	(0.8)
Distribution Generation – Other Costs – HONI - Variance Account	1533	0.6
Smart Grid Variance Account	1536	(12.1)
Distribution System Code (DSC) Exemption Deferral Account	1508	9.7
Total Regulatory Accounts for Disposition		**115.3**

11. BILL IMPACTS

Table 17 summarizes the 2018 total bill impacts for typical customers in all customer classes. Bill impacts across a range of consumption levels and for customer classes in 2019-2022 are provided in Exhibit H1, Tab 4, Schedule 1.

Table 17: 2018 Total Bill Impacts for Typical/Average Customers

Rate Class	Consumption Level	Monthly Consumption (kWh/kW)	Change in Total Bill ($)	Change in Total Bill (%)
UR	Typical	750	3.98	2.8%
	Average	755	3.99	2.8%
R1	Typical	750	4.74	2.9%
	Average	920	5.05	2.6%
R2	Typical	750	4.93	3.0%
	Average	1152	5.37	2.2%
Seasonal	Typical	350	3.07	2.7%
	Average	352	3.07	2.7%
GSe	Typical	2000	8.72	1.9%
	Average	1982	8.65	1.9%
UGe	Typical	2000	5.22	1.4%
	Average	2759	7.20	1.4%
GSd	Average	36104 / 124	274.18	3.5%
UGd	Average	50525 / 135	343.91	3.8%
St Lgt	Average	517	3.65	2.9%
Sen Lgt	Average	71	0.46	2.1%
USL	Average	364	-0.12	-0.1%
DGen	Average	1328 / 13	46.73	9.9%
ST	Average	1601036 / 3091	6231.28	2.6%

Distribution Business Plan 2017-2022

December 2, 2016

INTERNAL and CONFIDENTIAL

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Strategy and Business Objectives

Corporate Vision, Values and Strategy

Hydro One is transforming to achieve its **vision** of becoming a best-in-class, customer-centric commercial entity, with a culture of continuous improvement and excellence in execution. To achieve this vision, Hydro One will execute on its **strategy** to distribute electricity safely and reliably in a manner that produces the greatest value for customers. Hydro One seeks to be excellent in every facet of its operations, to the benefit of customers, employees and shareholders.

Hydro One's **commercial** orientation means that the company will be focused on customers, demonstrate corporate accountability for performance outcomes, and drive company-wide efficiency and productivity. Understanding customers' needs and preferences and delivering distribution system outcomes that are valued by customers are critical to Hydro One's future success.

Hydro One's vision and strategy reflects **values** that are integral to the well-being of communities:

- Maintaining a safe workplace;
- Caring for customers;
- Operating as one company;
- Being people-powered; and
- Executing with excellence.

Hydro One's executive leadership and Board of Directors are committed to building a strong performance management culture and the ability to measure and track performance is essential to this vision.

Hydro One's vision, strategy and values inform everything the company does, as it works to align three competing but equally important factors: customer needs and preferences, responsible stewardship of its distribution system, and customer rates.

Hydro One's approach to the development of this six-year business plan has been shaped by: (i) the company's commitment to reduce costs and increase productivity and efficiency before asking customers to pay more; (ii) directing investment to address specific customer needs and preferences; (iii) reducing or deferring investment levels to where increases in reliability risk can reasonably be justified by lower rates; and (iv) the resulting rates profile for the 2018 to 2022 portion of the planning period, evaluated in the context of the results of Hydro One's distribution customer engagement process.

Hydro One has also taken into account previous direction by the Ontario Energy Board (OEB) acknowledging that the company's distribution system is in need of additional investment, and that the company should be finding cost effective ways to improve its performance.

As a result of this approach, the investment planning process that culminated in this Distribution Business Plan and the Distribution System Plan described herein was iterative; Hydro One created several different asset investment plans with different customer outcomes and rate impacts, and these plans were evaluated by the Executive Leadership Team and discussed with the company's Board of Directors. The Distribution Business Plan and the associated Distribution System Plan in this document represent an investment plan that appropriately aligns the needs and preferences of customers, customer rates and effective stewardship of the distribution system by Hydro One.

Circumstances & Challenges

Hydro One is the largest electricity distributor in Ontario. Hydro One serves more than 1.3 million customers in largely rural and suburban areas across Ontario, with approximately 123,000 circuit kilometers of lower-voltage power lines, 1.6 million poles and over 1,000 distribution and voltage regulating stations.

Geography

Hydro One's service area is one of the largest in North America. It is predominantly rural, with below average customer density by land area, higher than average tree density, and a higher than average number of storms, especially in winter, that damage the distribution system on a regular basis. Hydro One maintains over 100,000 kilometers of rights-of-way, and although the majority of the company's distribution power lines are along roadways, one-third of the lines are off-road, requiring the use of special equipment for access and maintenance.

Reliability

Reliability performance is affected by factors such as: vegetation, equipment performance, geography, and exposure to adverse weather, and as a result, the reliability of Hydro One's distribution system varies by location. In addition, much of Hydro One's distribution network uses a radial circuit design to cover large areas. A radial circuit design does not provide the redundant power supplies that are common in urban areas. These factors increase both the frequency and duration of power outages and also increase the time and cost of restoring power when outages occur.

Aging and Deteriorating Infrastructure

Much of Hydro One's distribution system was built in the 1950s and 1960s and as a result, many of the company's assets are approaching or beyond the end of their expected service life. While replacement decisions are based on actual asset condition, age is an indicator of additional asset replacements over the business planning period. For example, Hydro One currently has 240,000 wood poles (15% of fleet) that are beyond their expected service life of 60 years and 144 station transformers (12% of fleet) are beyond their expected life of 50 years. If no replacements are made in the next five years, the number of wood poles beyond their expected service life rises to 400,000 (25% of fleet) and the number of transformers beyond their expected service life rises to 360 (30% of fleet). Assets that remain in use beyond their expected service life generally demonstrate higher failure rates. Significant investment is required to maintain the system in a reliable state.

Rising Cost of Power

Hydro One is very aware customers are experiencing increasing and, in many cases, unmanageable electricity bills. These increases have been driven by many factors, including investments in electricity generation, and material changes in generation fuel mix, from lower-cost coal to greater reliance on cleaner and more efficient natural gas, nuclear and renewable generation. In addition, conservation and demand management initiatives have increased costs, on a kWh basis, as predominately fixed system investment is recovered over lower total Ontario Demand. All of these factors, combined with the need for Hydro One to replace deteriorated assets and invest in the distribution system, have increased customer bills significantly. While Hydro One does not control external factors it is mindful of the overall impact these costs have had on customers and customers' willingness and ability to pay rates that support needed investment in Hydro One's distribution system.

Business Objectives

Hydro One Distribution's business objectives are directly aligned with the OEB's *Renewed Regulatory Framework for Electricity* (RRFE), as shown in the table below.

Hydro One's Values and Business Objectives

Customer Focus	**Customer Satisfaction**	• Improve current levels of customer satisfaction
	Customer Focus	• Engage with our customers consistently and proactively • Ensure our investment plan reflects our customers' needs and desired outcomes
Operational Effectiveness	**Cost Control**	• Actively control and lower costs through OM&A and capital efficiencies
	Safety	• Drive towards achieving an injury-free workplace for employees and the public
	Employee Engagement	• Achieve and maintain employee engagement
	System Reliability	• Provide reliability consistent with customer expectations
Public Policy Responsiveness	**Public Policy Responsiveness**	• Ensure compliance with all codes, standards, and regulations • Partner in the economic success of Ontario
	Environment	• Sustainably manage our environmental footprint
Financial Performance	**Financial Performance**	• Achieve the ROE allowed by the OEB • Manage planning and spending to mitigate customer impacts

In order to achieve its business objectives, Hydro One continues to devise new approaches to serve its customers, form its Distribution System Plan, and operate and maintain its assets, while maintain a strong commitment to safety and the environment. These initiatives are discussed, in turn, in the sections below.

Customer Focus

Customer Engagement for Developing the Distribution System Plan

Hydro One's objective is to engage with customers consistently and proactively. Hydro One has a three-pronged approach to engaging its distribution customers: formal customer engagement, stakeholder engagement and other on-going forums through which Hydro One interacts with its distribution customers. The company's full spectrum of customer initiatives is designed to: (i) increase the company's understanding of customers' needs and preferences; (ii) enhance Hydro One's ability to provide services that meet these needs; (iii) produce outcomes that are valued by customers; and (iv) result in an improvement of customers' overall satisfaction with the service they receive.

One critical element of achieving this objective is the development of a Distribution System Plan that is designed to meet customers' needs and preferences and result in outcomes that customers value.

In the summer of 2016, Hydro One undertook a comprehensive customer engagement initiative, the purpose of which was to inform the development of Hydro One Distribution's five-year Distribution System Plan. This initiative was structured to identify customer needs and preferences, result in the identification of customer needs and preferences, and allow for identified needs and preferences to inform the Distribution System Plan that is reflected in this Distribution Business Plan for the 2018 to 2022 planning period.

Hydro One engaged Ipsos, a global market research company, to assist in the design, execution, facilitation, and documentation of this customer engagement initiative. Ipsos also provided analysis of the feedback received during the engagement.

Customer Engagement Process

By engaging Ipsos, Hydro One set out to: (i) establish a comprehensive, best-in-class process; (ii) establish an inclusive, accessible, verifiable and transparent process; and (iii) ensure the associated customer and stakeholder research and feedback met the spirit and intent of the RRFE.

The objectives of the distribution customer engagement were to:

- Establish the process, vehicles, and conditions for effective engagement that captures the feedback of all distribution customer segments;

- Provide every customer with an opportunity to participate;
- Adopt a research-based approach to engagement to gather the data necessary to support an informed and representative view;
- Contribute to unbiased analysis of customer input by engaging external research professionals; and
- Demonstrate flexibility and provide tangible evidence of Hydro One's willingness to listen, learn and establish plans that reflect and respect the needs of its customers.

Methodology

The distribution customer engagement process included a comprehensive consultation methodology that was based on scientific method, by ensuring the rules of statistical validity and reliability are followed, and at the same time, was inclusive of any customer seeking the opportunity to voice an opinion. The methodology included both qualitative approaches in the form of Focus Groups and Workshop sessions and quantitative approaches including a Telephone Survey and Online Workbook.

The qualitative components were useful to uncover the reasons behind customer needs and preferences, while the quantitative components allowed Ipsos to provide Hydro One with a representative and reliable measurement of the magnitude of customer needs and preferences.

Hydro One's residential, seasonal and small business customers were surveyed using the following approaches:

- Online Workbook: representative sample of 1,604 customers and 17,053 customer responses from an open-link to the online workbook;
- Focus Groups: eight online focus groups with 56 customers;
- Telephone Survey: random and representative survey of 500 residential and seasonal customers; 200 small business customers; and 300 First Nations customers.

Hydro One's large distribution customers, comprised of large distribution accounts, local distribution customers, commercial and industrial customers, and connected distributed generation customers were surveyed using the following approaches:

- Nine in-person Workshop Sessions held in seven cities and attended by 129 people representing 104 customers; and
- Online Workbook completed by an additional 87 customers who did not attend the in-person Workshop session.

Results of Customer Engagement

The customer engagement process produced the following key findings that are consistent with the Distribution System Plan and Distribution Business Plan set out in this document:

- *Keeping costs as low as possible is customers' top priority.* This preference is influenced by a desire to see Hydro One demonstrate greater fiscal management and operational efficiency before considering rate increases. Many customers believe that total electricity costs are approaching being unaffordable.

- *Maintaining reliable electricity service is consistently second priority to cost.* Power quality events and unplanned momentary power interruptions of less than one minute, rather than sustained interruptions of one minute or more, is the primary concern. Some customers have capacity challenges and want more access to power in order to grow their enterprises. Customer service improvements are not something for which customers are willing to pay higher rates.
- *Large customers are more concerned with the reliability of service* they currently receive than residential and small business customers. However, although this group of customers is more inclined to value better reliability, they are not willing to entertain the corresponding rate impact.
- *All large customer segments prioritize the renewal program that focuses on replacing equipment that affects reliability* ahead of other options for improving reliability. Other options include: tree-trimming, using technology to reduce the chances of losing power, strengthening the grid to better withstand severe weather, better detection of outages and/or remotely responding to outages.
- *Willingness to accept a rate increase to maintain and improve service level is limited*. The majority of residential and small business customers are unwilling to accept higher rate impacts for better reliability; large customers generally accept that investments are needed; however they expect HONI Dx to exhaust all operational efficiencies before raising rates. At present, there is limited acceptance of any of the illustrative rate impact scenarios, even to maintain the current levels of reliability and service.

It is worth noting that when Residential & Small Business customers were informed that to maintain reliability and customer service, a typical customer's monthly bill would need to increase by about 1% ($2.00), about half of Residential and Seasonal customers were willing to accept it.

How the Distribution System Plan reflects Customer Needs and Preferences

Hydro One's Distribution System Plan reflects its general assessment of customer needs and preferences. Customer needs and preferences have been incorporated into the Distribution System Plan in the following ways:

- Pacing of investments in order to minimize rate impacts and offset the effects of a reduced load forecast. This includes managing asset replacement rates and, where appropriate, accepting potentially increased reliability risk to reduce or defer capital spending requirements in order to minimize customer rates;
- Hydro One has implemented a number of productivity initiatives to reduce unit and operating costs. Executing on identified productivity and efficiency enhancements to change and reduce its cost structure is expected to result in lower customer rates;
- Hydro One's overall business plan was optimized such that distribution reliability will not deteriorate. For example, pursuant to the pole replacement program, 77,400 poles will

be replaced over the term of the plan, managing the aging pole population and addressing the volume of poles that have been assessed to be in poor condition;

- A top priority for Large Customers is to improve power quality. Hydro One has therefore created an OM&A program to assist Large Distribution Account customers with investigations to determine the source of the power quality issue that they are experiencing. This program has been budgeted to complete one audit per year;
- To help address Power Quality issues for Hydro One's Large Customers a capital power quality program has been incorporated into the plan. This program will install power quality meters when needed to assist in power quality investigations, install surge arresters, or improve grounding. Approximately $200 thousand per year has been allocated to this work;
- Hydro One has increased the funding for reliability enhancement projects to specifically target Large Distribution Account (LDA) and mid-size industrial customers. These projects will be selected to improve system reliability where concerns have been raised by Hydro One's LDA and mid-size industrial customers that a performance issue with the existing network. Investments may include installing lightning arrestors, new switches, automatic sectionalizing devices, or creating feeder ties to improve restoration time. The funding for these investments will increase by approximately $3 million annually starting in 2018 from the current approximately $1.5 million per year; and
- Residential and Small Business customers requested that Hydro One maintain its existing level of reliability. To prevent an overall deterioration in reliability, Hydro One will be improving reliability on the worst performing feeders in the Province. This program will deploy communication to the open point switches, and install sectionalizers and feeder breakers. This will allow controllers to quickly isolate faults and restore power to the majority of effected customers soon after the issue is identified. This program will annually invest between $14 million in 2018 and $20 million in 2022.

The Distribution System Plan reflected in this Distribution Business Plan seeks to meet customers' needs regarding reliability and power quality, in a manner that produces outcomes that are valued by customers.

Customer Initiatives

In order to provide better service for Hydro One customers, the following major customer initiatives have been included in the business plan that will deliver cost savings and improved customer experiences:

Initiative	Description	Cost
eBilling	The number of eBilling customers is expected to increase from 8% currently to over 40% in 2022. This will result in a reduction of paper bill volumes and significant reduction in associated postage costs.	$12.6 million

High Bill Alerts	Customers will receive an alert if their energy usage is expected to surpass a certain threshold. This will reduce the volume of High Bill calls into the call center. High Bill Alerts will also increase a customer's ability to manage their energy usage and reduce their electricity bill.	
Web Redesign	The new corporate website and My Account self-service site is expected to increase the number of self-service transactions completed by customers from 90 thousand currently to 500 thousand in 2019, thereby reducing calls into the call center.	$15.1 million
Bill Redesign	The bill redesign project will help to improve customer understanding of their bill, thereby improving customer satisfaction and potentially reduce calls to the call center.	$5.0 million
Remote Disconnect	Remote Disconnect technology will reduce disconnection volumes in the field since fewer truck-rolls will be required, thereby reducing operational costs.	$4.5 million

First Nations and Métis

Hydro One's strategy insofar as it relates to First Nations and Métis is designed to ensure that the Company remains committed to developing and maintaining relationships with First Nations and Métis communities that are based on mutual respect. Hydro One's Distribution business serves the majority of the First Nations and Métis communities in Ontario and in many cases the needs of these communities are unique. Hydro One's ongoing engagement with First Nations and Métis communities reflects the issues faced by these communities, and the evolving commercial, legal and policy requirements necessary to develop and maintain strong relationships.

Hydro One has multi-faceted relationships with First Nations and Métis communities, and our management believes that there are many opportunities to strengthen and extend our relationships. First Nations and Metis communities are involved in a variety of customer engagement activities. For example, Hydro One's customer engagement initiative in preparation for its 2018-2022 Distribution System Plan included First Nations customers and over-sampled this group relative to their size within the total customer base, to ensure that we reliably captured the needs and preferences of this important customer group.

Hydro One is also in the process of developing a consolidated framework to guide our First Nations and Métis relations and engagement across all of our lines of business. This framework includes reviewing concerns raised and issues faced by First Nations and Métis communities, researching best practices across the industry, benchmarking Hydro One's activities to these best practices and holding workshops with internal stakeholders to give consideration to the new strategic approaches.

Hydro One is actively pursuing a number of initiatives that fit well with the new framework:

- Hydro One has been engaged with the Ontario Energy Board in the development of an on-reserve First Nations electricity rate. Hydro One is committed to supporting the OEB's work to develop meaningful solutions to the issues it is considering, including the options to design, develop and implement a new First Nations rate, as well as related cost and funding issues and their impact on other electricity consumers, distributors, transmitters and other stakeholders;
- Over the past year Hydro One has also successfully offered a new service model to several Ontario First Nation communities that focuses on in-community, face-to-face interactions, to ensure that customers understand and have access to all available programs. This service involves representatives from Hydro One's Customer Service and First Nations and Metis Relations teams visiting First Nations and Metis communities around the province to meet with Chiefs and Councils to conduct information sessions and hold one-on-one sessions with individual customers. During these meetings Hydro One is signing up interested customers for available conservation programs, collaborating with community service organizations such as the United Way to help low-income customers, and ensuring that customers who qualify are taking advantage of the Province's Ontario Electricity Support Program;
- Hydro One is in the early-stage development of discussions with First Nations and Metis representatives related to the company's upcoming distribution rates application for 2018-2022.

The Distribution System Plan to Achieve Business Objectives

System Planning Process

Infrastructure asset management is the combination of management, financial, economic, engineering, and other practices applied to physical assets with the objective of providing the required level of service in the most cost-effective manner. It includes management of the entire lifecycle - including design, construction, commissioning, operating, maintaining, repairing, modifying, replacing and decommissioning/disposal - of physical and infrastructure assets.

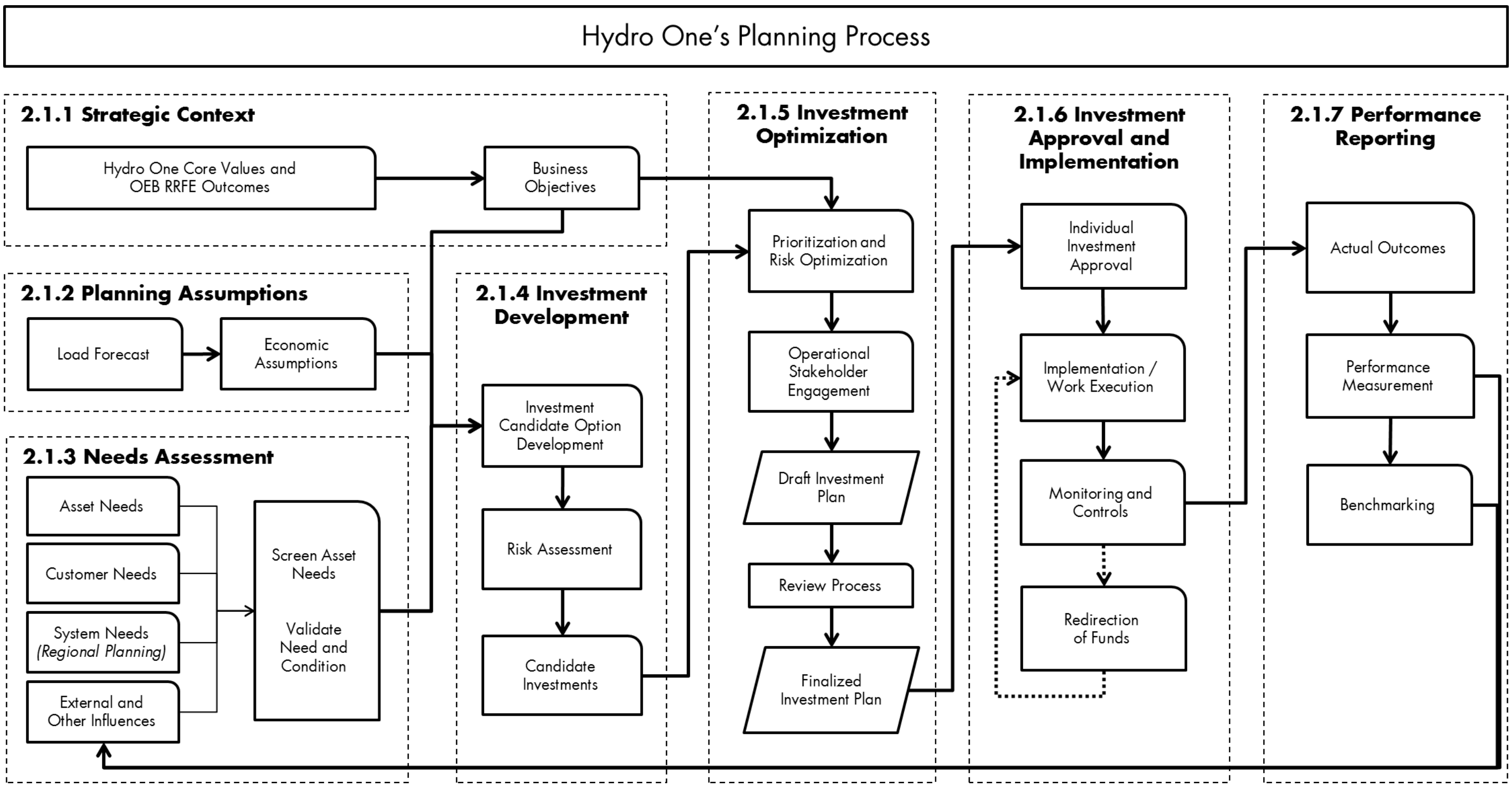
Hydro One Distribution's asset management process is designed to identify and scope the optimal timing of asset maintenance and capital investments in order to mitigate incremental risk to Hydro One's business objectives, while optimizing total cost and managing customer rate impacts.

Hydro One's planning process is an ongoing cyclical process that develops an annual budget for Operations, Maintenance and Administration (OM&A) and capital investments, and a five-year planning forecast that is consistent with the OEB's filing requirements for a consolidated five-year capital plan. All investments follow this same process. The planning process cycle in 2016, which underpins Hydro One's investments in its Distribution System Plan, includes the 2018 to 2022 period.

The Hydro One planning process consists of seven stages and is outlined in the figure below.

1. **Strategic Context**: Incorporation of strategic direction from Hydro One's Board of Directors and Executive Leadership Team that is used to focus the identification of needs and appropriately prioritize the candidate investments.
2. **Planning Assumptions**: Incorporation of load forecast and economic assumptions to guide the development of investments.
3. **Needs Assessment**: Assessment of needs based on the existing assets, customer needs and preferences, system requirements and other influences.
4. **Investment Development**: Development of candidate investments to address the identified needs.
5. **Investment Optimization**: Risk-based Prioritization of the proposed investments to yield an optimized investment plan.
6. **Investment Approval and Implementation**: Management of the investments within the optimized investment plan from planning, final approval and through execution to project completion.
7. **Performance Reporting**: Monitoring the plan through a set of performance metrics.

Hydro One's Investment Planning Process



Distribution System Plan

Hydro One's Distribution System Plan (DSP) reflects the outcome of Hydro One's iterative business planning process to appropriately prioritize and pace its investment plan over 2017 to 2022 planning period, to align (i) identified customer needs and preferences; (ii) responsible stewardship of Hydro One's distribution system; and (iii) customer rates. This iterative process is described below.

As part of the process to determine an investment plan for the 2018 to 2022 portion of the business planning period, three investment scenarios were developed and shared for review with the Executive Leadership Team and the Board of Directors for the purpose of understanding the rate impact of each plan. A particular emphasis was placed on the first year of that period, 2018.

Plan A:

- 2018 Capital spend of $784 million. Average capital spend of $798 million for 2019-2022; designed to meet business objectives; Customer Service IT investments implemented;
- 2018 Rate Increase of 7.1% and average annual rate increase 3.8% over 2018 to 2022; and
- Reliability: System Average Interruption Duration Index (SAIDI) improves by approximately 6% and System Average Interruption Frequency Index (SAIFI) by 4%, by 2022.

Plan B:

- 2018 Capital spend of $685 million. Average capital spend of $747 million for 2019-2022; business objectives largely achievable, but effect on reliability and related customer impacts may partly impair some objectives;
- 2018 rate increase of 6.2% and average annual rate increase 3.5% over 2018 to 2022;
- Lower reliability than Plan A;
- Reliability: SAIDI improves by approximately 3% and SAIFI by 2%, by 2022.

Plan C:

- 2018 Capital spend of $604 million. Average capital spend of $642 million for 2019-2022; high risk of missing business objectives due to a large increase in reliability risk;
- 2018 rate increase of 5.1% and average annual rate increase 2.9% over 2018 to 2022;
- Reliability: SAIDI and SAIFI decline by approximately 2% by 2022; and
- Lower value for money as unplanned corrective work increases.

Ultimately it was decided to adopt Plan B "as modified" resulting in capital spend reductions and additional OM&A savings from the corporate common groups in 2018 that would attain a 5.8% rate increase. Given the requirements of Hydro One's distribution system assets, the lower

2018 capital expenditure level would only be sustainable for one year. Also, the plan does not include a capital true-up in 2019-2022 for the reduction outlined in 2018.

Plan B "as modified" capital adjustments included a $5 million reduction in IT spend, $25 million reduction in the wood pole program, $15 million reduction in station refurbishment investment, $10 million in component replacement activities and $10 million reduction in facilities and fleet investments in 2018. Final plan has an average capital spend over 2018 to 2022 of $732 million.

The summary of 2017 to 2022 distribution capital expenditures is set out in the table below.

Summary of Distribution Capital Budget ($ Millions)

Description	2017	2018	2019	2020	2021	2022
Sustaining	$ 302	$ 282	$ 346	$ 369	$ 383	$ 467
Development	$ 217	$ 230	$ 240	$ 233	$ 232	$ 233
Operations	$ 13	$ 17	$ 46	$ 6	$ 7	$ 9
Corp Common Costs & Other Capital	$ 102	$ 106	$ 124	$ 111	$ 110	$ 109
Total	**$ 634**	**$ 634**	**$ 757**	**$ 719**	**$ 731**	**$ 818**

An overview of the main conditions driving the investments in each of the OEB-compliant asset investment categories is set out below.

System Access

System Access investment costs are projected to decline in 2017 due mainly to the completion of the metering CDMA replacement project and the expected decrease in distributed generation connections. New connections, line relocations, and service upgrades make up the bulk of activities in this category over the first four years leading to increases in-line with inflation. There is a significant increase in projected spending in 2022, which reflects the anticipated commencement of smart meter replacement, as the current population of smart meters approach end of service life.

System Renewal

System Renewal investment costs are projected to increase by an average of 3.7% annually during the forecast period. Storm damage restoration, pole replacements, and distribution station refurbishments make up the bulk of the activities in this category. Storm damage restoration costs are expected to remain flat. The pole replacement program is expected to increase until 2020 to address poles that have reached the end of their expected useful life and then level off thereafter. The station refurbishment program is expected to continue increasing over time to reflect the growing number of assets expected to reach the end of their useful life.

System Service

While System Service investment costs are projected to fall slightly over the Distribution System Plan period, Hydro One expects variability from year-to-year based on specific investment needs. The bulk of these investments accommodate increases in load that will constrain the ability of the system to provide consistent service. To alleviate this constraint, a number of investments throughout the province are planned to upgrade capacity of Hydro One's distribution assets.

Hydro One is implementing a new significant System Service approach in 2017, the modernization of the worst performing feeders, and expanding it through the forecast period. This investment will improve system reliability for poorly performing supply feeders.

General Plant

General Plant investment costs are expected to decline modestly over the forecast period. The largest portion of General Plant spending is on transport and work equipment investments. The next largest portion funds accommodation facility improvements. There is a significant increase in General Plant spending forecast between the years 2017 to 2020. This forecasted increase is primarily due to the new planned Integrated System Operations Centre, which will replace the existing backup power system control and telecommunications management centers and accommodate a new security operations center to meet business and regulatory requirements.

Distribution In-Service Additions

Capital expenditures and additions to rate base can be a significant contributor to revenue requirement increases. Hydro One has targeted a paced approach to its distribution capital program to address the needs and preferences of our customers; the condition and reliability of the distribution system; and mitigate the effect of in-service additions on customer rates.

Hydro One has pursued efficiencies and renewal capital deferrals over the 2017/18 period to mitigate the impact of in-service capital on customer rates.

There are two significant, non-typical investments in Hydro One's Distribution System Plan that represent a substantial increase over historically approved levels; these investments include the Integrated Systems Operations Centre in 2019 and the Advanced Metering Infrastructure ("smart meter") replacement beginning 2022, as discussed above.

Expected in-service additions over the 2018 to 2022 period that are needed to maintain the condition and reliability of the distribution system are forecast to increase by approximately 10% in 2019 versus 2016 levels, and stabilize through 2022, as shown in the figure below.

Integrated Systems Operations Centre

The Integrated System Operations Centre (ISOC) will serve as the backup center for the Ontario Grid Control Center and the Integrated Telecommunications Management Centre. The current backup facilities are currently at capacity and do not meet Hydro One minimum standards. Security Operations Centre and an Emergency Operating Centre are included due to the risk and lack of a primary site for operations, monitoring and coordinated response for physical security threats, which are imperative for business continuity. Security Event Monitoring provides cyber surveillance monitoring services and will be provisioned with Data Centre capacity.

The ISOC has a planned in-service of 2020 with capital spend of $10.5 million in 2018, $42.6 million in 2019 and $3.3 million in 2020.

Operations, Maintenance and Administration (OM&A) Expense

Summary of Distribution OM&A Budget ($ Millions)

Description	2017	2018	2019	2020	2021	2022
Sustaining	$ 334	$ 347	$ 349	$ 358	$ 364	$ 368
Development	$ 21	$ 22	$ 23	$ 25	$ 26	$ 27
Operations	$ 25	$ 25	$ 26	$ 26	$ 27	$ 27
Customer Services	$ 133	$ 132	$ 132	$ 132	$ 132	$ 132
Corp Common Costs & Other OM&A	$ 77	$ 75	$ 71	$ 67	$ 67	$ 66
Property Taxes & Rights Payments	$ 5	$ 5	$ 5	$ 5	$ 5	$ 6
Total	**$ 595**	**$ 606**	**$ 606**	**$ 613**	**$ 621**	**$ 626**

Distribution OM&A is forecast to increase over the 2017 to 2022 business planning period by approximately 1%. Forecast OM&A reflects Hydro One Distribution's planned Custom Incentive Rates application for 2018 to 2022, which includes an Annual Adjustment Mechanism that is adjusted for inflation, distribution industry productivity, and a Hydro One Distribution productivity stretch factor. Actual OM&A performance over the business planning period is expected to vary with the amount of OM&A costs notionally recovered in OEB-approved rates, due to the productivity and efficiency initiatives incorporated into this Distribution Business Plan.

Corporate Common Costs

Hydro One utilizes a centralized shared services model to deliver its common services to its transmission and distribution businesses and to its affiliated companies. Each business and affiliate pays its share of these costs based on a cost allocation methodology developed by Black and Veatch Corporation and approved by the OEB, which utilizes a breakdown of activities and drivers based on cost causality principles.

Distribution Corporate Common Costs and Other OM&A Costs ($ Millions)

Description	2017	2018	2019	2020	2021	2022
Common Corp Functions and Services	$ 92	$ 91	$ 91	$ 90	$ 91	$ 92
Asset Management	$ 14	$ 14	$ 14	$ 14	$ 15	$ 15
Information Technology	$ 80	$ 76	$ 75	$ 74	$ 74	$ 74
Cost of Sales	$ 4	$ 5	$ 5	$ 5	$ 5	$ 5
Other OM&A	$ (114)	$ (111)	$ (114)	$ (116)	$ (117)	$ (120)
Total	**$ 77**	**$ 75**	**$ 71**	**$ 67**	**$ 67**	**$ 66**

Productivity and Savings

Productivity Strategy

Hydro One's executive leadership and Board of Directors are committed to building a strong performance management culture and the ability to measure and track performance is essential to this vision. The Company has aligned its planning, execution and reporting functions around performance outcomes that are consistent with the OEB's RRFE outcomes that are reflected in the regulatory scorecards for both Transmission and Distribution. The RRFE has four outcome categories: Customer Focus, Operational Effectiveness, Policy Responsiveness and Financial Performance. The correlation between Hydro One's values and business objectives and the OEB's RRFE performance outcomes, is set out in the Table on page 6.

Although Hydro One's outcome measures scorecard has been designed for regulatory purposes, the measures will be used in the company operations to determine whether the execution of the company's investment and operating plans create outcomes that are valued by customers. Performance outcomes will also be tied directly to the variable or "at risk" portion of management compensation, ensuring managers are rewarded for achieving or exceeding performance outcomes that are aligned with outcomes that are valued by customers.

Hydro One will measure the impact of cost reduction strategies associated with implementing industry best practices and strategic initiatives by using a variety of metrics to baseline its historical performance and track progress. Despite increasing external cost pressures and inflation, Hydro One will improve its performance each year in line with its vision of creating a continuous improvement culture. For strategic initiatives or projects that enable productivity improvements, Hydro One will define measures that specifically track the effectiveness of each initiative. Each line of business will be accountable for planning and executing its respective productivity initiatives and will provide a plan to Hydro One's Finance department for review and implementation that will include measures to track performance outcomes based on the RRFE principles.

Performance measures from productivity enabling projects and work program spending will be tracked and reported by the Finance department. These results will be consolidated and reported quarterly to the Executive Leadership Team.

Productivity in the Business Plan

Over the past year, Hydro One completed a company-wide internal evaluation seeking to reduce costs without compromising service quality or work outputs. The purpose of the evaluation was to assess operations for potential efficiency gains and to align the company with industry best practices, freeing up additional resources that could be used to improve RRFE performance outcomes. The recommendations from this review were then investigated to determine if they were feasible and if they could create sustainable improvements. Quantifiable improvements were then embedded in the business plan and were tied to the work programs that they impact so that managers would be accountable for delivering the savings. The key sources for potential productivity savings include:

- More effective procurement programs, including investments in new processes and tools;
- Reductions in administrative expenditures through improved processes and optimization of internal staff skills;
- Rationalization of Hydro One's IT spending;

- Improved field efficiency through improved work planning; and
- Improved execution through the consolidation of stations work.

The cost savings anticipated from these productivity initiatives, along with a number of additional, more recent initiatives, have been included in the table below that illustrates the measurable savings that have been embedded in the business plan.

Productivity Improvements in Business Plan 2017-2022

$M	2017	2018	2019	2020	2021	2022
Operations	$ 7.0	$ 11.3	$ 11.5	$ 13.1	$ 13.5	$ 13.8
Procurement	$ 10.3	$ 14.2	$ 15.3	$ 19.1	$ 20.2	$ 20.8
Capital	**$ 17.3**	**$ 25.5**	**$ 26.8**	**$ 32.2**	**$ 33.7**	**$ 34.5**
Operations	$ 20.1	$ 23.5	$ 26.7	$ 28.4	$ 29.7	$ 33.1
Customer	$ 0.6	$ 1.8	$ 2.6	$ 3.2	$ 4.1	$ 4.8
Procurement	$ 1.5	$ 2.2	$ 2.1	$ 2.5	$ 2.7	$ 2.8
IT	$ 5.3	$ 7.3	$ 9.3	$ 9.3	$ 9.3	$ 9.3
OMA	**$ 27.5**	**$ 34.8**	**$ 40.7**	**$ 43.4**	**$ 45.8**	**$ 50.0**
Procurement	$ 1.8	$ 1.8	$ 1.8	$ 1.8	$ 1.8	$ 1.8
Administrative	$ 1.1	$ 1.4	$ 1.5	$ 1.5	$ 1.5	$ 1.5
Corporate Common	**$ 2.9**	**$ 3.2**	**$ 3.3**	**$ 3.3**	**$ 3.3**	**$ 3.3**
Grand Total	**$ 47.7**	**$ 63.5**	**$ 70.8**	**$ 78.9**	**$ 82.8**	**$ 87.8**

The major drivers of the savings in each category are highlighted below.

Operations

- Move-to-Mobile will increase field workforce efficiencies through the utilization of new mobile application technology to manage inventory, and document field work order management and enable onsite decision making;
- The vegetation management program will deliver savings from various initiatives such as use of hiring hall workers to complete low-skilled a large portion of the low-skilled brush control activities; and
- The cable locates program will be outsourced to significantly reduce the cost per unit.

Procurement

- Will achieve cost reduction by bundling multiple contracts with a single supplier and negotiating volume discounts across multiple categories and contracts; maximize competitive pressure through multiple feedback rounds; installation of catalogue buying via new SAP tools and enforcement of compliance with procurement contracts; and
- Standardization of spend and specifications will enable direct, like-for-like comparisons across bidders, reducing procurement costs and inventory requirements.

Customer

- The new eBilling solution will reduce the volume of paper bills and result in associated postage savings over the planning period. The department also anticipates approximately 500,000 self-service transactions by 2019 as a result of the Web Redesign project.

Information Technology

- 3rd Party contractor rate reduction will reduce rate by 20-30% effective 2017;
- Backup and storage optimisation will reduce SAP storage costs by 75% without a material change in risk profile; and
- Infrastructure and database decommissioning of 138 servers and 38 databases that had very little or no utilization and reduced monthly server and database fees; plans for additional decommissioning in 2017.

Administrative

- Leveraging expense IT systems has enabled additional efficiencies such as the reduction of company provided credit cards; and
- Organizational changes have enabled labour efficiencies resulting in recently vacant positions not being backfilled.

Pension Savings

Hydro One engaged Willis Towers Watson to prepare an updated actuarial valuation report relating to Hydro One's defined benefit pension plans as at December 31, 2015. As a result of changes in employee contribution rates, updated investment returns, changes in employee benefits and updated actuarial assumptions, Hydro One's pension contribution declined for the three years, as follows, allowing reductions in OM&A by $48 million and capital by $51 million for the three years, providing a significant and immediate reduction in customer rates. These savings are in addition to the productivity savings identified in the Productivity Improvements in Business Plan above.

$M	2016	2017	2018
OM&A	16	16	16
Capital	17	17	17
Total	**33**	**33**	**33**

The capital reductions are offset by additional reinvestment, and the OM&A reductions are included in the OM&A amounts.

Productivity and Outcome Measures Scorecard

Hydro One is accountable for identifying specific outcomes valued by its customers and demonstrating how the utility's plans and proposed operating and capital expenditures deliver those outcomes. These outcomes are aligned with the four outcomes of the RRFE; Customer Focus, Operational Effectiveness, Public Policy Responsiveness and Financial Performance.

Hydro One identified potential metrics drawn from internal and external sources that include: Hydro One's past performance management metrics, benchmarking studies, scorecards and metrics of other utilities in the public domain. The identified metrics were screened to select metrics that are relevant, objective, measurable and actionable. The company benefited significantly from knowledge obtained by the consideration of cost trends, benchmarking of comparable utilities, and from its customer engagement in setting outcomes and performance metrics.

Metrics were selected that promote behaviors that will drive desired outcomes for customers, stakeholders and shareholders. The proposed framework aligns customer and distributor interests, supports the achievement of important public policy objectives, and places a greater focus on delivering long term value to customers.

- The proposed measures have been selected based on guidance from the OEB's Handbook for Utility Rate Applications which indicates the OEB's key considerations for a utility's proposed outcomes and performance metrics reflects a focus on strategy and results, not activities;
- The need to demonstrate continuous improvement;
- Outcomes which are demonstrated to be of value to customers; and
- Performance metrics which will accurately measure whether outcomes are being achieved, and which include stretch goals to demonstrate enhanced effectiveness and continuous improvement.

The table below illustrates the draft productivity and outcomes measures scorecard that Hydro One is proposing in addition to the OEB distribution scorecard that is already in use. This scorecard is still under development with a completed version expected to be filed in the 2017 Distribution application.

Productivity and Outcome Measures Scorecard

				Historical Results		
RRFE Outcomes			Measure	2013	2014	2015
Customer Focus	Customer Satisfaction	1	Handling of Unplanned Outages Satisfaction (%)	78%	75%	76%
		2	Call Centre Customer Satisfaction	82%	81%	85%
		3	My Account Customer Satisfaction	64%	75%	78%
Operational Effectiveness	Cost Control	5	Pole Replacement - Cost Per Unit	7,824	8,928	8,392
		6	Vegetation Management - Cyclical Cost per km Line Clearing	7,994	10,317	9,032
		7	Station Refurbishments - Cost per Transformer Bank	New measure - to be defined.		
		8	OM&A per customer	498	551	454
		9	OM&A per km of line	5,398	5,872	4,917
	System Reliability	10	Line Equipment Caused Interruptions	7,266	8,311	8,164
		11	Vegetation Caused Interruptions	5,791	6,540	6,944
		12	Substation Caused Interruptions	129	158	141
		13	SAIDI - Rural	4.9	3.7	3.9
		14	SAIFI - Rural	30.0	10.9	14.3
		15	SAIDI - Urban	2.8	2.3	1.6
		16	SAIFI - Urban	11.1	3.1	3.5
		17	Large Customer Interruption Frequency (LDA's)	New measure - to be defined.		

Benchmarking

In the Decision relating to Hydro One's last Distribution Rate Application for 2015 to 2019 distribution rates (EB-2013-0416), dated March 12, 2015, the OEB found the proposed application showed limited prospects for continuous improvement, lacked externally imposed improvement incentives, included limited cost and productivity benchmarking support and failed to demonstrate value to customers commensurate with the forecast spending. To address the perceived shortcomings in the application, the OEB directed Hydro One to undertake a number studies and submit these reports in conjunction with its next application for distribution rates:

- Total factor productivity study of Hydro One's own productivity, included data from 2002 and following years at a minimum;
- A comprehensive trend analysis of the vegetation management program showing year over year comparisons in unit costs;
- A best practices study for vegetation management similar to the CN Utility study filed in EB-2009-0096;
- An external benchmarking study on the unit cost of the pole replacement program;
- An internal trend analysis to show the variability of the unit costs of the pole replacement program year over year;
- An external benchmarking study on the unit cost of the station refurbishment program;
- An internal trend analysis to show the variability of the unit costs of the station refurbishment program year over year; and
- A compensation study similar to the study filed as part of the application considered in EB-2013-0416 to allow benchmarking to comparable companies.

The Distribution System Plan and this Distribution Business Plan reflect the recommendations from each of these studies, consistent with the expectations of the OEB. Where recommendations have not been adopted by Hydro One, the company will explain why it was appropriate to do so or that adopting the recommendation was not otherwise feasible, in the upcoming application for 2018 to 2022 distribution rates.

Revenue Requirement & Customer Bill Impacts

Distribution Revenue Requirement	2017	2018	2019	2020	2021	2022
OM&A	$ 593	$ 592	$ 600	$ 607	$ 615	$ 623
Depreciation	$ 390	$ 394	$ 414	$ 429	$ 448	$ 464
Return on Debt	$ 183	$ 191	$ 200	$ 211	$ 224	$ 234
Return on Equity	$ 253	$ 269	$ 283	$ 298	$ 316	$ 330
Income Tax	$ 49	$ 58	$ 61	$ 63	$ 70	$ 71
Revenue Requirement	$ 1,468	$ 1,505	$ 1,558	$ 1,607	$ 1,674	$ 1,723
Acquired LDCs OM&A Adder	$ -	$ -	$ -	$ -	$ 11	$ 11
Rate Riders	$ 11	$ 23	$ 23	$ 23	$ 23	$ 23
Other revenue impacts	$ (53)	$ (47)	$ (47)	$ (47)	$ (47)	$ (47)
Rates Revenue Requirement	**$ 1,426**	**$ 1,480**	**$ 1,534**	**$ 1,583**	**$ 1,660**	**$ 1,710**
Rate Increase Required, excl Load		**3.8%**	**3.6%**	**3.2%**	**4.9%**	**3.0%**
Estimated Load Impact		2.0%	-0.2%	-0.7%	-2.5%	-0.6%
Rate Increase Required		**5.8%**	**3.4%**	**2.5%**	**2.4%**	**2.4%**
Est Total Bill Impact (R1 customer - 30%)		**1.7%**	**1.0%**	**0.7%**	**0.7%**	**0.7%**

Revenue requirement calculated above reflects the following:

- 2017 OEB approved revenue levels;
- 2018 rebasing year reflecting required revenues;
- 2019-2022 OM&A reflects OEB proposed Price Cap escalations; and
- 2019-2022 depreciation, return on debt and tax related revenues assume the implementation of a Custom Capital Factor.

Load Forecast Summary

Hydro One uses a number of methods, such as econometric models, end-use models, and customer forecast surveys to produce the load forecast required for its distribution business. This load forecast methodology is the same method that Hydro One has applied in previous Distribution Rate Applications (EB-2005-0378, EB-2007-0681, EB-2009-0096, and EB-2013-0416). Similar methods are also used by major utilities throughout North America.

The forecasts presented are weather-normal at the wholesale level unless otherwise specified. Abnormal weather effects are removed from the base year for load forecasting purposes so that the forecast assumes typical weather conditions based on the average of the last 31 years. This weather correction methodology was reviewed and approved by the Board in the Distribution Cost Allocation Review (EB-2005-0317).

Using this approved forecasting methodology; the forecast for the test years (2018 to 2022) is presented in the table below.

Distribution

	2017	2018	2019	2020	2021	2022
Number of Customers (by contract)	**1,291,963**	**1,300,519**	**1,309,221**	**1,317,972**	**1,326,734**	**1,335,373**
Energy (Consumption) Billed sales (GWh)	15,094	15,003	14,878	14,881	14,844	14,845
Demand Billed sales (GWh)	3,450	3,426	3,392	3,387	3,374	3,370
Sub-Transmission	4,912	4,877	4,828	4,818	4,807	4,808
Total Consumption Sales (GWh)	**23,457**	**23,306**	**23,098**	**23,086**	**23,025**	**23,023**
Demand sales (MW)	**11,925**	**11,848**	**11,739**	**11,731**	**11,692**	**11,685**

While the Provincial aggregate load growth is expected to decline, the customer count is expected to rise moderately. The decrease in load is mainly due to the impact of Conservation and Demand Management (CDM) and the current economic conditions. There are also pockets of load and customer growth expected to occur in Hydro One's service territory, primarily in areas that border major urban centers.

Acquired LDC's

Hydro One Distribution expects to continue to assess further opportunities to acquire other Ontario-based local distribution companies over the 2017 to 2022 business planning period. Consistent with OEB policies, the integration of acquired utilities for rate setting purposes will not occur until the conclusion of the OEB-approved rebasing deferral period. Hydro One Distribution plans to apply to the OEB for approval to close each of Norfolk, Haldimand and Woodstock to Hydro One's revenue requirement and rate base in 2021.

Acquired LDCs OM&A Budget ($ Millions)

Description	2017	2018	2019	2020	2021	2022
Norfolk	3.1	3.1	3.2	3.2	3.3	3.4
Haldimand	5.0	5.1	5.1	5.2	5.3	5.4
Woodstock	2.1	2.1	2.3	2.1	2.1	2.2
Total	**10.2**	**10.3**	**10.6**	**10.5**	**10.7**	**11.0**

Acquired LDCs Capital Budget ($ Millions)

Description	2017	2018	2019	2020	2021	2022
Norfolk	2.6	2.1	2.1	2.1	3.2	3.2
Haldimand	3.4	3.4	3.9	4.0	4.0	4.0
Woodstock	2.2	2.3	1.8	2.0	2.2	2.3
Total	**8.2**	**7.8**	**7.8**	**8.1**	**9.4**	**9.5**

Key Financial Results

Following is a summary of principal financial outcomes for Distribution for 2017-2022.

Key Financial Results	2017	2018	2019	2020	2021	2022
Revenue requirement	$ 1,468	$ 1,505	$ 1,558	$ 1,607	$ 1,684	$ 1,734
Net income	$ 252	$ 286	$ 302	$ 317	$ 328	$ 341
Achieved ROE	8.2%	8.8%	8.9%	8.9%	8.9%	8.9%
Allowed regulatory ROE	8.8%	8.8%	8.8%	8.8%	8.8%	8.8%
OM&A	$ 606	$ 616	$ 616	$ 624	$ 631	$ 637
Capital expenditures	$ 642	$ 642	$ 765	$ 727	$ 741	$ 827
Total rate base	$ 7,190	$ 7,672	$ 8,049	$ 8,477	$ 9,010	$ 9,408
Total fixed rate debt to rate base	56.0%	56.0%	56.0%	56.0%	56.0%	56.0%

Required revenue for Distribution aligns with that approved by the OEB for 2017. Forecast revenue requirement for 2018 through 2022 reflects Hydro One Distribution's planned Custom Incentive Rates application, which reflects an Annual Adjustment Mechanism and a Custom Capital Factor. It is assumed that the Distribution business will achieve the allowed ROE throughout the business planning period, with the exception of 2017. Shortfalls in financial performance in 2017 is largely attributable to load impacts arising from lower load relative to the forecast embedded in the approved Distribution rate application for 2015-2017.

Consolidated Business Plan 2017-2022

December 2, 2016

INTERNAL and CONFIDENTIAL

Strategy

The strategy and business goals set out below are consistent with and included in the business plans for Hydro One's Ontario-based transmission and distribution businesses. A statement of the company's vision, goals, and business objectives that includes non-Ontario growth, innovation, and other strategic imperatives is under development and will be presented to the Board in April 2017.

Hydro One's strategic vision for its Ontario-based, rate-regulated transmission and distribution businesses is the following: Hydro One is transforming to achieve its **vision** of becoming a best-in-class, customer-centric commercial entity, with a culture of continuous improvement and excellence in execution. To achieve this vision, Hydro One will execute on its **strategy** to transmit and distribute electricity safely and reliably in a manner that produces the greatest value for customers. Hydro One seeks to be excellent in every facet of its operations, to the benefit of customers, employees and shareholders.

Hydro One's **commercial** orientation means that the company will be focused on customers, demonstrate corporate accountability for performance outcomes, and drive company-wide efficiency and productivity. Understanding customers' needs and preferences and delivering transmission system outcomes that are valued by customers are critical to Hydro One's future success.

Hydro One's vision and strategy reflect **values** that are integral to the well-being of communities:

- Maintaining a safe workplace;
- Caring for customers;
- Operating as one company;
- Being people-powered; and
- Executing with excellence.

Hydro One's executive leadership and Board of Directors are committed to building a strong performance management culture and the ability to measure and track performance is essential to this vision.

Hydro One's vision, strategy and values inform everything the company does, as it works to align three competing but equally important factors: customer needs and preferences, responsible stewardship of its transmission system, and customer rates.

The key outcomes that the Company expects from its strategy are as follows:

- Improved levels of customer satisfaction;
- Minimizing the long-term cost of maintaining the reliability of the Transmission and Distribution systems;

- Maintain top quartile reliability in the Transmission system and continually improve reliability in the Distribution system by mitigating risk arising from asset deterioration;
- Achieve an injury free workplace and a safe environment for the public;
- Compliance with all regulatory and reliability standards; and
- Responsible environmental stewardship.

Customer Expectations

Hydro One will be a customer centric commercial entity that provides service to its customers that meets their needs and preferences while ensuring that the system continues to deliver safe, reliable energy. This customer focus requires that Hydro One have a strong understanding of customer's expectations for Hydro One. These expectations evolve and change over time which is why it is necessary for Hydro One to conduct formal customer engagement activities at regular intervals to ensure that Hydro One's business objectives and investment planning outcomes are appropriate, supplementing ongoing customer feedback and interaction. It also allows us to have focused discussions on system investment plans prior to rate filings.

Hydro One's Transmission and Distribution businesses have very different classes of customers that were segmented and engaged using a variety of consultation methods including but not limited to one-on-one sessions, online surveys and focus groups. The results of the engagement showed contrasting priorities between the two businesses. Transmission customers' top priority was reliability maintenance or improvement and they were willing to accept a small rate increase to achieve that outcome. In addition, energy quality was a significant factor for several sophisticated energy users. Distribution customers consistently prioritized low cost and wanted Hydro One to do its best to limit increases in rates. These preferences have guided the development of the investment plan for each business, with Transmission focusing on investments that will improve reliability and quality, and the Distribution investment plan designed to leverage productivity and keep rate impact low while still seeking some improvements in reliability. Both plans have benefited from a significant focus on analytics and cost efficiency plans to continue to reduce our own costs before we ask our customers for increases in rates.

More details on the methodology for customer engagement and detailed results of the findings can be found in the business plans for Transmission and Distribution.

Common Corporate Costs

Hydro One utilizes a centralized shared services model to deliver its common services to its transmission and distribution businesses and to its affiliated companies. Each business and affiliate pays their share of these costs based on a cost allocation methodology developed by Black and Veatch Corporation and approved by the OEB which utilizes a breakdown of activities and drivers based on cost causality principles.

Of the total common costs, 3.5% or $11 million per year is not allocated to a regulated business as it relates to management of non-regulated activities (for example mergers and acquisitions and non-regulated strategy work).

Total Corporate Common Costs 2016 to 2022

Corporate Common Cost $M	2016F	2017	2018	2019	2020	2021	2022	CAGR
Audit	$ 4	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	9.6%
Corporate Management	$ 20	$ 23	$ 23	$ 24	$ 24	$ 24	$ 24	3.6%
Customer and Corporate Relations	$ 45	$ 52	$ 52	$ 52	$ 52	$ 52	$ 52	2.5%
Facilities Real Estate	$ 9	$ 9	$ 9	$ 10	$ 10	$ 10	$ 10	1.6%
Finance Total	$ 29	$ 33	$ 33	$ 33	$ 31	$ 31	$ 32	1.8%
Finance Inergi	$ 12	$ 11	$ 12	$ 12	$ 13	$ 13	$ 13	1.7%
General Counsel and Secretary	$ 9	$ 10	$ 10	$ 10	$ 10	$ 11	$ 11	2.6%
Information Solutions Division	$ 22	$ 21	$ 21	$ 21	$ 21	$ 22	$ 22	0.2%
Network Operating	$ 49	$ 49	$ 49	$ 50	$ 50	$ 51	$ 51	0.9%
Operations COO Office	$ 3	$ 4	$ 4	$ 4	$ 4	$ 4	$ 4	3.4%
People & Culture	$ 14	$ 16	$ 16	$ 16	$ 17	$ 17	$ 17	3.5%
Planning	$ 49	$ 52	$ 52	$ 52	$ 52	$ 52	$ 53	1.3%
Regulatory Affairs	$ 23	$ 23	$ 23	$ 19	$ 19	$ 19	$ 21	-1.4%
Strategic Services	$ 1	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	10.4%
Total	**$ 288**	**$ 313**	**$ 312**	**$ 310**	**$ 312**	**$ 315**	**$ 320**	**1.8%**

	OM&A	Capital
Transmission Portion	19.0%	30.0%
Distribution Portion	26.4%	19.4%
Other Allocated	5.2%	

Over the planning period between 2016 and 2022, corporate common expenditures are expected to rise by approximately 11% with a compounded annual growth rate of less than 2%, but still in excess of the expected price cap factor of 1.3%. Planned productivity savings and cost efficiencies play an integral role in capping the costs and, in some cases, fully offsetting required increases. From 2018 onwards the costs stabilize and annual increases are mostly due to inflationary pressures.

Main cost drivers and major initiatives within the business planning period are as follows:

- In 2017, Internal Audit will be assuming responsibility for the company's ICFR (Bill 198) program and the associated personnel resulting in increased costs, and in 2016 the new management made a decision to increase both the talent and the scope of internal audit activities.

- People and Culture work requirements are growing over the business planning period, principally an investment in technology to introduce Employee Central and Workforce Analytics. This will allow for faster data extraction in generating reports and the ability to create customized dashboards for managers, and will result in better workforce planning based on attrition and workforce demand.
- The scope of work for Regulatory Affairs has increased significantly due to new requirements outlined in the OEB's Renewed Regulatory Framework (including the new customer engagement process) and new development projects and growth initiatives. Total costs for 2018 and beyond are as a result of efficiencies arising from the recent merging of the Reliability Compliance Assurance group with the Regulatory Compliance group.
- The 2017 to 2022 Customer and Corporate Relations group business plan allows Hydro One to deliver value to our customers and improve customer satisfaction while ensuring compliance with Ontario Energy Board regulations. Increased customer focus results in higher costs required to develop, implement and oversee initiatives leading to improved customer satisfaction results. Initiatives currently underway include improving First Call Resolution within the call centre, new technology that allows customers to interact with Hydro One through the channels of their choice, accommodated through various technology enhancements. Remote Disconnect technology will reduce disconnection volumes in the field since fewer truck-rolls will be required, resulting in approximately $3 million of annual OM&A savings over the planning period.

HYDRO ONE INTERNAL AUDIT REPORT ON AUDITOR-GENERAL FINDINGS AND ACTIONS

Hydro One's Internal Audit Report on the Auditor-General's Findings and Actions will be filed with the blue page update.

HYDRO ONE MANAGEMENT REPORT ON STATUS OF ACTIONS RELATING TO AUDITOR-GENERAL FINDINGS

Hydro One's Management Report on status of actions relating to the Auditor-General's findings will be filed with the blue page update.

CUSTOM IR APPLICATION SUMMARY

1. APPLICATION STRUCTURE

Hydro One's application is based on a Custom Incentive Rate-Setting approach for a 5-year period. The methodology utilized is a Revenue Cap IR in which revenue for the test year t+1 is equal to the revenue in year t inflated by the Revenue Cap Index ("RCI") set out below.

Hydro One's revenue requirement in the first year of the 5-year period (2018) is determined using a cost of service, forward test year approach, consistent with the Board's Renewed Regulatory Framework ("RRF") as most recently set out in the Handbook for Utility Rate Applications (the "Handbook"), released by the Board in October 2016. The revenue requirement in each of the following four years (2019-2022 inclusively) is determined using an RCI that is calculated for each year.

The RCI includes an industry-specific inflation factor and two custom productivity factors. Consistent with RRF, these productivity factors are explicitly included in the rate adjustment mechanism and provide an incentive for Hydro One to achieve capital and OM&A productivity improvements that are in addition to those imbedded in the 2018 to 2022 Hydro One Distribution Business Plan in Exhibit A, Tab 3, Schedule 1, Appendix 1.

The RCI also includes a Custom Capital Factor ("C") that is designed to recover revenue related to new capital investments that are placed in-service in each test year, as further described in this Exhibit.

The Custom Revenue Cap Index (RCI) is expressed as:

$$RCI = I – X + C$$

Where:

- "I" is the Inflation Factor, as determined annually by the OEB.
- "X" is the Productivity Factor that is equal to the sum of Hydro One's Custom Industry Total Factor Productivity measure and Hydro One's Custom Productivity Stretch Factor.
- "C" is Hydro One's Custom Capital Factor, determined to recover the incremental revenue in each test year necessary to support Hydro One's proposed Distribution System Plan, beyond the amount of revenue recovered in rates.

Although Hydro One is seeking the Board's approval for a Revenue Cap IR and Revenue Cap Index, the overall approach is consistent with the RRF and is similar to the custom Price Cap IR and Price Cap Index methodology approved by the Board in EB-2014-0016, for Toronto Hydro-Electric System Limited.

The proposed Revenue Cap IR has a number of advantages versus a Price Cap IR. The Revenue Cap IR:

- Gives Hydro One the needed flexibility to introduce new rate classes in 2021 to fully integrate Norfolk Power Distribution Inc., Haldimand County Hydro Inc., and Woodstock Hydro Services Inc. ("Norfolk", "Haldimand", and "Woodstock", together the "Acquired Utilities"), as described in Exhibit A, Tab 7, Schedule 1;
- Permits the continued transition to fully-fixed rates for residential customers (EB-2014-0416);
- Provides adequate flexibility to reset customer rates should the OEB proceed with the elimination of the Seasonal Rate Class over the 2018 to 2022 Custom IR term (EB-2013-0416/EB-2016-0315);
- Provides adequate flexibility to reset customer rates as the OEB advances its initiative relating to rate design for Commercial and Industrial electricity customers (EB-2015-0043); and

- Allows Hydro One to update its billing determinants to reflect estimated changes in the load forecast over the Custom IR term, consistent with its proposal to integrate the Acquired Utilities.

1.1 INFLATION FACTOR

In its December 2013 Report, "Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors" (EB-2010-0379), the OEB established a methodology for determining the annual Inflation Factor ("I") to be used in incentive-based rate adjustment mechanisms. The Inflation Factor is based on the weighted sum of:

- 70% of the annual percentage change in Canada's GDP-IPI (FDD) as reported by Statistics Canada; and
- 30% of the annual percentage change in the Average Weekly Earnings for workers in Ontario, as reported by Statistics Canada.

Although specifically created for use for incentive rate setting under the Price Cap IR and Annual Index plans, Hydro One proposes to use the same Inflation Factor in its custom Revenue Cap IR and Revenue Cap Index, and to update the Inflation Factor annually for 2019 through 2022, consistent with current Board practice.

The latest Inflation Factor of 1.9% was released by the Board on October 27, 2016 for use in applications for rates effective in 2017. Hydro One has used the 2017 Inflation Factor on a pro-forma basis in its RCI calculation for each of the 2019 to 2022 test years, for the purpose of this Application. The Inflation Factor will be updated annually; when the OEB calculates and makes available the Inflation Factor in each of 2018 to 2021, effective 2019 to 2022, respectively.

1.2 PRODUCTIVITY FACTOR

The Productivity Factor ("X") is equal to the sum of Hydro One's Custom Industry Total Factor Productivity measure and Hydro One's Custom Productivity Stretch Factor. Hydro One engaged Power System Engineering ("PSE") to undertake a study of the Total Factor Productivity ("TFP") for the electricity distribution functions of Hydro One and the Ontario industry (Exhibit A, Tab 3, Schedule 2, Appendix 1) and to undertake a custom econometric benchmarking study of Hydro One's total distribution costs and recommend a Custom Productivity Stretch Factor (Exhibit A, Tab 3, Schedule 2, Appendix 2), consistent with the Handbook.

Based on these studies, Hydro One's proposed Productivity Factor of 0.6% reflects the sum of the Custom Industry Total Factor Productivity measure of 0% and a Custom Productivity Stretch Factor of 0.6%. These metrics are consistent with the industry TFP metric of 0% adopted by the Board in EB-2010-0379 and with the productivity stretch factor assigned to Hydro One as determined by the total cost econometric model developed by Pacific Economics Group ("PEG").

Hydro One intends to update the PSE study to benchmark forecast total costs for 2018 with predicted costs and recalibrate the proposed Custom Productivity Stretch Factor, once actual, final 2016 financial information is available. Should a different Custom Productivity Stretch Factor be determined to be appropriate, Hydro One proposes to update this Application to reflect the new Custom Productivity Stretch Factor and Productivity Factor. Hydro One also intends to update the PEG study to benchmark its forecast total costs for 2018 with predicted costs and recalibrate the productivity stretch factor assigned to Hydro One by the Board using this approach, for comparative purposes.

The Productivity Factor used in the RCI will not be updated annually over the 2019 to 2022 portion of the Custom IR term.

1.3 CAPITAL FACTOR

The Custom Capital Factor proposed in this Application and used in the RCI is designed to ensure that total revenue resulting from the Custom IR is able to meet Hydro One's specific circumstances arising from the proposed capital investments set out in Hydro One's DSP (Exhibit B1).

The Custom Capital Factor is the percentage change in the Total Revenue Requirement (line 11 of Table 1 below) attributable to new capital investment that is not otherwise recovered from customers. This includes depreciation, return on equity, interest and taxes attributable to new capital investment placed in-service each year of the Custom IR term. The Capital Related Revenue Requirement (line 6) each year is based on the change in rate base.

The calculation of the Custom Capital Factor ("C") is set out in Table 1 below.

The Total Capital Related Revenue Requirement metrics in lines 1 to 8 of Table 1 will be calculated by Hydro One in conjunction with the Draft Rate Order using Board-approved values. These metrics will not change over the term of the Custom IR, with the exception of the applied-for cost of capital update in 2021. The Total Revenue Requirement (line 11 of Table 1) will change annually, as a result of the annual adjustment to the Inflation Factor as it applies to OM&A and costs associated with the integration of the Acquired Utilities (line 10).

The OM&A (line 9) provided for each year in Table 1 is determined based on the 2018 forecast provided in the Application and increased by the Inflation Factor ("I") and reduced by the proposed Productivity Factor ("X"), for a total increase of 1.3% per annum.

Table 1: Summary of Revenue Requirement Components ($ Million)

Line		Reference	2018	2019	2020	2021	2022
1	Rate Base	D1-1-1	7,672.3	8,049.1	8,476.8	9,035.4	9,434.7
2	Return on Debt	E1-1-1	190.9	200.3	211.0	224.9	234.8
3	Return on Equity	E1-1-1	269.5	282.7	297.7	317.3	331.3
4	Depreciation	C1-6-2	394.4	414.4	428.7	448.1	464.7
5	Income Taxes	C1-7-2	58.0	61.3	62.6	68.7	69.6
6	Capital Related Revenue Requirement		912.8	958.7	1,000.0	1,059.0	1,100.5
7	Less Productivity Factor (0.60%)			(5.8)	(6.0)	(6.4)	(6.6)
8	**Total Capital Related Revenue Requirement**		**912.8**	**953.0**	**994.0**	**1,052.6**	**1,093.9**
9	OM&A	C1-1-1	591.9	599.6	607.4	615.3	634.2
10	Integration of Acquired Utilities	A-7-1				10.7	
11	**Total Revenue Requirement**		**1,504.7**	**1,552.6**	**1,601.4**	**1,678.7**	**1,728.1**
12	Increase in Capital Related Revenue Requirement			40.2	41.0	58.6	41.3
13	Increase in Capital Related Revenue Requirement as a percentage of Previous Year Total Revenue Requirement			2.67%	2.64%	3.66%	2.46%
14	Less Capital Related Revenue Requirement in I-X			0.79%	0.80%	0.81%	0.82%
15	**Capital Factor**			**1.88%**	**1.84%**	**2.86%**	**1.64%**

The 2018 Total Revenue Requirement of $1,504.7 million (line 11) is determined based on a forward test year, cost of service approach and is the rebasing year for this Application.

In 2019, the Capital Related Revenue Requirement (line 6) increases to $958.7 million versus $912.8 million in 2018. Hydro One will reduce the Capital Related Revenue Requirement (line 6) by the proposed Productivity Factor of 0.6% or $5.8 million (line 7), such that the Total Capital Related Revenue Requirement is $953.0 million (line 8). The change in Total Capital Related Revenue Requirement (line 8) in 2019 versus 2018 is $40.2 million (line 12). This difference is equal to 2.67% of the 2018 Total Revenue Requirement of $1,504.7 million ($40.2 million divided by $1,504.7 million).

The 2.67% increase in Total Capital Related Revenue Requirement is the total increase in revenue requirement arising from the higher 2019 Capital Related Revenue Requirement (line 6). However, the 2.67% increase must be offset by the increase in revenue requirement that results from the application of the Inflation and Productivity Factors (I - X) of the RCI. This is done by determining the percentage of the Total Capital Related Revenue Requirement (line 8) that is already provided for by the Inflation and Productivity Factors. In 2019, this equals 0.79% ($912.8 million x 1.3% / $1,504.7 million). The net result of 1.88% (2.67% less 0.79%) is the 2019 Custom Capital Factor. The calculation of the Custom Capital Factor for each of 2020 through 2022 is the same, as set out in Table 1 above.

1.4 REVENUE CAP INDEX SUMMARY

Table 2 below summarizes the Custom Revenue Cap Index by Component that Hydro One is proposing to use in this Application to determine Total Revenue Requirement for rate-making purposes for 2019 through 2022.

Table 2: Custom Cap Index (RCI) by Component (%)

Custom Revenue Cap Index by Component	2019	2020	2021	2022
Inflation Factor (I)	1.90	1.90	1.90	1.90
Productivity Factor (X)	-0.60	-0.60	-0.60	-0.60
Capital Factor (C)	1.88	1.84	2.86	1.64
Custom Revenue Cap Index Total	3.18	3.14	4.16	2.94

Table 3 below summarizes the Total Revenue Requirement that would result from the Board's approval of Hydro One's Custom IR, were the Application to be approved as filed.

Table 3: Revenue Requirement by Year

Year	Formula	Revenue Requirement
2018	Cost of Service	$1,504.7 million
2019	2018 Revenue Requirement x 1.0318	$1,552.6 million
2020	2019 Revenue Requirement x 1.0314	$1,601.4 million
2021*	2020 Revenue Requirement x 1.0416 + 10.7M	$1,678.7 million
2022	2021 Revenue Requirement x 1.0294	$1,728.1 million

*Hydro One is proposing to update the 2021 Total Revenue Requirement with updated cost of capital parameters.

1.5 INTEGRATION OF ACQUIRED UTILITIES

Since its last rebasing application, Hydro One has acquired Norfolk, Haldimand and Woodstock. Consistent with the Board's Mergers, Acquisitions, Amalgamations, and Divestitures ("MAADs") Decisions and ratemaking policies, the Acquired Utilities are currently separate from Hydro One for rate-making purposes. As outlined in Exhibit A, Tab 7, Schedule 1, Hydro One proposes to integrate the Acquired Utilities effective January 1, 2021. As set out in Exhibit G1, Tab 2, Schedule 1, Hydro One will introduce six new rate classes at that time.

Consistent with the Board's MAADs policies, the financial information and the associated revenue requirement relating to the Acquired Utilities have been excluded from Hydro One's financial information for the test years prior to 2021. For the 2021 and 2022 test years, all financial information presented in this Application includes costs relating to both Hydro One and the Acquired Utilities.

This means that the gross fixed assets and accumulated depreciation of the rate base of the Acquired Utilities has been added to the opening balance of Hydro One's gross fixed assets and accumulated depreciation, respectively, effective January 1, 2021. The resulting increase in rate base of $168.4 million (Exhibit D1, Tab 1, Schedule 1) and capital expenditures is reflected in lines 1 through 6 of Table 1 above and captured as part of the Custom Capital Factor previously described. The OM&A associated with the Acquired Utilities will also remain outside of Hydro One's OM&A envelope for the test years prior to 2021. As a result, $10.7 million of OM&A associated with the Acquired Utilities (as described in Exhibit A, Tab 7, Schedule 1) will be added to the Revenue Requirement that results from the application of the RCI to determine Total Revenue Requirement in 2021. As set out in Table 1, the Total Revenue Requirement (line 11) for 2021 is $1,678.7 million and is equal to the 2020 Total Revenue Requirement of $1,601.4 million x 1.0416 + $10.7 million.

2. ADDITIONAL CUSTOM IR FEATURES

Hydro One is proposing the following additional features in this Application to align its interests with those of customers and provide an additional element of protection for customers.

2.1 EARNINGS SHARING MECHANISM (ESM)

Hydro One proposes to share with customers 50% of any earnings that exceed the OEB-allowed regulatory ROE by more than 100 basis points in any year of the Custom IR term. The customer share of the earnings will be adjusted for any tax impacts and will be credited to a new deferral account for clearance at the time of Hydro One Distribution's next rebasing. The calculation of the actual ROE for a test year will use the Board approved mid-year rate base for that period.

2.2 CAPITAL IN-SERVICE VARIANCE ACCOUNT (CISVA)

A CISVA is a mechanism to track the difference between the revenue requirement associated with the actual in-service capital additions during a rate year and the revenue requirement associated with the OEB-approved in-service capital additions for that year. If in-service additions in a test year are less than the OEB-approved level, the balance of the account would be negative and refunded to customers in a future rate-setting period. If actual in-service capital additions are equal or greater than the OEB-approved level in the test year, no entry would be recorded in the account.

Hydro One is proposing a CISVA with the following key features:

(i) Purpose is to track the impact on revenue requirement of any in-service additions that are on a cumulative basis 98% or lower of the OEB-approved amount for each year of the Custom IR term;

(ii) For cumulative in-service additions that are 98% or lower of the OEB-approved level or less, the associated revenue requirement impact will be computed and reported on an annual basis in the variance account; and

(iii) At the end of the five-year term of the Custom IR Plan, in 2023, the sum of the variances in each year will be disposed of for the benefit of customers with the following conditions;

- Revenue requirement associated with variances in in-service additions resulting from verifiable productivity gains will be excluded from the calculation; and
- Account will be asymmetrical, meaning that should the cumulative in-service additions in any year of the Custom IR term exceed 98% of the cumulative OEB-approved amount for that period, no entry will be made in the variance account and no amount will be recoverable from ratepayers.

3. Z-FACTOR

The challenge inherent in a five-year Custom IR is the need to contend with material, unexpected costs. The Revenue Requirement that Hydro One is seeking in this Application is expected to enable the company to carry out the work that is planned over the 2018 to 2022 test years. The applied-for Revenue Requirement is not sufficient to address the prudent costs of material events that are outside the control of the utility and have not been forecast. Therefore, Hydro One is proposing, consistent with the Handbook, that the Board's Z-factor mechanism be available over the 5-year term of this Custom IR Application. This is consistent with the principles of the RRF. The criteria that would apply to the use of the Z-factor mechanism are those outlined by the Board in Chapter 3 of the Filing Requirements for Electricity Distribution Rate Applications and the guidelines provided in section 2.6 of the Board's Report on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors (July 14, 2008).

Events that may necessitate the use of the Z-factor mechanism include:

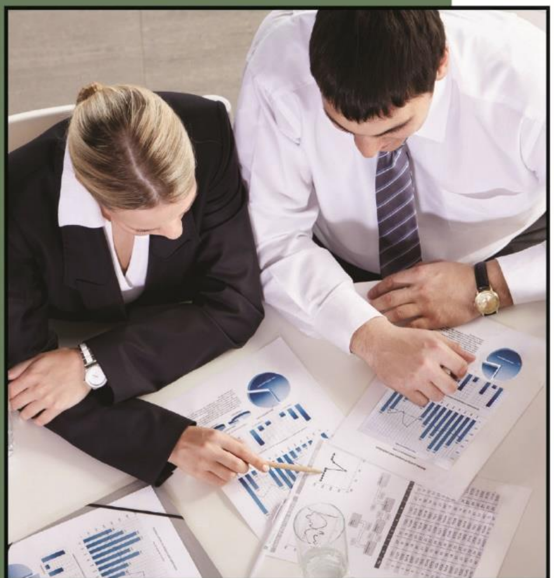
- Extreme weather events such as storms;
- Investments that are government-mandated or otherwise outside of management's control such as:
    - Smart Meters or similar type programs;
    - Conservation and Demand Management;
    - Regional Planning;
- Changes to IESO market rules;
- Changes to OEB codes, policies or other directions;
- Changes to accounting frameworks or technical standards;
- Changes to government policy, legislation, or regulation, such as environmental laws; and
- Any other one-time or ongoing events that meet the Z-factor criteria.

4. OFF-RAMPS

Hydro One proposes to apply the Board's existing policy with respect to off-ramps. The Handbook states that, although the purpose of incentive regulation is to drive productivity improvements within the utility, customers must also be protected from utility earnings that become excessive. Hydro One is therefore proposing to adopt the Board's existing off-ramp mechanism; a trigger mechanism with an annual return on equity dead band of plus or minus 300 basis points, at which point a regulatory review of the Revenue Requirement arising from Hydro One's Custom IR may be initiated.

Power System Engineering, Inc.

Full-service consultants



Total Factor Productivity Study of the Electric Distribution Functions of Hydro One and the Ontario Industry

Prepared by:

Power System Engineering, Inc.

November 4, 2016

Total Factor Productivity Study of the Electric Distribution Functions of Hydro One and the Ontario Industry

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Table of Contents

1 Executive Summary

In the March 12, 2015 Decision of the Ontario Energy Board (the Board, or OEB), in case EB-2013-0416, the OEB states on p. 17:

> The OEB sees value in Hydro One measuring its own total factor productivity over time to be able to demonstrate improvement in productivity to its customers and the OEB. The OEB leaves it to Hydro One to determine its preferred total factor productivity study method. However, the period of the study should include years at least going back to 2002. The results of the study must be filed as part of Hydro One's next rates application.

This report fulfills the Board's directive to Hydro One Networks Inc. (Hydro One) of measuring its total factor productivity (TFP) for its electric distribution functions beginning in 2002. The focus of this report is solely on the TFP trends of Hydro One and the Ontario industry and does not include econometric total cost benchmarking research. PSE was also requested by Hydro One to provide PSE's opinion on how to best apply the research results to Hydro One's upcoming incentive regulation application.

In this study, Power System Engineering, Inc. (PSE) performs three tasks: we measure two Hydro One TFP metrics and update previous research on TFP trends in the Ontario industry. The time period for the TFP research begins in 2002 and ends in 2015.

PSE calculated a measure of TFP that includes customary TFP outputs, such as number of customers served, kWh delivered, and maximum peak demand, and measured this TFP for Hydro One. This metric is called "unadjusted TFP" in this report. PSE also provides a second metric—a more comprehensive measure of Hydro One's performance trend that incorporates system reliability and employee safety. This metric is called "adjusted TFP" in this report, or "TFP with safety and reliability adjustment."

PSE has also updated the Ontario industry TFP research conducted in EB-2010-0379 by the Board Staff's consultant, Pacific Economics Group (PEG). The prior TFP research in EB-2010-0379 provided TFP trends from 2002 to 2012. PSE has updated the Ontario industry trends to include 2013, 2014, and 2015 data. This provides updated information regarding the productivity expectation of an industry participant.

1.1 Hydro One's Unadjusted and Adjusted TFP

Hydro One's 2002 to 2015 average annual growth rate in unadjusted TFP is -1.4%. When the reliability and safety performance metrics are incorporated, the growth rate for the adjusted TFP over the same period is -0.9%. For both indexes, much of the negative growth occurred in the earlier years of the sample. From 2002 to 2010 the index adjusted for performance declined by 1.8%, but from 2010 to 2015 it rose by an average of 0.5% annually.

The following table displays Hydro One's unadjusted and adjusted indexes.

Table 1 Hydro One Unadjusted and Adjusted TFP

Year	TFP (unadjusted)	TFP with Safety and Reliability Adjustment
2002	1.00	1.00
2003	1.00	1.00
2004	1.02	1.02
2005	1.01	1.02
2006	0.96	0.99
2007	0.89	0.91
2008	0.90	0.92
2009	0.86	0.88
2010	0.84	0.86
2011	0.84	0.88
2012	0.85	0.90
2013	0.81	0.86
2014	0.80	0.85
2015	0.83	0.88
Average Annual Growth Rate		
2002-2015	-1.4%	-0.9%
2002-2010	-2.1%	-1.8%
2010-2015	-0.4%	0.5%

We note that TFP results specific to Hydro One should not be used as the basis of a productivity parameter within an incentive regulation plan. We later discuss the updated Ontario TFP trend we calculated which can be used as the basis for a productivity component within an incentive regulation plan. Incentive regulation parameters (input price inflation and productivity factor) should be external to the utility that they are being applied to. The 4th Generation Incentive Regulation proceeding followed this incentive regulation principle when estimating industry-wide TFP and setting the productivity factor.

The 3rd Generation Incentive Regulation report from the Board also emphasized the need for an "external benchmark" for the productivity factor. On page 12 it states,

> The productivity component of the X-factor is intended to be the external benchmark which all distributors are expected to achieve. It should be derived from objective, data-based

> analysis that is transparent and replicable. Productivity factors are typically measured using estimates of the long-run trend in TFP growth for the regulated industry.[1]

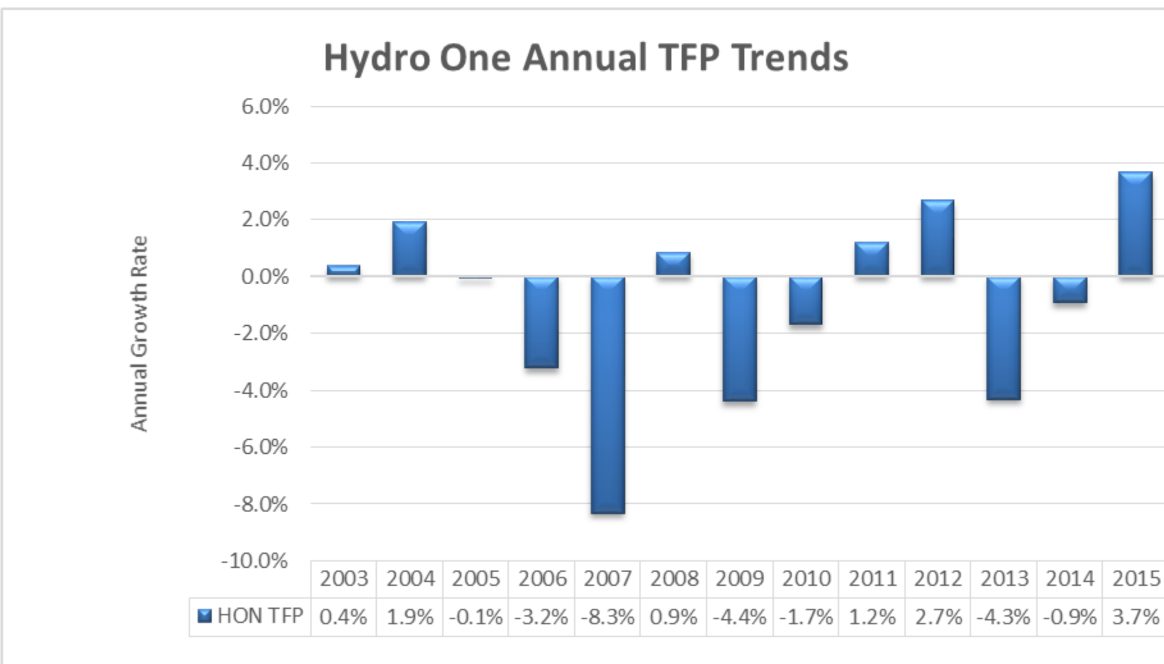
Lastly, the Renewed Regulatory Framework (RRF) stated on page 17,

> The Board has concluded that X-factors for individual distributors under 4th Generation IR will continue to consist of an empirically derived industry productivity trend (productivity factor) and stretch factor, but will be based on Ontario Total Factor Productivity (TFP) trends.[2]

The outputs used for the industry TFP trends should also be generally based on billing determinants that are related to how the distributor collects revenue. However, in determining performance, other non-revenue producing, valued outcomes should be incorporated into the evaluation. The condition to have outputs and weights that approximate distribution revenue collection would exclude the use of the adjusted TFP index as the basis for the productivity factor in incentive regulation, even if we had an industry-wide measure of it.

The following figure provides the annual growth rates in Hydro One's adjusted TFP.

Figure 1 Hydro One Annual TFP Growth Rates (Adjusted TFP)



Hydro One has modest growth in 2003 and 2004, nearly zero growth in 2005, and then negative TFP in 2006 and 2007. Another two years of negative growth occurred during and right after the

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[1] Ontario Energy Board. EB-2007-0673 Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors. July 14, 2008. Page 12.

[2] Ontario Energy Board. Report of the Board on Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach. October 18, 2012.

economic downturn in 2009 and 2010. This was followed up by fairly large increases in 2011 and 2012, a drop in 2013 and 2014, and then an increase in 2015.

TFP trends will fluctuate in the short-term, especially for individual distributors. Short-term output and input fluctuations are to be expected. While the 2006 to 2010 TFP growth rates had negative declines in four out of the five years, the time periods preceding and subsequent to that period has shown steady or slightly increasing TFP growth. Section 3.2 will discuss some possible explanations for observing negative TFP growth.

1.2 Ontario Industry TFP Update

During the 4th Generation Incentive Regulation proceeding (EB-2010-0379), PEG conducted a TFP study for the Ontario electric distribution study (PEG Study). The study objective, as PSE understands it, was to provide an empirically-based recommendation on the productivity factor. This focused objective did not include an evaluation of the performance trend of individual distributors. Rather, the study was meant to inform the Board regarding the most appropriate productivity factor.

The PEG study determined the Ontario electric distribution TFP for 2002 to 2012 was -0.3%. Since the time of that study, industry data has become available for the years 2013, 2014, and 2015. PSE has replicated PEG's methodology for the 2002 and 2012 period and updated the Ontario industry TFP study to 2015.[3]

The updated average annual growth rate in the Ontario TFP is -0.9%. Consistent with the prior study, this excludes Hydro One and Toronto Hydro.[4]

Table 2 Ontario Industry TFP

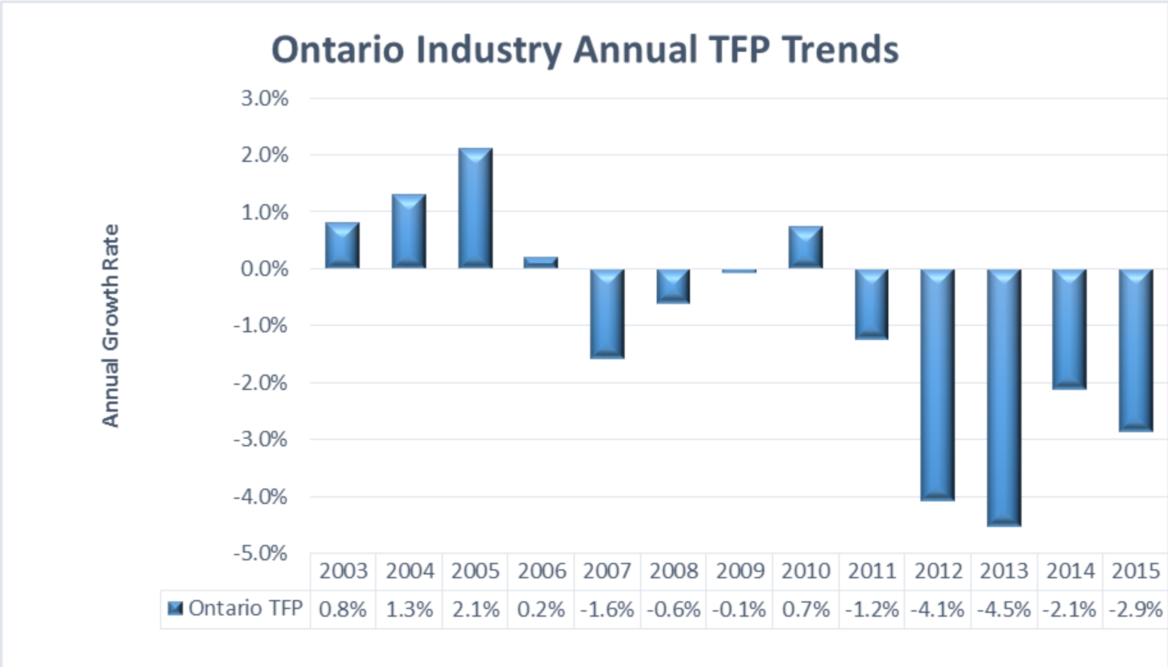
Ontario Industry TFP	Average Annual Growth Rate
2002-2012 (PEG Study)	-0.3%
2002-2015 (Updated Study)	-0.9%

The following figure provides the annual growth rates in the Ontario industry's TFP.

[3] For the updated years, we made two minor, but necessary changes. The first is using a different construction cost index in 2015. This is because the index used by PEG (the EUCPI) was suspended after its 2014 data release, making 2015 unavailable. For the years 2013 and 2014 we used the EUCPI. The second change was using the capital expenditures reported in the OEB Yearbooks as the basis for plant additions for the years 2013, 2014, and 2015. This is the same change PEG has made in their total cost benchmarking updates and is necessary due to accounting changes within the industry.

[4] PSE did not support this exclusion during the EB-2010-0379 proceeding. However, we replicated this exclusion in this study to be consistent with the Board Staff's TFP study and the Board's Decision.

Figure 2 Ontario Industry Annual TFP Trend



The Ontario industry had four consecutive years of TFP growth from 2002 to 2006. Then mixed results from 2007 to 2010. Since 2010, Ontario has experienced five consecutive years of TFP declines. Some of this drop is possibly due to the economic downturn. Other factors, such as aging infrastructure, increasing unmeasured outputs (e.g. environmental, regulatory, safety, customer service), and the general slowing of output growth, are also possibilities.

1.3 Summary of Findings and Recommendations

The adjusted TFP trend of Hydro One displays an overall trend of -0.9%. Since 2010, Hydro One has shown positive TFP growth. While the indexes are not directly comparable, the upward trajectory of Hydro One's TFP trend is contrasted with the recent downward TFP trend of the rest of the Ontario industry. The ascending trajectory of Hydro One's TFP provides evidence that productivity has improved during the most recent years of the sample.

After updating the Ontario industry TFP to 2015, PSE found the 2002-2015 trend is -0.9%. The 2002-2012 Ontario TFP trend was -0.3%. Based on the empirical evidence of declining industry TFP and the OEB's 4th Generation IR decision to set the productivity factor at 0.0%, PSE recommends setting Hydro One's productivity factor no higher than 0.0%.

The X-factor is calculated as the sum of the productivity factor and the stretch factor. Stretch factors are normally determined using benchmarking research. PSE is of the opinion that accurate total cost benchmarking is the best approach in setting stretch factors. The long term 2002-2015 Hydro One adjusted TFP trend of -0.9% and the recent positive TFP growth of +0.5% provides evidence that there is the chance for modest TFP growth in the near term. On this basis, PSE recommends setting the stretch factor no higher than 0.6%. This is the maximum stretch factor put forth in 4th Generation IR and combined with a 0.0% productivity factor would amount to an X-factor of 0.6%. This would be a challenging X-factor in light of the industry TFP trend of -0.9% and would require Hydro One to outpace the Ontario historical TFP trend by 1.5%.

2 Introduction

In the Board's March 12, 2015 Decision in EB-2013-0416, page 17.

> The OEB sees value in Hydro One measuring its own total factor productivity over time to be able to demonstrate improvement in productivity to its customers and the OEB. The OEB leaves it to Hydro One to determine its preferred total factor productivity study method. However, the period of the study should include years at least going back to 2002. The results of the study must be filed as part of Hydro One's next rates application.

This report fulfills the Board's directive to Hydro One of measuring its TFP for its distribution functions beginning in 2002. In this study, PSE performs three tasks: we measure two Hydro One TFP metrics and update previous research on trends in the Ontario industry. The time period for this study begins in 2002 and ends in 2015.

PSE calculated a measure of TFP that includes traditional TFP outputs, such as number of customers served, kWh delivered, and peak demand, and measured this TFP for Hydro One. This metric is called "unadjusted TFP" in this report. PSE also provides a second metric—a more comprehensive measure of Hydro One's performance trend that incorporates reliability data and employee safety. This metric is called "adjusted TFP" in this report, or "TFP with safety and reliability adjustment."

PSE has also updated the Ontario industry TFP research conducted in EB-2010-0379 by the Board Staff's consultant. The prior TFP research in EB-2010-0379 provided TFP trends from 2002 to 2012. PSE has implemented the methodology used by PEG in that proceeding to update the Ontario industry trends to include 2013, 2014, and 2015 data. This provides updated information regarding the most suitable productivity expectation of an industry participant.

2.1 Application of Study Results

2.1.1 Purpose of PSE's Unadjusted and Adjusted TFP

The purpose of measuring Hydro One's unadjusted and adjusted TFP was to meet the Board's directive for Hydro One to "be able to demonstrate improvement in productivity to its customers and the OEB."[5]

The purpose of calculating an adjusted TFP for Hydro One, in addition to the unadjusted TFP, is to make the performance trends more comprehensive. Connecting customers to the distribution grid and investing in the system capacity to deliver energy at peak demands is a highly valued service to customers. However, enhancing the reliability of the grid and assuring a safe work environment are also highly valued outcomes of distribution utilities. In evaluating distributor performance it is important to incorporate these important activities.

[5] March 12, 2015 OEB Decision in EB-2013-0416, page 17.

This study does not adjust for and incorporate all factors that may influence TFP trends. While reliability and safety are prominent functions of a utility, there are other causes, outputs, and reasons for TFP trends to increase or decrease. For more discussion, please see Section 3.2.

2.1.2 Purpose of Updating PEG's Industry Calculations

Incentive regulation parameters should be external to the utility that they are being applied to. This mimics a competitive market where firms are price takers rather than price setters. That is to say, competitive market prices are set by the interplay between consumer demand and the industry's supply curve and are external to individual firms. Prices are not influenced by an individual firm's decisions, productivity, or costs.

Including externally-driven price cap parameters breaks the link between a utility's costs and the electricity prices and revenue it collects during the incentive regulation term. Therefore, the TFP that informs the productivity factor within a price cap index should be based on industry-wide data.

The objective for the TFP calculated in the 4th Generation IR proceeding (EB-2010-0379) was to calculate the most appropriate productivity factor to be used in the price cap escalation formula. PSE understands that the objective was not to determine the performance trends of individual distributors. The EB-2010-0379 research methodology and the 2015 update, therefore, are appropriate for the productivity factor in Hydro One's rate application.

PSE has provided an update to the Ontario industry TFP trends found in the 4th Generation IR proceeding. These updated TFP trends can be used to inform the Board regarding the appropriate productivity factor in the upcoming Hydro One rate application. The 2015 updated industry TFP trend is now -0.9%.

Table 3 Ontario Industry TFP (PEG method)

Ontario Industry TFP	Average Annual Growth Rate
2002-2012	-0.3%
2002-2015	-0.9%

2.1.3 The Hydro One and Ontario TFPs Should Not Be Used for Comparative Purposes

PSE provides a word of caution about the incongruities between (1) the Hydro One unadjusted and adjusted TFP results, and (2) the updated Ontario industry results. As stated, the Ontario industry TFP methodology had a narrow purpose of calculating the appropriate productivity factor to be used in 4th Generation IR. In contrast, PSE's calculations for Hydro One has the purpose of fulfilling the Board's directive for Hydro One to "be able to demonstrate improvement in productivity to its customers and the OEB."[6]

The Hydro One TFP trends and performance adjustments are meant to provide information about the performance trends over time of Hydro One. The performance adjustments further inform stakeholders on the performance trend of the utility after adjusting for reliability and safety performance.

The purpose of calculating an adjusted TFP for Hydro One, in addition to the unadjusted TFP, is to make the performance trends more comprehensive than only including the number of customers, kWh deliveries, and peak demand. Connecting customers to the distribution grid and investing in the system capacity to deliver energy at peak demands is a highly valued service to customers. However, enhancing the reliability of the grid and assuring a safe work environment are also valuable services both to Hydro One's customers and to the OEB. While these activities do not increase revenue for Hydro One, for the most part, they do bring externalized benefits to customers or employees.[7]

The adjusted TFP does not correct for and incorporate all factors that may influence TFP trends. While reliability and safety are prominent functions of a utility, there are other causes, outputs, and reasons for TFP trends to increase or decrease. For more discussion, please see Section 3.2.

2.1.4 The Hydro One TFP Results Should Not Be Used for Calculating the Productivity Component

The TFP results specific to Hydro One should not be used as the basis of a productivity parameter within an incentive regulation plan. However, the updated Ontario TFP trend we calculated can be used as the basis for a productivity component within an incentive regulation plan. Incentive regulation parameters (input price inflation and productivity factor) should be external to the utility that they are being applied to. The 4th Generation Incentive Regulation proceeding followed this incentive regulation principle when estimating industry-wide TFP and uses that external benchmark as the basis for the productivity factor.

The 3rd Generation Incentive Regulation report from the Board also emphasized the need for an "external benchmark" for the productivity factor. On page 12 it states,

> The productivity component of the X-factor is intended to be the external benchmark which all distributors are expected to achieve. It should be derived from objective, data-based

[6] March 12, 2015 OEB Decision in EB-2013-0416, page 17.

[7] Reducing outages will increase revenue, however, this revenue increase is small relative to the externalized value of reducing outages to customers. The same can be said for employee safety. The utility will likely have some increased productivity if employee injuries are reduced, however, this increased productivity is small compared to the value to employees of experiencing fewer on-job injuries. Said another way, PSE is assuming that typical utilities spend far more money on reliability and employee safety than they would if there were no externalized benefit of increasing reliability or safety.

> analysis that is transparent and replicable. Productivity factors are typically measured using estimates of the long-run trend in TFP growth for the regulated industry.[8]

Lastly, the Renewed Regulatory Framework (RRF) stated on page 17,

> The Board has concluded that X-factors for individual distributors under 4th Generation IR will continue to consist of an empirically derived industry productivity trend (productivity factor) and stretch factor, but will be based on Ontario Total Factor Productivity (TFP) trends.[9]

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[8] Ontario Energy Board. EB-2007-0673 Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors. July 14, 2008. Page 12.

[9] Ontario Energy Board. Report of the Board on Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach. October 18, 2012.

3 The Basics of TFP

Productivity, in the context of a distribution utility, is the quantity of output produced by the utility divided by the input quantity expended by the utility. The output quantity index measures the level of output provided by the utility. The input quantity index measures the level of resources used. PSE uses indexing techniques to capture outputs and inputs, which are in turn used to create a productivity term. We then examine how this productivity ratio changes over time to determine the productivity index trend.

The input quantity index consists of economic resources such as OM&A labour and materials, and capital stock. The output quantity index in this study includes the number of customers served, kilowatt hours delivered, and maximum peak demand for the unadjusted index and then adds employee safety and reliability metrics for the adjusted index.

The TFP trend is the difference between the annual growth rate in the output quantity index and the input quantity index.

$$\boldsymbol{TFP\ trend = Output\ Quantity\ trend - Input\ Quantity\ trend}$$

TFP trend measurement differs from total cost benchmarking; in the latter, utilities are compared relative to the average efficiency level of other utilities within the industry. TFP measures how productivity is changing over time for that same utility. It does not, however, provide a comparative efficiency assessment to other utilities within the industry.

3.1 Sample Period Used

3.1.1 Data Sample: Unadjusted and Adjusted Hydro One TFP

The sample period for calculating Hydro One's own TFP trend is 2002 to 2015. As directed by the Board in EB-2013-0416, the TFP study has a beginning year of 2002. Due to data constraints resulting in the many amalgamations prior to 2002, this is the first conceivable start year.

3.1.2 Data Sample: PEG Industry Update

Regarding the Ontario industry TFP update, Board Staff commissioned a study conducted by PEG during the 4th Generation Incentive Regulation proceeding (EB-2010-0379) that examined the TFP of the Ontario industry from 2002-2012.[10] PSE updated the Ontario TFP study to 2015.

For the years 2013 and 2014, we used the same data sources and implemented the methodology used by PEG in EB-2010-0379. In updating the Ontario industry TFP to 2015, PSE was unable to use the Electric Utility Construction Price Index (EUCPI), because it has been suspended after the

[10] This TFP result excluded Hydro One Networks and Toronto Hydro Electric System Limited from the industry calculations. PSE did not support this exclusion during the proceeding. However, we replicated this exclusion in this study to be consistent with the Board Staff's TFP study and the Board's Decision.

2014 data release. We instead escalated the EUCPI for 2014 by the change in the northeast U.S. Handy Whitman indexes for electric distribution from 2014 to 2015.

3.2 Interpretation of Negative TFP Growth

The Board requested Hydro One measure its own TFP trend to demonstrate improvement in productivity. Changes in TFP will have tangible impacts on distributor costs and the value provided to consumers. A potential explanation for a changing TFP trend is a change in the underlying performance and efficiency of the distributor. PSE's research measuring Hydro One's adjusted TFP is an effort to quantify and demonstrate Hydro One's comprehensive performance trend over time.

Notwithstanding our best efforts to measure Hydro One's performance trend through TFP research, PSE provides some caveats and urges a degree of caution in the interpretation of both Hydro One's 2002-2015 negative TFP growth rate of 0.9% and the 2010-2015 positive growth rate of 0.5%. While these are important measures of performance, we discuss below some considerations for not automatically assuming the TFP trends are unconditionally indicative of changing performance and efficiency.

For both Hydro One and the Ontario industry, there are years and time periods that show negative TFP trends. The OEB addressed this possibility in the Board's Decision dated November 21, 2013 in EB-2010-0379 (page 17).

> The Board acknowledges that achieved industry TFP may be negative due to unforeseen events and/or situations in which costs may be incurred with no corresponding increase in output.

TFP is a measure of the change in the outputs delivered by the utility (or industry) relative to the inputs required to deliver those outputs. However, it is important to note that a negative TFP growth rate does not <u>necessarily</u> indicate declining efficiency at either the industry or the utility level. Recall that the TFP trend equals the Output Quantity Index trend minus the Input Quantity Index trend. Negative TFP trends do indicate that measured outputs are growing slower than inputs.

While declining efficiency is certainly one possibility for observing negative TFP trends, there are a number of other possibilities. Given the presence of incentive regulation, it seems unlikely that efficiency is declining across the entire industry. Other systemic possibilities include:

1. The increasing of "outputs" that are not being measured within the TFP calculation. PSE attempts to partially solve this issue with the performance adjustments found in this study. As applied to Hydro One, we see that the long-term trend for Hydro One goes from slightly negative to slightly positive after incorporating and adjusting for the valued services of reliability and employee safety. While PSE's performance adjustments (discussed in the following section) attempt to quantify these performance outputs, there are other valued utility functions that are difficult, if not impossible, to incorporate and quantify. These other valued functions could include customer service activities, meeting increased

regulatory requirements, providing enhanced environmental stewardship, and increasing other aspects of power quality.

2. External circumstances can change over time. One of these circumstances often found in modern western economies is slower growth. Output growth has slowed due to more energy efficient appliances and machinery and conservation programs. This has slowed both the total amount of energy delivered (in kWh) and peak demands (in kW). The growth in customers, especially in more rural areas, has also slowed. Since the TFP trend is a function of the output index, this slower growth will tend to slow down TFP from historical norms.

3. A common external circumstance that is changing across the electric industry, but is problematic to quantify, is the aging of capital infrastructure. Due to the post-World War II population boom and increasing use per customer during that time, utilities needed to heavily invest in capital infrastructure to meet the higher number of customers and peak demands (unlike today they were able to fund much of this investment through increasing billing determinants rather than higher prices). At a number of utilities throughout North America a high proportion of capital infrastructure is now past its useful life and is in need of replacement. However, capital expenditures may need to increase to replace this capital. Additionally, maintenance costs will also tend to increase as the grid becomes older. The capital replacement expenditures and increasing maintenance costs will tend to cause a decline in TFP.

Unfortunately, it is impossible to empirically adjust for all of the underlying causes of observed TFP trends. PSE addressed the safety and reliability metrics in an effort to move the TFP trends closer to being true measures of performance. Incorporating these metrics had the effect of improving Hydro One's TFP trend. There are still other unmeasured outputs, changing circumstances, and aging infrastructure that are not incorporated in the TFP measure. Yet, TFP measures are useful indicators of performance assuming these other considerations are kept in mind.

3.3 Performance Adjustments to Hydro One TFP

PSE adjusted the Hydro One TFP trends for changes in reliability and employee safety. As previously discussed, the output quantity index in the TFP trends does not incorporate all possible activities of the utility that bring value to customers or society. Two important activities are: (1) the reliability of the distribution grid, and (2) the safety of the employees.

3.3.1 Employee Safety Adjustment

The performance metric used for employee safety is a 3-year rolling average of Hydro One's annual number of recordable injuries per 200,000 hours worked. As the graph shows below, Hydro One has drastically improved its performance in this area. It has also increased its safety-related spending over that time. The number of recordable injuries peaked in 2004 (the first year of available data) at a value of 7.1 injuries per 200,000 hours worked. By 2015, this number has declined to 1.7 injuries per 200,000 hours worked.

Figure 3 Hydro One Recordable Injuries

3.3.2 Reliability Adjustment

Two performance metrics are commonly used for the reliability performance adjustment. These two are:

1. System Average Interruption Frequency Index (SAIFI). SAIFI is the average number of interruptions that a customer would experience in a given year.

2. Customer Average Interruption Duration Index (CAIDI). CAIDI is the average duration of those interruptions.

Another popular reliability metric is the System Average Interruption Duration Index (SAIDI). Mathematically, SAIDI is the product of SAIFI and CAIDI.

$$SAIDI = SAIFI * CAIDI$$

By adjusting for SAIFI and CAIDI, this covers the two major customer impacts of outages. The first is the initial (or upfront) cost impact, from the customer perspective, of the electricity going off (measured by SAIFI) and then the duration cost impact of the electricity remaining off for a given time (measured by CAIDI). More details are provided in Section 5.1.2 regarding the calculation of the weights for these two customer cost impacts.

Both the CAIDI and SAIFI metrics are based on 3-year rolling averages and exclude extreme weather events (i.e., major event days). This makes the indexes less weather dependent and provides a performance metric on the "normal weather" reliability of the Hydro One system.[11]

[11] Utility performance during extreme weather events is important. However, measuring the annual change in this

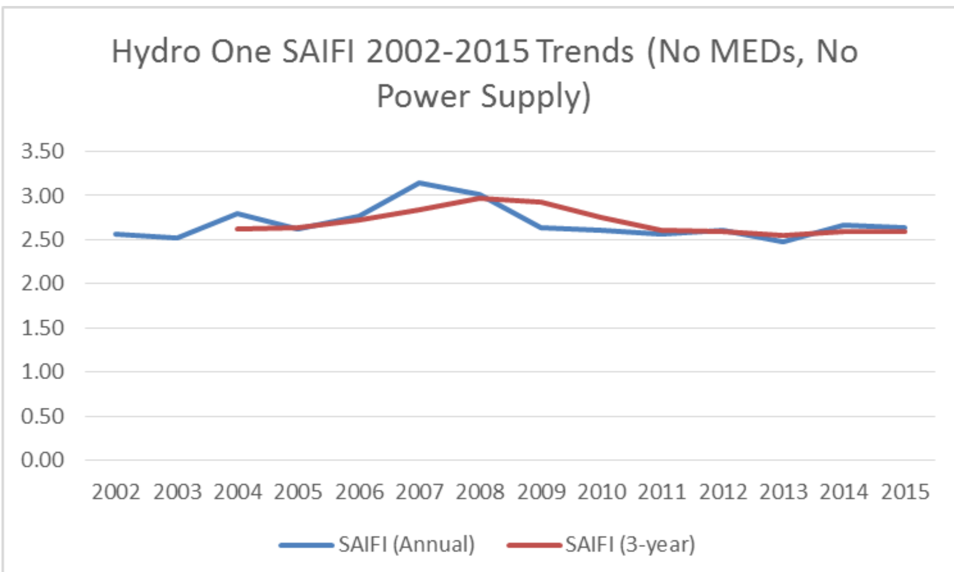
The extreme weather definition used is consistent throughout the study period and based on Hydro One's definition of a major event. The definition of a "major event day" used by Hydro One is any day when 10% or more of Hydro One's customers have been interrupted by an event.

Since this study is focused on Hydro One's distribution functions, the metrics also exclude power supply outages. This isolates the reliability performance to the distribution system and, thus, provides a better performance metric when evaluating the distribution functions of Hydro One.

One important caveat should be made. PSE requested reliability data from Hydro One for the entire study period of 2002 through 2015. Hydro One made their best efforts to provide that data to us but is not as confident about the accuracy of the reliability data provided to PSE prior to 2006. Given the consistency in the metrics during the entire 2002 through 2015 period, we have included all of the reliability metrics in the study.

The following graph shows the annual and 3-year rolling averages of SAIFI for Hydro One. Through the study period, there has been minimal change in SAIFI.

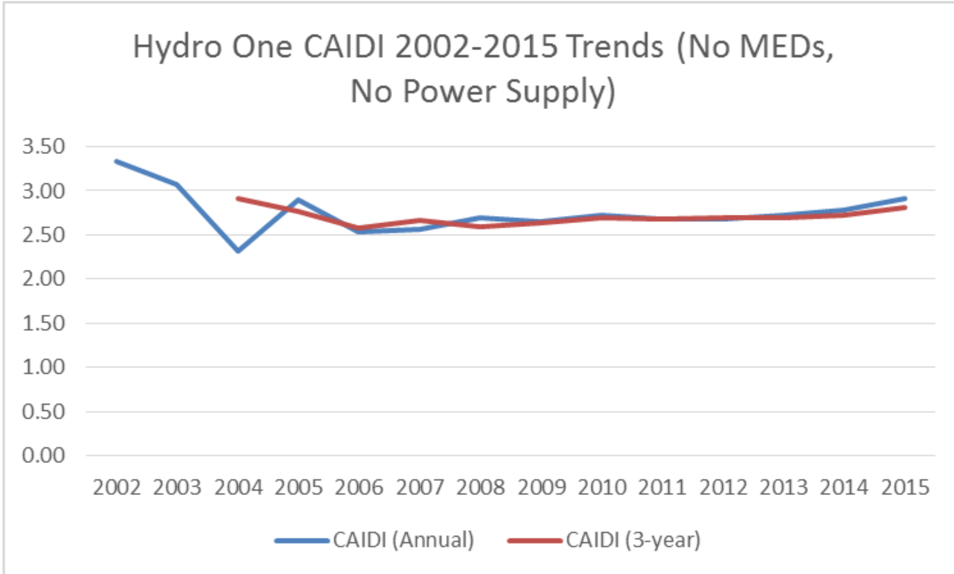
Figure 4 Hydro One Historical SAIFI



The following graph shows the annual and 3-year rolling averages of CAIDI for Hydro One. Through the study period, there has been minimal change in CAIDI.

performance is difficult, if not impossible, because of the inability to properly normalize for the different extreme weather events.

Figure 5 Hydro One Historical CAIDI



3.3.3 Comparative Performance Levels of Reliability and Safety

We would caution against comparing the raw reliability values or safety metrics to other distributors that do not face similar operating conditions as Hydro One. In other research, we have found that variables such as customer density and vegetation levels can have a profound influence on reliability metrics, and these variables should be properly adjusted for prior to comparatively evaluating the reliability metrics of a given utility.

PSE is making no claim regarding the relative levels to other distributors of either employee safety or of the reliability metrics of SAIFI and CAIDI. The scope of this study is to examine and demonstrate the performance trend of Hydro One. This means, essentially, we are comparing Hydro One to itself throughout time.

4 Index Methodology

This section describes methods for calculating the output quantity index and the input quantity index. These two indexes are used for both the Hydro One TFP calculations and the Ontario industry calculations. In many respects the methods for calculating the two indexes are the same for both the Hydro One TFP and the industry TFP. We point out any instances where the methods are different for the Hydro One TFP calculations and the Ontario industry calculations.

For Hydro One and the industry TFP calculations, the output quantity index and input quantity index are constructed using the Tornqvist indexing method. An indexing method is needed to combine multiple outputs and inputs into one comprehensive index. The Tornqvist method is a popular indexing method used in a number of TFP studies. It is the same method used in the 4th Generation Incentive Regulation proceeding.

The annual growth rate of each index is calculated using the formula:

$$\ln\left(\frac{Index_t}{Index_{t-1}}\right) = \sum_{i=1}^{N} \frac{(w_{i,t} + w_{i,t-1})}{2} * \ln(\frac{X_{i,t}}{X_{i,t-1}})$$

Where *t* designates the year, *w* is the weight of each component, *i* is the individual output or input component, and X is the output quantity or input quantity of the individual component.

During the sample period, Hydro One merged with Norfolk Power Distribution Inc. Separate Norfolk OEB Yearbook data is reported through 2014 and then combined data is reported under Hydro One for 2015. For years prior to 2015, PSE added Norfolk's data to Hydro One to make a consistent series across all years.

4.1 Output Quantity Index

4.1.1 Definitions and Hydro One Data Change

This section describes the Hydro One TFP output quantity index prior to making the safety and reliability adjustments. For the unadjusted Hydro One TFP, PSE used the same outputs and output weights that were used in the 4th Generation IR proceeding for the industry TFP. The three outputs are:

1. Total customers served as used in the 4th Generation IR proceeding and updated using the OEB Electricity Distributor Yearbooks.

2. Total kWh delivered as used in the 4th Generation IR proceeding and updated using the OEB Electricity Distributor Yearbooks.

3. Maximum Peak Demand as used in the 4th Generation IR proceeding and updated using the OEB Electricity Distributor Yearbooks. With the exception of one data change for Hydro One in 2013. This change is discussed below.

The outputs and weights are based on the Ontario industry econometric total cost model developed by Pacific Economics Group. The weights are 60.6%, 28.9%, and 10.6% for total customers, maximum demand, and kWh deliveries, respectively.

The maximum peak demand for Hydro One's TFP is the same peak demand definition used in the 4th Generation IR proceeding for the industry TFP. In the 4th Generation IR, the peak demand variables was calculated by gathering the annual peak demand for each distributor and taking the maximum value of the variable since 2002. For Hydro One's TFP, we follow the same approach, with the one data change described below.

PSE made one change to Hydro One's 2013 data versus what is being used in the 4th Generation IR benchmarking updates and reported in the Yearbooks, based on an inconsistent increase in the reported annual peak demand. In 2013 the Yearbook reports an annual peak demand of 6,367,000 kW for Hydro One. As can be seen in the following table this would be an unrealistic increase, and it would inaccurately inflate Hydro One's TFP growth. PSE inquired about the 2013 peak demand value to Hydro One. Hydro One informed PSE that the 2013 Yearbook number included embedded distributors. The peak demand in 2013 excluding embedded distributors is a more consistent 4,291,656. PSE used this revised number, rather than the one found in the 2013 Yearbook and PEG's benchmarking dataset, as the proper peak demand number.[12]

[12] The 4,291,656 number is prior to adding in Norfolk's peak data. For this reason, the annual peak demand reported in Table 4 is a bit higher than this number.

Table 4 Hydro One Historical Peak Demand (kW)

Year	Annual Peak Demand	Maximum Peak Demand (2002 to year indicated)
2002	4,361,813	4,361,813
2003	4,418,983	4,418,983
2004	4,410,533	4,418,983
2005	4,475,785	4,475,785
2006	4,234,804	4,475,785
2007	4,224,645	4,475,785
2008	3,942,436	4,475,785
2009	4,235,501	4,475,785
2010	4,268,492	4,475,785
2011	4,004,537	4,475,785
2012	3,803,038	4,475,785
2013	4,368,794	4,475,785
2014	3,838,295	4,475,785
2015	4,243,390	4,475,785

4.1.2 Output Quantity Index Result for Hydro One

The three components of the unadjusted output quantity index for Hydro One are provided in the following table. After combining the three components, the overall index is provided in the last column. The average annual growth rate for output is measured at 0.6% for the entire 2002 to

2015 time period. The growth rate has slowed for Hydro One in recent years with slower growth of 0.4% from 2010 to 2015 compared to average annual growth of 0.7% from 2002 to 2010.

Table 5 Hydro One Output Components

Year	Total Customers	Maximum Peak Demand (kW)	kWh Deliveries	Output Quantity Index
2002	1,130,073	4,361,813	22,926,851,117	**1.00**
2003	1,145,781	4,418,983	23,810,074,569	**1.02**
2004	1,157,591	4,418,983	24,038,500,006	**1.02**
2005	1,170,160	4,475,785	24,422,487,934	**1.04**
2006	1,182,345	4,475,785	23,778,211,255	**1.04**
2007	1,192,001	4,475,785	24,851,252,881	**1.05**
2008	1,206,059	4,475,785	24,555,499,692	**1.06**
2009	1,212,662	4,475,785	23,822,133,912	**1.06**
2010	1,221,970	4,475,785	23,776,751,207	**1.06**
2011	1,229,727	4,475,785	23,929,063,582	**1.07**
2012	1,240,106	4,475,785	23,848,181,213	**1.07**
2013	1,239,438	4,475,785	24,428,413,393	**1.07**
2014	1,238,851	4,475,785	24,442,549,275	**1.07**
2015	1,257,016	4,475,785	24,117,389,179	**1.08**
Average Annual Growth Rates				
2002-2015	0.8%	0.2%	0.4%	**0.6%**
2002-2010	1.0%	0.3%	0.5%	**0.7%**
2010-2015	0.6%	0.0%	0.3%	**0.4%**

4.2 Input Quantity Index

There are two components to the input quantity index for calculating Hydro One's TFP: OM&A quantity and capital quantity. These two measures are then combined using Tornqvist indexes based on using the cost shares of each input component.

4.2.1 OM&A Quantity

The OM&A quantity used in the TFP calculation is derived by dividing annual OM&A expenses in year *t* by the OM&A input price index in year *t*.

$$OM\&A\ Quantity_t = \frac{OM\&A\ Expenses_t}{Input\ Price\ Index_t}$$

4.2.1.1 OM&A Cost and Input Price Definitions

The OM&A expense definition used for Hydro One's TFP is the same definition that was used in the TFP work found in the 4th Generation IR proceeding.[13] This definition is based on examining the distribution functions of the utility.

The OM&A input price is also calculated using the same input prices and weights as were used in the 4th Generation IR proceeding. The non-labour weight is set at 30% and the labour weight is the remaining 70%. The non-labour price index is the GDPIPI for Canada (Final Domestic Demand) and the labour price index is the Average Weekly Earnings (AWE) of all employees in Ontario.

4.2.1.2 OM&A Quantity Calculation

The following table displays Hydro One's historical OM&A expenses, the OM&A input price components, the OM&A input price index, and the OM&A input quantity index. The OM&A quantity grew by an average of 1.8% for the entire 2002 to 2015 time period. Since 2010, Hydro One's measured OM&A quantity index declined by 1.6%.

[13] Definitions discussed starting on page 32 of Pacific Economic Group's November 2013 report: *Productivity and Benchmarking Research in Support of Incentive Rate Setting in Ontario: Final Report to the Ontario Energy Board*.

Table 6 Hydro One OM&A Unadjusted Input Components and OM&A Quantity Calculation

Year	OM&A Distribution Expenses	GDPIPI-Canada	AWE-All Employees-Ontario	OM&A Price Index	OM&A Input Quantity Index
2002	314,638	90.3	711.29	1.00	**314,638**
2003	318,186	91.8	728.7	1.02	**311,303**
2004	305,724	93.4	748.98	1.05	**291,901**
2005	333,219	95.4	776.33	1.08	**308,298**
2006	377,591	97.6	788.78	1.10	**343,128**
2007	459,664	100.0	819.18	1.14	**403,845**
2008	452,127	102.6	838.34	1.17	**387,848**
2009	489,371	103.7	849.07	1.18	**414,747**
2010	525,571	104.8	881.44	1.22	**432,541**
2011	528,786	107.3	893.44	1.24	**428,049**
2012	515,527	109.1	906.15	1.25	**411,153**
2013	569,253	111.0	920.24	1.27	**446,803**
2014	601,149	113.4	938.27	1.30	**462,496**
2015	531,571	115.3	962.73	1.33	**399,667**
Average Annual Growth Rates					
2002-2015	4.0%	1.9%	2.3%	2.2%	**1.8%**
2002-2010	6.4%	1.9%	2.7%	2.4%	**4.0%**
2010-2015	0.2%	1.9%	1.8%	1.8%	**-1.6%**

4.2.2 Capital Quantity: Perpetual Inventory Capital Method

PSE's measure of capital quantity is based on the perpetual inventory capital method. This approach has a solid basis in economic theory, and is the same method chosen by PEG in their 4th Generation IR research.[14] The approach also has ample precedent in government-sponsored cost research. It is used by the Bureau of Labor Statistics of the U.S. Department of Labor in computing multi-factor productivity indexes for the U.S. private business sector and for several subsectors, including the utility services industry.

Based on this approach, the cost of capital in each period *t* is the product of indices of the capital service price and capital quantity in place at the end of the prior period. The formula for this is given by:

$$CK_t = WKS_t \cdot XK_{t-1}$$

In each period *t*:

- CK_t is the cost of capital,

[14] See Hall and Jorgensen (1967) for a seminal discussion of the use of service price methods for measuring capital cost.

- WKS_t is the capital service price index, and
- XK_{t-1} is the capital quantity index value at the start of the period.

The capital quantity index is constructed using inflation-adjusted data on the value of net utility plant in a benchmark year, and on distribution gross plant additions in subsequent years. It also uses an assumption about service lives. The PEG study used 1989 as the benchmark year for each utility when that data was available; if 1989 was not feasible, PEG used 2002 as the benchmark year. We use 2002 as the benchmark year in the current study for Hydro One. This is the same benchmark year used by PEG for Hydro One in the 4th Generation IR study. For other utilities, we use the same benchmark year as the PEG study, which is either 1989 or 2002 for the individual distributors that comprise the Ontario industry update. Based on the benchmark year, a "triangulated weighted average" ("TWA") is used to calculate the capital stock.

The formula for calculating the capital quantity index in 2002 is provided below. Note, if the distributor has a benchmark year of 1989, the 1989 net plant value is used rather than the 2002 value and the TWA is recalculated to correspond with this change.

$$XK_{2002}^{i} = \frac{Net\ Plant_{2002}^{i}}{TWA_{2002}^{i}}$$

Subsequent years use the previous year's capital stock and escalate it by plant additions minus depreciation.

For Hydro One's own TFP trend, PSE used distribution plant addition data filed by Hydro One in prior rate cases or received directly from the company.

For the Ontario industry update, we used the plant additions calculated by PEG for years prior to 2013, and then for the update (2013-2015) used the capital expenditures reported by the distributors in the OEB Electricity Yearbooks as the basis for the plant additions. The formula for calculating the capital quantity index for years after is provided below.

$$XK_t^i = XK_{t-1}^i * d + \frac{Add_t^i}{WKA_t^i}$$

Under the service price approach employed in this study, capital cost has two components: opportunity cost and depreciation. The capital service price index is thus given by the formula:

$$WKS_t = r_t * WKA_{t-1} + d_t * WKA_t$$

Here, r_t is the allowed rate of return based on the Board's historical calculated returns. The parameter d_t is the economic depreciation rate. We use the same value as PEG did (4.59%) for this parameter in the study.

The variable that the capital service price components have in common is WKA_t. This is an index of the price of capital assets used in power distribution. To be as consistent as possible with PEG's 4th

Generation IR study, for the Ontario industry TFP update we used the EUCPI for 2013 and 2014 but then escalated the EUCPI in 2015 by the growth rate in the total distribution plant Handy-Whitman index in 2015. This was a necessary modification to the Ontario industry study, because the EUCPI has been suspended after the 2014 data release pending a review of the models.

For calculating Hydro One's own TFP, we use the Handy-Whitman indexes for total power distribution plant for the northeast region of the U.S for the entire sample period adjusted by the Canadian Purchasing Price Parity (PPP) in each year. This is a modification of the TFP research found in 4th Generation IR, which used the EUCPI. This alteration was made because it allows for a more accurate performance assessment of Hydro One. The EUCPI measures the construction price index of both transmission and distribution systems, whereas the Handy-Whitman index is measuring total power distribution construction costs alone rather than combining transmission and distribution as the EUCPI does.

The EUCPI also appears to contain the financial costs embedded in the index, which makes it inappropriate for demonstrating the change in input quantity. Recall that the TFP index is measuring the change in the ratio of output quantity to input quantity. Quantity is calculated by dividing costs by price. By including financial costs, the EUCPI is no longer able to be used to calculate the quantity of capital assets purchased in a given year.

The following explanation found on the Stats Canada website, on August 3, 2016, describing the EUCPI, leads us to believe that financing costs are embedded in the index. The first line in the second section reads: "Prices are collected for three general categories of inputs; materials and equipment, labour and finance costs." An ideal construction cost index would only include the materials, equipment, and labour components required to construct the asset. Including the costs of financing the asset skew the TFP calculations when attempting to determine input quantity. Financing costs already enter the equation through the allowed rate of return and should not be used when measuring the quantity of the assets put into service.

> **Data sources**
>
> Data are collected from other Statistics Canada surveys and/or other sources.
>
> Prices are collected for three general categories of inputs; materials and equipment, labour and finance costs. Price series related to materials and equipment come from the Statistics Canada Industrial Product Price Index (IPPI) and Non-residential Building Construction Price Index series, and the U.S. Bureau of Labour Statistics (BLS) producer price index series. Data on labour costs comes from the Statistics Canada Survey of Employment, Payrolls and Hours (SEPH) and the Construction Union Wage Rate Index (CUWR) series. The information pertaining to finance costs is obtained from the Bank of Canada.

Notice in the description above that some of the data sources used in calculating the EUCPI are from the U.S. Using the total distribution cost indexes from the northeast U.S. may provide a more regional index than what the EUCPI is providing.

The EUCPI has also been suspended pending a program review. Here is that notice from the Stats Canada website on August 3, 2016.

Notice of program review

Following the release of data for reference year 2014, the Electric Utility Construction Price Index (EUCPI) will be suspended.

The program will be reviewed to ensure the models used in the future take into account current practices in construction.

For these reasons, PSE is far more comfortable using the Handy-Whitman indexes that measure total power distribution construction costs in the northeast U.S. In the U.S.-based TFP work, PEG regularly uses these same indexes. They do not include financing costs and are specific to the electric distribution industry.

This discussion is not meant to imply the 4th Generation IR research undertaken by PEG produced an improper price cap escalation formula. In a price cap mechanism there are two components that depend on the construction cost index used. These are: (1) the TFP trend (used for the productivity factor), and (2) the industry input price differential to a macroeconomic price index (e.g., GDPIPI). If the index is modified for one component, then it should also be modified for the other component. In other words, if EUCPI/Handy-Whitman is used for one component, the same source should also be used for the other component. These will tend to have off-setting impacts, making the choice of the construction cost index somewhat irrelevant to the overall escalation formula used within the price cap index.

However, this is not an irrelevant choice when demonstrating an individual distributor's TFP trend. In this study application of demonstrating Hydro One's performance, the best index to use is the Handy-Whitman index.

The table below displays the capital price, cost, and quantity indexes for Hydro One. Over the 2002 to 2015 time period, Hydro One has increased its measured capital quantity by 2.1% annually.

Table 7 Hydro One Capital Price, Cost, and Quantity Indexes

Year	Capital Cost	Capital Price	Capital Quantity Index
2002	526,012	56.7	**9,272**
2003	557,331	58.6	**9,515**
2004	587,296	60.7	**9,673**
2005	635,426	64.9	**9,788**
2006	671,851	67.2	**10,004**
2007	746,266	72.1	**10,348**
2008	845,601	80.0	**10,573**
2009	930,882	85.6	**10,874**
2010	975,625	87.9	**11,097**
2011	1,017,696	90.4	**11,254**
2012	1,013,138	89.0	**11,386**
2013	1,048,851	89.5	**11,725**
2014	1,130,684	95.2	**11,883**
2015	1,218,828	100.2	**12,165**
Average Annual Growth Rate			
2002-2015	6.5%	4.4%	**2.1%**
2002-2010	7.7%	5.5%	**2.2%**
2010-2015	4.5%	2.6%	**1.8%**

4.2.3 Hydro One Input Quantity Index

The input quantity index is provided in the table below. For the 2002 to 2015 period, the average annual growth rate of Hydro One's input quantity index grew at 2.0%. The index grew noticeably slower more recently due to the slowing growth rate of OM&A quantity (in fact, OM&A quantity was negative during this period). From 2002 to 2010 the input quantity index grew at a 2.9% rate but since 2010 has grown by 0.7%.

Table 8 Hydro One Input Quantity Index

Year	Capital Quantity Index	OM&A Quantity Index	Input Quantity Index
2002	9,272	314,638	**1.00**
2003	9,515	311,303	**1.01**
2004	9,673	291,901	**1.00**
2005	9,788	308,298	**1.03**
2006	10,004	343,128	**1.08**
2007	10,348	403,845	**1.17**
2008	10,573	387,848	**1.17**
2009	10,874	414,747	**1.22**
2010	11,097	432,541	**1.26**
2011	11,254	428,049	**1.26**
2012	11,386	411,153	**1.26**
2013	11,725	446,803	**1.32**
2014	11,883	462,496	**1.35**
2015	12,165	399,667	**1.30**
Average Annual Growth Rate			
2002-2015	2.1%	1.8%	**2.0%**
2002-2010	2.2%	4.0%	**2.9%**
2010-2015	1.8%	-1.6%	**0.7%**

5 Hydro One’s Adjusted TFP: Reliability and Safety Adjustments

In this report, PSE calculates Hydro One’s TFP in two ways. First, PSE created a measure of TFP that includes traditional TFP outputs, such as number of customers served, kWh delivered, and peak demand, and measured this TFP for Hydro One. This metric is called “unadjusted TFP” in this report.

PSE also provides a second metric—a more comprehensive measure of Hydro One’s performance trend that incorporates reliability data and employee safety. This metric is called “adjusted TFP” in this report, or “TFP with safety and reliability adjustment.”

This section explains the second metric. For the second metric, we made two performance adjustments (safety and reliability) to describe Hydro One’s TFP trend with a more holistic and comprehensive performance measurement. We again caution that while employee safety and reliability are central to an electric distributor, the two components are not fully inclusive of all possible performance metrics or extenuating circumstances that may alter TFP trends. In other words, this analysis moves towards a more comprehensive measurement of the trend in performance, but is not fully comprehensive.

5.1.1 Safety

Employee safety is an important aspect of evaluating the performance of electric distribution utilities. A company must spend time and money on safety measures and practices, but the result of these efforts would not be reflected in the traditional TFP outputs of customers, kWh delivered, and peak demand.

PSE requested Hydro One provide employee safety data and also estimate the costs spent on employee safety. The employee safety metric used is the annual number of recordable injuries at Hydro One per 200,000 hours worked (assuming around 2,000 hours per year for a full-time equivalent employee, this is roughly the number of recordable injuries per 100 full-time employees). Hydro One only had data available beginning in 2004. PSE used a 3-year rolling average of employee safety to smooth out any large increases or decreases.

The table below provides the employee safety annual data and the 3-year rolling average used in the performance adjustment. As is evident, employee safety performance at Hydro One has drastically improved since 2004.

Table 9 Hydro One Historical Safety Data

Year	Recordable Injuries per 200,000 hours worked	3-year Rolling Average
2002	n/a	n/a
2003	n/a	n/a
2004	7.1	n/a
2005	3.9	n/a
2006	4.7	5.2
2007	5.0	4.5
2008	5.1	4.9
2009	4.8	5.0
2010	2.6	4.2
2011	3.7	3.7
2012	2.3	2.9
2013	2.5	2.8
2014	1.8	2.2
2015	1.7	2.0

5.1.1.1 Weights Used

The weight given to performance metrics such as reliability and safety is an important one. But this leads to the question of 'what value should be placed on employee safety?' Or on the reliability of the grid? These are challenging questions to answer, yet vital to calculating a more comprehensive performance metric. Rather than getting into an abstract and murky discussion on the value of human safety, PSE asked Hydro One to provide an annual cost estimate of their internal trackable costs of providing a safe working environment for their employees. This ranged from 1.2% of total distribution costs to 6.8%. In 2015, the weight is 6.1%. We use these annual weights as the basis for including employee safety into the output index.

Safety-related activities span across numerous departments and functions of the utility. Hydro One was only able to provide an estimate of its trackable safety related costs to PSE starting in 2009. To determine the weights for years prior to 2009, PSE adjusted the 2009 estimate for inflation based on the GDPIPI-Canada index.

The following table displays the trackable safety-related expenses used to formulate the weight for the safety performance adjustment.

Table 10 Hydro One Safety-Related Expenses[15]

Year	Trackable Safety-Related Expenses (1,000 $)	Safety Weight in Adjustment
2002	*14,747*	*1.8%*
2003	*15,073*	*1.7%*
2004	*15,445*	*1.7%*
2005	*15,939*	*1.6%*
2006	*16,228*	*1.5%*
2007	*16,785*	*1.4%*
2008	*17,191*	*1.3%*
2009	17,400	1.2%
2010	85,752	5.7%
2011	100,515	6.5%
2012	102,439	6.7%
2013	110,524	6.8%
2014	109,810	6.3%
2015	107,031	6.1%

5.1.2 Reliability

Two performance metrics are used for the reliability performance adjustment. These two are:

1. System Average Interruption Frequency Index (SAIFI). SAIFI is the average number of interruptions that a customer would experience in a given year.

2. Customer Average Interruption Duration Index (CAIDI). CAIDI is the average duration of those interruptions.[16]

By adjusting the TFP for SAIFI and CAIDI, we can account for the two major impacts of outages on customers. The first impact is the initial (upfront) cost impact, from the customer perspective, of the electricity going off (measured by SAIFI), and the second impact is the duration cost impact of the electricity remaining off for a given time (measured by CAIDI).

Both the CAIDI and SAIFI metrics are based on 3-year rolling averages and exclude extreme weather events (i.e., major event days). This makes the indexes less weather dependent and provides a performance metric on the "normal weather" reliability of the Hydro One system.

[15] Hydro One was only able to provide an estimate of its trackable safety related costs to PSE starting in 2009. To determine the weights for years prior to 2009, PSE adjusted the 2009 estimate for inflation based on the GDPIPI-Canada index.

[16] Another popular reliability metric is the System Average Interruption Duration Index (SAIDI). Mathematically, SAIDI is the product of SAIFI and CAIDI. Including all three indexes would be redundant so we include the two components of SAIDI within the reliability adjustment.

The extreme weather definition used is consistent throughout the study period, and is based on Hydro One's definition of a major event. The definition of a major event day is any day when 10% or more of Hydro One's customers have been interrupted by an event.

Since this study is focused on Hydro One's distribution functions, the metrics exclude power supply outages. This exclusion is appropriate when evaluating the distribution functions of Hydro One.

PSE requested reliability data from Hydro One for the entire study period of 2002 through 2015. Hydro One made their best efforts to provide that data, but is less certain about the accuracy of the reliability data provided to PSE prior to 2006. Given the consistency in the metrics during the entire 2002 through 2015 period, we have decided to include all years of the reliability metrics in the study.

The following table provides the SAIFI and CAIDI annual data supplied to PSE from Hydro One, and the 3-year rolling averages used for the performance adjustment calculation. Again, these metrics exclude MEDs and power supply outages.

Table 11 Hydro One Historical SAIFI/CAIDI

Year	SAIFI	SAIFI (3-year Rolling Average)	CAIDI	CAIDI (3-year Rolling Average)
2002	2.57	n/a	3.33	n/a
2003	2.52	n/a	3.08	n/a
2004	2.79	2.63	2.32	2.91
2005	2.62	2.64	2.89	2.76
2006	2.77	2.73	2.54	2.58
2007	3.15	2.85	2.57	2.67
2008	3.01	2.98	2.69	2.60
2009	2.63	2.93	2.65	2.64
2010	2.61	2.75	2.73	2.69
2011	2.57	2.60	2.68	2.68
2012	2.61	2.60	2.67	2.69
2013	2.48	2.55	2.73	2.69
2014	2.67	2.59	2.78	2.73
2015	2.63	2.59	2.91	2.81

5.1.2.1 Weights Used

SAIFI measures the "upfront" economic costs to customers that occur immediately upon an electricity outage. By "upfront" we mean the costs that are incurred regardless of how long the outage lasts. For businesses, interruption costs can stem from interrupted manufacturing processes, harm to equipment, machinery, or electronics. Costs can also take the form of lost revenues when electricity is interrupted. On the residential side, the interruption costs can range from simple inconvenience (e.g., re-setting clocks), to life-threatening situations where electricity is needed to run medical equipment.

CAIDI measures the economic costs to customers that occur subsequent to the immediate costs. CAIDI costs grow as the outage gets longer. For example, for businesses, loss of manufacturing production, customers leaving the building, spoiled products, and spoiled food all increase as the duration of an electricity outage lengthens.

To incorporate Hydro One's SAIFI and CAIDI performance into the reliability adjustments, we needed to develop weights for each one. However, assigning a specific dollar amount to customer interruption costs is a challenging task. To PSE's knowledge, a direct study from Hydro One has not been conducted to quantify interruption costs.

To estimate the SAIFI and CAIDI costs and weights, PSE used interruption estimates from a publically-available paper published in June 2009 by the Ernest Orlando Lawrence Berkeley National Laboratory and prepared for the U.S. Department of Energy. The title of the paper is *Estimated Value of Service Reliability for Electric Utility Customers in the United States*.

PSE used the following table found in the Executive Summary of the LBNL report (page xxvi). The table reveals the estimated customer interruption costs (in U.S. 2008$) for various rate classes for outages with varying interruption duration times.

Table 12 LBNL Interruption Costs

Table ES- 5. Estimated Average Electric Customer Interruption Costs US 2008$ Anytime By Duration and Customer Type

Interruption Cost	Interruption Duration: Momentary	30 minutes	1 hour	4 hours	8 hours
Medium and Large C&I					
Cost Per Event	$6,558	$9,217	$12,487	$42,506	$69,284
Cost Per Average kW	$8.0	$11.3	$15.3	$52.1	$85.0
Cost Per Un-served kWh	$96.5	$22.6	$15.3	$13.0	$10.6
Cost Per Annual kWh	9.18E-04	1.29E-03	1.75E-03	5.95E-03	9.70E-03
Small C&I					
Cost Per Event	$293	$435	$619	$2,623	$5,195
Cost Per Average kW	$133.7	$198.1	$282.0	$1,195.8	$2,368.6
Cost Per Un-served kWh	$1,604.1	$396.3	$282.0	$298.9	$296.1
Cost Per Annual kWh	1.53E-02	2.26E-02	3.22E-02	$0.137	$0.270
Residential					
Cost Per Event	$2.1	$2.7	$3.3	$7.4	$10.6
Cost Per Average kW	$1.4	$1.8	$2.2	$4.9	$6.9
Cost Per Un-served kWh	$16.8	$3.5	$2.2	$1.2	$0.9
Cost Per Annual kWh	1.60E-04	2.01E-04	2.46E-04	5.58E-04	7.92E-04

PSE examined Hydro One's RRR data in 2008 to determine the number of residential, small C&I, and Medium and Large C&I customers that correspond with the preceding table. To determine the SAIFI-related interruption costs per outage in 2008, we used the "Momentary" cost per event estimate for each rate class. To determine the CAIDI-related interruption costs per outage in 2008, we took the "1 hour" cost per event for each rate class and then subtracted out the momentary costs. For all of the estimates we also translated the U.S. dollar figure into Canadian dollars using the 2008 Canadian Purchasing Price Parity (PPP) ratio. We then multiplied by the number of customers in that rate class and by the SAIFI to ascertain the SAIFI-related costs.

For the CAIDI-related costs, we multiplied by the number of customers in each rate class and by the CAIDI value. This gives us an estimate of the cost for each outage at the average duration. We then multiplied that value by the average number of outages (i.e., the SAIFI value) to give us the total CAIDI-related costs for each rate class.

The equation to determine the 2008 SAIFI-related customer interruption costs is:

$$SAIFI\ Costs_j = Momentary\ Costs_j * PPP * Customers_j * SAIFI$$

The equation to determine the 2008 CAIDI-related customer interruption costs is:

$$CAIDI\ Costs_j = \left(1\ Hour\ Costs_j - Momentary\ Costs_j\right) * PPP * Customers_j * CAIDI * SAIFI$$

The table below provides the SAIFI-related costs by rate class and the total estimated interruption costs related to SAIFI.

Table 13 SAIFI Costs

Rate Class	Momentary Interruption Costs (US$ 2008)	2008 PPP	Number of Hydro One Customers in 2008	2008 SAIFI (no MEDs, no power supply)	Total SAIFI Customer Interruption Costs (US$ 2008)
Residential	2.10	1.23	1,077,500	3.01	$8,377,379
Small C&I	293	1.23	109,722	3.01	$119,023,562
Medium & Large C&I	6,558	1.23	31	3.01	$752,670
Sum of All Classes					**$128,153,611**

The table below provides the CAIDI-related costs by rate class and the total estimated interruption costs related to CAIDI.

Table 14 CAIDI Costs

Rate Class	1 hour - Momentary Interruption Costs (US$ 2008)	2008 PPP	Number of Hydro One Customers in 2008	2008 CAIDI (no MEDs, no power supply)	2008 SAIFI (no MEDs, no power supply)	Total CAIDI Customer Interruption Costs (US$ 2008)
Residential	1.20	1.23	1,077,500	2.69	3.01	$12,877,228
Small C&I	326	1.23	109,722	2.69	3.01	$356,233,864
Medium & Large C&I	5,929	1.23	31	2.69	3.01	$1,830,489
Sum of All Classes						**$370,941,582**

The total SAIFI and CAIDI costs are weighted based on their proportion to Hydro One's distribution total costs in 2008 calculated in the TFP study. The 2008 weights are applied for all years of the study. This leads to the following weights for each reliability component:

Table 15 Reliability Weights

Reliability Performance Component	Weight
SAIFI	9.9%
CAIDI	28.6%

There are a number of assumptions embedded in the calculation of the weights. One key assumption is that the system-wide SAIFI and CAIDI metrics are applicable to each of the rate classes. That is to say, all customers experience the same reliability levels. A second assumption is that Hydro One customers are similar to the U.S. customers that formulate the interruption costs in the 2009 LBNL reliability study (i.e. the 2009 study adequately reflects the true interruption costs of Hydro One customers). Another assumption is that interruption costs have not changed since the 2009 LBNL study. Given these and other uncertainties with determining the value of service (VOS), PSE views these weights as a "first approximation" proposal. We are certainly open to suggestions on how to best formulate the weights when making these reliability adjustments.

6 Hydro One TFP and Performance Assessment Results

This Chapter provides the Hydro One TFP trend from 2002 to 2015, both without and with the performance adjustments discussed in previous chapters. These results are Hydro One's own TFP and performance trend. The Ontario industry TFP results are provided in the following chapter.

6.1 Hydro One Unadjusted TFP

Hydro One's TFP trend absent the performance adjustments declined by an average annual growth rate of 1.4% from 2002 to 2015. Much of the decline in TFP occurred in the earlier years of this time period. From 2002-2010, Hydro One's TFP declined by 2.1%. Since 2010, Hydro One's unadjusted TFP has declined by 0.4%.

Table 16 Hydro One Unadjusted 2002-2015 TFP Trend

Year	Output Quantity Index	Input Quantity Index	TFP Index
2002	1.00	1.00	**1.00**
2003	1.02	1.01	**1.00**
2004	1.02	1.00	**1.02**
2005	1.04	1.03	**1.01**
2006	1.04	1.08	**0.96**
2007	1.05	1.17	**0.89**
2008	1.06	1.17	**0.90**
2009	1.06	1.22	**0.86**
2010	1.06	1.26	**0.84**
2011	1.07	1.26	**0.84**
2012	1.07	1.26	**0.85**
2013	1.07	1.32	**0.81**
2014	1.07	1.35	**0.80**
2015	1.08	1.30	**0.83**
Average Annual Growth Rates			
2002-2015	0.6%	2.0%	**-1.4%**
2002-2010	0.7%	2.9%	**-2.1%**
2010-2015	0.4%	0.7%	**-0.4%**

As discussed in Section 3.2 negative TFP does not necessarily imply worsening efficiency. It simply means that measured input quantity growth is outpacing measured output quantity growth. Possibilities for causes, other than worsening efficiency, include: the economic downturn, slowing output growth even absent the downturn, aging infrastructure requiring large capital replacement and increased maintenance costs, and an increase in unmeasured outputs (e.g., safety, reliability, customer service, regulatory, public safety, and environmental concerns).

6.2 Hydro One Adjusted TFP

PSE made two adjustments to the Hydro One TFP index to incorporate the impacts of changing reliability and employee safety performance. This makes the TFP index more comprehensive and indicative of performance' however, we caution that it does not include all possible performance metrics and other possible influencers of TFP trends.

6.2.1 TFP After Safety Adjustment

Due to Hydro One not having employee safety data prior to 2004 and PSE using a 3-year rolling average of the employee safety metric, the TFP index is not affected by the safety performance adjustment until 2007. For the years 2002-2006, we assume employee safety was constant and does not impact the TFP trend for those years.

The following table displays the unadjusted TFP and then the adjustment for employee safety.

Table 17 Hydro One TFP Adjusted for Safety

Year	TFP (unadjusted)	TFP with Safety Adjustment
2002	1.00	**1.00**
2003	1.00	**1.00**
2004	1.02	**1.02**
2005	1.01	**1.01**
2006	0.96	**0.96**
2007	0.89	**0.90**
2008	0.90	**0.90**
2009	0.86	**0.86**
2010	0.84	**0.85**
2011	0.84	**0.85**
2012	0.85	**0.88**
2013	0.81	**0.84**
2014	0.80	**0.84**
2015	0.83	**0.88**
Average Annual Growth Rate		
2002-2015	-1.4%	**-1.0%**
2002-2010	-2.1%	**-2.0%**
2010-2015	-0.4%	**0.6%**

Incorporating employee safety changes the measured TFP trend from -1.4% to -1.0% over the entire sample period. Recall, however, that for the earliest years (2002 to 2006) no adjustment was able to be made due to a lack of available data and we assumed constant employee safety. For the latter years, incorporating safety performance improves Hydro One's TFP indexes. From 2010 to 2015, Hydro One's safety-adjusted TFP trend is a positive 0.6%.

6.2.2 TFP After Reliability Adjustment

The reliability adjustment incorporates the two primary aspects of reliability: the number of outages experienced (i.e., SAIFI) and the duration of those outages (i.e., CAIDI). PSE is using a 3-year rolling average to smooth out annual fluctuations and excluding MEDs and power supply outages. The data provided to PSE prior to 2006 cannot be fully verified by Hydro One. However, given the consistency with the more recent years, we have included the estimates of the 2002 to 2005 reliability data.

The following table provides the unadjusted TFP findings for Hydro One along with the reliability performance adjustment index.

Table 18 Hydro One TFP Adjusted for Reliability

Year	TFP (unadjusted)	TFP with Reliability Adjustment
2002	1.00	**1.00**
2003	1.00	**1.00**
2004	1.02	**1.02**
2005	1.01	**1.02**
2006	0.96	**0.99**
2007	0.89	**0.91**
2008	0.90	**0.92**
2009	0.86	**0.88**
2010	0.84	**0.86**
2011	0.84	**0.86**
2012	0.85	**0.87**
2013	0.81	**0.83**
2014	0.80	**0.81**
2015	0.83	**0.84**
Average Annual Growth Rates		
2002-2015	-1.4%	**-1.4%**
2002-2010	-2.1%	**-1.9%**
2010-2015	-0.4%	**-0.5%**

As is evident in the table above, incorporating the reliability adjustment does not alter the TFP trends in a meaningful way. The 2002 to 2015 TFP trend remains unchanged, the 2002 to 2010 trend improves slightly, and the 2010 to 2015 worsens slightly. These minor differences are due to the fact that Hydro One's reliability indexes have remained relatively stable since 2002.

6.2.3 TFP After Safety and Reliability Adjustment

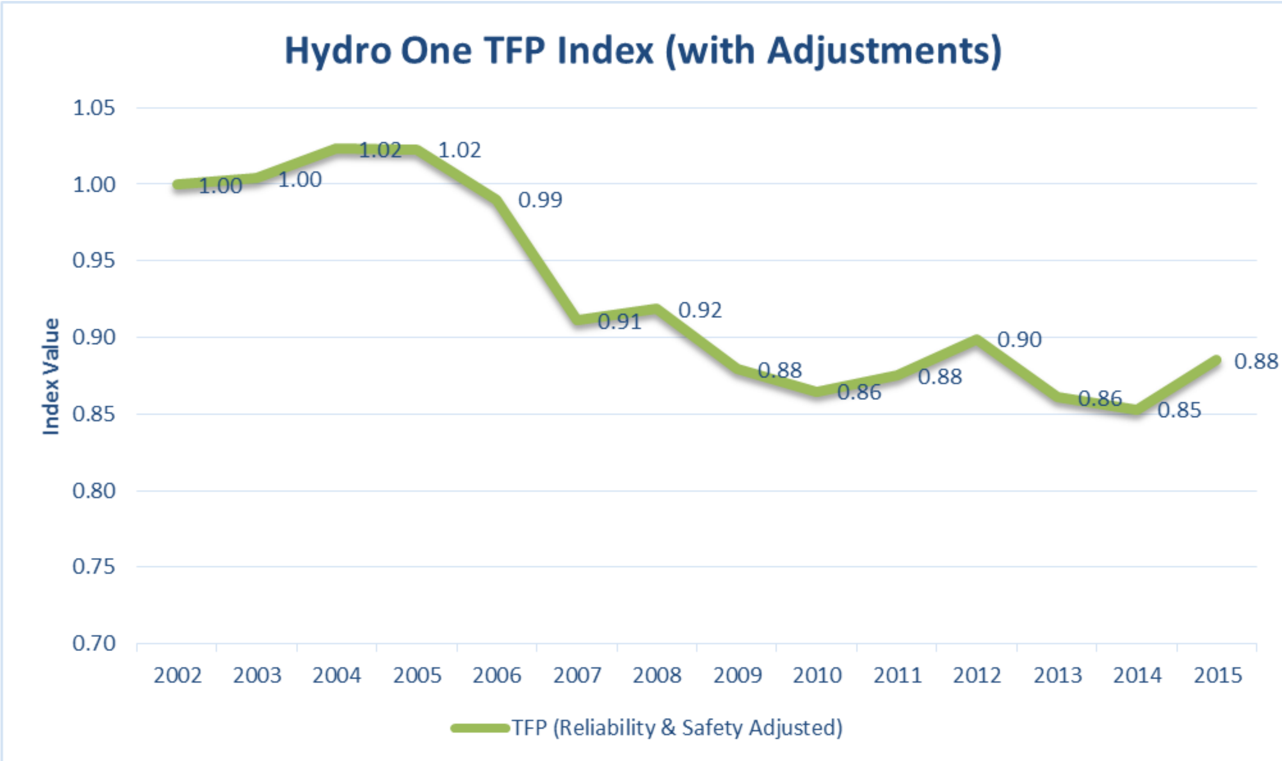
The following table incorporates both the safety and the reliability adjustments together into one index. This adjusted index provides a more comprehensive performance picture relative to the unadjusted index.

Table 19 Hydro One TFP Adjusted for Safety and Reliability

Year	TFP (unadjusted)	TFP with Safety Adjustment	TFP with Reliability Adjustment	TFP with Safety and Reliability Adjustment
2002	1.00	1.00	1.00	**1.00**
2003	1.00	1.00	1.00	**1.00**
2004	1.02	1.02	1.02	**1.02**
2005	1.01	1.01	1.02	**1.02**
2006	0.96	0.96	0.99	**0.99**
2007	0.89	0.90	0.91	**0.91**
2008	0.90	0.90	0.92	**0.92**
2009	0.86	0.86	0.88	**0.88**
2010	0.84	0.85	0.86	**0.86**
2011	0.84	0.85	0.86	**0.88**
2012	0.85	0.88	0.87	**0.90**
2013	0.81	0.84	0.83	**0.86**
2014	0.80	0.84	0.81	**0.85**
2015	0.83	0.88	0.84	**0.88**
Average Annual Growth Rate				
2002-2015	-1.4%	-1.0%	-1.4%	**-0.9%**
2002-2010	-2.1%	-2.0%	-1.9%	**-1.8%**
2010-2015	-0.4%	0.6%	-0.5%	**0.5%**

After incorporating the safety and reliability adjustments into the TFP trend, Hydro One's 2002-2015 TFP index average annual growth rate is -0.9%. The earlier years, 2002 to 2010, saw a larger decline of -1.8%. From 2010 to 2015, Hydro One has produced modest positive TFP growth (after adjustments are made) of +0.5%.

Figure 6 Hydro One TFP Adjusted for Safety and Reliability



7 Ontario Industry TFP Results

PSE has updated the Ontario industry TFP research found in EB-2010-0379. PSE has implemented the methodology used by the Board Staff consultant in that proceeding to update the Ontario industry trends to include the most recent 2015 data. This provides updated information regarding the most suitable productivity expectation applicable to Hydro One's upcoming rate application.

The objective, as PSE understands it, for the TFP calculated in the 4th Generation IR proceeding (EB-2010-0379) was to calculate the most appropriate productivity factor to be used in the price cap escalation formula (the 2002 to 2012 TFP trend was found to be -0.3% by PEG). The objective was not, as PSE understands it, to determine the performance trends of individual distributors. The EB-2010-0379 research methodology, therefore, is appropriate for the productivity factor in Hydro One's rate application. Using the PSE calculations of Hydro One's own TFP (whether unadjusted or adjusted) as the basis for the productivity factor is unsuitable, not only because the trends are not external to Hydro One, but also they are not related to how the utility collects revenue.

As stated above, the Ontario industry TFP methodology had a narrow purpose of calculating the appropriate productivity factor to be used in 4th Generation IR. In contrast, PSE's calculations for Hydro One have the purpose of fulfilling the Board's directive for Hydro One to "be able to demonstrate improvement in productivity to its customers and the OEB."[17] Therefore, the Ontario industry TFP trends and Hydro One trends are not directly comparable.

7.1 Updated Industry TFP Results

In updating the Ontario industry TFP to 2015, PSE was unable to use the Electric Utility Construction Price Index (EUCPI), because it has been suspended after the 2014 data release. We instead escalated the EUCPI for 2014 by the change in the northeast U.S. Handy Whitman indexes for electric distribution from 2014 to 2015. For the 2013, 2014, and 2015 plant additions, we use the capital expenditures found in the OEB Yearbooks. All other procedures remained the same relative to EB-2010-0379. For more information on the methodology, procedures, and 2002 to 2012 results please see the November 2013 report by PEG (*Productivity and Benchmarking Research in Support of Incentive Rate Setting in Ontario: Final Report to the Ontario Energy Board).*

The following table and figure provide the updated TFP indexes for the Ontario industry. In an effort to be consistent with the 4th Generation IR findings, Toronto Hydro and Hydro One have been excluded from the data.

The Ontario industry TFP has declined by 0.9% from 2002 to 2015. This decline has been accelerating in recent years. During the 4th Generation IR proceeding, the Board Staff consultant found a negative TFP trend of 0.3%. The addition of three years of data (2013, 2014, and 2015) has now decreased the long-term TFP trend by 0.6%.

[17] March 12, 2015 OEB Decision in EB-2013-0416, page 17.

Table 20 Ontario Industry Historical TFP

Year	Output Quantity Index	Input Quantity Index	TFP Index
2002	100.0	100.0	**100.0**
2003	102.1	101.3	**100.8**
2004	104.0	101.8	**102.1**
2005	106.8	102.4	**104.3**
2006	108.2	103.5	**104.5**
2007	109.7	106.6	**102.9**
2008	110.6	108.1	**102.3**
2009	110.8	108.4	**102.2**
2010	111.8	108.6	**103.0**
2011	112.8	110.9	**101.7**
2012	114.0	116.7	**97.7**
2013	114.8	123.0	**93.3**
2014	115.6	126.5	**91.4**
2015	115.6	130.2	**88.8**
Average Annual Growth Rate			
2002-2015	1.1%	2.0%	**-0.9%**
2002-2010	1.4%	1.0%	**0.4%**
2010-2015	0.7%	3.6%	**-3.0%**

Figure 7 Ontario Industry Historical TFP

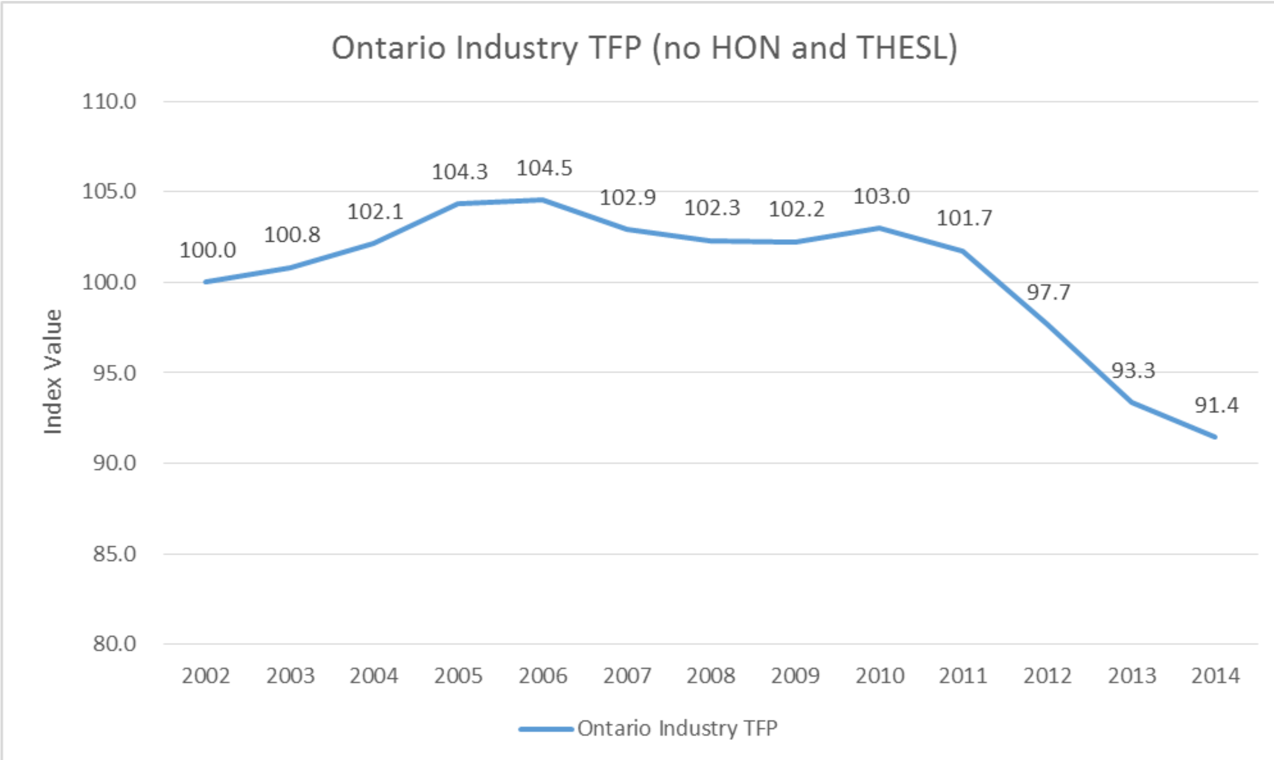


Table 21 Ontario Industry TFP

Ontario Industry TFP	Average Annual Growth Rate
2002-2012	-0.3%
2002-2015	-0.9%

8 Conclusion

Hydro One's 2002 to 2015 average annual growth rate in unadjusted TFP is -1.4%. When the reliability and safety performance metrics are incorporated, the growth rate becomes -0.9%. For both indexes, much of the negative growth occurred in the earlier years of the sample. From 2002 to 2010 the index adjusted for performance declined by 1.8% but rose by 0.5% from 2010 to 2015.

Year	TFP (unadjusted)	TFP with Safety Adjustment	TFP with Reliability Adjustment	TFP with Safety and Reliability Adjustment
2002	1.00	1.00	1.00	**1.00**
2003	1.00	1.00	1.00	**1.00**
2004	1.02	1.02	1.02	**1.02**
2005	1.01	1.01	1.02	**1.02**
2006	0.96	0.96	0.99	**0.99**
2007	0.89	0.90	0.91	**0.91**
2008	0.90	0.90	0.92	**0.92**
2009	0.86	0.86	0.88	**0.88**
2010	0.84	0.85	0.86	**0.86**
2011	0.84	0.85	0.86	**0.88**
2012	0.85	0.88	0.87	**0.90**
2013	0.81	0.84	0.83	**0.86**
2014	0.80	0.84	0.81	**0.85**
2015	0.83	0.88	0.84	**0.88**
Average Annual Growth Rate				
2002-2015	-1.4%	-1.0%	-1.4%	**-0.9%**
2002-2010	-2.1%	-2.0%	-1.9%	**-1.8%**
2010-2015	-0.4%	0.6%	-0.5%	**0.5%**

PSE also updated the Ontario industry TFP research to 2015. The updated Ontario industry TFP has declined by 0.9% during the 2002 to 2015 time period. This decline has accelerated in recent years. Since 2010, the Ontario industry TFP has declined by 3.0%.

While the indexes are not directly comparable, the upward trajectory of Hydro One's adjusted TFP trend is contrasted with the recent downward TFP trend of the rest of the Ontario industry. The ascending trajectory of Hydro One's TFP provides evidence that productivity has improved during the most recent years of the sample.

After updating the Ontario industry TFP to 2015, PSE found the trend is now -0.9%. The 2002-2012 Ontario TFP trend was -0.3%. Based on the empirical evidence of declining industry TFP and the OEB's 4th Generation IR decision to set the productivity factor at 0.0%, PSE recommends setting Hydro One's productivity factor no higher than 0.0%.

The X-factor is calculated as the sum of the productivity factor and the stretch factor. Stretch factors are normally determined using benchmarking research. PSE is of the opinion that accurate total cost benchmarking is the best approach in setting stretch factors. The long term 2002-2015 Hydro One adjusted TFP trend of -0.9% and the recent positive TFP growth of +0.5% provides evidence that there is the chance for modest TFP growth in the near term. On this basis, PSE recommends setting the stretch factor no higher than 0.6%. This is the maximum stretch factor put forth in 4th Generation IR and combined with a 0.0% productivity factor would amount to an X-factor of 0.6%. This would be a challenging X-factor in light of the industry TFP trend of -0.9% and would require Hydro One to outpace the Ontario historical TFP trend by 1.5%.

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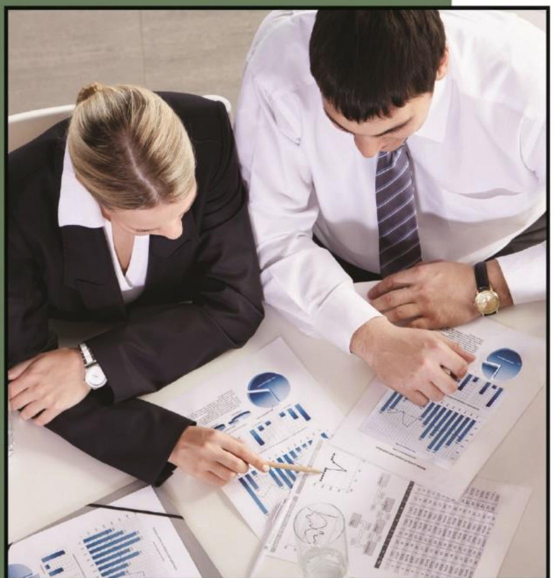

Econometric Benchmarking Study: Total Distribution Costs of Hydro One Network

Prepared by:

Power System Engineering, Inc.

March 8, 2017

Econometric Benchmarking Study: Total Distribution Costs of Hydro One Network

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1 Executive Summary

Power System Engineering, Inc. ("PSE") was engaged by Hydro One Networks ("Hydro One") to recommend an appropriate stretch factor for their upcoming incentive regulation application. To accomplish this request, PSE conducted an econometric benchmarking study of Hydro One's total distribution costs. This report provides the details of the research and results. The results of the study guide PSE's recommendation on the stretch factor for Hydro One's upcoming electric distribution rate application.

1.1 Summary of PSE's Benchmarking Process

When evaluating utility cost performance, PSE recommends econometric benchmarking instead of basic peer group comparisons, because in most cases econometric benchmarking is more accurate. The econometric benchmarking method has the following advantages: (1) the ability to statistically test candidate variables, (2) the ability to statistically test results, (3) the capacity to include a relatively large number of variables in the analysis, and (4) it does not require the researcher to subjectively choose a peer group.

The purpose of PSE's benchmarking analysis is to benchmark Hydro One's historical total distribution costs and provide a recommendation on the appropriate stretch factor to apply to Hydro One's incentive regulation application. The benchmark analysis is done by comparing Hydro One's *actual* total distribution cost values with the benchmarking model's *predicted* values.[1]

When making this comparison, we use the logarithmic percentage difference of Hydro One's actual total costs and the predicted total costs.[2] A percentage difference finding above zero implies Hydro One's costs are above the benchmark level (i.e., a positive value implies that Hydro One's total costs are higher than expected).

$$\%\, Difference = Natural\ Log\ \left(\frac{Actual\ Total\ Cost}{Benchmark\ Total\ Cost}\right)$$

To arrive at the predicted (benchmarked) costs for a utility, PSE uses historical cost data from a U.S. dataset comprised of multiple utilities to create a model; this model relates cost to certain variables. The model takes publicly available variable data for each utility in the dataset (such as number of customers, peak demand, vegetation levels, wage levels, weather, etc.) and creates a model that predicts the expected costs for each utility, given the specific variable data.[3] The

[1] In this report we will use "predicted", "expected" or "benchmark" costs to refer to the econometric model's outputs for those metrics. Hereafter, when we use the term "costs" or "total costs" we are referring to distribution costs, unless otherwise stated.

[2] We use the logarithmic percentage rather than the arithmetic percentage because it is the convention within the benchmarking industry. It is the same method used by the Board Staff's benchmarking consultant, Pacific Economics Group.

[3] A complete list of variables used in the model appears in Section 2.

expected costs (benchmark costs) for each utility represent the costs we would expect from that utility, given its specific variable data, if that utility were an "average" performer. Thus for any utility in the dataset, actual costs can be compared to expected costs. The model is used to predict Hydro One's "expected" (benchmarked) total costs.

A dataset which includes U.S. observations is required for an accurate benchmark assessment of Hydro One's performance. This is due to Hydro One's large number of customers and rural service area relative to an Ontario-only dataset. The need for a dataset beyond Ontario distributors is made clear by the fact that the company's distribution system is, by far, the largest in Ontario and spans approximately 75% of the province.[4] The U.S. utility dataset has a number of utilities with large distribution systems and with systems serving rural areas; these utilities (when used to create the model) reflect how large rural distribution areas can impact costs.

In an effort to produce a dataset that can adequately capture Hydro One's large size and rural characteristics, PSE used a sample consisting of 380 U.S. distributors spanning a time period starting in 2002 and ending in 2015.[5] An appropriate benchmark sample requires observations that have explanatory variable values that encompass those of the studied utility. For example, if the "target" utility has a large rural area, the appropriate benchmark sample will contain a number of utilities with a large rural area (as well as some utilities with a smaller, more urban service area). These utilities are needed to capture the effect that a large rural area has on cost. For this reason, PSE incorporated both U.S. investor-owned utilities ("IOUs") and U.S. rural electric cooperatives ("RECs"). The IOUs tend to serve a large number of customers; a number of IOUs in the sample have customer populations that exceed Hydro One's customer population. The RECs tend to serve the rural areas of the U.S.; a number of cooperatives in the sample have fewer customers per square kilometer than Hydro One.

The total number of observations in the dataset is 3,998 (here an "observation" means one utility's costs over one year, with the variable data for that year). This is a relatively large and diverse dataset.[6] The large number of distributors and diversity within the dataset enhances the model's ability to adequately capture the cost impacts of specific variables. For some utilities, certain individual years did not yield usable observations, due to incomplete or missing data.

The general approach of our benchmarking analysis is as follows:

1. PSE assembled the historical costs of all utilities in the dataset, along with the variables that affect cost, such as customer levels, weather, wage levels, etc.
2. Using the historical data, PSE estimated an econometric model that expresses the relationship between the variables and cost.
3. PSE can then produce "benchmark" values for a given utility. The benchmark values are determined from the model. In Hydro One's case, the benchmark represents the total cost

[4] http://www.hydroone.com/OurCompany/Pages/QuickFacts.aspx

[5] Not all included distributors will have data for every year due to unavailable or implausible reported data in individual years.

[6] To PSE's knowledge, this is the largest econometric benchmarking dataset used in a North American regulatory proceeding.

amount we would expect for an average-performing utility with the number of customers, peak demand, customer density, weather, wage levels, etc. faced by Hydro One.

4. We then compare the total costs that are expected (predicted) by the model to Hydro One's actual historical costs, which allows us to: (1) evaluate the historical cost performance, and (2) recommend a stretch factor based on that result.

1.2 Total Cost Benchmark Findings

Using the sample of 380 distributors, PSE estimated a translog total cost econometric model. As required by accepted best practice, all first order variables are signed according to theory and are statistically significant at a 90% level of confidence.[7]

The benchmark scores are derived by taking the logarithmic percentage difference from Hydro One's actual total costs and their model-predicted total costs. That is to say, a positive number implies that the company's actual costs are higher than the benchmark. The table below shows the scores for the last three years (2013 – 2015) and the average of that three-year period.

Table 1-1 Hydro One's Cost Performance 2013-2015

Year	% Difference from Benchmark Total Cost
2013	+25.7
2014	+29.3
2015	+23.2
Average 2013-2015	**+26.0**

The model results indicate the following findings as applied to Hydro One.

1. For the most recent three year period (2013-2015), average total cost levels of Hydro One are above benchmark expectations by 26.0%. In the most recent year of 2015, Hydro One's total costs are 23.2% above benchmark expectations.

2. Using the 4th Generation Incentive Regulation ("4GIR") Decision for determining stretch factors, the total cost benchmark finding implies a stretch factor of 0.60%.[8]

[7] In fact, all first order variables in the model are statistically significant at the 99% confidence level.

[8] Case EB-2010-0379

2 Total Cost Benchmarking Datasets, Methods, Variable Definitions

The data for the U.S. utilities used in the study were acquired from publicly available data sources. There are 380 U.S. utilities in the sample, plus Hydro One. The sample includes: (1) U.S. IOUs serving more than 10,000 customers, and (2) RECs serving more than 10,000 customers.

The observations span the years 2002 to 2015. The total observations in the dataset is 3,998. Observations were excluded if key data (cost or outputs) were missing or implausible. Additional exclusions were made on the basis of missing or implausible explanatory variable data. The large number of observations is more than sufficient for the creation of a statistically robust econometric model.

The output variables used in the total cost econometric benchmarking research are:

- Retail customers, and
- Maximum peak demand.

The business condition variables used in the total cost econometric benchmarking research are:

- Regional input prices,
- Percent electric customers (out of total gas and electric customers),
- Forestation of the service territory,
- Squared kilometers of territory served per customer,
- Percent of territory designated as "artificial surface",
- Percent customer service and information expenses in distribution OM&A,
- Extreme weather conditions, and
- A time trend variable

Both OM&A and total costs used in the benchmarking models for the U.S. distributors are derived using FERC Form 1 filing data for the IOUs, and United States Department of Agriculture ("USDA") Form 7 filing data for the RECs.[9,10] United States IOUs are required to file FERC Form 1 data annually, which includes operation and maintenance expenses broken down into specific cost categories (e.g. distribution, transmission, generation, customer billing, administrative and general). Form 1s also include plant in service and accumulated depreciation information that is used in constructing capital costs. RECs are required to annually file RUS Form 7s if they are borrowing from the USDA. Publically-available Form 7 data ends in 2011.

The cost definition for Hydro One is used to create cost comparability with the U.S. sample. PSE

[9] All FERC and Form 7 data was downloaded by PSE from SNL Energy's database tool.

[10] The USDA forms are no longer referred to Form 7 by the USDA. They are now referred to the "Financial and Operating Report Electric Distribution." https://www.rd.usda.gov/files/UEP_Support_DCS.pdf

For simplicity, we will use the former name of "Form 7" throughout this report.

began with the benchmark-based cost definition used by the Board Staff's consultant ("PEG") in the 4th Generation Incentive Regulation proceeding. PSE then added Hydro One's high voltage expenses to the company's cost definition. The FERC Form 1 and Form 7 do not break out high versus low voltage distribution expenses like Ontario reporting does. For that reason, Hydro One's high voltage expenses have been added to make costs comparable. For the same reasons, contributions in aid of construction ("CIAC") have been excluded from Hydro One's cost definition, due to those expenses not being included in the U.S. Form 1 or Form 7 data. Bad debt expenses have been added to Hydro One's costs since the Form 7 reporting data does not break out those expenses. The table below summarizes the cost definition treatment.

Table 2-1 Cost Definitions

Cost Element	Treatment
4th Generation IR Benchmark-Based Costs	Used this as a starting point for Hydro One
CIAC	Not included in Hydro One's costs, since U.S. cost data does not include CIAC
High Voltage Expenses	Added to Hydro One costs, since U.S. cost data includes distribution high voltage costs
Bad Debt Expenses	Added to Hydro One costs, since U.S. cost data includes bad debt expenses

The total cost model includes two output variables. The first is the total number of customers served, the second is the maximum peak demand for each utility during the sample period. For U.S. utilities, the output variables are calculated from FERC Form 1s and Form 7's. The historical output data for Hydro One comes directly from the company. For Hydro One, PSE added the "embedded" distribution demand to Hydro One's maximum peak demand value. This was done because the Hydro One distribution system network needs to be built to accommodate both its own system demands and those of the embedded distributors.

Input prices are divided into two categories: capital and OM&A. The capital input price calculation is discussed in detail in the following section. The OM&A input price captures the regional market price level that each sampled company encounters when procuring OM&A inputs, such as employees or materials and services. There are two components used to construct the OM&A input price. These are labour and non-labour.

The labour component is calculated by taking wage levels of numerous job occupations and weighting them based on the U.S. Bureau of Labor Statistics ("BLS") estimates of job occupation weights in the Electric Power Generation, Transmission, and Distribution Industry. The BLS has estimates for wage levels for each job occupation by city and metropolitan area. For Hydro One, we gathered job occupation wage estimates from Statistics Canada, using wage data from Ontario, translated job occupations to match their U.S. counterparts, and then weighted the job occupation wages by the BLS estimates. This provides consistency from the U.S. and Hydro One regarding labour input prices and also puts the input price in terms of each country's currency.

The non-labour component of the OM&A input price uses the gross domestic product price index ("GDP-PI") for the U.S. utilities. The Ontario non-labour component uses the same GDP-PI in each year, but adjusted for the purchasing power parity ("PPP") index. This translates the non-labour input price component into Canadian dollars.

To construct the overall OM&A input price we weighted each index using a 70% labour and a 30% non-labour rate. This was the same weighting used by PEG in their benchmarking research. Using the capital and OM&A cost shares, PSE calculated a total input price index. Total cost is divided by this comprehensive input price to adjust for regional input price differences between distributors.

The variable that measures the percentage of electric customers out of total gas and electric customers. This variable measures the economies of scope available from serving both electric and gas customers. Billing and other customer-related activities can be shared between the gas and electric divisions when a utility serves its customers with both commodities. The value is set to 100% for Hydro One, since the company does not serve natural gas customers.

The percentage of forestation variable is based on GIS (geographic information system) land cover maps. PSE used the GlobCover 2009 product processed and produced by the European Space Agency ("ESA") and the Université catholique de Louvain. These maps are matched with the areas served by each utility to create the forestation variable. We would expect that the higher the level of forestation, the higher OM&A costs required for right-of-way clearing and service restoration activities. GIS variable data is available for all sampled U.S. utilities and for Hydro One.

The square kilometers per customer variable is calculated using GIS coordinates of each utility's service area provided to PSE by Platts. The variable equals the total square kilometers of the area of the distributors service territory divided by the number of retail customers served. The customer variable is the same as the output variable that enters the model. We would expect distributors that have to cover more service territory per customer to have higher costs.

PSE calculated the percent artificial surfaces variable using PSE's GIS experts, the GlobCover 2009 product from the ESA, and the Université catholique de Louvain. This variable denotes the percentage of a distributor's service territory that is predominately "artificial" or man-made. Serving electricity in areas covered by asphalt, concrete, buildings, and other artificial surfaces is expected to increase utility costs due to the required added construction costs.

The percentage of customer service and information expenses is calculated by taking customer service and information expenses and dividing by the total OM&A. Since some U.S. distributors include their conservation demand management expenses within the customer service and information expense category, this variable accounts for those cases. We would expect a higher percentage of customer service and information expenses to be associated with higher total costs.

The extreme temperature variable is defined as the annual absolute sum of the number of hours in which temperatures were below minus 15 degrees Celsius or above 30 degrees Celsius. Utilities serving in extremely cold or extremely hot climate conditions will tend to have higher costs, due to increased crew breaks and reduced productivity relative to utilities serving in more moderate conditions.

2.1 Perpetual Inventory Capital Cost Method

This report evaluates Hydro One's capital costs as a component of the total cost definition. PSE's measure of capital cost is based on a service price approach. This approach has a solid basis in economic theory, and is the same method chosen by PEG in their 4th Generation IR research.[11] It allows for a clear-cut and standardized way to account for differences between utilities with respect to historical plant additions. The service price approach also has ample precedent in government-sponsored cost research. It is used by the Bureau of Labor Statistics of the U.S. Department of Labor in computing multi-factor productivity indexes for the U.S. private business sector and for several subsectors, including the utility services industry.

Based on this approach, the cost of capital in each period *t* is the product of indices of the capital service price and capital quantity in place at the end of the prior period. The formula for this is given by:

$$CK_t = WKS_t \cdot XK_{t-1}$$

Here, in each period *t*, CK_t is the cost of capital, WKS_t is the capital service price index, and XK_{t-1} is the capital quantity index value at the start of the period.

The capital quantity index is constructed using inflation-adjusted data on the value of net utility plant in a benchmark year, and on gross plant additions in subsequent years. It also uses an assumption about service lives. We use 2002 as the benchmark year in the current study for all utilities, including Hydro One. This is the first feasible year to use for Hydro One, due to lack of data availability in years prior to 2002. This is also the same benchmark year used for Hydro One in PEG's 4th Generation IR benchmarking work.

We used Hydro One's distribution net plant in 2002. For the rest of the sample we calculated each utility's total net electric plant and then allocated the distribution portion by the percentage of gross distribution plant in total gross electric plant in 2002.

Based on the benchmark year, a "triangulated weighted average" ("TWA") is used to calculate the capital stock in 2002. Subsequent years use the previous year's capital stock and escalate it by plant additions minus depreciation. This method is used both for Hydro One and U.S. distributors. The formulas for the capital quantity index in 2002 and in subsequent years are provided below.

$$XK_{2002}^{i} = \frac{Net\ Plant_{2002}^{i}}{TWA_{2002}^{i}}$$

$$XK_t^i = XK_{t-1}^i * d + \frac{Add_t^i}{WKA_t^i}$$

Under the service price approach employed in this study, capital cost has two components: opportunity cost and depreciation. The capital service price index is thus given by the formula:

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[11] See Hall and Jorgensen (1967) for a discussion of the use of service price methods for measuring capital cost.

$$WKS_t = r_t * WKA_{t-1} + d_t * WKA_t$$

Here, r_t is the allowed rate of return based on the Board's historical calculated returns. This same annual value is also used in the capital service price computation for the U.S utilities in the dataset. Setting the same rate of return for all distributors provides consistency in determining the capital costs, so that decisions by regulators do not enter into the benchmark evaluation, which is attempting to assess the performance of the utility itself. The parameter d_t is the economic depreciation rate. We use the same value as PEG did (4.59%) for this parameter in the study.

The variable that the capital service price components have in common is WKA_t. This is an index of the price of capital assets used in power distribution. We compute this index using data on differences in the cost of constructing utility plant between regions, and within regions over time. In particular for U.S. distributors, we use the Handy-Whitman indexes for total power distribution plant, which vary over time and across six geographic regions. For Hydro One, we used the Handy-Whitman index for the North Atlantic region.

We determine the relative levels of utility plant asset prices for 2012 by using the City Cost Indexes for electrical work in RSMeans' *Heavy Construction Cost Data*.[12] These indexes measure differences among cities in the cost of labour needed to install electrical equipment and differences in equipment prices. The construction service categories covered are: raceways; conductors and grounding; boxes and wiring devices; motors, starters, boards, and switches; transformers and bus ducts; lighting; electric utilities; and power distribution. The level of the asset price index for each utility is the simple average of the RSMeans index values for cities in the service territory. This same source is used for both U.S. and Hydro One. The index is already adjusted for currency differences between the two countries.

[12] RS Means (2011).

2.2 Econometric Method

The benchmarking approach used in this report is the econometric approach. PSE believes this is the most accurate and fair method to use when comparing utility cost and reliability levels. It is also the same method preferred by the Board in the 4GIR Decision.

The econometric approach explicitly adjusts for differences in utilities' service territories. In the power distribution industry, simple comparisons of costs or reliability indexes do not result in appropriate comparisons when evaluating performance. Uncontrollable factors such as service territory characteristics influence total costs. Therefore, more sophisticated tools that normalize for specific influencing factors must be employed to accurately assess performance. With this concept in mind, PSE has developed an econometric benchmarking model that takes into account factors that have proven to be statistically influential on distribution utility costs.

The econometric benchmarking approach relies on comparing actual data values to the predicted values, which are obtained from the econometric models. The researcher determines an appropriate functional form (a model) for the relationship between the studied metric and factors (variables) that influence it. This is done by using appropriate econometric methods to obtaining parameter estimates for each variable of the specified model.

In this report, we estimate the "translog cost function". The translog cost function is well established in academic literature and provides a high level of flexibility in estimating costs. This is also the same functional form preferred by the Board in the 4th Generation IR proceeding.

Cost predictions for each firm are obtained by inserting company-specific variable values into the estimated equation. Performance is defined as the percentage difference of the observed data to the predicted value of the data, as shown below.

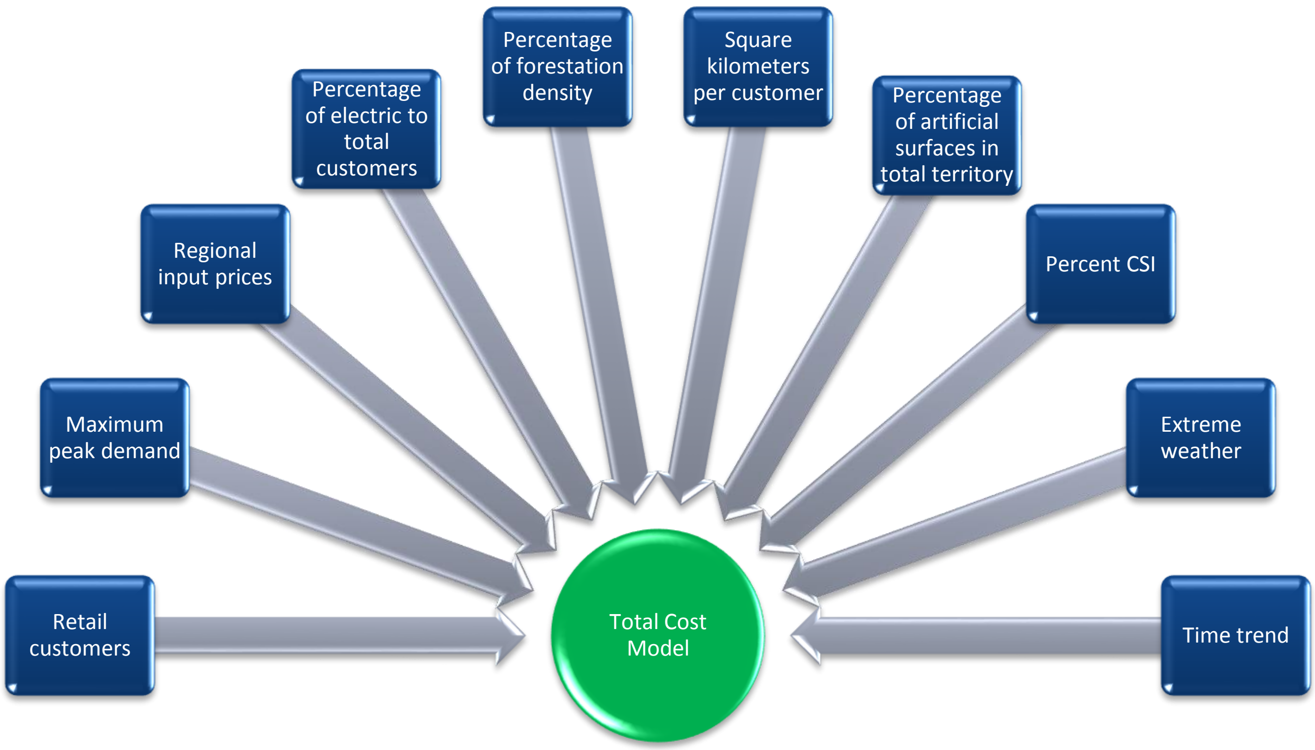
$$Performance = \ln\left(\frac{Observed\ Cost\ Data}{Predicted\ Cost\ Data}\right)$$

> NOTE: The term "ln" above denotes the natural log. The formula above is the calculation for log arithmetically calculating percentage differences. It is typically used by both PSE and PEG to display benchmark scores.

2.3 Variables Used

The variables included in the benchmark analysis are shown in the figure below.

Figure 2-1 Variables in Econometric Cost Models



A diverse dataset which includes utilities with varying operational conditions is necessary to determine the influence on costs resulting from those conditions. There are many U.S. utilities in the PSE dataset which are: (1) larger or smaller than Hydro One, or (2) have higher or lower customer densities than Hydro One. This is in contrast to an Ontario-only dataset, where Hydro One tends to be an outlier due to its size and rural characteristics.

2.4 Estimation Procedure and Translog Cost Function

As a starting point, we assume that the relationship between a utility's cost and the conditions that affect it, called "cost drivers" (i.e., the variables), can be quantified and captured by a statistical function. This function, called a "cost function," allows PSE to specify cost as a dependent variable that can be explained by relevant independent or explanatory variables and associated parameters; the latter capture the effect of the independent variables on cost. Such a cost function is estimated using econometric techniques that rest on certain fundamental assumptions.

As implied by the term "independent," one of these assumptions is that the explanatory variables used in the model are factors that are outside the control of utility decision-makers. For instance, the wage paid to labour is driven by market conditions in the service territory, and is largely outside the control of a firm's managers. On the other hand, the number of employees hired are within management's control, and thus cannot serve as an independent variable.

In general, cost is assumed to be a function of input prices, the output produced by the firm, and other independent variables that affect cost but are outside management's control. While a function specified in this manner can capture a reasonable level of cost variability, it does not explain all the elements that affect cost. Therefore, the function includes a random noise term to account for such idiosyncratic factors.

The following equation provides an example of a simple cost function:

$$C = \beta_o + \beta_1 * Y + \varepsilon$$

In this equation, the terms C and Y, denote cost and output, respectively. The beta terms denote model parameters that capture the magnitude and sign of the effect of the explanatory variables on cost, and the error term captures random noise. The latter is assumed to be independent of the explanatory variables.

The data used to estimate this cost relationship can consist of different types of observations, as follows:

- Data from a single utility with multiple time observations (time series data),
- Data from many utilities observed at a single time period (cross-sectional data), or
- Data from many utilities with multiple time observations (cross-sectional time-series or panel data).

The estimation procedure used to estimate model parameters is affected by the type of data used to estimate the model. In our present study, we have a panel dataset with cost data from multiple utilities with observations starting in 2002 and extending to 2015.

2.4.1 Statistical Tests

The precision of parameter estimates is an important dimension of the cost estimation exercise. It identifies business condition variables that have a statistically significant effect on cost. In particular, standard errors of parameter estimates, which measure the precision with which a parameter is estimated, are used to construct a test of a relevant hypothesis. The hypothesis to be tested is "the explanatory variable in question has no statistically significant effect on cost." This procedure is called the *t*-test. A variable is statistically significant if this hypothesis is rejected at a pre-specified level of confidence. We use a 90 percent confidence threshold in our research.

A cost model with plausibly signed and statistically significant parameter estimates is ultimately used to assess the cost performance of each firm in the sample. By "plausibly signed" we mean that its sign (positive/negative) accords with our intuitive understanding of the relationship between that parameter and the variable. For example, we would "expect" to see costs rise as the number of customers served increases (i.e. the customer parameter would be positively signed).

A cost model with estimated parameters is fitted with the business conditions of each utility to generate cost benchmarks, against which actual cost is evaluated. A cost benchmark reflects the performance of an average utility facing the business conditions of the utility whose values are used to generate the benchmark.

If a given utility's actual cost is below the benchmark cost, its cost performance is better than average—it spent less than did a hypothetical utility (with the same particular characteristics) would be expected to spend. If its actual cost is above the benchmark cost, its cost performance is worse than average. A statistical test of a cost efficiency hypothesis, based on the *t*-test, can also be constructed to identify whether the cost performance identified by the above exercise is statistically significantly different from average.

2.4.2 Model Specification

A translog function is selected for the total cost model estimated in this study. The translog cost function was the same functional form chosen by PEG in their 4th Generation Incentive Regulation benchmarking research and the same one preferred by the Board in its November 2013 Board Report.

The model is estimated using generalized least squares (GLS) in order to correct for cross-sectional heteroskedasticity. The parameter estimates that result from this procedure are both consistent and efficient.

3 Total Cost Benchmarking Results

The estimates from the total cost model are presented in Table 3-1. We note that the cost function parameter estimates are plausibly signed and have reasonable magnitudes. The first order terms of all variables have the theoretically expected signs and are statistically significant at a 99% level of confidence.

Table 3-1 Total Cost Model Estimates

Total Cost Model Estimates						
VARIABLE KEY						
		N=	Number retail customers			
		D=	Maximum peak demand			
		A=	Square kilometers of territory per customer			
		E=	Percent electric customers			
		F=	Percent forestation in service territory			
		CSI=	Percent customer service and information expenses			
		W=	Extreme weather			
		Art=	Percent of territory that is artificial surfaces			
EXPLANATORY VARIABLE	**ESTIMATED COEFFICIENT**	**T STATISTIC**		**EXPLANATORY VARIABLE**	**ESTIMATED COEFFICIENT**	**T STATISTIC**
N	0.811	130.712		CSI	0.010	9.195
NN	0.130	10.393				
ND	-0.134	-6.026		W	0.00001	13.284
D	0.097	16.269		Art	1.868	23.086
DD	0.019	1.893				
				Trend	-0.002	-3.955
A	0.066	31.493				
				Constant	12.043	1358.844
E	0.109	12.205				
				Adjusted R-Squared	0.996	
F	0.057	25.095				
				Sample Period:	2002-2015	
				Number of Observations	3998	

At the sample mean, a 1% increase in the number of customers (N on the table) and maximum peak demand (D) are estimated to raise cost by 0.811% and 0.097%, respectively. The number of customers served is the dominant output-related cost driver, which is an expected result for an electric distribution total cost model. The business condition coefficients are also signed as our hypothesis would suggest. All business condition variables are plausibly signed and statistically significant at the required 90% confidence level.

The benchmark scores are derived by taking the logarithmic percentage difference from Hydro One's actual total costs and their model-predicted total costs. That is to say, a positive number implies that the company's actual costs are higher than the benchmark. The table below shows the scores for the most recent three years (2013 to 2015) and the average of that three-year period.

Table 3-2 Hydro One's Cost Performance 2013-2015

Year	% Difference from Benchmark Total Cost
2013	+25.7
2014	+29.3
2015	+23.2
Average 2013-2015	**+26.0**

In the most recent three-year period, Hydro One's total costs are 26.0% above benchmark expectations. In the latest available year, 2015, we find Hydro One's costs to be 23.2% above benchmark expectations.

4 PSE Stretch Factor Recommendation

For the most recent three year period (2013- 2015), average total cost levels of Hydro One are above benchmark expectations by 26.0%. In the most recent year of 2015, Hydro One's total costs are 23.2% above benchmark expectations.

The stretch factors in 4^{th} Generation Incentive Regulation are based on the total cost benchmarking scores of each distributor. Distributors with average scores greater than 25% are assigned a stretch factor of 0.6%. Based on PSE's total cost benchmark findings found in this report and the 4^{th} Generation Incentive Regulation Board Decision, we currently recommend a stretch factor of 0.6% for Hydro One's custom incentive regulation application.

This 0.6% recommendation comes with the caveat that the most recently available benchmarking scores should be used as the basis for the stretch factor. Therefore, if new data for additional years becomes available and possible to incorporate into the benchmarking evaluation during the course of Hydro One's upcoming custom IR application, then PSE's stretch factor recommendation would be adjusted to reflect the more recent result.

FORM A

Proceeding: EB-2017-0049

ACKNOWLEDGMENT OF EXPERT'S DUTY

1. My name is Steven Fenrick (*name*). I live at Verona (*city*), in the Wisconsin (*province/state*) of United States of America

2. I have been engaged by or on behalf of Hydro One Networks (*name of party/parties*) to provide evidence in relation to the above-noted proceeding before the Ontario Energy Board.

3. I acknowledge that it is my duty to provide evidence in relation to this proceeding as follows:

   (a) to provide opinion evidence that is fair, objective and non-partisan;

   (b) to provide opinion evidence that is related only to matters that are within my area of expertise; and

   (c) to provide such additional assistance as the Board may reasonably require, to determine a matter in issue.

4. I acknowledge that the duty referred to above prevails over any obligation which I may owe to any party by whom or on whose behalf I am engaged.

Date 2/10/17

Steve Fenrick

Signature

STEVEN A. FENRICK

Leader, Economics & Market Research Group

SUMMARY OF EXPERIENCE AND EXPERTISE

- Leader of PSE's Economics and Market Research group which conducts research in the fields of DSM, performance benchmarking, incentive regulation, load research and forecasting, and survey design and implementation
- Manages PSE's cost, productivity, and reliability performance benchmarking practice
- Directs research on value-based reliability planning efforts for electric utilities
- Expert in performance-based ratemaking and incentive regulation
- Directs economic research on investigating the impacts and costs/benefits of DSM programs and designing statistically robust pilot designs

PROFESSIONAL EXPERIENCE

Power System Engineering, Inc.– Madison, WI (2009 to present)

Leader, Economics and Market Research

Responsible for providing consulting services to utilities and regulators in the areas of reliability and cost benchmarking, incentive regulation, value-based reliability planning, demand-side management including demand response and energy efficiency, load research, load forecasting, end-use surveys, and market research.

- Leads research, on an annual basis, with over a dozen electric utilities in evaluating cost, productivity, and reliability performance and uncovering methods to improve their operations
- Benchmarking consultant to the Ontario Energy Board regarding their 3rd Generation Incentive Regulation Plan for the last two years
- In the process of designing and analyzing DSM pilot projects at over 25 electric utilities across the country
- Testimony experience regarding performance value-based reliability planning, benchmarking and productivity analysis
- Has given several presentations on performance benchmarking and productivity analysis, costs and benefits of DSM programs, and measurement and verification (M&V) techniques.
- Key speaker at EUCI conferences regarding cost and reliability performance evaluation and productivity analysis of distribution utilities

Pacific Economics Group – Madison, WI (2001 - 2009)

Senior Economist

- Co-authored research reports submitted as testimony in numerous proceedings in several states and in international jurisdictions. Research topics included statistical benchmarking, alternative regulation, and revenue decoupling.

- Managed and supervised PEG support staff in research and marketing efforts.

EDUCATION

University of Wisconsin - Madison, WI
Bachelor of Science, Economics (Mathematical Emphasis)

University of Wisconsin - Madison, WI
Master of Science, Agriculture and Applied Economics

Publications & Papers

- "Peak-Time Rebate Programs: A Success Story", *TechSurveillance*, July 2014 (with David Williams and Chris Ivanov).
- "Demand Impact of a Critical Peak Pricing Program: Opt-In and Opt-Out Options, Green Attitudes and other Customer Characteristics:, *The Energy Journal*, January 2014. (With Lullit Getachew, Chris Ivanov, and Jeff Smith).
- "Evaluating the Cost of Reliability Improvement Programs", *The Electricity Journal*, November 2013. (With Lullit Getachew)
- "Expected Useful Life of Energy Efficiency Improvements", Cooperative Research Network, 2013 (with David Williams).
- "Cost and Reliability Comparisons of Underground and Overhead Power Lines", *Utilities Policy*, March 2012. (With Lullit Getachew).
- "Formulating Appropriate Electric Reliability Targets and Performance Evaluations, *Electricity Journal*, March 2012. (With Lullit Getachew)
- "Enabling Technologies and Energy Savings: The Case of EnergyWise Smart Meter Pilot of Connexus Energy", November 2012. (With Chris Ivanov, Lullit Getachew, and Bethany Vittetoe)
- "The Value of Improving Load Factors through Demand-Side Management Programs", Cooperative Research Network, 2012 (with David Williams and Chris Ivanov).
- "Estimation of the Effects of Price and Billing Frequency on Household Water Demand Using a Panel of Wisconsin Municipalities", *Applied Economics Letters*, 2012, 19:14, 1373-1380.
- "Altreg Rate Designs Address Declining Average Gas Use", *Natural Gas & Electricity*. April 2008. (With Mark Lowry, Lullit Getachew, and David Hovde).
- "Regulation of Gas Distributors with Declining Use per Customer", *Dialogue*. August 2006. (With Mark Lowry and Lullit Getachew).
- "Balancing Reliability with Investment Costs: Assessing the Costs and Benefits of Reliability-Driven Power Transmission Projects." April 2011. *RE Magazine*.
- "Ex-Post Cost, Productivity, and Reliability Performance Assessment Techniques for Power Distribution Utilities". Master's Thesis.
- "Demand Response: How Much Value is Really There?" *PSE whitepaper.*
- "How is My Utility Performing" *PSE whitepaper*.
- "Improving the Performance of Power Distributors by Statistical Performance Benchmarking" *PSE whitepaper*.
- "Peak Time Rebate Programs: Reducing Costs While Engaging Customers" *PSE whitepaper*.
- "Performance Based Regulation for Electric and Gas Distributors" *PSE whitepaper*.

- “Revenue Decoupling: Designing a Fair Revenue Adjustment Mechanism” *PSE whitepaper.*

Expert Witness Experience

- Docket EB-2015-0004, Hydro Ottawa, Custom Incentive Regulation Application.
- Docket 15-SPEE-357-TAR, Application for Southern Pioneer Electric Cooperative, Inc., Demand Response Peak Time Rebate Pilot Program.
- Docket EB-2014-0116, Toronto Hydro, Custom Incentive Regulation Application.
- Docket EB-2010-0379, The Coalition of Large Distributors in Ontario regarding “Defining & Measuring Performance”.
- Docket No. 6690-CE-198, Wisconsin Public Service Corporation, “Application for Certificate of Authority for System Modernization and Reliability Project”.
- Expert Witness presentation to Connecticut Governors “Two Storm Panel”, 2012.
- Docket No. EB-2012-0064, Toronto Hydro’s Incremental Capital Module (ICM) request for added capital funding.
- Docket No. 09-0306, Central Illinois Light rate case filing.
- Docket No. 09-0307, Central Illinois Public Service Company rate case filing.
- Docket No. 09-0308, Illinois Power rate case filing.

Recent Conference Presentations

- Wisconsin Manager’s Meeting, “Reliability Target Setting Using Econometric Benchmarking”. November 2016.
- Institute of Public Utilities Advanced Rate Conference at Michigan State University, “Performance Benchmarking”. October 2016.
- Wisconsin Electric Cooperative Association (WECA) Conference, “An Introduction to Peak Time Rebates”. September 2016.
- Institute of Public Utilities Advanced Rate Conference at Michigan State University, “Performance Benchmarking”. October 2015.
- EUCI conference chair, 2015. “Evaluating the Performance of Gas and Electric Distribution Utilities.”
- Institute of Public Utilities Advanced Rate Conference at Michigan State University, “Performance Benchmarking”. October 2014.
- Cooperative Exchange Conference, Williamsburg VA. “Smart Thermostat versus AC Direct Load Control Impacts”. August 2014.
- EUCI conference chair in Chicago. “The Economics of Demand Response”. February 2014.
- Institute of Public Utilities Advanced Rate Conference at Michigan State University, “Performance Benchmarking”. October 2013.
- EUCI conference chair in Chicago. “Evaluating the Performance of Gas and Electric Distribution Utilities.” August 2013.
- Presentation to the Ontario Energy Board, “Research and Recommendations on 4th Generation Incentive Regulation”.
- Presentation to the Canadian Electricity Association’s best practice working group. 2013

- Conference chair for EUCI conference in March 2013 titled, “Performance Benchmarking for Electric and Gas Distribution Utilities.”
- Presentation to the board of directors of Great Lakes Energy on benchmarking results, December 2012.
- Presentation on making optimal infrastructure investments and the impact on rates, Electricity Distribution Association, Toronto, Ontario. November 2012.
- Conference chair for EUCI conference in August 2012 titled, “Performance Benchmarking for Electric and Gas Distribution Utilities.”
- 2012 presentation in Springfield, IL to the Midwest Energy Association titled, “Reliability Target Setting and Performance Evaluation”.
- 2012 presentation in Springfield, IL to the Midwest Energy Association titled, “Making the Business Case for Reliability-Driven Investments”.
- Conference chair for EUCI conference in 2012 titled, “Balancing, Measuring, and Improving the Cost and Reliability Performance of Electric Distribution Utilities”. St. Louis.
- Conference chair for EUCI conference in 2012 titled, “Demand Response: The Economic and Technology Considerations from Pilot to Deployment”. St. Louis.
- 2012 Presentation in the Missouri PSC Smart Grid conference entitled, “Maximizing the Value of DSM Deployments”. Jefferson City.
- 2011 conference chair on a nationwide benchmarking conference for rural electrical cooperatives. Madison.
- 2011 presentation on optimizing demand response program at the CRN Summit. Cleveland.
- Conference chair for EUCI conference in 2011 titled, “Balancing, Measuring, and Improving the Cost and Reliability Performance of Electric Distribution Utilities”. Denver.
- 2010 presentation on cost benchmarking techniques for REMC. Wisconsin Dells.

History of Major Research Projects

1. Washington Utilities Transportation Commission (UTC) Reliability Benchmarking and Target-Setting for 3 Washington IOUs, 2017.
2. Hydro One Networks total cost benchmarking research, 2017.
3. Hydro One Networks total factor productivity research, 2016/2017.
4. Butte Electric Peak Time Rebate full deployment, 2017.
5. Southern Pioneer Pre-pay metering cost-benefit research, 2016.
6. Sunflower Electric load forecasts, 2015-ongoing.
7. PG&E customer satisfaction benchmarking and target setting, 2016.
8. Vectren reliability benchmarking and target setting, 2016.
9. Butte Electric PTR pilot design, implementation, and M&V. 2015/2016.
10. Central Wisconsin demand response dispatch model, 2015-present.

11. Cost and reliability econometric benchmarking in Custom Incentive Regulation filing, Hydro Ottawa, 2015.
12. Long-range load forecasts for six distribution utilities and G&T, Sunflower Electric, 2015.
13. Load research study review and VEE process review, Minnesota Power, 2015.
14. Demand Side Management Business Case Guidebook, CRN, 2015/2016.
15. Prepare research, design, and application to Kansas Commission on Peak Time Rebate Pilot for Southern Pioneer Electric Cooperative, 2015.
16. Cost and reliability econometric benchmarking in Custom Incentive Regulation filing, Toronto Hydro, 2014/2015.
17. Emergency response benchmarking for gas utilities, Vectren, 2014.
18. Set-up DSM pilots and optimize portfolio, Sunflower G&T, 2014/2015.
19. Central Wisconsin Electric demand response study, 2014/2015.
20. Long range load forecasts for Wolverine, Allegheny, and Sunflower, 2014.
21. Spatial load forecast for Rochester Public Utilities, 2014.
22. Revenue requirement and cost of service study for Todd-Wadena, 2014.
23. Development of a performance based regulation plan for Toronto Hydro. 2013/2014.
24. Set internal econometric reliability targets for Great Lakes Energy, 2014.
25. Conduct research, provide recommendations, and provide expert witness testimony on the 4th Generation Incentive Regulation on behalf of the Coalition of Large Distributors, 2013.
26. Testimony for Wisconsin Public Service Corporation (WPS) regarding the cost effectiveness of their reliability-driven capital project, 2013.
27. Transmission & Distribution Cost Benchmarking for Pacific Gas & Electric, 2013.
28. Evaluation and review of business cases for reliability-driven projects, Toronto Hydro, 2012/2013.
29. Cost and reliability benchmarking research for Toronto Hydro, 2012/2013.
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CUSTOMER SERVICE STRATEGY

1. INTRODUCTION

Hydro One is accountable for the delivery of service to 1.3 million residential, seasonal, and small business ("R&SB") customers. It is also accountable to deliver services to approximately 8,000 commercial and industrial ("C&I") customers, 90 large distribution accounts ("LDAs"), and 60 Local Distribution Companies ("LDCs").

This Exhibit outlines Hydro One's cohesive and integrated Customer Service Strategy Framework which focuses on three pillars: (1) Easy To Do Business With; (2) Always There for our Customers; and (3) Always Connected. This Exhibit discusses Hydro One's method of engaging with customers, collecting customer feedback to ensure customers' needs and preferences are fully understood by those making investment decisions at Hydro One, and reviewing and refining Hydro One's policies and practices in a cost-effective manner to ensure the alignment of customers needs and preferences, responsible stewardship of distribution assets and rate impacts.

2. HYDRO ONE'S CUSTOMER SERVICE STRATEGY

Hydro One's Customer Service Strategy seeks to elevate the customer experience by listening to customers in all rate classes and responding with swift and measurable distribution system outcomes that deliver value and establish Hydro One as one of the most trusted brands in the utility industry. Hydro One aims to strengthen its ongoing customer engagement, with a focus on continuous improvement, transparent processes and an understanding of how it is perceived by customers.

By focusing on the three pillars of its Customer Service Strategy Framework, Hydro One aims to improve accessibility, enhance communication, and ultimately increase customer engagement. These pillars are expected to have positive impact on how Hydro One delivers customer service.

We Are Easy To Do Business With – Hydro One's objective is to complete every customer transaction in a timely, efficient, and accurate fashion. When achieved, customers will take away a positive experience from each transaction and will contribute to Hydro One's vision of delivering great value as a trusted partner.

Always There For Our Customers – Hydro One recognizes that our customers are not well served by a 'one-size-fits-all' approach. By increasing our presence in the communities we serve, Hydro One can more effectively address challenges many Hydro One customers face. Based on customer feedback, Hydro One has determined that a physical presence in the community is the best approach to reaching customer segments and addressing matters that are of most concern. Meeting and interacting with customers face-to-face, in their communities allows employees and Hydro One representatives to engage, educate, and manage issues directly. Resolving customer inquiries and issues in real time will contribute to our vision of delivering great value as a trusted partner.

We Are Always Connected – One of Hydro One's objectives is to empower customers to choose how and when they engage with Hydro One, develop profiles specific to customer needs and behaviours, and precisely target communications to customers so that Hydro One can deliver value. Aligned with this objective are several digital investments, which address customer feedback received.

3. VOICE OF THE CUSTOMER

Hydro One reaches out on a regular basis to ensure customers' needs and preferences are known and fully understood by those making investment decisions at Hydro One. This iterative feedback has also informed the Company's Customer Service Strategy.

As part of this Distribution Rate Application, a Customer Engagement initiative was undertaken to ensure that Hydro One customers' needs and preferences were accounted for as part of the investment plan underpinning this application. More information about this specific process can be found in Section 1.3.2 of the Distribution System Plan (Exhibit B1, Tab 1, Schedule 1).

Furthermore, there are several means by which Hydro One interacts with both residential and business customers to obtain this information on an ongoing basis. These activities are consistent with those performed as part of the Customer Engagement work in 2016 in support of this Distribution Rate Application.

To ensure Hydro One maintains a regular view of its customers' needs and preferences, Hydro One performs the following activities on an ongoing basis to monitor changing customer service trends:

- Customer Satisfaction Transactional Surveys
- Customer Satisfaction Perception Surveys
- Call Centre Trends for Residential and Small Business Customers
- Call Centre Trends for Commercial and Industrial Customers
- Key Account Executives for Local Distribution Companies
- Zone Superintendents for Large Distribution Accounts
- External Relations (MPPs, Agencies, First Nations and Métis)
- Hydro One's Ombudsman Office

A. Customer Satisfaction Transactional Surveys

Hydro One conducts surveys on a monthly basis to monitor customer needs and preferences, monitor trends, address any transactional concerns in a timely fashion, and influence those practices in future. As such, a sub-set of Hydro One customers are contacted after they have had an interaction with Hydro One to determine how well Hydro One met their expectations with regards to the quality of customer service they received. These Customer surveys measure operational effectiveness for the call centre, service upgrades, new connections, and forestry work. Survey results and customer comments are reviewed by management on a regular basis with appropriate actions to follow.

B. Customer Satisfaction Perception Surveys

Hydro One also measures customers' perception of the company as a whole, whether they have interacted with Hydro One recently or not. These surveys monitor how well the company meets customers' expectations and delivers on critical success factors. These perception surveys are conducted twice per year for our R&SB customers, LDCs, and LDAs. C&I customers and the Ontario Grid Control Centre ("OGCC") are surveyed once a year.

C. Call Centre Trends for Residential and Small Business Customers

Residential and small business customers work with the Customer Call Centre ("CCC") when they have a question about their service or bill. Whether the customer contacts Hydro One by phone, e-mail, fax, or mail, these interactions are monitored closely and concerning trends are escalated and analyzed to assure Hydro One's performance is continuously improving and distribution system outcomes are aligned with customer needs and preferences.

Customer calls are actively monitored for quality control purposes to ensure Hydro One customers receive quality service and the timely and accurate information they need. Feedback is also received through the Customer Relationship Centre, which addresses escalated calls that require more detailed investigation and resolution.

D. Call Centre Trends for Commercial and Industrial Customers

Commercial and industrial customers who are demand or interval metered are serviced by a dedicated team within the call centre. This dedicated team is the customer's 'one-stop-shop' for questions regarding technical support or their bill. These representatives have the training to address billing questions or concerns and are readily able to navigate through the Lines of Business to get the technical information or contact needed, should it be required. Through surveys and the Customer Engagement work held in 2016, Hydro One confirmed that it needed a renewed focus on this customer segment.

E. Key Account Executives for Local Distribution Companies

Local Distribution Companies are assigned a Key Account Executive as their primary contact with the company, through whom they convey their company's needs and preferences. The key account executive is their 'one-stop-shop' within Hydro One for any issues or concerns that arise, which are tracked and measured, with actions taken as required.

Furthermore, Hydro One hosts an annual Large Customer Conference which allows Hydro One to provide an update on key work programs and talk to LDCs about their needs for the near future.

F. Zone Superintendents for Large Distribution Accounts

Hydro One is divided up into eight zones, each of which has a Zone Superintendent with overall accountability for the large distribution accounts in their geographic area. These

Zone Superintendents meet with the large distribution accounts in their area at least once a year and are accountable for maintaining a relationship with these businesses. Part of this accountability is also to ensure they are aware of any evolving needs and preferences in this customer segment. This is another source of information about customer needs and preferences, in particular, those which would need to be addressed in a more technical or operational fashion.

G. External Relations (MPPs, Agencies, First Nations and Métis)

Hydro One's External Relations department maintains relationships with representatives of the Ontario government, Members of Provincial Parliament ("MPPs"), representatives and elected officials of Ontario municipalities, and key stakeholder groups that represent large customer segments for Hydro One, such as the Ontario Federation of Agriculture and the Federation of Ontario Cottagers' Associations. Through these interactions, Hydro One is able to stay current with the issues these key stakeholders and their constituents or members may have, and External Relations is able to coordinate assistance on behalf of the Company.

External Relations also coordinates Hydro One's presence at several stakeholder and community events to interact directly with customers and community leaders, providing information about Hydro One's services and programs and listening to their views and concerns. Public consultation for major infrastructure investments and operational programs across Ontario is also a large part of the Division's work. An open and transparent consultation process is integral in helping Hydro One achieve regulatory approvals and community acceptance for these major projects.

For almost 10 years, Hydro One has and continues to engage with First Nations and Métis communities through ongoing relationship building efforts. Hydro One seeks input from First Nations and Métis to understand their specific customer needs and preferences and aspirations with respect to its distribution and transmission systems. Further information relating to Hydro One's First Nations and Métis Relations Strategy can be found in Exhibit A, Tab 4, Schedule 2.

H. Hydro One's Ombudsman Office

When customers do not feel that a response or decision made by Hydro One was fair, they can reach out to the Hydro One Ombudsman. The Ombudsman addresses these specific customer issues, but also performs systemic investigations. These investigations can highlight where changes are needed to better meet customers' needs and preferences. Customer Service works with the Ombudsman's office on a regular basis to understand any underlying trends of concern which have arisen, which can then inform Customer Service how to better align how it works with its residential and commercial customers.

4. CONCLUSION

The Hydro One Customer strategy is in a period of transformation. Hydro One will continue to elevate the customer experience by listening and taking swift and measurable actions to build trust. At the same time, communicating who Hydro One is and how Hydro One creates and delivers services customers value will be critical to improving customer satisfaction.

FIRST NATIONS AND MÉTIS STRATEGY

1. INTRODUCTION

Hydro One is committed to developing and maintaining positive relationships with First Nations and Métis communities and customers across Ontario. Hydro One recognizes the unique rights and interests of Aboriginal peoples in Canada and seeks to work with First Nations and Métis communities in Ontario in the spirit of collaboration, mutual respect and trust, and shared responsibility.

Hydro One provides electricity transmission and distribution services to 85 First Nations communities. Approximately 21,700 First Nations customers residing on reserve lands receive service, 88% of which are residential and 12% are general service customers. Transmission and distribution facilities used to provide this service are situated across reserve lands, traditional or treaty lands.

On an ongoing basis, Hydro One engages with First Nations and Métis communities to gain an appreciation of their needs as rights holders, partners, customers, and employees. This Exhibit outlines Hydro One's First Nations and Métis Relations Strategy Framework which focuses on three pillars: integrating First Nations and Métis considerations into Hydro One's lines of business, developing partnerships with communities, and developing and promoting future First Nations and Métis employees and leaders within Hydro One.

2. STRATEGY FRAMEWORK

The three pillars of the Hydro One's First Nations and Métis Relations Strategy Framework are as follows:

a) **Integration** - Improve communication with First Nation and Métis communities and develop programs to ensure their unique interests and concerns are integrated into Hydro One's lines of business and that Hydro One works with communities in a way that recognizes and respects Aboriginal and treaty rights;
b) **Partnership** - Develop opportunities to collaborate with First Nations and Métis communities in Ontario through the development of business, technical, knowledge, and advocacy partnerships; and
c) **Leadership** - Provide opportunities to First Nations and Métis individuals within our organization to support the training, development, and promotion of First Nations and Métis employees and future leaders.

Hydro One is continuing to research and consider industry best practices to benchmark its activities in these three areas and will seek input on and give consideration to new strategic approaches to achieve these objectives.

3. INTEGRATION

Hydro One is committed to ensuring that the unique interests and concerns of First Nations and Métis communities and customers are considered and integrated into Hydro One's lines of business.

Hydro One reinforces the Company's focus on First Nations and Métis relations through clear commitments and policies that support positive relationships across the organization. Hydro One's First Nations and Métis relations is overseen by the Health, Safety, Environment and First Nations and Métis Committee, which is a standing committee appointed by the Board of Directors. The Committee is responsible for overseeing Hydro One's relationships with First Nations and Métis communities and customers, including the development of initiatives to address unique interests and concerns and advance shared priorities.

Hydro One has led many engagements and rights-based consultations with First Nations and Métis communities regarding its services and new development or maintenance projects. These discussions have covered a variety of matters related to Hydro One's business, including but not limited to distribution and transmission projects, forestry and provincial lines, system reliability, electricity rates, customer services and conservation programs. These engagements have also focused on how investments in the Company's system can support greater Aboriginal employment, business development, partnership opportunities, and overall stronger relationships with First Nations and Métis communities.

Since 2008, Hydro One has had over 250 meetings with First Nations and Métis communities, including representatives from 71 First Nations, the Métis Nation of Ontario, and several other Métis organizations and community councils.

In early 2017, Hydro One also held a province-wide First Nations engagement session with Hydro One's senior executives. All of the 85 First Nation Chiefs from communities served by Hydro One and the Ontario First Nations Regional Organizations were invited to attend this engagement session. At the session, Hydro One presented and solicited feedback on its approach to customer care and anticipated system investments to improve reliability. Hydro One also explained and answered questions about its Distribution System Plan and current Application to the Board for distribution rates from 2018 to 2022.

The top five concerns that Hydro One heard from various engagement sessions with First Nations and Métis communities and customers are listed below.

(i) **Affordability:** First Nations communities and customers feel they are disproportionately impacted by high electricity costs. Many have raised concerns that their delivery charge is higher than their electricity consumption. In addition, as outlined in Section 1.3 of the Distribution System Plan, First Nations customers are most sensitive to cost and place the greatest importance on cost over improvements in the service they receive.

(ii) **Reliability:** First Nations communities have raised concerns about the high frequency and duration of power outages, particularly in northern Ontario. Some communities have also indicated that the electricity supply is not sufficiently reliable to serve businesses on reserve and are concerned about degrading Hydro One asset conditions on reserve.

(iii) **Liability and Access**: Some First Nations have raised concerns about outdated access rights/permits on reserve lands and the sufficiency of compensation, or the lack thereof, for Hydro One transmission and distribution assets on reserve land. Some First Nations have also expressed concerns about the lack of compensation for Hydro One transmission and distribution assets off reserve, but within their traditional territories, and the need for Hydro One to seek permission from or notify First Nations communities when planned and unplanned disconnection/reconnection related work is being conducted on reserve.

(iv) **Partnerships:** First Nations and Métis communities would like to see an increase in procurement, investment/ownership opportunities, and other business partnership opportunities for Aboriginal businesses.

(v) **Employment:** First Nations and Métis communities are interested in more employment opportunities at Hydro One and have requested increased training and employment opportunities for Aboriginal individuals.

Hydro One acknowledges these concerns and is working to address many of these issues, as further detailed in this Exhibit. Some of these issues raise competing priorities and preferences which must be balanced by Hydro One (i.e., keeping distribution rates low versus making additional capital investments to improve system reliability). Furthermore, some of the issues are beyond Hydro One's authority, jurisdiction, and mandate as a publicly-traded utility and require or depend on broader action by the provincial and federal governments.

Where issues do fall within Hydro One's authority, jurisdiction, and mandate and there are no existing responsive initiatives, Hydro One will work in collaboration with affected communities to explore, define, and prioritize additional strategies and processes to effectively address these concerns. Where there are existing initiatives, Hydro One will continue to work to make meaningful progress in addressing these concerns and consider new initiatives that may assist Hydro One in this effort. The development of such strategies and processes with First Nations and Métis communities will proceed on the basis of the following pillars: action-oriented, collaborative, transparent, cost-effective and efficient.

3.1 IMPROVING CUSTOMER SERVICE

Hydro One has developed a number of initiatives in order to improve customer service and assist customers with energy affordability.

In 2016, Hydro One developed a new First Nations Conservation Program. This program offers on-reserve residents the opportunity to improve the energy efficiency of their homes and manage their energy use more effectively. The program is delivered by a wholly-owned First Nations company. Over 3,400 homes located on reserve lands in Ontario have successfully achieved energy efficiency improvements under this program.
Hydro One has also developed a new service model for First Nations communities that focuses on in-community, face-to-face interactions, and ensuring customers understand

and have access to all of the available programs that can provide assistance with energy conservation and bill payment support. Under this new service model that was launched in September 2016, representatives from Hydro One's Customer Service team visit First Nations communities around the province to meet with Chiefs and Councils, conduct community information sessions, and have one-on-one sessions with individual customers. During these sessions, Hydro One helps customers by providing information about conservation programs and resources that may assist low-income customers and ensure that qualifying customers are aware of and accessing the Province of Ontario's Ontario Electricity Support Program.

In addition, Hydro One created a dedicated First Nations and Métis team in its customer call centre in 2014. The team consists of specialized customer service representatives that are dedicated to interacting with First Nations and Métis communities and customers. The dedicated phone number provides a direct link to this specialized Hydro One team and enhances customer service to First Nations and Métis communities.

In the past year, Hydro One has also made submissions to the Ontario Energy Board, at the request of the Minister of Energy, to provide advice on options for an appropriate electricity rate (or rate assistance) for on-reserve First Nations electricity consumers. In the submissions, Hydro One recommended the adoption of a percentage credit to the Delivery Charge, for ease of understanding and implementation.

3.2 SYSTEM RELIABILITY

Over the course of various engagement sessions, many First Nations communities and customers raised concerns about the frequency of power outages, unreliable power, and degrading conditions of Hydro One assets on reserve.

Hydro One recognizes that this is a significant concern. In the past year, Hydro One has mapped out all transmission lines and distribution stations and feeders serving First Nations communities and collected relevant system reliability data in order to make sound and targeted investments to improve system reliability for First Nations communities. First Nation communities served by Hydro One are supplied from 55 transmission lines and 89 distribution lines. Historically, approximately 77% of power failures on these transmission lines were caused by deteriorated equipment (e.g., insulators, wood poles, conductor, etc.) or caused by adverse weather (freezing rain, ice, lightning, etc.). Approximately 50% of power failures on distribution lines occur from tree contacts which lead to equipment failures (e.g., poles, transformers, lines failures, etc.).

Hydro One will be implementing a three-pronged strategy that is intended to increase system reliability within First Nations communities. The strategy consists of: increasing capital investments and replacing equipment that affects reliability; leveraging technology to allow Hydro One to better detect, limit the scope, and remotely respond to certain types of outages; and reducing planned outages by bundling work.

3.3 LIABILITY AND ACCESS

The terms and status of historical access permits for reserve lands and the sufficiency of compensation for Hydro One assets on reserve land have also been raised as concerns. Some First Nations have also expressed concern about the lack of compensation for Hydro One transmission and distribution assets that are off reserve but within traditional territories. Some First Nations have also expressed their need that Hydro One seek permission from or notify First Nations communities when planned and unplanned disconnection/reconnection related work is being conducted on reserve.

Hydro One is bound by the *Indian Act*, which requires that any use or occupation of reserve lands be legally authorized by a permit issued by Indigenous and Northern Affairs Canada. Any payment required under a permit is paid by Hydro One to Indigenous and Northern Affairs Canada.

Hydro One is committed to seeking resolution of on-reserve transmission and distribution line tenancy issues and opportunities. Hydro One recognizes the need to accelerate the process and timeline to resolve some of these long term outstanding tenancy issues. Hydro One is committed to developing a formal strategy and process to address these real estate concerns in a cost and time effective and efficient manner, in collaboration with relevant First Nations communities and Indigenous and Northern Affairs Canada.

3.4 ASSERTED AND ESTABLISHED RIGHTS

Hydro One recognizes and respects Aboriginal and treaty rights and operates in accordance with the legal framework applicable to Aboriginal peoples. Hydro One recognizes that the Crown has a duty to consult, and where appropriate, accommodate Aboriginal groups whenever it is contemplating a decision or activity that could impact asserted or established Aboriginal or treaty rights. While this is a duty owed by the Crown, procedural aspects of the Crown's duty to consult can and are delegated to Hydro One by the Crown. Hydro One works to mitigate impacts on asserted and established Aboriginal and treaty rights and has provided funding to support the involvement of First Nations and Métis communities in environmental and archaeological monitoring during transmission and distribution enhancement and refurbishment related projects.

3.5 EMPLOYEE TRAINING

At recent engagement sessions with First Nations communities, a common concern was the current level of Hydro One employee awareness, education, and training on First Nations' cultures, customs, treaties, etc. This concern was presented as a real impediment to building strong and lasting relationships with First Nations communities.

Hydro One is committed to ensuring that its employees better understand the history of Aboriginal peoples and the unique interests and circumstances of First Nations and Métis communities in Ontario.

Hydro One has established a mandatory on-line Aboriginal awareness training course for all employees. The training provides a basic understanding of: Aboriginal peoples before European contact, perspectives on both the historic and modern treaty making processes, and the *Indian Act* and its implications for First Nations communities in Ontario. The on-line training also offers information on the key program initiatives at Hydro One as they relate to First Nations and Métis Relations. Hydro One's Aboriginal awareness training programs have been developed with the input of several First Nation and Métis individuals that have expertise in this area.

Hydro One's leadership and managers also receive Aboriginal cultural awareness training and receive information on various First Nations and Métis relation matters as they relate to their respective line of business.

Furthermore, Hydro One actively promotes awareness of Aboriginal history and cultures at Hydro One through various internal communications relating to the National Aboriginal History Month, National Aboriginal Day, and Historic Treaties Recognition Week and encourages the participation of all Hydro One employees.

4. PARTNERSHIP

Hydro One has introduced a number of measures to increase opportunities for Aboriginal businesses and to provide support for community priorities.

4.1 PROCUREMENT OPPORTUNITIES

Aboriginal businesses currently supply a diverse and growing range of materials and services to Hydro One. Hydro One's annual Aboriginal procurement has increased from $13.1 million in 2014 to $16.5 million in 2016. Examples include: brush clearing, winter road construction, archaeological services, general contracting, and printing supplies.

Hydro One sources materials and services through an auditable and competitive process open to qualified vendors. Hydro One has introduced a number of measures to help increase access to procurement opportunities for Aboriginal businesses and ensure Aboriginal inclusion is considered early in project development. These measures include a dedicated Aboriginal procurement team; Aboriginal Interactive Procurement Workshops (an interactive engagement sessions with Aboriginal communities to share information on how to do business with Hydro One); detailed Aboriginal procurement procedures to facilitate increasing Aboriginal contract awards; and an Aboriginal business registry (whereby Aboriginal businesses register to facilitate increasing Aboriginal contract awards).

Hydro One's Aboriginal Procurement policy also requires at least one of the following options in all Requests for Proposals:

1. **Aboriginal Business Participation Opportunities –** All Hydro One Requests for Proposals at a minimum provide bidders incentives to include and involve Aboriginal

business and or communities in the proposed work. Predetermined evaluation criteria allow preference to be given to submissions that demonstrates Aboriginal inclusion.

2. **Mandatory Aboriginal Business Participation –** This type of procurement opportunity specifies that a portion of the contract must be provided by an Aboriginal component (e.g., portion or percentage of work completed include work by an Aboriginal business, subcontracting, joint venture or through Aboriginal employment).
3. **Targeted Procurement Strategy** – In certain situations, Hydro One may, at its sole discretion, target the procurement to a subset of qualified Aboriginal businesses, as opposed to a formal open competition.
4. **Direct Award –** Direct Award is an invitational procurement opportunity to a single qualified Aboriginal business or community if value-for-money is maintained throughout the Hydro One contract. Single Source justification will be documented and preapproved by Supply Chain. This typically occurs in remote communities, whereby the First Nation is often the only available vendor capable of supplying the required products or services on the reserve either as a matter of local governance or a result of the isolated location.

4.2 BUSINESS DEVELOPMENT

Hydro One continues to examine ways to develop long term strategic business partnerships with First Nations and Métis communities where commercially feasible. In December 2014, Hydro One entered into a limited partnership on the 180 km Bruce to Milton Transmission Project with the Saugeen Ojibway Nation under which the Saugeen Ojibway Nation invested $72M to obtain a 34% interest in the partnership. This was a ground-breaking agreement for Hydro One and both parties are now in a position to create greater prosperity for customers and community members.

4.3 ABORIGINAL GRANTS

Hydro One recognizes the importance of giving back to the communities in which work is carried out. Hydro One has a number of dedicated Aboriginal community grant investment programs, including supporting healthy and safe lifestyles for children and youth and energy conservation initiatives.

Since 2010, Hydro One has invested over $3 million into First Nations and Métis communities via donations, sponsorships, and scholarships. Through its PowerPlay program, Hydro One has supported healthy, active and safe lifestyles for Aboriginal children and youth through funding for sports and recreational facilities, programs and equipment in 40 First Nations communities. Hydro One has also provided funding to Right To Play's "PLAY" program (Promoting Life Skills in Aboriginal Youth) since 2014, investing over $100,000 each year to support after-school programming, sport for developmental activities, youth leadership, and health and wellness education.

5. LEADERSHIP

5.1 EMPLOYMENT OPPORTUNITIES

Increasing Aboriginal employment at Hydro One is an important part of its workforce development. Through numerous outreach career fair discussions with young Aboriginal people, Hydro One has heard the importance of facilitating employment and training within the company. Hydro One commits resources for recruiting, retaining, and developing Aboriginal talent to achieve equitable representation of Aboriginal persons in the workplace through a number of initiatives.

- **Employment Outreach**: Hydro One recruits Aboriginal individuals for positions throughout the year and engages in a number of outreach activities, including community visits, summer student and post-secondary outreach programs, Hydro One ambassadors/employee volunteers, and Aboriginal networking circles. In addition, Hydro One has a dedicated email address for Aboriginal people interested in Hydro One careers and who have employment related questions.
- **Post-Secondary Students**: Hydro One provides an opportunity for Aboriginal students to complement their classroom learning with hands-on experience in the office or field. Hydro One designates 10% of summer student positions for Aboriginal students.
- **Apprenticeships**: Hydro One offers four apprenticeships through a joint committee established with the Power Workers' Union (Electrician, Power Line Technician, Truck & Coach Technician, and Utility Arborist). Hydro One engages in a number of outreach activities to encourage Aboriginal applicants, including community visits, summer student and post-secondary outreach programs through information sessions and career fairs.

5.2 SCHOLARSHIPS

Hydro One has several scholarships for Aboriginal individuals across the province.

- **Leonard S. (Tony) Mandamin Scholarship**: Hydro One has an annual educational scholarship that supports First Nations, Métis and Inuit students enrolled in electricity industry related programs at a recognized Ontario college or university. Each year, up to 15 post-secondary students will be granted this academic award, which includes both $5,000 in financial support and a full-time summer work term. The sixth anniversary of the awards was in 2016.
- **Aboriginal Award for Graduate Studies:** This award for Graduate Studies in Public Policy and Administration provides financial assistance ($5,000) and recognizes the

academic achievement of an Aboriginal student entering the Master of Arts in Public Policy and Administration program at Ryerson University. The award is issued annually to up to two Aboriginal students entering the program.

- **Leadership Circle of Indigenous Works:** Hydro One is also a member of the Leadership Circle of Indigenous Works, whose mandate is to improve the inclusion and engagement of Indigenous people in the Canadian economy. The Leadership Circle of Indigenous Works recognizes Hydro One's commitment to support and advance Indigenous inclusion in its workplace.

6. CONCLUSION

Hydro One is continuing to gain a better appreciation of the aspirations, goals, interests and needs of First Nation and Métis communities and individuals as rights holders, partners, landlords, customers and employees. Feedback received from First Nation and Métis communities and customers has resulted in Hydro One introducing measures intended to help address a number of the concerns raised. Hydro One recognizes that more work needs to be done. Hydro One will continue to engage and work with First Nations and Métis communities as it develops and executes programs intended to provide better service and customer care and works to build and maintain positive relationships with First Nations and Métis communities across Ontario.

ELECTRICITY DISTRIBUTOR SCORECARD

1. HYDRO ONE SCORECARDS

Hydro One, as part of its internal operating systems and external reporting requirements, has several scorecards that it maintains and reports against. There are three primary scorecards that relate to the Distribution business and are discussed throughout this application:

- Electricity Distributor Scorecard;
- Distribution OEB Scorecard; and
- Team Scorecard.

The Electricity Distributor Scorecard is the OEB mandated scorecard for all electricity distributors in the province and discussed in this Exhibit.

The Distribution OEB Scorecard is a proposed scorecard developed by Hydro One to supplement the Electricity Distributor Scorecard and is provided in Section 1.4 of the Distribution System Plan. It contains additional measures that provide greater transparency to the outcomes that customers value and to areas that Hydro One has targeted for improved performance.

The Team Scorecard is a shared short term compensation scorecard for all Hydro One management staff and has been provided in Exhibit C1, Tab 2, Schedule 1, Attachment 4.

2. ELECTRICITY DISTRIBUTOR SCORECARD: COMPARATOR SELECTION

To provide context and perspective in discussing Hydro One's historical performance over the 2011 to 2015 period, the Company reviewed its comparable Electricity Distributor Scorecard measures against a set of other distributors. Several metrics on the Electricity Distributor Scorecard remain self-defined[1] with no common standard or distributor targets in-place, are defined and reported by third-parties using specific adjustments[2], or may not be directly comparable to Hydro One due to significant differences in service territories[3]. For these metrics, a direct comparison between Hydro One and other distributors was not included, and assessments of historical performance were limited to internal comparisons. The distributors were selected using results from the OEB's *2015 Yearbook of Electricity Distributors*[4] (the Yearbook) published on August 3, 2016, for the following criteria:

- Top ten distributors by Total Customers; and
- Top ten distributors by Property Plant & Equipment (as gross values).

The Company also selected distributors using the *Stretch Factor Assignments by Group* from the July 2016 report published by the Pacific Economics Group Research LLC ("PEG"), titled *Empirical Research in Support of Incentive Rate-Setting: 2015*

[1] First Contact Resolution, Customer Satisfaction Survey Results, DSP Implementation Progress
[2] Efficiency Assessment, Total Cost per Customer, Total Cost per km of Line
[3] Average Number of Hours that Power to a Customer is Interrupted, Average Number of Times that Power to a Customer is Interrupted
[4] Ontario Energy Board. "2015 Yearbook of Electricity Distributors". Electricity Distributor Scorecards. August 3, 2016. https://goo.gl/ZIl39P (accessed December 5, 2016).

Benchmarking Update[5] ("the PEG report"), and from members of the Coalition of Large Distributors ("CLD").

The selected distributors and supporting data are summarized in Table 1.

In addition to the existing industry and distributor targets used on distributors' scorecards (see Figure 1), and for the purposes of discussing its historical performance within the context of this application, Hydro One established an "industry average" metric. The current industry average is the average value of the distributor scorecard measure being discussed for all distributors (including Hydro One), spanning the 2011 to 2015 period. An example of the calculation is shown in Table 2.

[5] Pacific Economics Group LLC. "Empirical Research in Support of Incentive Rate-Setting: 2015 Benchmarking Update. Report to the Ontario Energy Board". July 2016. https://goo.gl/i4KHDe (accessed December 5, 2016).

Table 1: Peer Selection Process, Based on 2015 Yearbook Values

Method	Selection	Distributors	Value
PEG report	Stretch Factor Assignments by Group	Algoma Power Inc.	Stretch Factor = 0.60% Group V
		Hydro One Networks Inc.	
		Toronto Hydro-Electric System Ltd.	
		West Coast Huron Energy Inc.	
Yearbook Total Customers	Top ten	Enersource Hydro Mississauga Inc.	203,466
		Horizon Utilities Corporation	241,986
		Hydro One Brampton Networks Inc.	154,105
		Hydro One Networks Inc.	1,257,016
		Hydro Ottawa Limited	323,919
		Kitchener-Wilmot Hydro Inc.	92,404
		London Hydro Inc.	153,947
		PowerStream Inc.	358,772
		Toronto Hydro-Electric System Ltd.	758,311
		Veridian Connections Inc.	118,481
Yearbook Property Plant & Equipment Gross	Top ten	Enersource Hydro Mississauga Inc.	$ 786,506,176
		Horizon Utilities Corporation	$ 563,273,667
		Hydro One Brampton Networks Inc.	$ 408,831,665
		Hydro One Networks Inc.	$ 10,972,447,791
		Hydro Ottawa Limited	$ 955,318,230
		Kitchener-Wilmot Hydro Inc.	$ 344,063,198
		London Hydro Inc.	$ 448,419,044
		PowerStream Inc.	$ 1,413,687,406
		Toronto Hydro-Electric System Ltd.	$ 4,074,177,648
		Veridian Connections Inc.	$ 462,369,987
CLD	CLD Members	Enersource Hydro Mississauga Inc.	
		Horizon Utilities Corporation	
		Hydro Ottawa Limited	
		PowerStream Inc.	
		Toronto Hydro-Electric System Ltd.	
		Veridian Connections Inc.	

Using Table 1, eleven distributors were selected, as listed below, and an example of the industry (simple) average calculation, using these distributors is shown in Table 2:

- Algoma Power Inc.
- Enersource Hydro Mississauga Inc.
- Horizon Utilities Corporation
- Hydro One Brampton Networks Inc.
- Hydro Ottawa Limited
- Kitchener-Wilmot Hydro Inc.
- London Hydro Inc.
- PowerStream Inc.
- Toronto Hydro-Electric System Ltd.
- Veridian Connections Inc.
- West Coast Huron Energy Inc.

Table 2: Industry Average Calculation Example

New Residential/Small Business Services Connected On-Time	2011	2012	2013	2014	2015	Industry Target	Industry Average (Simple 5 Year Average)
Algoma Power Inc.	97.6	94.7	99.0	100.0	100.0	90.0	97.8
Enersource Hydro Mississauga Inc.	98.9	99.2	98.6	97.6	99.1		
Horizon Utilities Corporation	99.4	99.2	99.9	99.9	99.8		
Hydro One Brampton Networks Inc.	100.0	100.0	99.8	100.0	99.7		
Hydro One Networks Inc.	**92.6**	**95.5**	**97.5**	**97.4**	**97.5**		
Hydro Ottawa Limited	100.0	100.0	100.0	100.0	100.0		
Kitchener-Wilmot Hydro Inc.	94.3	91.3	91.3	90.9	90.3		
London Hydro Inc.	97.6	96.8	99.9	100.0	97.6		
PowerStream Inc.	93.1	98.1	98.1	97.8	99.5		
Toronto Hydro-Electric System Limited	94.0	92.5	94.2	91.5	96.9		
Veridian Connections Inc.	100.0	100.0	100.0	100.0	97.7		
West Coast Huron Energy Inc.	100.0	99.3	100.0	100.0	100.0		

For reference, Hydro One's 2015 Electricity Distributor Scorecard is shown below in Figure 1. The targets provided in Figure 2 are the results the Company aims to achieve during the five-year term of the Application. Additional details on Hydro One's historical performance and targets, for each metric, are provided in the following sections. Where no target has been provided, the rationale has been provided in the respective explanatory section below.

Electricity Distributor Scorecard – Hydro One Networks Inc.

9/29/2016

Performance Outcomes	Performance Categories	Measures		2011	2012	2013	2014	2015	Trend	Target	
										Industry	Distributor
Customer Focus Services are provided in a manner that responds to identified customer preferences.	Service Quality	New Residential/Small Business Services Connected on Time		92.00%	95.70%	97.40%	97.40%	97.50%		90.00%	
		Scheduled Appointments Met On Time		93.90%	98.60%	98.40%	99.30%	98.50%		90.00%	
		Telephone Calls Answered On Time		81.40%	83.40%	63.90%	69.60%	76.40%		65.00%	
	Customer Satisfaction	First Contact Resolution				78.30%	79%	82%			
		Billing Accuracy					94.63%	98.59%		98.00%	
		Customer Satisfaction Survey Results				87%	85%	85%			
Operational Effectiveness Continuous improvement in productivity and cost performance is achieved; and distributors deliver on system reliability and quality objectives.	Safety	Level of Public Awareness						81.00%			
		Level of Compliance with Ontario Regulation 22/04 [1]		NI	NI	NI	NI	C			C
		Serious Electrical Incident Index	Number of General Public Incidents	8	6	7	4	5			4
			Rate per 10, 100, 1000 km of line	0.066	0.051	0.059	0.033	0.042			0.035
	System Reliability	Average Number of Hours that Power to a Customer is Interrupted [2]		21.17	10.58	26.57	9.42	12.22			15.35
		Average Number of Times that Power to a Customer is Interrupted [2]		3.93	3.15	4.23	2.96	3.07			3.44
	Asset Management	Distribution System Plan Implementation Progress				Under Review	97%	116%			
	Cost Control	Efficiency Assessment			5	5	5	5			
		Total Cost per Customer [3]		$1,072	$1,041	$1,046	$1,069	$983			
		Total Cost per Km of Line [3]		$11,064	$10,741	$10,682	$10,916	$10,198			
Public Policy Responsiveness Distributors deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board).	Conservation & Demand Management	Net Cumulative Energy Savings [4]						17.27%			1,159.02 GWh
	Connection of Renewable Generation	Renewable Generation Connection Impact Assessments Completed On Time		95.79%	99.39%	100.00%	100.00%	100.00%			
		New Micro-embedded Generation Facilities Connected On Time				99.71%	100.00%	99.78%		90.00%	
Financial Performance Financial viability is maintained; and savings from operational effectiveness are sustainable.	Financial Ratios	Liquidity: Current Ratio (Current Assets/Current Liabilities)		0.99	0.99	1.00	0.99	0.97			
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio		1.34	1.30	1.35	1.31	1.19			
		Profitability: Regulatory Return on Equity	Deemed (included in rates)	9.66%	9.66%	9.66%	9.66%	9.30%			
			Achieved	8.80%	8.72%	8.00%	6.26%	8.77%			

1. Compliance with Ontario Regulation 22/04 assessed: Compliant (C); Needs Improvement (NI); or Non-Compliant (NC).
2. The trend's arrow direction is based on the comparison of the current 5-year rolling average to the fixed 5-year (2010 to 2014) average distributor-specific target on the right. An upward arrow indicates decreasing reliability while downward indicates improving reliability.
3. A benchmarking analysis determines the total cost figures from the distributor's reported information.
4. The CDM measure is based on the new 2015-2020 Conservation First Framework. This measure is under review and subject to change in the future.

Legend: 5-year trend: up, down, flat. Current year: target met, target not met.

Figure 1 -- 2015 - Hydro One Networks Inc. Electricity Distributor Scorecard for Year-End 2015[6]

[6] Ontario Energy Board. "Hydro One Networks Inc. 2015 Scorecard." Electricity Distributor Scorecards. September 29, 2016. https://goo.gl/tkYwgk (accessed December 5, 2016).

Witness: Michael Vels

Electricity Distributor Scorecard - Hydro One Networks Inc. - Rate Application Five-Year Targets

Performance Outcomes	Performance Categories	Measures		2011	2012	2013	2014	2015	Rate Application Five-Year Target	Industry	Distributor
				ANALYSIS PERIOD							
Customer Focus Services are provided in a manner that responds to identified customer preferences.	Service Quality	New Residential/Small Business Services Connected on Time		92.00%	95.70%	97.40%	97.40%	97.50%	98.00%	90.00%	
		Scheduled Appointments Met On Time		93.90%	98.60%	98.40%	99.30%	98.50%	99.00%	90.00%	
		Telephone Calls Answered On Time		81.40%	83.40%	63.90%	69.60%	76.40%	80.00%	65.00%	
	Customer Satisfaction	First Contact Resolution*				78.30%	79.00%	82.00%	88.00%	*	
		Billing Accuracy					94.63%	98.59%	99.00%	98.00%	
		Customer Satisfaction Survey Results*				87.00%	85.00%	85.00%	89.00%		
Operational Effectiveness Continuous improvement in productivity and cost performance is achieved; and distributors deliver on system reliability and quality objectives.	Safety	Level of Public awareness						81.00%	N/A		
		Level of Compliance with Ontario Regulation 22/04 [1]		NI	NI	NI	NI	C	C		C
		Serious Electrical Incident Index	Number of General Public Incidents	8	6	7	4	5	4		4
			Rate per 10, 100, 1000km of line	0.066	0.051	0.059	0.033	0.042	N/A		0.035
	System Reliability	Average Number of Hours that Power to a Customer is Interrupted [2]		21.17	10.58	26.57	9.42	12.22	14.30		15.35
		Average Number of Times that Power to a Customer is Interrupted [2]		3.93	3.15	4.23	2.96	3.07	3.30		3.44
	Asset Management	Distribution System Plan Implementation Progress*				Under Review	97%	116%	100%		
	Cost Control	Efficiency Assessment			5	5	5	5	5		
		Total Cost per Customer[3]		$1,072	$1,041	$1,046	$ 1,069	$ 983	N/A, PEG		
		Total Cost per km of Line[3]		$11,064	$10,741	$10,682	$ 10,916	$ 10,198	N/A, PEG		
Public Policy Responsiveness Distributors deliver on obligations mandated by government (e.g. in legislation and in regulatory requirements imposed further to Ministerial directives to the Board).	Conservation & Demand Management	Net Cumulative Energy Savings[4]						17.27%	100.00%		1,221 GWh
	Connection of Renewable Generation	Renewable Generation Connection Impact Assessments Completed On Time[5]		95.79%	99.39%	100.00%	100.00%	100.00%	99.00%		
		New Micro-embedded Generation Facilities Connected On Time				99.71%	100.00%	99.78%	99.00%	90.00%	
Financial Performance Financial viability is maintained; and savings from operational effectiveness are sustainable.	Financial Ratios	Liquidity: Current Ratio (Current Assets/Current Liabilities)		0.99	0.99	1.00	0.99	0.97	N/A		
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio		1.34	1.30	1.35	1.31	1.19	N/A		
		Profitability: Regulatory Return on Equity	Deemed (included in rates)	9.66%	9.66%	9.66%	9.66%	9.30%	N/A		
			Achieved	8.80%	8.72%	8.00%	6.26%	8.77%	N/A		

Figure 2 -- Internal Targets for the 2018 to 2022 Application Period[7]

[7] For scorecard footnotes 1 to 4, refer to Figure 1 above. Hydro One's current Conservation and Demand Management plan reflects a target of 1,221 GWh from 2015 to 2022. * represents self-defined distributor metrics with no common industry standard.

3. CUSTOMER FOCUS

3.1 SERVICE QUALITY: NEW RESIDENTIAL/SMALL BUSINESS SERVICES CONNECTED ON-TIME

In 2015, Hydro One processed 16,908 new connection requests for residential and small business low-voltage customers (those with service less than 750 Volts). Of these, 97.5 per cent were completed within five business days (or as agreed to by the customer and the distributor), exceeding the industry target of 90 per cent for the fifth consecutive year. The Company's five-year average performance was 96 per cent; consistently above the industry target and trending towards the current industry average of 97.8 per cent (see Figure 3).

Over the term of the Application, the Company is targeting to be better than both the industry target and its historical average, targeting 98 per cent. This will be achieved mainly through further process and measurement improvements following the implementation of proposed upgrades to the Enterprise Geographical Information System ("GIS") software, improving the ability to bundle work geographically and from scheduling efficiencies that will be realized through enhanced process initiatives such as Move-to-Mobile.

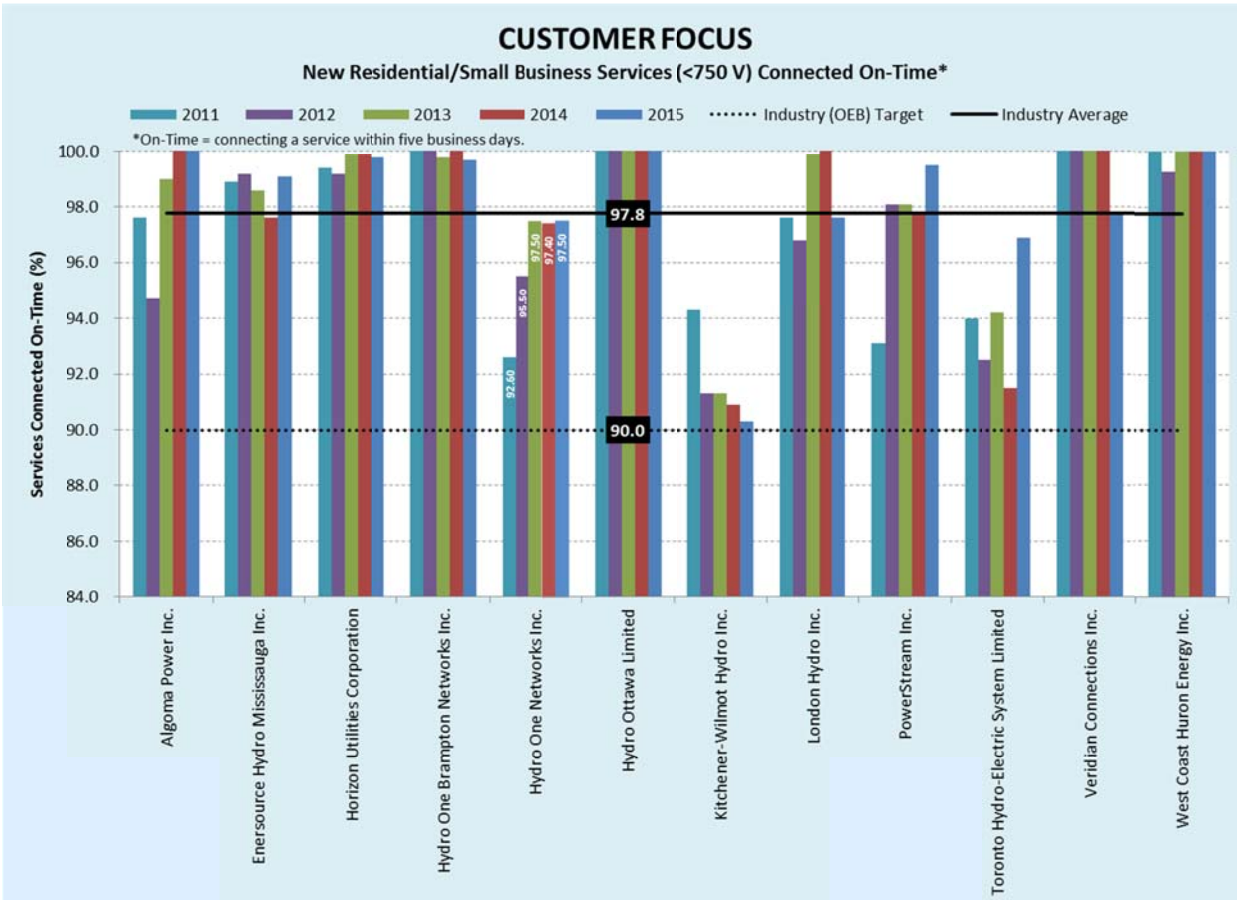

Figure 3 – Customer Focus - New Residential/Small Business Services Connected On-Time[8]

3.2 SERVICE QUALITY: SCHEDULED APPOINTMENTS MET ON TIME

Hydro One scheduled 29,909 appointments in 2015 and recorded a 98.5 per cent success rate in meeting these commitments, exceeding the industry target of 90 per cent for the fifth consecutive year. Although the Company's 2015 results showed a marginal

[8] For the period 2011 to 2013, the performance levels shown in Figure 3 do not match the Electricity Distributor Scorecard shown in Figure 1. Hydro One will revise the 2011 to 2013 data through the OEB's RRR change request process.

reduction of 0.50 percentage points compared to 2014, the five-year trend remained positive and within 0.30 percentage points of the industry average in 2015 (see Figure 4). Hydro One's performance from 2011 to 2015 was mainly attributable to process and measurement improvements and represents a historical average of 98.2 per cent.

Over the term of the Application, Hydro One anticipates it will realize similar benefits from the proposed GIS upgrades and process-driven scheduling initiatives, as discussed in Section 3.1, leading to an improvement over the historical average performance and is targeting 99 per cent.

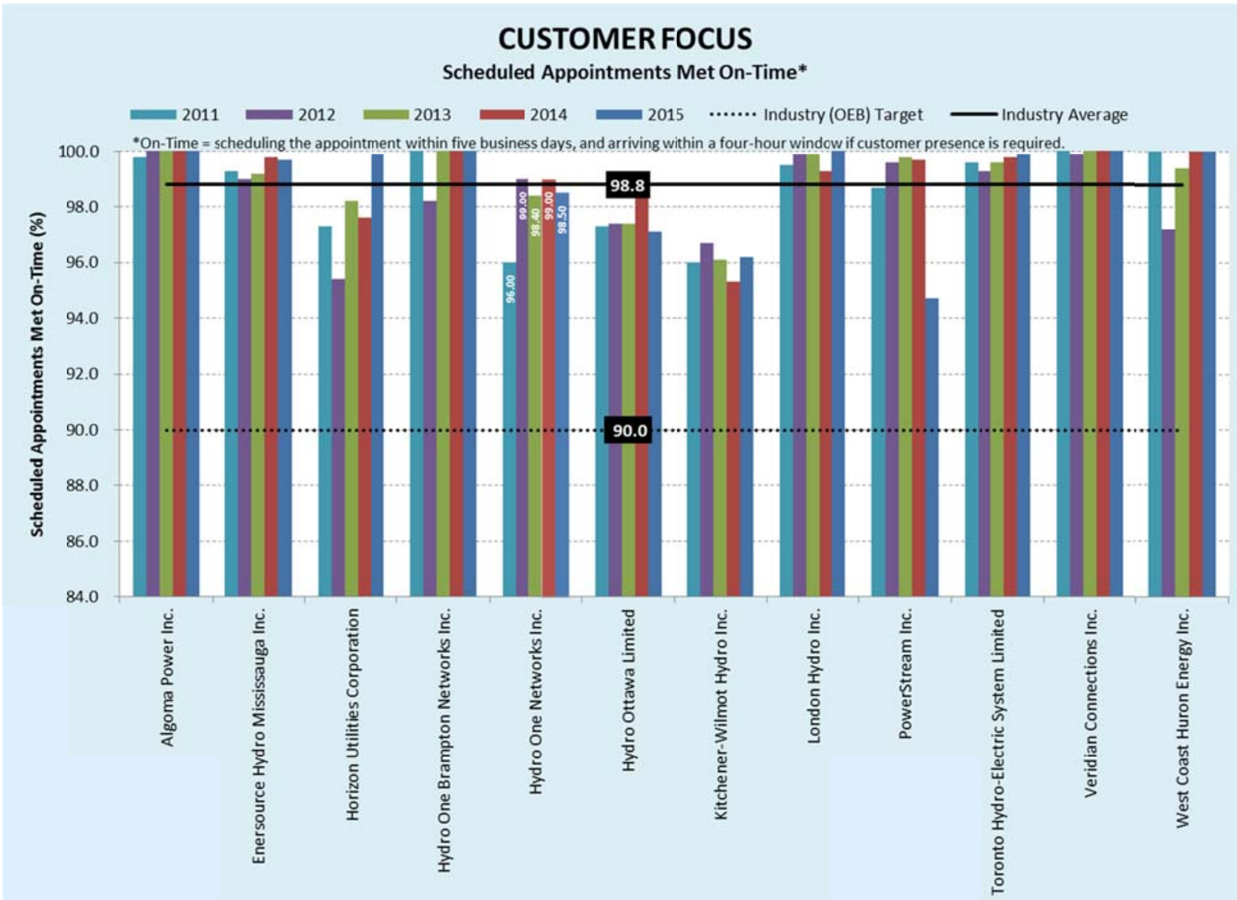

Figure 4 - Scheduled Appointments Met On-Time[9]

[9] For 2012 and 2014, the performance levels shown in Figure 3 do not match the Electricity Distributor Scorecard shown in Figure 1. Hydro One will revise the data through the OEB's RRR change request process.

3.3 SERVICE QUALITY: TELEPHONE CALLS ANSWERED ON-TIME

Hydro One call centre agents handled approximately 1.34 million[10] phone calls from customers in 2015, out of a total of about 2.6 million[11] phone calls. The Company's Interactive Voice Response (IVR) system handled about 1.25 million phone calls, with the remaining difference in call volumes attributable to abandoned calls and calls offered to the Business Call Center Complex/Distributed Generation. In 2015, the Company answered 76.4 per cent of calls within 30 seconds and exceeded the industry target by 11.4 percentage points. Performance for the year was marginally below the industry average of 78.6 per cent, however 2015 marked a notable improvement of 6.8 percentage points compared to 2014 (see Figure 5).

Over the past five years, Hydro One's average performance was 74.9 per cent, exceeding the industry target of 65 per cent every year except in 2013, when the Company introduced a new Customer Information System (CIS). Billing issues encountered due to the implementation of CIS, along with a significant storm in December of 2013, led to an average increase in call volumes of about 40,700 calls per month (from May to December) compared to the same period in the previous year (see Figure 6), impacting Hydro One's ability to meet the industry target in 2013. Performance has steadily improved in 2014 and 2015, exceeding the industry target, and the Company expects to continue to improve annually on this trend.

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[10] Total Calls Offered to Agents, less Call Transfers
[11] Actual Calls Offered to the Customer Call Centre, less Forced Disconnects

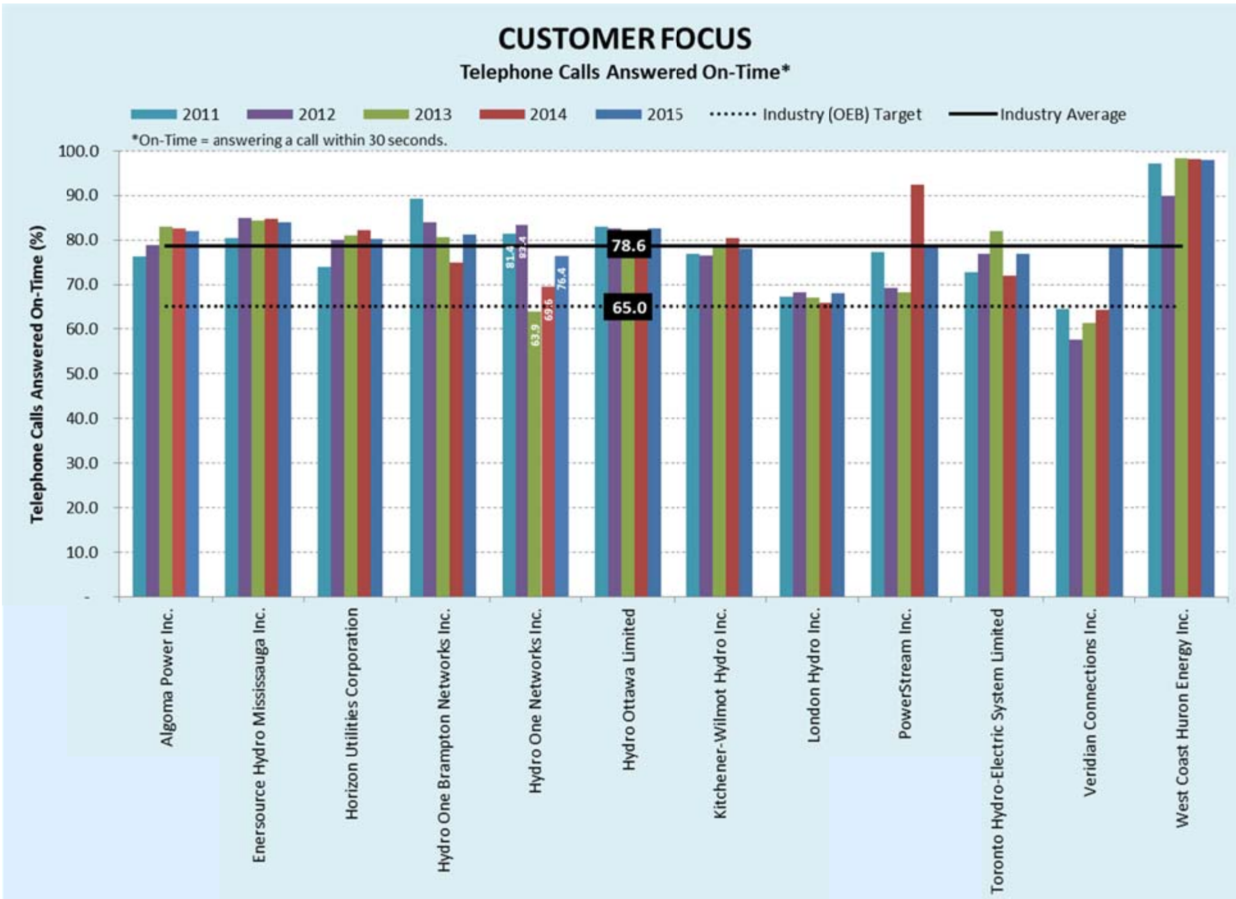


Figure 5 - Telephone Calls Answered On-Time

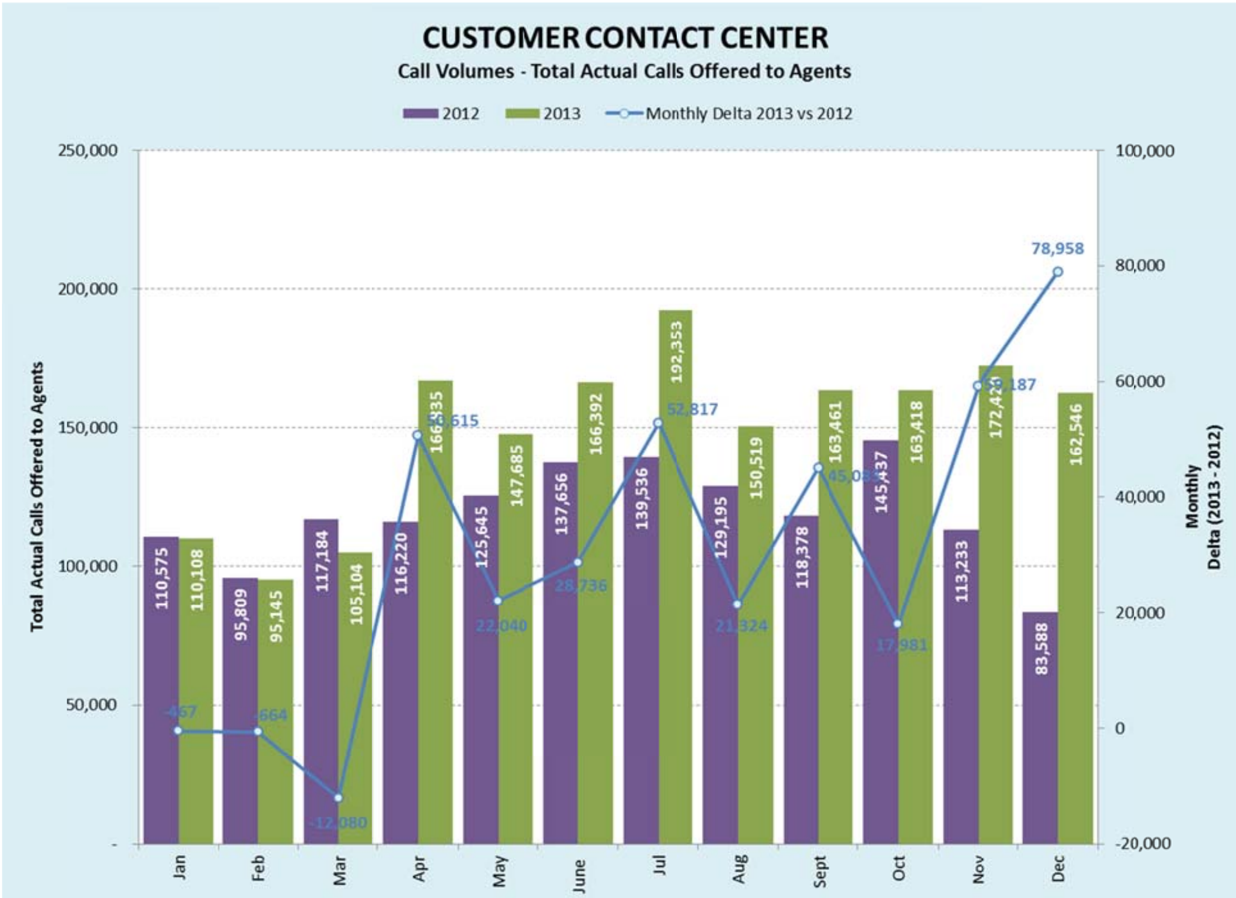


Figure 6 – 2012 and 2013 Calls Volumes – Total Actual Calls Offered to Agents

Hydro One has significant plans in place to improve the customer experience and reduce costs in its call centre. This includes plans to enhance the Company's customer self-service technology within the online My Account capability, and add web-chat as an alternative communications channel. These upgrades are expected to increase the adoption levels of self-service channels by providing customers with additional self-service options, thereby reducing the number of phone calls to the call centre whilst at the same time allowing customers to access the information they need using their preferred method of contacting the Company.

Investments in improved tools and analytics will also provide customers with advanced features such as High Usage Alerts, energy usage information, personalized energy savings recommendations based on usage patterns, and access to an enhanced customer web portal. These tools will provide Hydro One with a better understanding of customer needs and energy usage and the ability to communicate more effectively, thus reducing the need for customers to call into the call centre. Enhanced functionality such as High Usage Alerts is expected to reduce call volumes and improve first call resolution.

Investments are also planned for the implementation of a dedicated customer complaint management system to track complaints from initiation to resolution, which is expected to improve overall customer satisfaction through faster average handling times and by better identifying trends and root causes of complaints.

Investments are planned to the Company's call centre technology to replace the aging Computer Telephony Integration ("CTI") and IVR systems and to enhance the existing Customer Relationship Management ("CRM") and iCare systems. These planned investments will improve the Company's capability to route calls to the appropriate customer service representative within the call center, improve customer service with modern speech recognition and text-to-speech technologies, more intuitive graphical user interfaces, improved system performance, integration of relevant caller information into a unified dashboard for the agents, and more effective monitoring of call center agents and the overall performance of the call centre.

A further reduction in call volumes to the call centre is expected to be realized through the planned investment in the redesign of the customer bill. The planned redesign will make it easier for customers to understand the bill, resulting in lower billing-related call volumes to the call centre. The reduction in call volumes and average handling times is expected to lead to an improvement in the call centre's ability to answer calls within 30 seconds, reduce costs and improve overall customer satisfaction. The improvements to Outage Handling, discussed in section 3.6, are also expected to have a positive impact on Hydro One's ability to answer telephone calls on-time.

Over the term of the Application, Hydro One has a target of answering calls within 30 seconds, 80 per cent of the time. The Company's planned investments as described above, are expected to result in gradual performance improvements through the application period, ensuring performance levels will be well above the OEB industry target of 65 per cent, above the Company's historical average performance of 74.9 per cent, and continuing the recent three-year upward trend.

3.4 CUSTOMER SATISFACTION: FIRST CONTACT RESOLUTION (FCR)

The OEB has allowed electricity distributors flexibility and discretion as to how this measure is implemented. Although this flexibility recognizes and acknowledges the varied capabilities, technologies, and service demographics of electricity distributors, it may not allow for a direct comparison between distributors since each distributor can self-define the methodology it uses to measure and report on the metric.

Hydro One measures FCR based on transactional surveys that are performed within five days of interacting with a customer. In 2015, 82 per cent of issues were resolved during the first contact with a customer, representing an improvement of 3 percentage points from 2014, and marginally below the Company's internal target of 83 per cent. Over the past three years, Hydro One's average performance was 79.8 per cent, trending positively towards the current industry average of 87.1 per cent (see Figure 7). Historical performance was mainly attributable to improved quality assurance programs in the customer call centre, effective listening and empowerment training for call centre agents, increased monitoring and feedback within the call centre, and detailed review of customer feedback to determine trends and root causes.

Over the term of the Application, the Company plans to improve its performance, targeting 88 per cent for this measure and exceeding the current industry average. Although it is expected that FCR performance will indirectly benefit from the planned investments outlined in Section 3.6– such as investments in call centre operations and technology, bill redesign and billing accuracy – the planned investment directly focused on improving FCR is the investment in customer tools and analytics. This planned investment will provide customers with advanced features such as High Usage Alerts; energy usage information; personalized energy savings recommendations based on usage patterns; and access to an enhanced customer web portal. These tools will at the same time provide Hydro One agents access to customer analytics and insight tools, allowing for a better understanding of individual customer needs and energy usage, reducing the need for customers to call into the call centre and improving agents' abilities to solve customer queries and issues. Enhanced functionality such as the High Usage Alerts is expected to reduce average handle times within the call centre for calls related to high usage and also improve first call resolution.

The improvements to Outage Handling, as discussed in section 3.6, are also expected to have a positive impact on Hydro One's FCR performance.

Hydro One is focused on improving the ease of doing business from the customer's perspective. Improvements in call centre operations and billing accuracy are fundamental transactions requiring attention to advance and build further credibility with the customer base. Hydro One is also planning improvements to the training of its call centre agents and empowering them to make more decisions. Furthermore, the planned investments in the call centre technology are expected to improve effective monitoring of call centre agents and their overall performance, to ensure customer care agents resolve issues during the first contact.

Figure 7 – First Contact Resolution

3.5 CUSTOMER SATISFACTION: BILLING ACCURACY

In 2015, the Company exceeded the industry target by 0.59 percentage points, achieving a score of 98.59 per cent and improving from 2014 by about 4 percentage points. In 2015, the OEB approved the Company's request to exempt 170,000 "hard-to-reach" customers from Time of Use (TOU) billing because the meters of these customers were unable to communicate reliably due to poor cellular coverage[12]. If these meters had been excluded in 2014, the Company would have recorded a 97.86 per cent billing accuracy. The Company's two-year average performance, based on published results, was 96.61 per cent, marginally lower than the industry target and current industry average of 98.14 per cent, but trending positively (see Figure 8). As cellular coverage improves, the number of exempted customers continues to decline.

As discussed in Section 3.3, the Company encountered billing issues due to the implementation of CIS in 2013, which along with other factors, impacted various performance measures for the Company, including Billing Accuracy. The performance improvements over the 2014 to 2015 period were mainly attributable to the Company's recovery efforts. The synchronization and integration of CIS with the smart meter network concluded in 2014, at which point Hydro One determined that billing accuracy could meet or exceed the industry target. This determination was confirmed in 2015 when the Company achieved a 98.59 per cent billing accuracy score.

The Company has planned for investments to expand the Advanced Metering Infrastructure ("AMI") network and to replace various smart meter network support tools with up-to-date technology. These tools include Customer Migration; Customer Meter Order Management; Collector Design and Deployment; Customer Service Order Network; Index Read Tracking; Itron Enterprise Edition Meter Data Management; and Network Infrastructure Performance Reporting. In addition, as commercial cellular coverage improves across the province, Hydro One will continue to reduce the number of non-communicating meters and offer Time-of-Use billing to these customers. Along

[12] Ontario Energy Board. "Decision and Order EB-2015-0176 Hydro One Networks Inc. Application for Exemption from Sections 2.10.1, 7.11.1-7.11.7 of the Distribution System Code." September 24, 2016. https://goo.gl/n7DzPg (accessed December 5, 2016).

with the scheduling efficiency gains expected from the Move-to-Mobile initiative, Hydro One also expects to improve the success rate of manual meter reads, improving overall billing accuracy.

Over the term of the Application, Hydro One plans to exceed its historical average and the industry target of 98 per cent. Hydro One is targeting 99 per cent billing accuracy through the realization of benefits arising from planned investments. The planned investments are also expected to create efficiencies in the Company's meter-to-bill process through improved reporting and analytics, which will likely result in improvements to overall customer satisfaction.

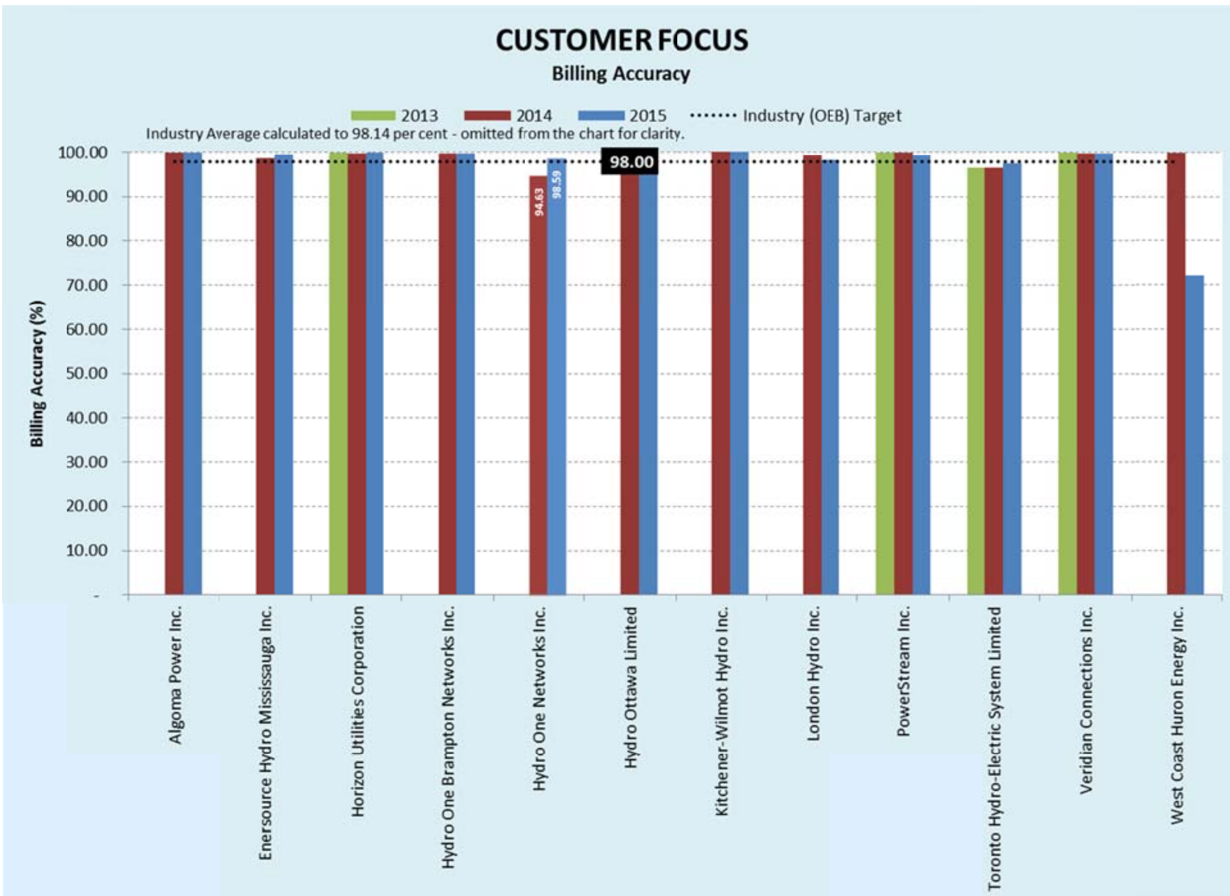


Figure 8 -- Billing Accuracy

3.6 CUSTOMER SATISFACTION: CUSTOMER SATISFACTION SURVEY RESULTS

The OEB has allowed electricity distributors flexibility and discretion as to how this measure is implemented. At a minimum however, electricity distributors are required to measure and report their results every other year. Although this flexibility recognizes and acknowledges the varied capabilities, technologies, and service demographics of electricity distributors, it may not allow for a direct comparison between distributors since each distributor can self-define the methodology it uses to measure and report on the metric.

The Company measures customer satisfaction using an equally weighted composite index of the following seven components: (1) Outage Handling; (2) Agent Handled Call Satisfaction; (3) Forestry Services; (4) Lines New Connections and Upgrades; (5) My Account; (6) Large Distribution Accounts (LDAs); and (7) Distributed Generation Customers (estimated as per cent of new connections met on-time). Customer satisfaction remained steady at 85 per cent in 2015 compared to 2014 but declined 2 percentage points compared to 2013. Customer Satisfaction with Agent Handled Calls and My Account both increased from 2013 to 2015 due to Hydro One's increased focus on customer service with call centre agents and improvements to Hydro One's My Account self-service portal. The decline over this period was mainly attributable to a marginal decline in the Outage Handling component, resulting from CIS-related billing issues and a large number of storms in 2013.

Hydro One's average performance over the last three years was 85.7 per cent, with a marginally declining trend and below the current industry average of 87.3 per cent (Figure 9). There are several planned investments to improve overall customer satisfaction, including: High Usage Alerts, Paperless Billing notifications, Bill Redesign, allowing customers to set their own billing date, and an enhanced web portal. High Usage Alerts will proactively deliver alerts to customers during their billing cycle to warn them that they are consuming more electricity than normal. Hydro One will issue the High Usage Alerts prior to the actual bill being delivered. The alert will also suggest ways the customer can adjust their energy use before the end of the billing period.

Paperless Billing notifications will inform customers that have signed up for e-billing that their bill is ready. Hydro One's new Paperless Billing notifications will provide customers with personalized insights about their energy consumption, promotions for conservation and demand management programs, and will encourage customers to use self-service channels instead of calling the call center.

The Bill Redesign initiative will design a modern and customer-friendly bill for Hydro One customers in order to reduce customer frustration with hard-to-read bills. An enhanced web portal will provide seamless integration of Hydro One's My Account self-service portal with interactive access to energy usage information and energy savings recommendations based on energy usage patterns.

The Forestry and New Connection teams are also taking steps to enhance their customer communication, scheduling, and execution of customer requests.

For Outage Handling, Hydro One offers various sources of information to its customers to ensure they are informed and have current and relevant information regarding the status of outages. This includes the outage map on the Company's external website, a smartphone application, text message notifications, automated calls to land lines, and email messages. Planned areas of performance improvement include improved overall data accuracy for customers and network connectivity, enhancements to the outage map and smartphone application, and proactive outage reporting options for Hydro One customers. The Company will continue to focus on improving the Estimated Time to Resolution ("ETR") accuracy, through enhanced network analytics, including meter ping capability and improvements to the Outage Management System.

Automated calls enhancements are also being explored to allow for increased capacity for the system to report proactively and to provide near-real-time outage restoration notifications. Hydro One will also continue to explore upgrades to the outage management system in an effort to improve the support and stability of the platform and pursuing outage confirmation through smart-meter ping capability and enhanced network analytics.

On an annual basis, plans for continuous improvement are reviewed and internal performance targets are calculated for one year forward, based on the five-year rolling average of each component. Over the term of the Application, Hydro One plans to outperform both its historical average and the current industry average, achieving 89 per cent customer satisfaction.

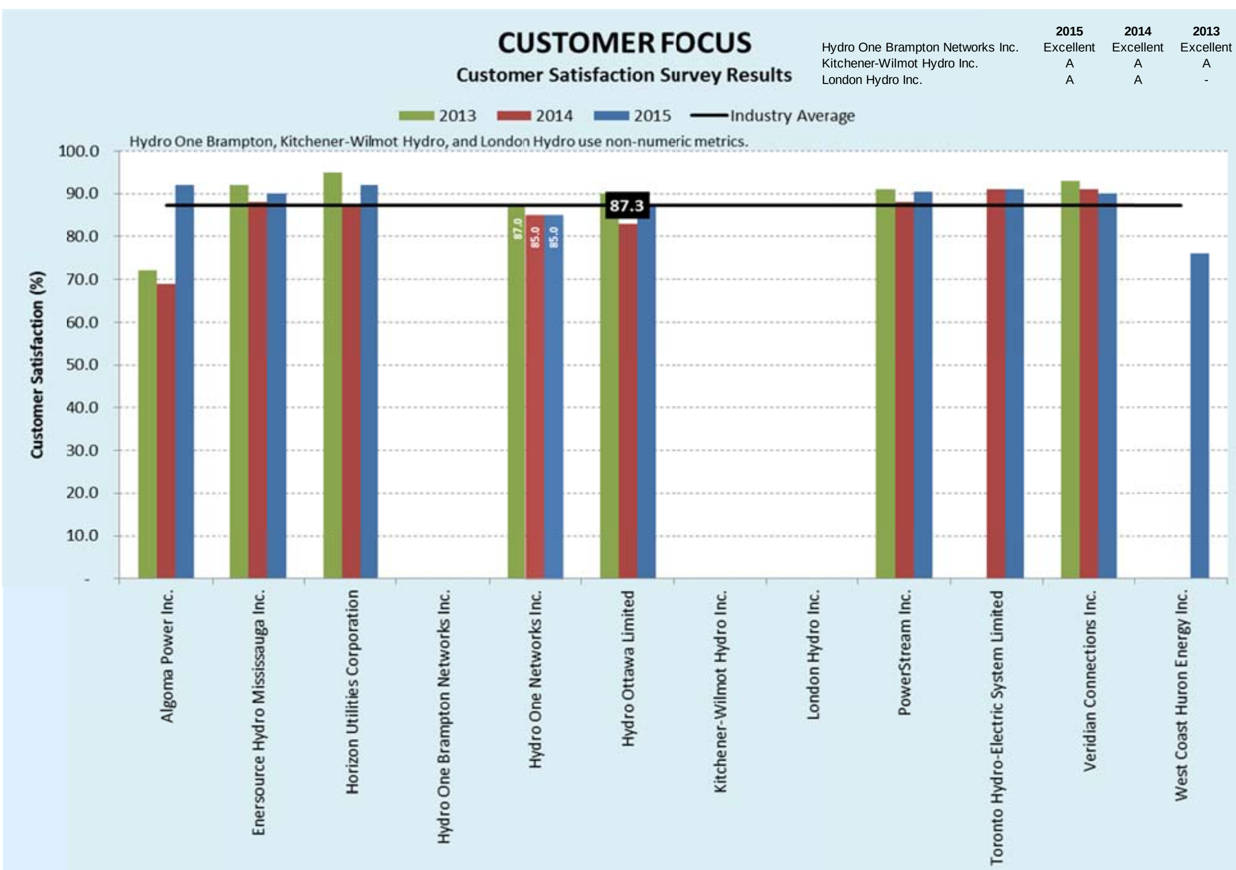


Figure 9 – Customer Satisfaction Survey Results

4. OPERATIONAL EFFECTIVENESS

4.1 SAFETY: LEVEL OF PUBLIC AWARENESS

2015 was the first year this metric was reported. In 2015, Hydro One achieved an overall index score of 81 per cent, which was better than the current industry average of 78.9 per cent (see Figure 10). During 2015, Hydro One conducted a survey to measure electrical safety awareness among people living in its service territory. The standardized survey was composed of six core questions and focused on the likelihood that a customer will call before digging, the impacts of touching a power line, safe distances when around power lines, safe distances when around downed power lines, tampering with electrical equipment, and the correct course of action when an occupied vehicle is in contact with a power line. The data was weighted by age, gender, and region using distribution information from the 2011 Statistics Canada census to reflect the demographic composition of the service territory, and responses were weighted to arrive at the aggregated awareness score of 81 per cent.

The Company's performance in 2015 was mainly attributable to its community outreach and educational initiatives that are supported by our Public Safety Policy and Programs. The general objectives of these programs are:

- Commitment to protecting the public by following good utility work practices, incorporating public safety considerations into business decisions, promoting public safety awareness and supporting community safety initiatives through the Company's Community Citizenship Program; and

- Engaging in education and public awareness activities to assure customers of the safety of the services provided by the Company.

Programs that support Hydro One's Public Safety Policy include the Hazard Hamlet Program, attending Community Safety Events and Agricultural Fairs, the Mobile Electricity Discovery Centre ("EDC"), partnering with the Electrical Safety Association (ESA), Safety Donations and Sponsorships, and providing related information on the company's external website.

Public safety is also reinforced through internal requirements to include a public safety component when performing work on the electricity system, ensuring work activities do not create public hazards and always protect the public from harm.

With the ESA, Hydro One participates as a member of the ESA Community Powerline Safety Alliance. In 2015, Hydro One was awarded the ESA's Powerline Safety Award for its community outreach with the Company's EDC. The EDC is a 1,000 square foot mobile education centre that features interactive exhibits and hands-on displays. Through 2016, the EDC has welcomed more than 80,000 visitors from 70 communities. The EDC's guests learn about electrical safety, how to conserve energy and the role that Hydro One plays in their community.

Hydro One will continue performing the standardized survey in future years. Since 2015 was a baseline year and the survey is completed every two years, further results will not be available until 2018. Therefore, the Company has not set a target for the term of the rate application period.

Over the term of the Application, the Company expects to maintain or improve the results of its level of public awareness by continuing with similar community outreach and educational initiatives as discussed above and remains committed to participating in educating the general public on electrical safety.

Figure 10 – Level of Public Awareness

4.2 SAFETY: LEVEL OF COMPLIANCE WITH ONTARIO REGULATION 22/04

For 2015, the Company received a Compliant (C) score from the ESA, improving from the historical assessments of Needs Improvement (NI), as shown in Figure 11. The Company has met and will continue to meet all the necessary reporting requirements as defined by the OEB and the ESA. The Company's historical assessments were mainly attributable either to failures to fully comply with components of Ontario Regulation 22/04 (Reg. 22/04) or non-pervasive failures to comply with adequate, established procedures for complying with Reg. 22/04 as determined by the ESA. For establishing compliance with Reg. 22/04, the ESA evaluates five elements: (1) Audit; (2) Declaration of Compliance; (3) Due Diligence Inspections; (4) Public Safety Concerns; and (5) Compliance Investigations. These elements are evaluated by the ESA as whole and a compliance status is established.

Over the term of the Application, the Company will maintain a target of Compliant (C). The Company will continue to follow and enforce established processes to ensure full compliance with Reg. 22/04. Internal quality assurance audits combined with due diligence inspections are opportunities for continuous improvement to potentially improve processes, training and standards. Technology and systems, such as equipping workers with mobile devices that connect directly to the Company's document management system, will streamline information flow, improve governance, and create additional rigor for documentation purposes.

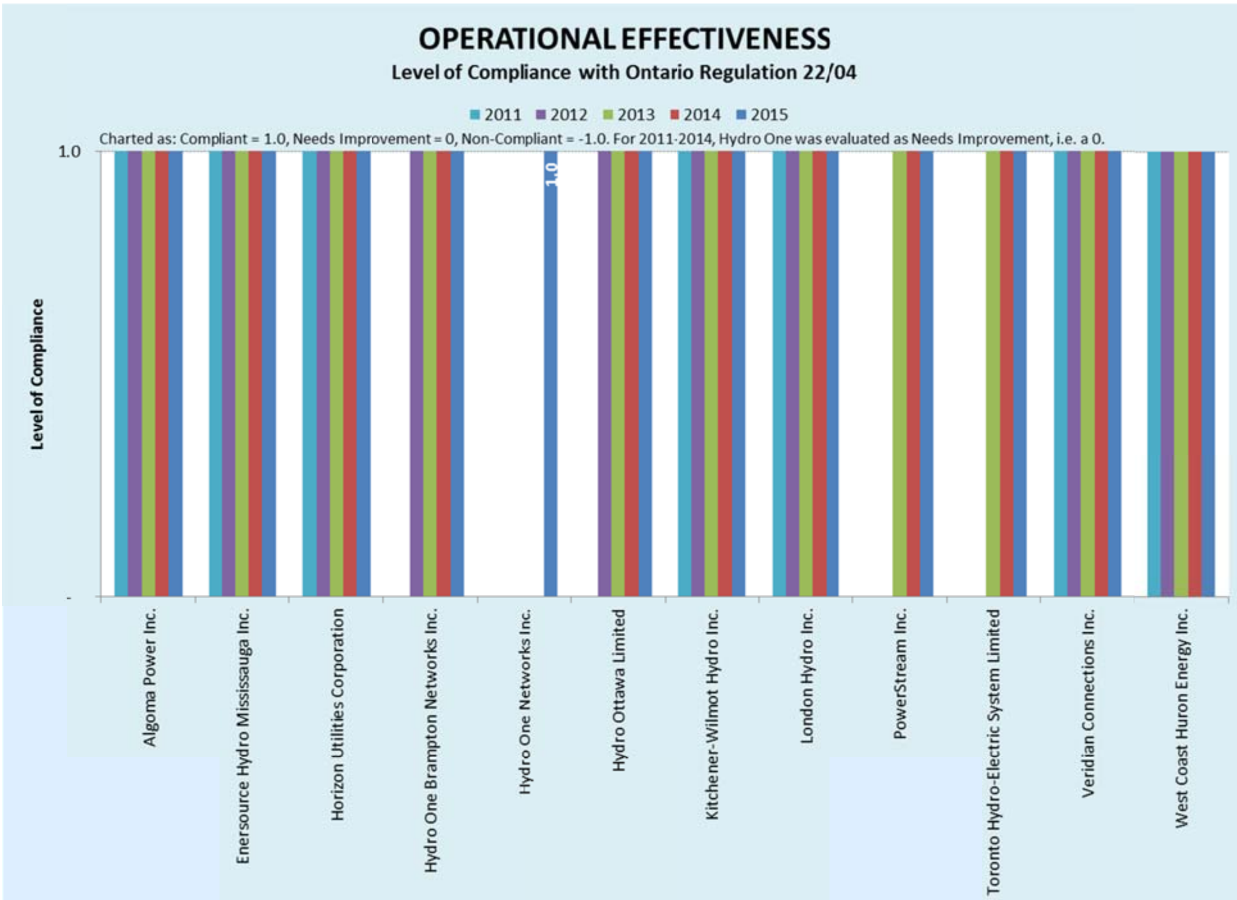


Figure 11 – Level of Compliance with Ontario Regulation 22/04

4.3 SAFETY: SERIOUS ELECTRICAL INCIDENT INDEX – NUMBER OF GENERAL PUBLIC INCIDENTS & RATE PER 10, 100, 1,000 KM OF LINE

For 2015, the ESA identified five serious recordable electrical public incidents (as defined by the ESA), resulting in an index value of 0.042 incidents per 1,000 km of line for Hydro One. Although above the Hydro One specific ESA target index value of 0.035 or four recordable incidents, the overall trend continues to show a reduction of serious electrical incidents and electrical incidents per kilometer of line on the Company's distribution system (see Figure 12). The Company's historical average over the 2011 to 2015 was six serious recordable electrical public incidents or an index value of 0.050, which resulted mainly from motor vehicle accidents and tree trimming incidents.

During the term of the rate application period, the Company will use an internal limit or maximum allowable level of less than five serious recordable electrical public incidents, and will continue to report all incidents on the distribution system to the ESA. In the fourth quarter of 2016, Hydro One initiated enhancements to the managed process for reporting incidents to the ESA, including investigations of public safety events to identify opportunities for improvement to standards, work practices, and communication to mitigate the risk of future similar incidents.

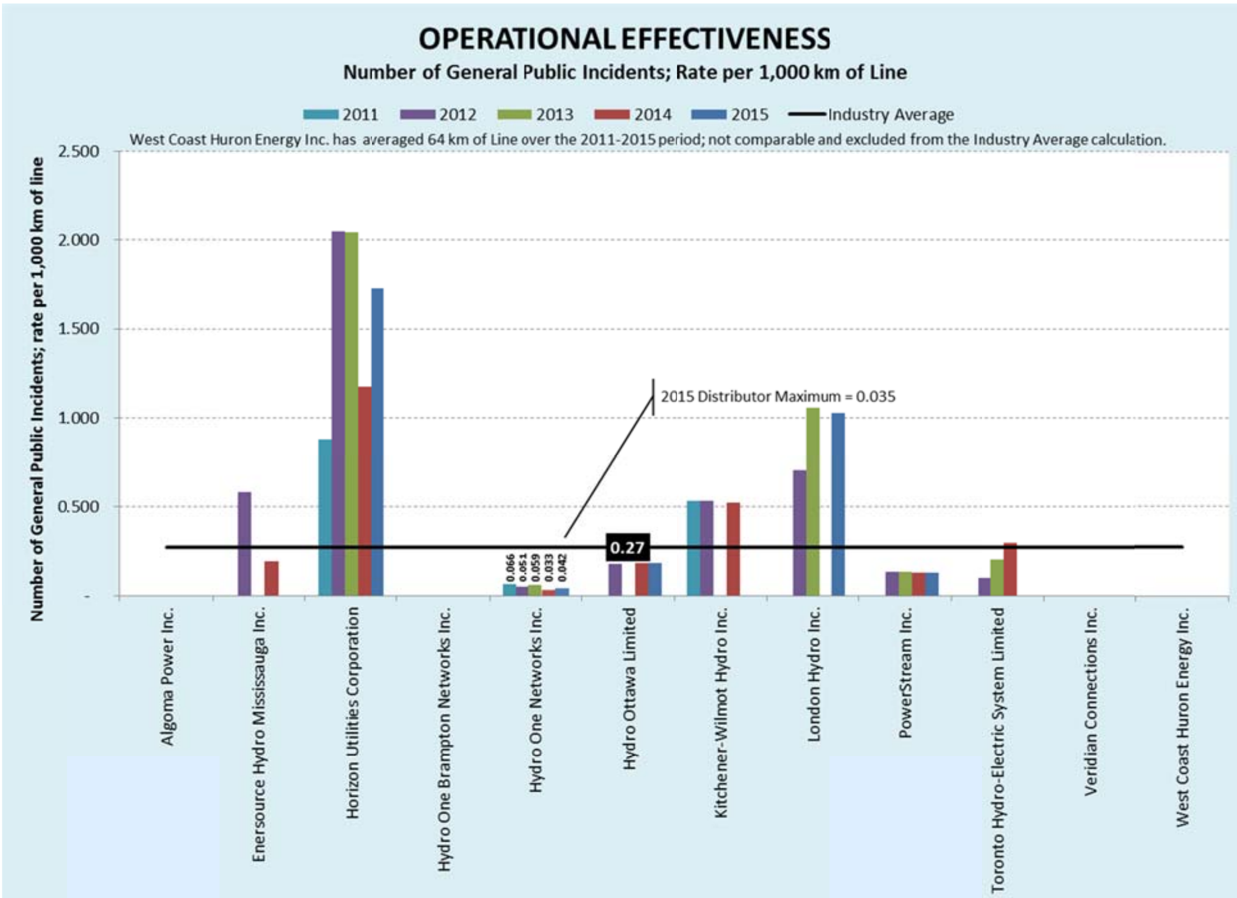


Figure 12 – Number of General Public Incidents per 10, 100, 1,000 km of Line

4.4 SYSTEM RELIABILITY: AVERAGE NUMBER OF HOURS THAT POWER TO A CUSTOMER IS INTERRUPTED (SAIDI)

For 2015, the Company reported an average outage duration of 12.22 hours, representing an increase of about three hours from 2014, mostly due to weather-related interruptions. The five-year trend shows improvement, with the average number of hours of power interruption per customer decreasing. The five year historical average is 15.99 hours of interruption which is higher than the distributor target of 15.35 hours. However, Hydro One has improved with performance in both 2014 and 2015 scoring better than target

(Figure 13). While these results are higher than the industry average of 4.3 hours, Hydro One is a rural utility and continuous improvement against internal benchmarks is more relevant than comparison to utilities that do not have similar low customer density and radial networks as Hydro One.

The increase in the 2015 metric was mainly attributable to three significant weather events, each of which impacted ten per cent or more of Hydro One's distribution customers and caused damage to both distribution and transmission systems. From August 1 to 4, a severe thunderstorm caused significant tree damage to power lines, resulting in interruptions to about 144,000 customers, which is approximately 11% of the total customers connected to Hydro One's Distribution system.

Between November 6 and 9, wind speeds of up to 100 km/h damaged distribution poles and caused downed trees in Southwestern Ontario, Northwestern Ontario and the Georgian Bay area, resulting in interruptions to about 277,000 customers, or approximately 21 per cent of Hydro One's distribution customers. From December 25 to 26, winds of 70 km/h to 90 km/h passed through Southwestern Ontario along the shores of Lake Huron causing tree-related damage to Hydro One's distribution system and resulting in interruptions to about 189,000 customers (nearly 14 per cent of total customers).

For the term of the Application, the Company's internal SAIDI target will be 14.30 hours, representing a modest improvement compared to the historical average of 15.99 hours. An extensive customer stakeholder process was undertaken by Hydro One in 2016 to determine customer needs and preferences. Hydro One's customers indicated that they value cost control and minimizing rate impacts over reliability improvements. Hydro One's Distribution System Plan ("DSP", Exhibit B, Tab 1, Schedule 1) aligns the needs and preferences of customers, the compliance and condition requirements of the system's assets, and rate impacts.

When establishing targets for SAIDI and SAIFI over the term of the Application, Hydro One considered distribution system outcomes that would also align with customer preferences and provide outcomes valued by customers. The Company expects to achieve its SAIDI target by continuing to pace investments to achieve continued asset performance levels with recent history. Some improvements in its vegetation management will yield modest improvements in performance; a worst performing feeder program and an LDA customer reliability program will make localized improvements that will be offset by deferrals of some capital renewal investments in other locations. The expectation is that the recent 2014 to 2015 upward SAIDI trend will stabilize and reverse direction (i.e., reducing average outage duration) as the improvements discussed are realized beyond 2018.

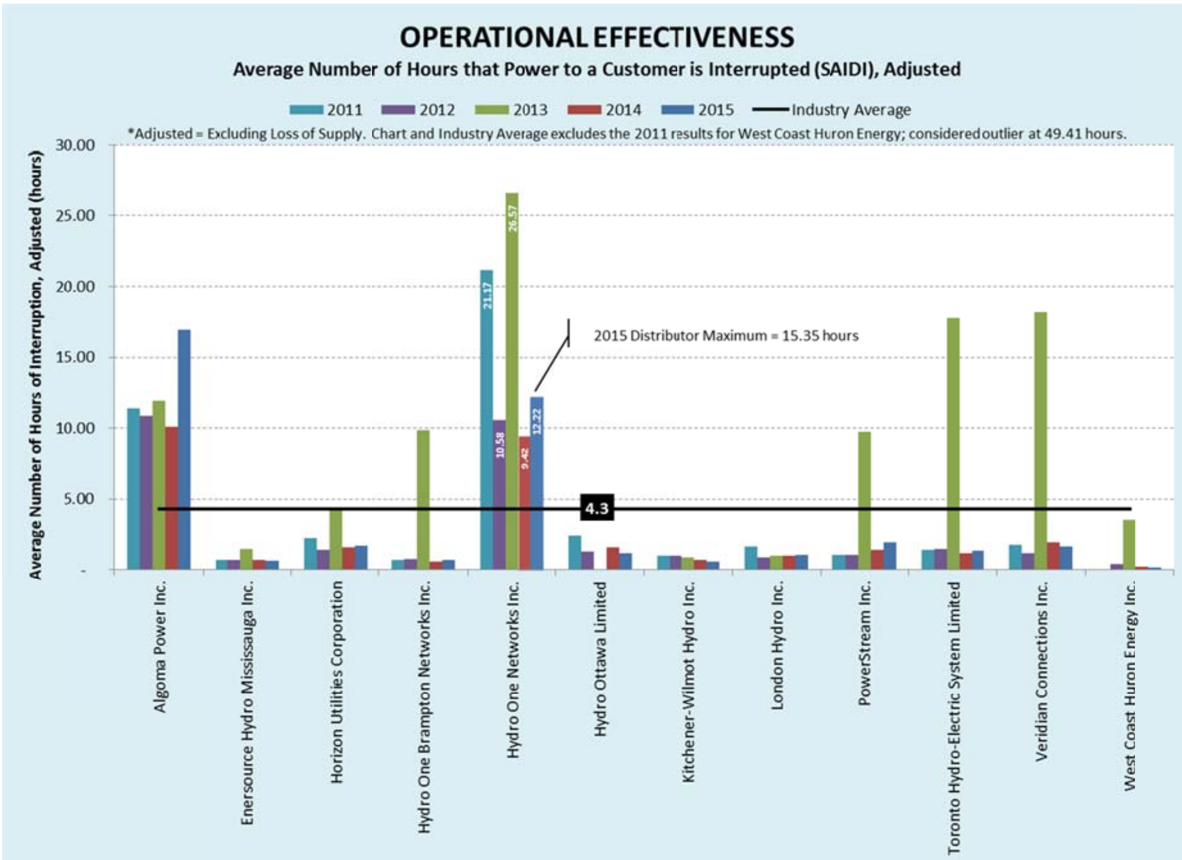


Figure 13 – Average Number of Hours that Power to a Customer is Interrupted (SAIDI), Adjusted

4.5 SYSTEM RELIABILITY: AVERAGE NUMBER OF TIMES THAT POWER TO A CUSTOMER IS INTERRUPTED (SAIFI)

Frequency of customer outages was reported at 3.07 outages per customer for 2015 representing a marginal increase compared to 2014. SAIFI performance for 2015 was better than the distributor target of 3.44, but higher than the current industry average of 1.8 (see Figure 14). The overall trend continues to improve, showing a reduction to the number of times that power is interrupted to Hydro One customers by about 22 per cent since 2011, and representing a historical average performance of 3.47. Due to the significant rural aspect of the Company's distribution system, all weather in the Province affects some part of the Company's network and can result in significant variations in the duration and frequency portions of the system reliability metrics. Additional factors impacting the Company's historical performance are discussed in Section 4.4, and are also applicable to SAIFI.

Over the term of the Application, the Company's internal SAIFI target will be 3.3, representing modest improvement compared to the five-year historical average of 3.47, however consistent with more recent performance. As discussed in Section 4.4 above, his internal target is consistent with the needs and preferences of Hydro One customers, as determined from the 2016 stakeholder process. The Company expects this performance target to be realized through the same plans and actions, as discussed earlier in Section 4.4.

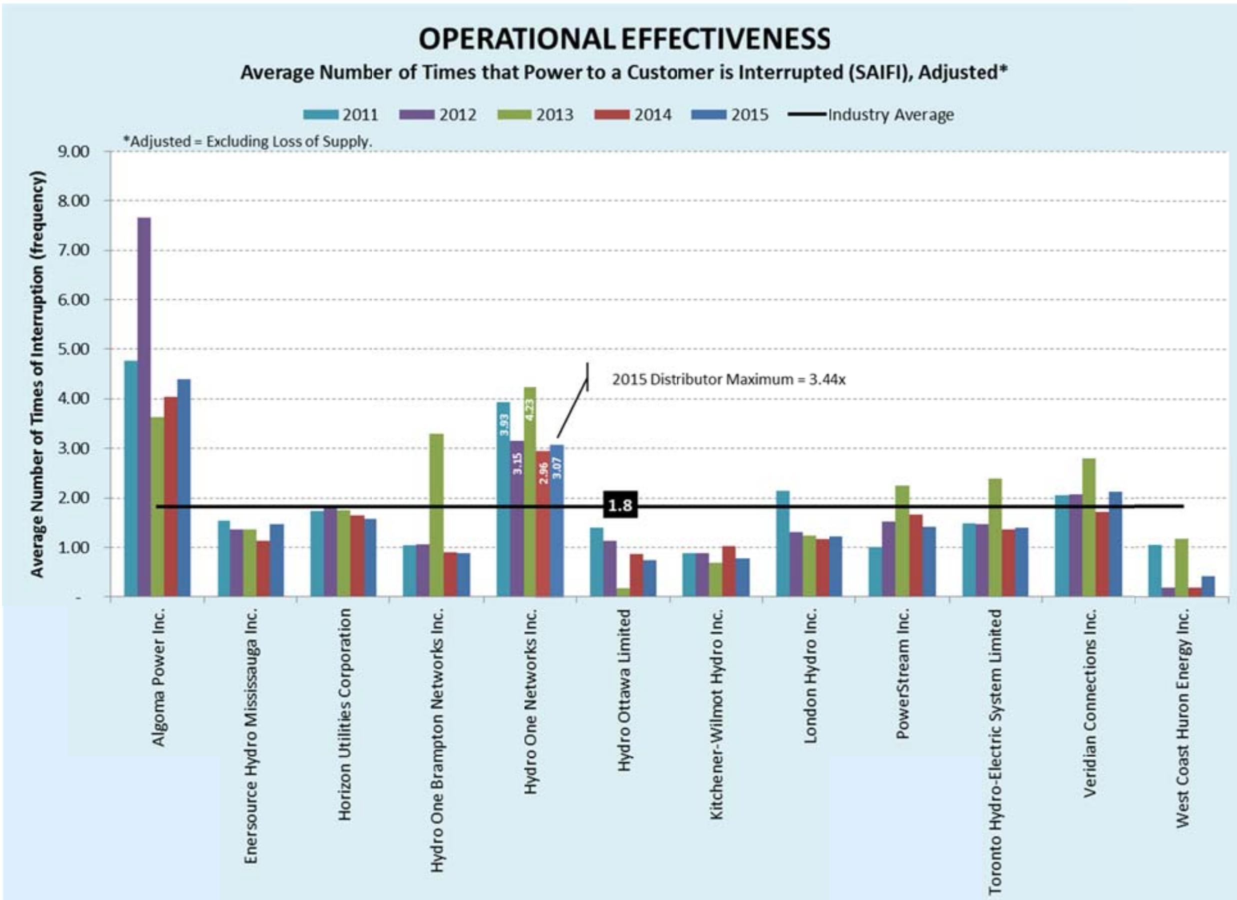


Figure 14 – Average Number of Times that Power to a Customer is Interrupted (SAIFI), Adjusted

4.6 ASSET MANAGEMENT: DISTRIBUTION SYSTEM PLAN IMPLEMENTATION PROGRESS

The OEB has allowed electricity distributors flexibility and discretion as to how this measure is implemented. Although this flexibility recognizes and acknowledges the varied capabilities, technologies, and service demographics of electricity distributors, it may not allow for a direct comparison between distributors since each distributor can self-define the methodology it uses to measure and report on the metric.

The Company's historical performance average, based on the two reported years, was 107 per cent and was driven by two main factors in 2015. For 2015, the Company exceeded its planned investments in the distribution system largely due to storm restoration requirements and a requirement to advance collector and meter replacements for the smart metering system as telecom carriers decommissioned their CDMA networks earlier than expected. This increase was partially offset by lower development costs, as shown in Figure 15.

Hydro One's DSP outlines the Company's forecast capital expenditures over the next five years, required to maintain and expand the electricity system to serve current and future customers. Progress is measured as the ratio of actual total in-service capital expenditures made in a calendar year to the total amount of planned in-service capital expenditures for the same year. The Company will continue to work towards meeting its planned total in-service capital expenditure plan levels, and is targeting 100 per cent for the 2018 to 2022 period.

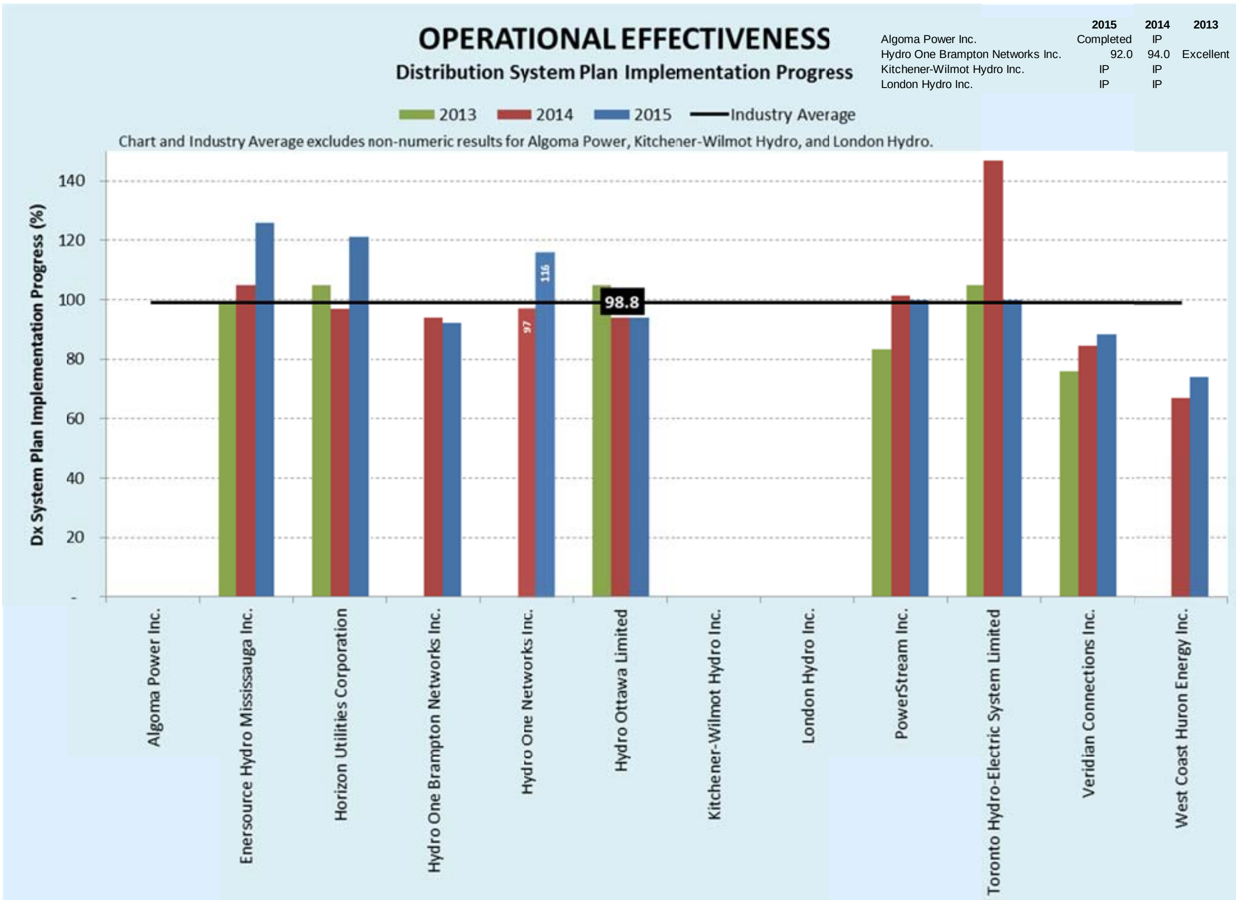


Figure 15 – Distribution System Plan Implementation Progress

4.7 COST CONTROL: EFFICIENCY ASSESSMENT

For 2015, Hydro One remained in Group 5, along with Algoma Power Inc., Toronto Hydro-Electric System Ltd., and West Coast Huron Energy Inc.

Cost control metrics are evaluated on behalf of the OEB by the Pacific Economics Group Research LLC (PEG), an independent party. The PEG study segments electrical distributors into five groups based on a benchmarking evaluation of cost efficiency as measured by the difference between actual costs and PEG's prediction of costs, including various adjustments made by PEG. Group 1 distributors are considered most efficient, with actual costs 25 per cent or more below predicted costs and Group 5 distributors are considered least efficient, according to the PEG methodology, with actual costs 25 per cent or more above predicted costs. Cost benchmarking is impacted by the nature and profile of distribution systems. A rural system, such as Hydro One's, generally ranks lower than a typical urban utility.

For the 2018 to 2022 period, the Company has set the target at the current level of Group 5. Through the various planned improvements discussed in this Section and the initiatives described in the productivity section of the DSP (Section 1.5), Hydro One expects to reduce costs significantly. However, Hydro One also recognizes it is an extreme outlier within the Ontario dataset that underlies the PEG model and results. The cost savings expected during the term of this Application will not likely to result in a change in Hydro One's assessment compared to other Ontario distributors. The need for a dataset of comparators beyond Ontario distributors is more appropriate, such as provided in the Total Cost Benchmarking Study Hydro One has provided with this application in Exhibit A, Tab 3, Schedule 2, Appendix 2.

4.8 COST CONTROL: TOTAL COST PER CUSTOMER

In 2015, Hydro One's annual cost performance improvement represented a reduction of over eight per cent on total cost per customer, or $86 per customer, compared to 2014. This was largely a result of lower OM&A expenditures related to enhanced collections (lower bad debt expenses), lower vegetation management costs, and a lower volume of work to locate and restore power interruptions. The total cost per customer is defined as the total Capital and Operations, Management, & Administration ("OM&A") costs, divided by the total number of customers served, including certain specific adjustments, as calculated and reported by PEG.

For the 2018 to 2022 period, the Company does not have a target for this metric but does have a target for OM&A cost per customer as part of its Distribution OEB Scorecard, discussed in Section 1.4 of the DSP. The various investments discussed in this Section, the Investment Summary Documents, and the initiatives described in the productivity section of the DSP (Section 1.5), present various planned investments, which collectively are expected to have a positive impact on various aspects of the Company including this performance metric.

4.9 COST CONTROL: TOTAL COST PER KM OF LINE

In 2015, Hydro One achieved a reduction of about 6.6 per cent for total cost per kilometre of line or $718 per kilometre compared to 2014. This improvement was largely attributable to the lower OM&A expenditures noted in Section 4.8. The total cost per kilometre of line is defined as the total Capital and OM&A costs, divided by the total number of kilometres of line operated to serve customers, including certain specific adjustments, as calculated and reported by PEG.

For the 2018 to 2022 period, the Company does not have an internal target for this metric but does have a target as part of its Distribution OEB Scorecard, discussed in Section 1.4 of the DSP specifically for OM&A costs per KM of Line. The various investments discussed in this Section, the Investment Summary Documents, and the initiatives described in the productivity section of the DSP (Section 1.5), present various planned investments, which collectively are expected to have a positive impact on various aspects of the Company including this performance metric.

5. PUBLIC POLICY RESPONSIVENESS

5.1 CONSERVATION & DEMAND MANAGEMENT: NET CUMULATIVE ENERGY SAVINGS

On March 31, 2014, the Minister of Energy issued a directive outlining the new Conservation First Framework (the “New Framework”) for the period 2015 to 2020, requiring distributors to submit their Conservation & Demand Management (CDM) plans by May 2015. The new directive effectively changed the metrics against which distributors reported their CDM performance. The OEB modified the scorecard accordingly, removing the previously reported metrics.

Prior to the issuance of the new framework, Hydro One’s approved CDM Plan outlined annual milestones in order to reach a target of 1,159.02 GWh net energy savings by December 31, 2020, including a first year 2015 target of 180.8 GWh. In 2015, Hydro One, excluding Norfolk Power, achieved energy savings of 200.16 GWh, 17.27 per cent of its total 2020 energy savings goal, exceeding the overall industry average of 14.08 per cent (see Figure 16).

In December 2016, Hydro One submitted a revised CDM plan up to and including the year 2020, to the Independent Electricity System Operator (“IESO”), which increased the Company’s distributor target to 1,221 GWh, reflecting the recent acquisitions of Norfolk Power Distribution Inc., Haldimand County Hydro Inc., and Woodstock Hydro Services Inc. Additional changes to the distributor target will be made as required by the IESO or as necessary stemming from future mergers, acquisitions, amalgamations, or divestitures or addition of new CDM programs.

Hydro One will continue its efforts to meet the planned distributor targets through monthly monitoring and reporting efforts, performing transactional customer surveys, and regular monitoring and performance tracking of its CDM support vendors. The Company has planned for investments to implement a Dynamic Pricing Pilot which is a program offered by the Government to encourage energy conservation. Hydro One intends to seek the OEB's approval to implement the new rate design for Commercial and Industrial customers. The Company expects this initiative will encourage energy conservation efforts among its Commercial and Industrial customers.

The Company's efforts and planned investments are expected to encourage energy conservation, allowing the Company to achieve 100 per cent of its revised CDM plan.

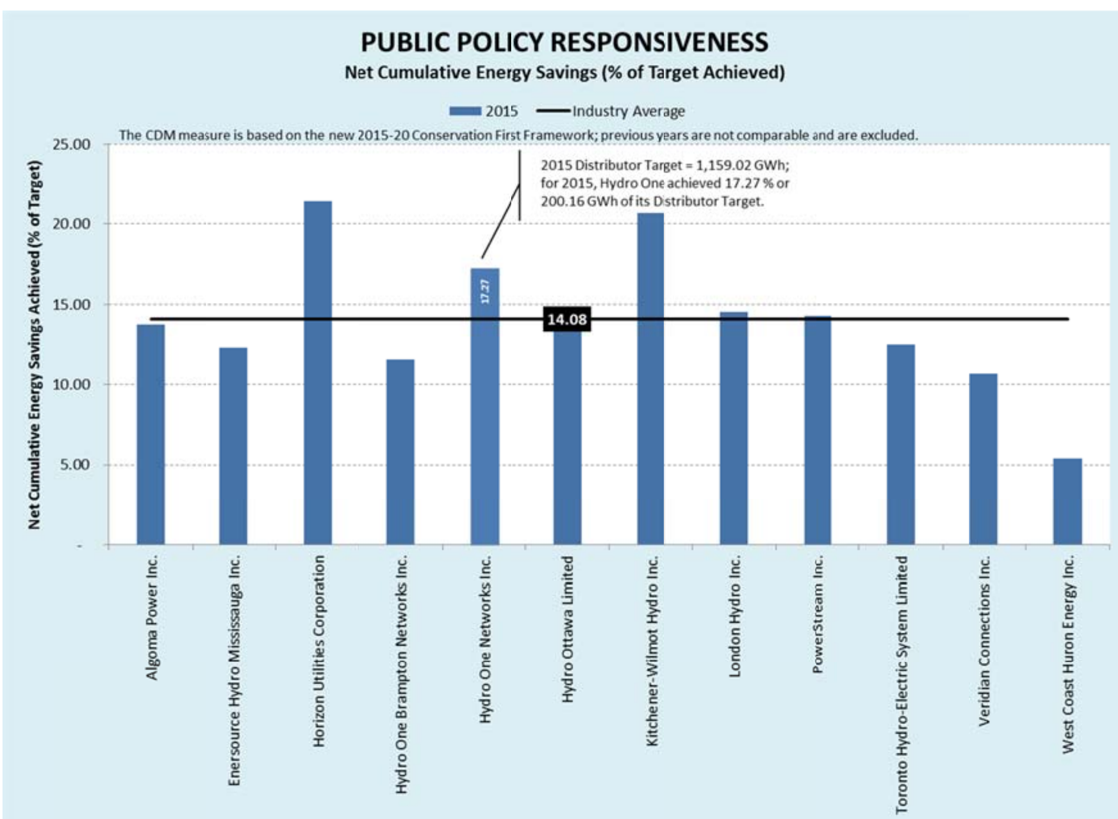


Figure 16 – Net Cumulative Energy Savings (% of Target Achieved)

5.2 CONNECTION OF RENEWABLE GENERATION: RENEWABLE GENERATION CONNECTION IMPACT ASSESSMENTS COMPLETED ON TIME

For 2015, and for the third consecutive year, the Company completed 100 per cent of the Connection Impact Assessments (CIAs) received, on time (within 60 days from the date the CIA is received), exceeding the current industry average of 95.41 per cent, and representing a historical average performance of 99 per cent (see Figure 17).

The Company's performance over the 2011 to 2015 period was mainly attributable to process improvements and due diligence oversight.

Over the term of the Application, Hydro One plans to maintain the internal target at 99 per cent. The decision to maintain performance over the application period at its historical average is due to various factors such as a significant influx of Feed-In-Tariff ("FIT") 4.0 applications received since December 2016; the expected release of FIT 5.0 in the third quarter of 2017; expected increases in the number of net metering customers; and uncertainty due to changes to the FIT program over the term of the Application. Hydro One expects to meet its internal target through further process optimization and workflow automation, including regular monitoring of CIA application volumes and performance against the internal target.

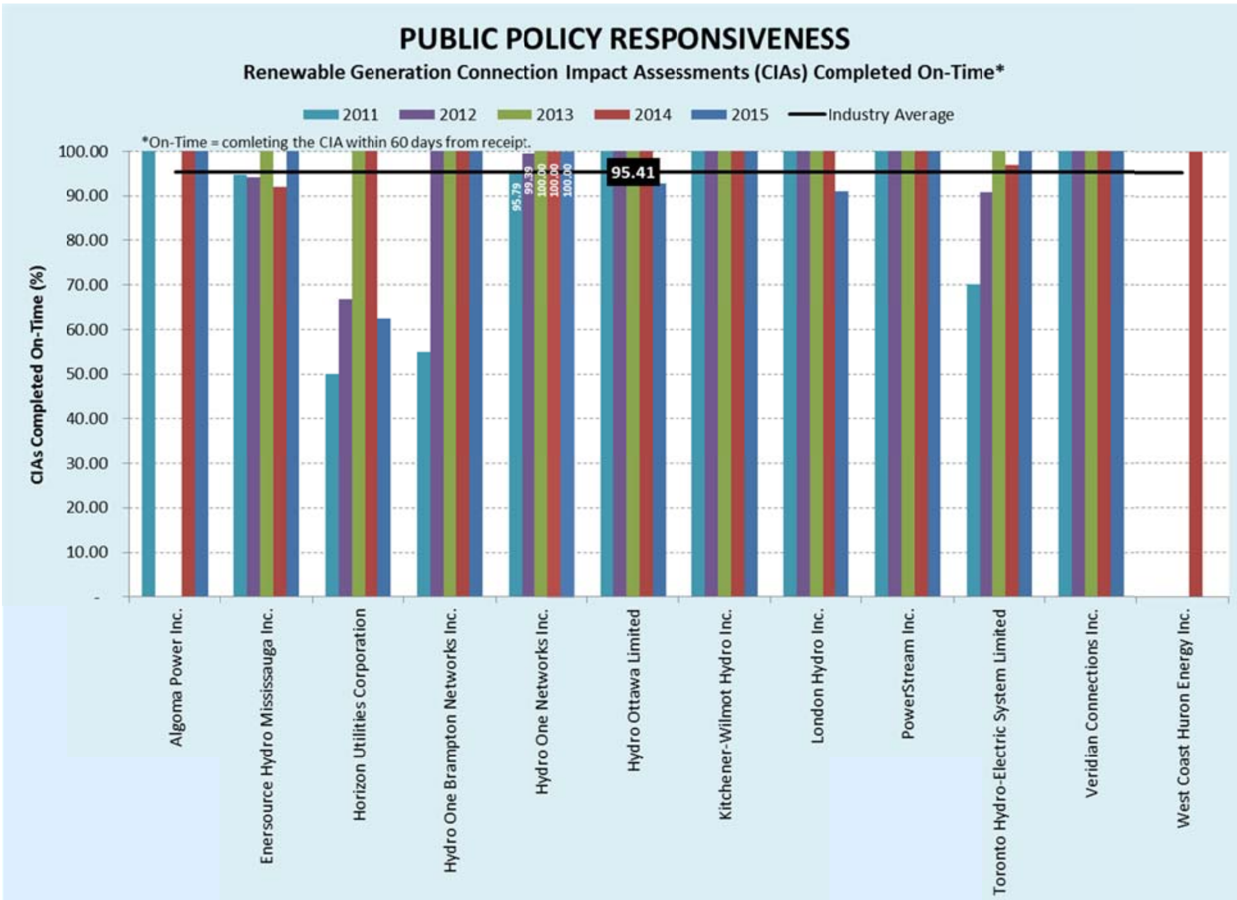


Figure 17 -- Renewable Generation Connection Impact Assessments Completed On-Time

5.3 CONNECTION OF RENEWABLE GENERATION: NEW MICRO-EMBEDDED GENERATION FACILITIES CONNECTED ON-TIME

For the third consecutive year, the Company exceeded the industry target achieving a 99.78 per cent on-time rate for connecting new micro-embedded generation facilities, exceeding the current industry average of 98.29 per cent, and representing a historical average performance of 99.83 per cent (see Figure 18).

The Company's performance over the 2011 to 2015 period was mainly attributable to process improvements and due-diligence oversight.

Over the term of the Application, the Company plans to maintain the internal target at 99 per cent. The Company expects that its ability to maintain its current historical performance of 99.83 per cent may be moderately affected by an expected increase in net metering applications; the challenges presented with customers connecting MicroFIT and net metering generation on the same premises; and the expected introduction of Federal and Provincial programs such as microGrid and Net Zero which will require the definition of standard processes. Hydro One expects to meet its internal target through similar process optimization and workflow automation, as discussed in Section 5.2, and through improved work notifications and an overhaul of working instructions, better education, and improved communication of expectations to the field staff.

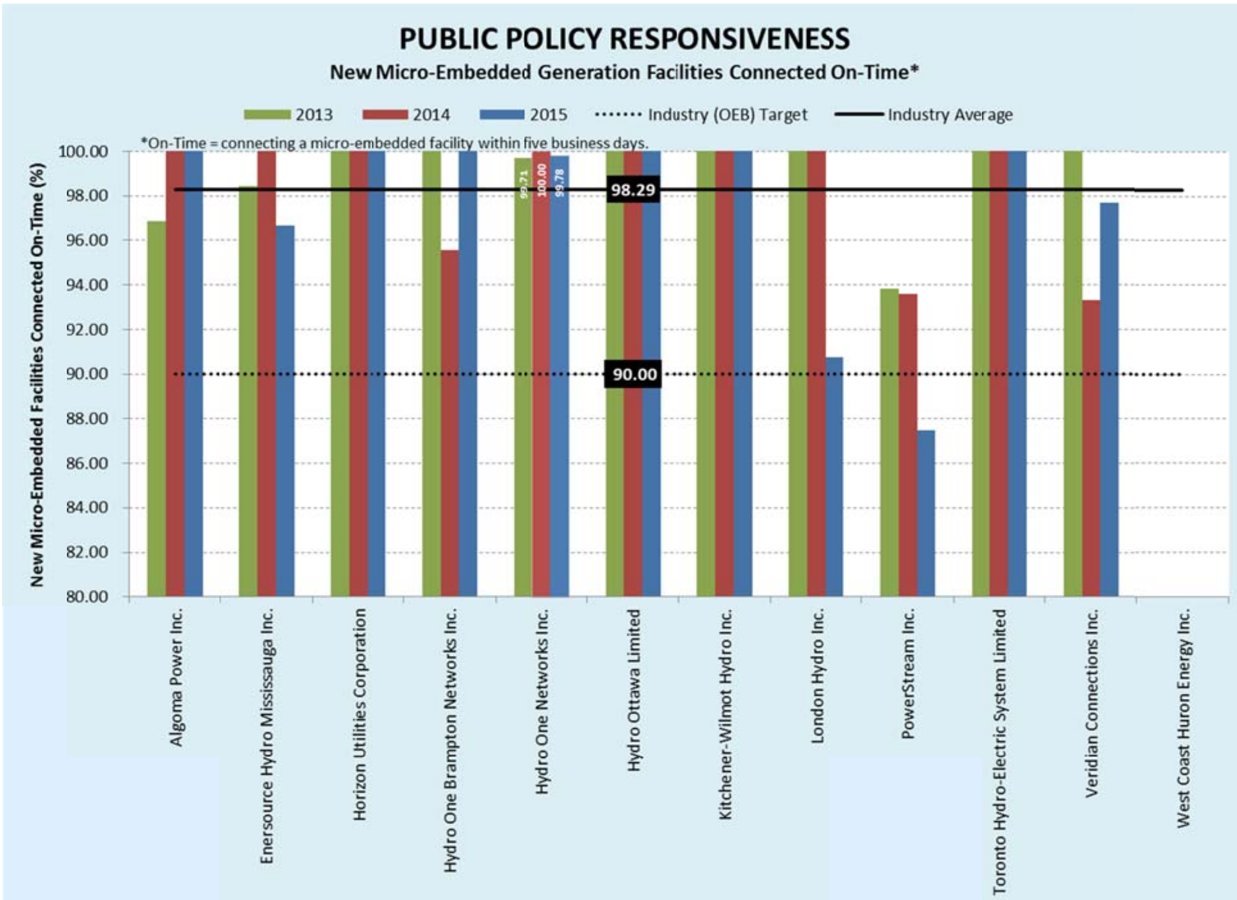


Figure 18 -- New Micro-Embedded Generation Facilities Connected On-Time

6. FINANCIAL PERFORMANCE

6.1 FINANCIAL RATIOS: LIQUIDITY – CURRENT RATIO

For 2015, the current ratio was reported as 0.97 or about 2 per cent lower than in 2014 and historically the current ratio has been relatively flat, averaging 0.99 over the past five years. The 2015 result indicates that for every one dollar of current liabilities, the Company had $0.97 in current assets (Figure 19). The five-year average current ratio for the Company was 0.99 as reported to the OEB. The Company measures current ratio as the ratio of its current assets to its current liabilities. Current assets are defined as cash or other assets to be converted to cash within the year and which can be used to fund daily operations and pay ongoing expenses. Current liabilities are defined as debt or financial obligations that become due within the year.

Due to the forward-looking nature of this metric, the Company has not provided a forecast outlining future financial performance expectations.

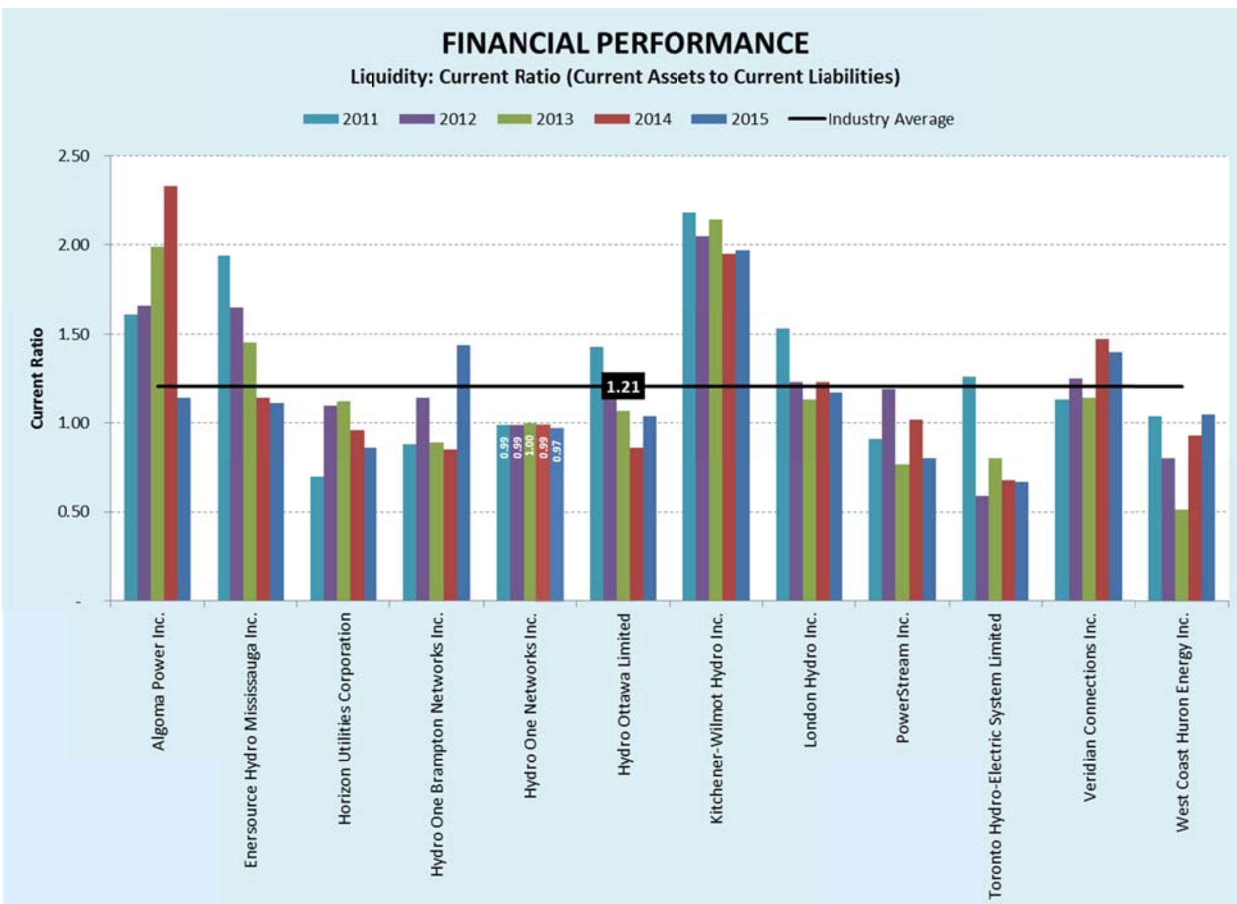


Figure 19 – Current Ratio

6.2 FINANCIAL RATIOS: LEVERAGE – TOTAL DEBT TO EQUITY

The debt-to-equity ratio is a measure of the Company's financial leverage and serves to identify the ability to finance assets and fulfill obligations to creditors. The OEB-deemed capital structure is 60 per cent to 40 per cent debt-to-equity structure (a ratio of 1.5). For 2015, the Company's debt-to-equity ratio was 1.19, and historically has averaged 1.30, as shown in Figure 20.

The average debt-to-equity ratio of 1.30 has averaged less than the deemed structure of 1.50 largely due to a low dividend payout for the business, as directed by its prior sole shareholder, the Province of Ontario. After the Company's IPO in 2015, the Company's debt to equity ratio was adjusted to conform more closely to the OEB-deemed capital structure, and company management have stated publicly that it intends to maintain this ratio at or around that level.

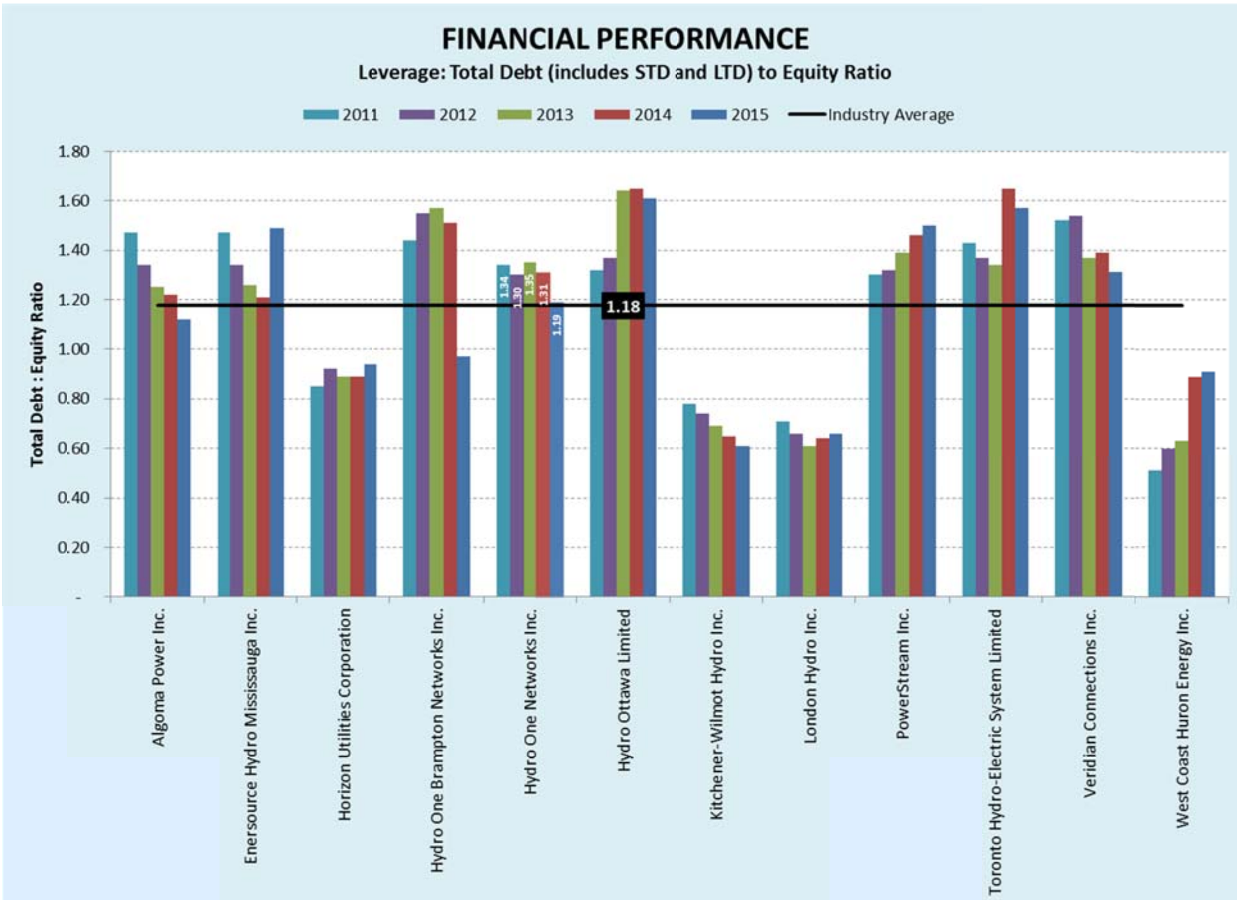


Figure 20 – Total Debt to Equity

6.3 FINANCIAL RATIOS: PROFITABILITY – ACHIEVED REGULATORY RETURN ON EQUITY

For the year 2015, the Company achieved a regulatory return on equity of 8.77 per cent for its Distribution business, compared to the deemed and industry average ROE of 9.30 per cent, as per Figure 21. This represents an increase of 2.51 percentage points compared to 2014, although still lower than the deemed ROE. In 2014, earnings were reduced by an increase in expenses related to customer service, reflecting the Company's efforts to address billing and other customer service issues. With these issues improving during 2015, the ROE showed an improvement compared to 2014. Historically, the Company has achieved an average regulatory ROE of 8.11 per cent.

For 2011, the regulatory ROE of 8.80 per cent was above the average, however was still below allowed ROE of 9.66 per cent as a result of higher OM&A and depreciation expense relative to OEB approved levels. In 2012, achieved regulatory ROE was 8.72 per cent, largely a result of electing to retain the same distribution rates for 2012 as approved by the OEB for 2011. For 2013, the achieved regulatory ROE of 8.01 per cent was the result of increased OM&A and depreciation expense.

Due to the forward-looking nature of this metric, the Company has not provided a forecast outlining future financial performance expectations.

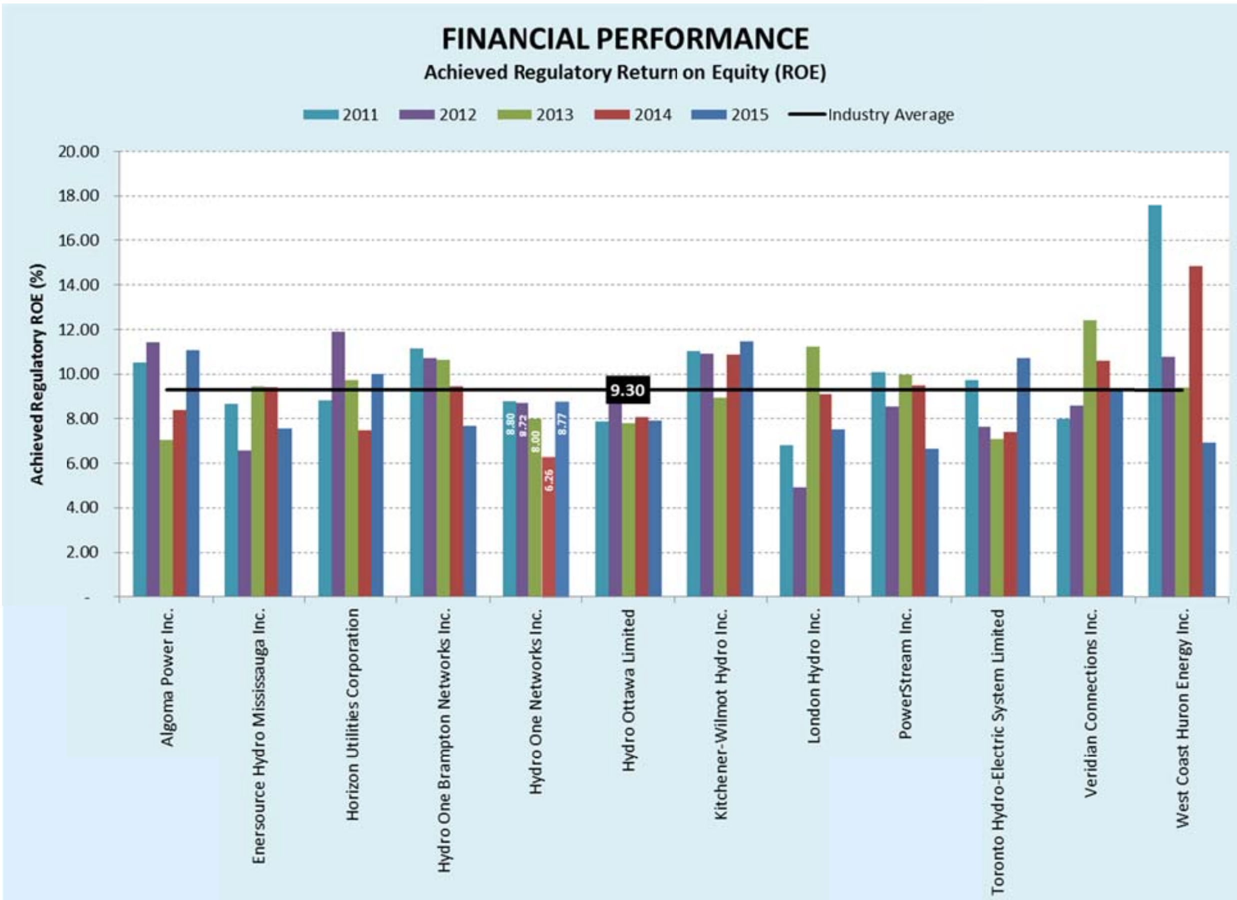


Figure 21 – Achieved Regulatory Return on Equity

TOTAL COST BENCHMARKING FORECAST

1. INTRODUCTION

As part of Section 2.1.7 of the filing requirements, applicants must provide a forecast of its efficiency assessment using the Pacific Economics Group Research, LLC (“PEG”) forecasting model for the test year for the purposes of providing the OEB with a directional indicator of efficiency. Use of this model for a 2018 test year requires the input of 2016 financial information in a format consistent with the Uniform System of Accounts. Hydro One will complete the PEG forecasting model and provide appropriate analysis of the results when this information is available. Hydro One will file the results as part of a Blue Page update planned for early June, 2017.

As discussed in Exhibit A, Tab 5, Schedule 1, Hydro One was ranked in Group 5 for cost efficiency in 2015, as described in the PEG Report to the OEB entitled ‘Empirical Research in Support of Incentive Rate-Setting: 2015 Benchmarking Update (July 2016)’. This is the result of having costs in excess of predicted costs by 25% or more. Hydro One is committed to increasing productivity and efficiency company-wide as it strives to be a best-in-class, customer-centric, commercial entity. Developing a culture of continuous improvement is pivotal to producing a business plan and application that align customer needs and preferences, the condition and compliance needs of its assets, and rate impacts. The steps taken by Hydro One to improve productivity and efficiency are outlined in the Distribution System Plan in Section 1.5

SERVICE QUALITY PERFORMANCE

1. INTRODUCTION

Hydro One Distribution monitors and reports service quality indicators as required by the OEB's Reporting and Record-keeping Requirements ("RRR"). The Electricity Service Quality Requirements ("ESQRs") to be included in this Application are set out in Chapter 7 of the Distribution System Code ("DSC"). Hydro One tracks and internally reports results on 10 customer service quality indicators on a monthly basis. Reports are provided to the OEB annually in accordance with the Distribution System Code ("DSC") amendments, issued in March and June 2008.

Hydro One's customer service results and targets are reported for the past five historical years, 2012 to 2016, as required by the Board in Section 2.2.2.8 of Chapter 2 of the Filing Requirements for Electricity Distribution Rate Applications, dated July 14, 2016. Over the historical period, Hydro One Distribution met all of the OEB customer service indicator targets except Telephone Accessibility in 2013, Emergency Rural Response in 2013 and 2015, and Rescheduling a Missed Appointment from 2012 to 2015. Final results for 2016 are not yet available and will be provided in the Blue Page Update. Details regarding Hydro One's past reliability performance are available in section 1.4.2.1 of the Distribution System Plan (Exhibit B1, Tab 1, Schedule 1).

2. CUSTOMER SERVICE INDICATORS

Hydro One consistently tracks, analyzes and reports 10 customer service indicators on a monthly basis as part of its internal performance reporting process. This process identifies areas of concern so that Hydro One's performance can be immediately addressed and brought back in line with OEB requirements.

In an effort to develop a culture of continuous improvement, analysis of monthly and annual result trends provides valuable information for corporate planning, program planning and management of resources for services.

2.1 DEFINITIONS

The ten customer service indicators are defined below:

2.1.1. APPOINTMENTS

2.1.1.1 APPOINTMENT SCHEDULING

The percentage of appointment scheduling requests that are made within five business days of the day on which all applicable service conditions are satisfied or at a later date agreed upon by the customer and Hydro One. This applies regardless of whether the customer or customer representative's presence is required.

In instances where customer or customer representative presence is required, Hydro One must offer to schedule the appointment during Hydro One's regular hours of operation within a window of time no greater than four hours, and must attend the meeting at the appropriate time. This does not apply to appointments that are subject to the requirements in the section on Connection of New Services.

2.1.1.2 APPOINTMENTS MET

The percentage of appointments at a customer's premises or work site met at the appointed time of the customer's choosing (defined as morning or afternoon of a particular date). This indicator includes appointments for disconnects and/or reconnects for maintenance or upgrades, connecting new services, underground cable locates, inspections, meter reading and instructions on prepaid meters. The appointment may be considered to be met even when the customer failed to attend.

2.1.1.3 RESCHEDULING A MISSED APPOINTMENT

In instances when appointments need to be rescheduled, this indicator measures the percentage of instances in which Hydro One has made: (i) an attempt to inform the customer before the scheduled appointment that the appointment is going to be missed; and (ii) made and an attempt to reschedule the appointment one business day following the initial appointment. This does not apply if the appointment is missed due to the failure of customer or customer representative to attend.

Section 7.5 of the DSC requires that, where an appointment is missed or is going to be missed, distributors must attempt to contact the customer: (a) before the scheduled appointment to inform the customer that the appointment will be missed; and (b) within one business day to reschedule the appointment.

2.1.2. CONNECTION OF NEW SERVICES

2.1.2.1 LOW VOLTAGE CONNECTIONS

The percentage of requests for connection of a new low voltage service (<750 volts) that are completed within five business days from the day on which all applicable service conditions are satisfied, or at a later date agreed upon by the customer and Hydro One.

2.1.2.2 HIGH VOLTAGE CONNECTIONS

The percentage of requests for connection of a new high voltage service (>=750 volts) that are completed within 10 business days from the day on which all applicable service conditions are satisfied, or at a later date agreed upon by the customer and Hydro One. Hydro One does not separately report on this measure due to the complexity of gathering the data. The >=750 volts connections are included with the <750 volts connections which is a more stringent measure. All connections that are not met within five days are analysed to confirm that no connections >=750 volts failed.

2.1.3. EMERGENCY RESPONSE

The percentage of responses to emergency trouble calls (including fire, ambulance, police) met within 120 minutes for rural utilities. Due to the predominantly rural nature of its distribution system, Hydro One Distribution is required to meet the 120 minutes response time. The elapsed time is measured from the call to the arrival of Hydro One qualified service personnel on site.

2.1.4. TELEPHONE

2.1.4.1 TELEPHONE ACCESSIBILITY

The percentage of incoming calls answered within 30 seconds by the customer care center. Time begins at the moment the customer chooses to speak to a customer service representative (using the interactive voice recognition system) or from first ring in all other cases.

2.1.4.2 TELEPHONE CALL ABANDON RATE

The percentage of incoming calls abandoned before being answered following the 30 second period outlined in 2.1.4.1 Telephone Accessibility.

2.1.5. WRITTEN RESPONSE TO ENQUIRIES

This indicator measures the percentage of responses to requests by a customer for written information relating to their accounts made within the performance standard of 10 working days following receipt of the request or, if applicable, 10 working days from the date on which any conditions associated with their enquiry have been satisfied. The written response is deemed to be sent on the date it is faxed, mailed or e-mailed by Hydro One, and when it includes a written acknowledgement of receipt of the qualified enquiry and a specific date in which a complete response will be provided.

2.1.6. RECONNECTION PERFORMANCE STANDARD

The percentage of reconnections of a disconnected customer for non-payment that are completed within two business days after the customer has made full overdue payment or entered into an arrears payment agreement with Hydro One.

3. RESULTS

The performance results of the 10 Customer Service Performance Indicators from 2012 through 2016 are shown in Table 1. The required targets for each measure, as specified by the DSC, are also shown. Hydro One Distribution has met all of these indicators with the exception of Telephone Accessibility in 2013, Emergency Rural Response in 2013 and 2015, and Rescheduling a Missed Appointment in all years. Further details are provided in Table 1.

Table 1: Customer Service Indicators

Indicator	OEB Minimum Standard	2012	2013	2014	2015	2016
Low Voltage Connections	90.00%	95.50%	97.54%	97.40%	97.50%	TBD
High Voltage Connections*	90.00%	96.30%	100.00%	100.00%	n/a	n/a
Telephone Accessibility	65.00%	83.40%	63.90%	69.60%	76.40%	TBD
Appointments Met	90.00%	99.00%	98.40%	99.02%	98.50%	TBD
Written Response to Enquires	80.00%	99.80%	99.30%	100.00%	100.00%	TBD
Emergency Rural Response**	80.00%	81.40%	61.16%	81.10%	76.30%	TBD
Telephone Call Abandon Rate***	10.00%	1.30%	5.60%	4.70%	2.10%	TBD
Appointment Scheduling	90.00%	98.50%	98.70%	99.00%	98.50%	TBD
Rescheduling a Missed Appointment	100.00%	97.60%	87.10%	91.10%	96.20%	TBD
Reconnection Performance Standard	85.00%	97.60%	97.77%	95.70%	98.10%	TBD

Note 1 – 2016 data will be provided in the Blue Page Update.
Note 2 – Discrepancies between the data in this table and Hydro One's OEB Electricity Distributor Performance Scorecard, detailed in Exhibit A, Tab 5, Schedule 1 have been noted in that exhibit. Hydro One will be filing a separate letter to the OEB to correct its historical RRR data. The information presented in this Table reflects the corrected data.
*High Voltage Connections results are included with Low Voltage results.
**Emergency Response results include the impact of Force Majeure events.
***Telephone Call Abandon Rate OEB Minimum Standard of 10.0% should be interpreted as no more than 10.0% of calls.

3.1.1. TELEPHONE ACCESSIBILITY IN 2013

Over the past five years, Hydro One has exceeded the industry target of 65%, each year except 2013, when the Company introduced a new Customer Information System ("CIS") in May. Billing issues encountered due to the implementation of CIS in May along with a significant storm in December impacted Hydro One's ability to meet the industry target in 2013. The two issues caused Hydro One to experience an average increase in call volumes of about 40,700 calls monthly (from May to December) compared to the same period in the previous year. The CIS-related billing issues also prompted the Company to cease all collection activity, which resumed in 2014. Also in 2014, Hydro One engaged in a customer service recovery project to offset the impacts of the CIS-related billing issues. Although the Company's performance improved and exceeded the industry target in 2014, the drop in performance experienced in 2013 reversed the overall trend which remains negative as of 2015.

3.1.2. EMERGENCY RURAL RESPONSE IN 2013 AND 2015

In 2015, Ontario experienced unusually large storm events that caused significant outages to Hydro One customers during the months of August, November and December. This corresponds with the months where Hydro One did not meet Emergency Rural Response measures (51% in August, 59% in November, and 51% in December). These three months brought the overall year end percentage down to 76.3%. Similarly, in 2013, there were seven significant storm events that caused significant outages to Hydro One customers during the months of April, May, July, November and December. These events correspond with four months in which Hydro One did not meet its performance targets for the Emergency Rural Response (39.3% in April, 40.1% in July, 55.4% in November and 41.2% in December). These months brought the overall year end percentage down to 61.2% for 2013. The performance shown in 2013 and 2015 was the result of severe stroms and is not representative of the ability Hydro One regularly demonstrates to respond to emergency trouble calls in 120 minutes, at least 80% of the time. The details of the storm events are described in Exhibit B1, Tab 1, Schedule 1, Section 1.4.2.1.

3.1.3. RESCHEDULING A MISSED APPOINTMENT IN 2012-2015

In 2013, the Company's capability to quickly make and reschedule appointments was compromised with the newly installed Customer Information System. The administrative errors that have resulted in ongoing rescheduling failures happened when staff unintentionally deviated from proper rescheduling practices. Since implementation of compliance improvement initiatives, performance has significantly improved. However, clerical errors in scheduling and rescheduling of appointments continued, which compromised the success of meeting the required time frame and the OEB minimum standard of 100%.

In Hydro One's last Custom IR distribution rate application, Hydro One requested a permanent exemption to the 100% rescheduling measure. In its decision in the EB-2013-0416/EB-2014-0247 proceeding, the OEB found that Hydro had failed to demonstrate that a permanent exemption should be granted and denied Hydro One's request. Hydro One then filed a compliance plan with the OEB that included proposals for more accurate monitoring and reporting, and increased management attention to the issue. The compliance plan is provided as Attachment 1 to this Exhibit.

In accordance with the compliance plan, staff and supervisors in lower-performing Zones receive coaching to understand impacts and prevent future rescheduling failures. In addition, more recent improvement efforts include updated and more detailed process instruction on rescheduling practices and requirements for staff to report regularly on failures. Performance in 2015 improved quarterly from Q1 at 94% to Q4 at 96%. Significant improvement has been made with performance increasing from 87.1% in 2013 to 96.2% in 2015.

BY E-MAIL

May 6, 2015

Mr. Karim Karsan
Vice President, Consumer Services and Chief Compliance Officer
Ontario Energy Board
Suite 2700, 2300 Yonge Street
P.O. Box 2319
Toronto, ON
M4P 1E4

Dear Mr. Karsan,

Re: Hydro One's Compliance Plan -- Distribution System Code Section 7.5.2

In response to your April 24, 2015 letter respecting Hydro One's self-reported non-compliance with the above section of the Distribution System Code, please find attached Hydro One's Compliance Plan, as requested.

Sincerely,

ORIGINAL SIGNED BY ODED HUBERT

Oded Hubert

Attach.

HYDRO ONE'S COMPLIANCE PLAN RESPECTING THE DISTRIBUTION SYSTEM CODE, SECTIONS 7.5.1 AND 7.5.2

BACKGROUND

Hydro One Networks Inc. ("Hydro One") had requested an exemption from the Distribution System Code ("DSC") sections 7.5.1 and 7.5.2 which oblige a distributor to attempt to notify a customer before missing an appointment and to attempt to re-schedule a missed appointment within one business day, 100% of the time on a yearly basis. This request was made as part of Hydro One's 2015-2019 Distribution Custom Rates Application (EB-2013-0416, Exhibit A, Tab 18, Schedule 1, Appendix A, submitted May 30, 2014).

In its Decision issued on March 12, 2015, the Board denied the request, finding that Hydro One's evidence was not sufficient. While acknowledging that Hydro One's jurisdiction included areas lacking full cell coverage, the Board noted that the information provided did not identify these instances, nor any avenues to minimize non-compliant occurrences. The Board emphasized the need for more rigorous communications protocols and employee training to reinforce the implementation of customer communications and reduce the incidence of non-compliance not related to communications infrastructure.

HYDRO ONE'S COMPLIANCE PLAN

PURPOSE

Consistent with the Board's Decision, the purpose of this plan is to outline Hydro One's actions to reduce the incidence of non-compliance in cases where it is practical to do so, and to institute the necessary tracking and reporting, including identification of those instances where compliance is not achievable. It is Hydro One's intent, in this compliance plan, to (i) improve compliance, (ii) continue to foster a culture which demonstrates consideration for the customer's time, and (iii) implement improvements in communication based on a better understanding of the occasions when insufficient cell coverage is not the issue. Hence, a major aspect of this plan is more precise reporting of non-compliance issues, enabling better decision-making, coaching of staff and customer communications. Hydro One expects a correspondingly significant reduction, if not complete elimination, of instances of non-compliance.

INITIATIVES ALREADY IMPLEMENTED

As discussed on page 3 of Hydro One's exemption application, today, if a Hydro One field employee knows that he or she will be unable to keep an appointment, the process is to contact the appropriate field office so that office staff can call the customer, inform the customer that Hydro One is unable to keep the appointment and re-schedule to another date and time. On some occasions, such as during a storm, the field office, knowing that resources will be re-prioritized to restoration efforts, will proactively contact customers to re-schedule planned work with them at a later date.

Hydro One also has implemented a weekly report which tracks each zone's performance on this measure. Since January of this year, these reports have been compiled into a new Monthly Management Report, which is a standing item for review during the monthly meetings of the Provincial Lines management team – more specifically, the Director, all Provincial Lines Superintendents, Zone Business Managers and Field Managers.

However, Hydro One is cognizant that further attention to this issue is needed and accordingly, is undertaking the initiatives stated in the table below.

COMPLIANCE IMPROVEMENT INITIATIVES UNDERWAY

	Initiative	Timing
A.	**More Accurate Monitoring and Reporting**	
	a. The weekly compliance reports currently track the instances when an attempt to notify a customer of a missed appointment or to re-schedule a missed appointment has not been made, but do not provide additional explanatory information for these non-compliance instances. Therefore, the weekly reports are being refined along the following lines: • Attempts to <u>Notify a Customer of a Missed Appointment</u>: - Incidents when *inadequate cell coverage* prevented advance customer notification of a missed appointment will be separately identified. - When inadequate cell coverage was not the reason for any non-compliant incidents, reasons and employee-suggested measures to prevent recurrence will be reported. • Attempts to <u>Re-Schedule a Missed Appointment:</u> - Incidents when a field office's focus on emergency situations (e.g., outage restoration during extreme weather conditions) resulted in missed attempts to re-schedule an appointment within the required time will be separately identified. - For incidents when emergency situations are not the cause of a missed appointment re-scheduling attempt, reasons for the non-compliance and any employee-suggested measures to address these will be reported.	Beginning in May 2015
B.	**Increased Management Attention, Development of Improved Communication and Employee Awareness**	
	a. With an improved understanding of their zones' specific issues, the Zone Business Managers will develop instructions to assist their staff in managing their compliance accountabilities. Such instructions will incorporate employees' suggested measures and other recommendations to improve compliance. They will emphasize staff's	Beginning May through June, 2015

	responsibility to maintain timely customer communication in balance with other responsibilities (e.g., managing one's own health and safety during a travel emergency, provision of road-side assistance when needed, co-ordination or participation in outage restoration in extreme weather events) and the need for best efforts to reach 100% compliance. These instructions, once developed, will be reviewed with zone staff.	
	b. Zones with reported levels of compliance below 97% will be highlighted for further review by the Director of Quality Assurance and Operations Support and the Director of Provincial Lines, to review the specific reasons and determine any additional remediation measures which may be needed.	Beginning in June and on-going as needed
	c. Staff of the lower-performing zones will review the compliance reports and receive additional coaching to ensure that all fully understand: • their specific compliance accountabilities directly applicable to service appointments and • the applicable instructions for customer communication in non-routine situations.	Beginning in June, per zone, on-going as needed
	d. The compliance reports will also be discussed with Customer Support Supervisors to ensure that the staff accountable for scheduling customer appointments are aware of the need for accuracy and timeliness in both scheduling and reporting.	Beginning in June, ongoing as needed
	e. To reinforce the importance of appropriate and timely customer communications and appointment re-scheduling, Hydro One will include a bulletin highlighting this issue in the monthly communications package to Provincial Lines employees.	To be included in the June communication package

MILESTONES

Hydro One believes that these initiatives will promote a culture that enables all employees to consciously manage their accountabilities for customer appointments in better balance with those for managing other non-routine or emergency events. While emphasizing best efforts to attain 100% compliance, Hydro One expects progressive improvement in meeting the Distribution System Code Section 7.5.1 requirements according to the milestones provided below:

1.	93% of the time	End of Q2
2.	96% of the time	End of Q3
3.	99% - 100%[1] of the time	End of Q4

[1] Hydro One takes this issue seriously and is making efforts to achieve 100% compliance. Where unavoidable circumstances may cause a situation when even an attempt at customer communication cannot be made, these will be reported.

ACCOUNTING INFORMATION

1. ACCOUNTING STANDARD

On November 23, 2011, the Board issued its Decision with Reasons in EB-2011-0268, granting Hydro One's request to use United States Generally Accepted Accounting Principles for regulatory purposes in its distribution business. Based on this decision, Hydro One adopted this accounting standard for regulatory purposes.

Hydro One confirms that its accounting treatment segregates any non-utility business it conducts from its rate-regulated activities.

2. CHANGES TO ACCOUNTING POLICIES

In keeping with good corporate governance, Hydro One reviews and, if appropriate, revises its policies and procedures from time to time. No financial accounting policy changes have been made that impact the 2018-2022 rate base or revenue requirement since the Board's review of Hydro One's distribution revenue requirements and rates for 2015, 2016 and 2017 (EB-2013-0416) other than as specified in this section.

On November 5, 2015, Hydro One adopted "Accounting Standards Codification 718 – Compensation – Stock Compensation" to address the accounting of stock-based compensation. Adoption of this accounting policy has no impact on revenue requirement.

According to this policy, Hydro One measures share grant plans based on the fair value of the grants, which is determined by the share price on the grant date. The costs are recognized in the financial statements using the graded-vesting attribution method for share grant plans that have both a performance condition and a service condition. Hydro One records a regulatory asset equal to the accrued costs of share grant plans recognized in each period, as management considers it probable that such costs will be recovered in rates in the future.

Hydro One also records the liabilities associated with its Directors' Deferred Share Unit Plan at fair value on each reporting date until settlement, recognizing the compensation expense over the vesting period on a straight-line basis. The fair value of this expense is based on the common share closing price at the end of each reporting period.

Additionally, Hydro One Limited's Board of Directors approved awards under the Long-Term Incentive Plan ("LTIP") on March 31, 2016. Presently composed of Performance Stock Units ("PSU") and Restricted Stock Units ("RSU"), the LTIP awards are equity-settled awards recorded using the fair value method. Using this method, the compensation expense is measured at the fair value of the PSU and RSU granted on the grant date, and it is recognized on a straight-line basis over the vesting period. The PSUs and RSUs vest upon the completion of a three-year term. The value of the PSUs depends on the company's performance against performance targets set out under the LTIP, which could impact compensation expense and would only be known at the end of the three-year vesting term.

3. ACCOUNTING ORDERS

There are two existing accounting orders applicable to Hydro One Distribution, which created deferral accounts described in Exhibit F1, Tab 1, Schedule 1.

3.1 POLE ATTACHMENT CHARGE - TELECOMMUNICATIONS (EB-2015-0141)

In its decision of August 4, 2016, (EB-2015-0141), the Board directed Hydro One to establish two deferral accounts. The first account will record the revenue difference between the interim pole attachment charge and the rate approved in the decision and the second account will record the difference between the pole attachment charge initially proposed in Hydro One’s rate application and the rate approved in the decision. On September 28, 2016 the Board approved the accounting order with respect to both accounts.

3.2 LONG-TERM LOAD TRANSFER (HYDRO ONE NETWORKS – HYDRO OTTAWA) (EB-2016-0167)

In its decision of August 18, 2016, (EB-2016-0167), the Board approved Hydro One’s request for a deferral account to record lost revenue resulting from the rate impact mitigation plan as well as any costs involved in the set-up of such a plan. On November 24, 2016, the Board approved the accounting order with respect to this account.

HYDRO ONE DISTRIBUTION FINANCIAL STATEMENTS - HISTORICAL YEARS 2014- 2016

Included in this exhibit are the Historic Distribution Financial Statements as follows:

- Attachment 1: 2014 Audited Distribution Financial Statements
- Attachment 2: 2015 Audited Distribution Financial Statements
- Attachment 3: 2016 Audited Distribution Financial Statements – To be filed behind this Tab when it becomes available.

HYDRO ONE NETWORKS INC.

DISTRIBUTION BUSINESS

FINANCIAL STATEMENTS

DECEMBER 31, 2014

HYDRO ONE NETWORKS INC.
DISTRIBUTION BUSINESS
INDEPENDENT AUDITORS' REPORT

To the Directors of Hydro One Networks Inc.

We have audited the accompanying carve-out financial statements of the Distribution Business (a business of Hydro One Networks Inc.), which comprise the carve-out balance sheet as at December 31, 2014, the carve-out statements of operations and comprehensive income, and cash flows for the year then ended, and notes, comprising a summary of significant accounting policies and other explanatory information. The carve-out financial statements have been prepared by management in accordance with the basis of accounting in Note 2 to the carve-out financial statements.

Management's Responsibility for the Carve-out Financial Statements

Management of Hydro One Networks Inc. is responsible for the preparation of these carve-out financial statements in accordance with the basis of accounting in Note 2 to the carve-out financial statements; this includes determining that the basis of accounting is an acceptable basis for the preparation of these carve-out financial statements in the circumstances, and for such internal control as management determines is necessary to enable the preparation of carve-out 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 carve-out financial statements based on our audit. We conducted our audit 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 carve-out financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the carve-out financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the carve-out financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity's preparation of the carve-out 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 carve-out financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the carve-out financial statements as at and for the year ended December 31, 2014 are prepared, in all material respects, in accordance with the basis of accounting in Note 2 to the carve-out financial statements.

Basis of Accounting and Restriction of Use

Without modifying our opinion, we draw attention to Note 2 to the carve-out financial statements, which describes the basis of preparation used in these carve-out financial statements. In particular, in preparing the carve-out financial statements, long-term debt, shared functions and service costs, and payments in lieu of corporate income taxes have been allocated to the Distribution Business (a business of Hydro One Networks Inc.) using the method of allocation described in Note 2 to the carve-out financial statements. As a result, the carve-out financial statements may not necessarily be identical to the balance sheet, results of operations and cash flows that would have resulted had the Distribution Business (a business of Hydro One Networks Inc.) historically operated on a stand-alone basis. The carve-out financial statements are prepared to assist Hydro One Networks Inc. to comply with its reporting requirements of the Ontario Energy Board. As a result, the carve-out financial statements may not be suitable for another purpose.

Our report is intended solely for the Directors of Hydro One Networks Inc. and the Ontario Energy Board and should not be used by parties other than Hydro One Networks Inc. or the Ontario Energy Board.

KPMG LLP

Chartered Professional Accountants, Licensed Public Accountants
Toronto, Canada
March 24, 2015

HYDRO ONE NETWORKS INC.
DISTRIBUTION BUSINESS
STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME
For the years ended December 31, 2014 and 2013

Year ended December 31 (millions of Canadian dollars)	**2014**	**2013**
Revenues		
Energy sales	4,176	3,806
Rural rate protection *(Note 18)*	126	125
Other	38	40
	4,340	3,971
Costs		
Purchased power *(Note 18)*	2,979	2,620
Operation, maintenance and administration *(Note 18)*	675	611
Depreciation and amortization *(Note 4)*	347	321
	4,001	3,552
Income before financing charges and provision for payments in lieu of corporate income taxes	339	419
Financing charges *(Notes 5, 18)*	147	137
Income before provision for payments in lieu of corporate income taxes	192	282
Provision for payments in lieu of corporate income taxes *(Notes 6, 18)*	3	24
Net income	189	258
Other comprehensive income	–	–
Comprehensive income	189	258

See accompanying notes to Financial Statements.

HYDRO ONE NETWORKS INC.
DISTRIBUTION BUSINESS
BALANCE SHEETS
At December 31, 2014 and 2013

December 31 (millions of Canadian dollars)	**2014**	**2013**
Assets		
Current assets:		
Inter-company demand facility *(Notes 12, 13, 18)*	–	47
Accounts receivable (net of allowance for doubtful accounts – $64; 2013 – $32) *(Notes 7,18)*	985	853
Regulatory assets *(Note 10)*	11	15
Materials and supplies	7	6
Deferred income tax assets *(Note 6)*	9	8
Derivative instruments *(Note 12)*	1	1
Other	13	11
	1,026	941
Property, plant and equipment *(Note 8)*:		
Property, plant and equipment in service	9,426	8,864
Less: accumulated depreciation	3,503	3,279
	5,923	5,585
Construction in progress	326	323
Future use land, components and spares	49	45
	6,298	5,953
Other long-term assets:		
Regulatory assets *(Note 10)*	789	705
Intangible assets (net of accumulated amortization – $179; 2013 – $145) *(Note 9)*	197	204
Goodwill	73	73
Deferred debt costs	13	13
Derivative instruments *(Note 12)*	–	2
Other	3	–
	1,075	997
Total assets	8,399	7,891

See accompanying notes to Financial Statements.

HYDRO ONE NETWORKS INC.
DISTRIBUTION BUSINESS
BALANCE SHEETS (continued)
At December 31, 2014 and 2013

December 31 (millions of Canadian dollars)	**2014**	**2013**
Liabilities		
Current liabilities:		
Inter-company demand facility	225	–
Accounts payable	65	59
Accrued liabilities *(Notes 6, 14, 15, 18)*	605	592
Accrued interest *(Note 18)*	38	38
Regulatory liabilities *(Note 10)*	8	26
Long-term debt payable within one year *(Notes 11, 12, 13, 18)*	221	176
	1,162	891
Long-term debt *(Notes 11, 12, 13, 18)*	3,161	3,140
Other long-term liabilities:		
Post-retirement and post-employment benefit liability *(Note 14)*	844	824
Deferred income tax liabilities *(Note 6)*	388	306
Environmental liabilities *(Note 15)*	124	139
Regulatory liabilities *(Note 10)*	110	110
Net unamortized debt premiums	10	11
Asset retirement obligations *(Note 16)*	4	4
Long-term accounts payable and other liabilities	1	1
	1,481	1,395
Total liabilities	5,804	5,426
Contingencies and commitments (Notes 20, 21)		
Excess of assets over liabilities *(Notes 13, 17)*	2,595	2,465
Total liabilities and excess of assets over liabilities	8,399	7,891

See accompanying notes to Financial Statements.

On behalf of the Board of Directors:

Carmine Marcello
Chair

Ali R. Suleman
Director

HYDRO ONE NETWORKS INC.
DISTRIBUTION BUSINESS
STATEMENTS OF CASH FLOWS
For the years ended December 31, 2014 and 2013

Year ended December 31 (millions of Canadian dollars)	**2014**	**2013**
Operating activities		
Net income	189	258
Environmental expenditures	(10)	(9)
Adjustments for non-cash items:		
Depreciation and amortization (excluding removal costs)	295	270
Regulatory assets and liabilities	(58)	(12)
Deferred income taxes	15	3
Other	1	2
Changes in non-cash balances related to operations *(Note 19)*	(80)	(30)
Net cash from operating activities	352	482
Financing activities		
Long-term debt issued	243	533
Long-term debt retired	(175)	(230)
Payments to Hydro One Inc. to finance dividends	(59)	(112)
Other	(1)	(2)
Net cash from financing activities	8	189
Investing activities		
Capital expenditures *(Note 19)*		
Property, plant and equipment	(614)	(563)
Intangible assets	(14)	(66)
Other	(4)	–
Net cash used in investing activities	(632)	(629)
Net change in inter-company demand facility	(272)	42
Inter-company demand facility, beginning of year	47	5
Inter-company demand facility, end of year	(225)	47

See accompanying notes to Financial Statements.

1. DESCRIPTION OF THE BUSINESS

Hydro One Inc. (Hydro One) 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.

Hydro One Networks Inc. (Hydro One Networks or the Company) was incorporated on March 4, 1999 under the *Business Corporations Act* (Ontario) and is a wholly-owned subsidiary of Hydro One. The Company owns and operates Hydro One's regulated transmission and distribution businesses. The regulated distribution business (Distribution Business) operates a low-voltage electrical distribution network that distributes electricity from the transmission system, or directly from generators, to customers within Ontario. The Distribution Business is regulated by the Ontario Energy Board (OEB).

2. SIGNIFICANT ACCOUNTING POLICIES

Basis of Accounting

These Financial Statements are prepared and presented in accordance with the accounting policies summarized below and in Canadian dollars. These policies are consistent with United States (US) Generally Accepted Accounting Principles (GAAP). These Financial Statements have been prepared for the specific use of the OEB. Consolidated Financial Statements of Hydro One for the year ended December 31, 2014 have been prepared and are publicly available.

These Financial Statements have been prepared on a carve-out basis to provide the financial position, results of operations and cash flows of the Company's regulated Distribution Business on a basis approved by the OEB. The Financial Statements are considered by management to be a reasonable representation, prepared on a rational, systematic and consistent basis, of the financial results of the Company's Distribution Business. As a result of this basis of accounting, these Financial Statements may not necessarily be identical to the financial position and results of operations that would have resulted had the Distribution Business historically operated on a stand-alone basis.

The Financial Statements have been constructed primarily through specific identification of assets, liabilities (other than debt), revenues and expenses that relate to the Distribution Business. The Company's long-term debt is allocated based on the respective borrowing requirements of the Company's transmission and distribution businesses. A portion of the Company's shared functions and services costs is allocated to the Distribution Business on a fully allocated-cost basis, consistent with OEB-approved independent studies. Payments in lieu of corporate income taxes (PILs) have been recorded at effective rates based on income taxes as reported in the Statements of Operations and Comprehensive Income as though the Distribution Business was a separate taxpaying entity. Certain other amounts presented in these Financial Statements represent allocations subject to review and approval by the OEB.

Hydro One Networks performed an evaluation of subsequent events through to March 24, 2015, the date these Financial Statements were available to be issued, to determine whether any events or transactions warranted recognition and disclosure in these financial statements. See Note 22 – 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 on-going 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, 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 OEB has approved the use of US GAAP for rate setting and regulatory accounting and reporting by the Company's Distribution Business beginning with the year 2012.

In June 2012, Hydro One Networks filed an Incentive Regulation Mechanism (IRM) application with the OEB for 2013 distribution rates, to be effective January 1, 2013. In December 2012, the OEB issued its final Decision, 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. In April 2013, Hydro One Networks filed an IRM application with the OEB for 2014 distribution rates, to be effective January 1, 2014. In December 2013, the OEB issued its final Decision, which resulted in an increase in 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.

Regulatory Accounting

The OEB has the general power to include or exclude revenues, costs, gains or losses in the rates of a specific period, resulting in a change in the timing of accounting recognition from that which would have applied in an unregulated company. Such change in timing involves the application of rate-regulated accounting, giving rise to the recognition of regulatory assets and liabilities. The Distribution Business' 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 Distribution Business has recorded regulatory liabilities that generally represent amounts that are refundable to future customers. The Distribution Business 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 Distribution Business 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.

Revenue Recognition

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 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 Distribution Business' 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 Distribution Business 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 Networks is required to remit 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 judgment is required to determine recognition thresholds and the related amount of tax benefits to be recognized in the 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 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 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 deferred income tax asset to report the net asset 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 Distribution Business has recognized regulatory assets and liabilities associated with deferred income taxes that will be included in the rate-setting process.

The Distribution Business 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.

Inter-company Demand Facility

Hydro One maintains pooled bank accounts for its use and for the use of its subsidiaries, and implicitly, by the regulated businesses of its subsidiaries. The balance in the inter-company demand facility represents the cumulative net effect of all deposits and withdrawals made by the Distribution Business to and from the pooled bank accounts. Interest is earned on positive inter-company balances based on the average of the bankers' acceptance rate at the beginning and end of the month, less 0.02%. Interest is charged on overdraft inter-company balances based on the same bankers' acceptance rate, plus 0.15%.

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 replacements of asset components, is included on the 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 overhead includes 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 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.

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 amounts incurred to acquire land rights and other 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 Distribution Business' 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 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.

Hydro One 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
Distribution	43 years	1% – 20%	2%
Communication	13 years	1% – 9%	5%
Administration and service	15 years	3% – 20%	8%

The cost of intangible assets is included primarily within the administration and service classification above. Amortization rates for computer applications software 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 and amortization, 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, 2014, based on the qualitative assessment performed as at September 30, 2014, 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, 2014.

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.

The carrying costs of most of the Distribution Business’ long-lived assets are included in rate base where they earn an OEB-approved rate of return. Asset carrying values and the 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. As at December 31, 2014, no asset impairment had been recorded.

Costs of Arranging Debt Financing

For financial liabilities classified as other than held-for-trading, the Company defers its proportionate share of the relevant Hydro One external transaction costs related to obtaining debt financing and presents such amounts as deferred debt costs on the 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 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 and net income are presented in a single continuous 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 investments; 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 which are measured at the lower of cost or fair value. Accounts receivable are classified as loans and receivables. The Company considers the carrying amount of accounts receivable to be a reasonable estimate 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. All financial instrument transactions are recorded at trade date.

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. Hydro One Networks 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 its risk management policy disclosed in Note 12 – Fair Value of Financial Instruments and Risk Management.

Derivative Instruments and Hedge Accounting

Hydro One closely monitors the risks associated with changes in interest rates on its operations and, where appropriate, uses various derivative 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 hedge relationships. Hydro One's derivative instruments, or portions thereof, are mirrored down to Hydro One Networks, and are allocated between the Company's transmission and distribution businesses. The derivative instruments are classified as fair value hedges or undesignated contracts, consistent with Hydro One's derivative instruments classification.

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 Balance Sheets. For derivative instruments that qualify for hedge accounting, Hydro One may elect to designate such derivative instruments as either cash flow hedges or fair value hedges. Hydro One offsets fair value amounts recognized in its 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 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 Statements of Operations and Comprehensive Income. Additionally, Hydro One 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 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. Hydro One does not engage in derivative trading or speculative activities and had no embedded derivatives at December 31, 2014.

Hydro One periodically develops hedging strategies taking into account risk management objectives. At the inception of a hedging relationship where Hydro One 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. Hydro One 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 pension, post-retirement and post-employment benefit plans are recorded over the periods during which employees render service.

Hydro One 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 funds 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 of Hydro One 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 post-retirement and post-employment benefit plans are unfunded because there are no related plan assets. For the year ended December 31, 2014, the measurement date for the Plans was December 31.

Pension benefits

Hydro One has a contributory defined benefit pension plan covering all regular employees of Hydro One and its subsidiaries, except Hydro One Brampton Networks Inc. The Hydro One pension plan does not segregate assets in a separate account for individual subsidiaries, nor is the accrual cost of the pension plan allocated to, or funded separately by, entities within the consolidated group. Consequently, for purposes of these financial statements, the pension plan is accounted for as a defined contribution plan and no deferred pension asset or liability is recorded.

A detailed description of Hydro One pension benefits is provided in Note 15 – Pension and Post-Retirement and Post-Employment Benefits, to the Consolidated Financial Statements of Hydro One for the year ended December 31, 2014.

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.

The Company records a regulatory asset equal to the incremental net unfunded projected benefit obligation for post-retirement and post-employment plans 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 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 associated regulatory asset, to the extent of the remeasurement adjustment.

For post-employment obligations, the actuarial gains and losses that are incurred during the year are recognized immediately to results of operations. The post-employment benefit obligation is remeasured to its fair value at each year end based on an annual actuarial report, with an offset to associated regulatory asset, to the extent of the remeasurement adjustment.

All post-retirement and post-employment future benefit costs are attributed to labour and are either charged to results of operations or capitalized as part of the cost of property, plant and equipment and intangible assets.

A detailed description of Hydro One post-retirement and post-employment benefits is provided in Note 15 – Pension and Post-Retirement and Post-Employment Benefits, to the Consolidated Financial Statements of Hydro One for the year ended December 31, 2014.

Loss Contingencies

Hydro One and its subsidiaries are involved in certain legal and environmental matters that arise in the normal course of business. In the preparation of the Distribution Business' Financial Statements, management makes judgments 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 Distribution Business 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 judgments 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 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 Distribution Business.

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 favorable 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. The Distribution Business 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 present value is determined 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 it is anticipated 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. The estimates of future environmental expenditures are reviewed 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 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 Distribution Business 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 case, an ARO would be recorded at that time.

The Distribution Business' 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 July 2013, the Financial Accounting Standards Board (FASB) 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. 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. The adoption of this ASU did not have a significant impact on the Distribution Business' 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. The Distribution Business is currently assessing the impact of adoption of ASU 2014-09 on its financial statements.

In August 2014, the FASB issued ASU 2014-15, Presentation of Financial Statements – Going Concern (Subtopic 205-40): Disclosure of Uncertainties about an Entity's Ability to Continue as a Going Concern. This ASU provides guidance about management's responsibility to evaluate whether there is substantial doubt about an entity's ability to continue as a going concern and related disclosures. This ASU is effective for the annual period ending December 31, 2016, and for annual and interim periods thereafter. The adoption of this ASU is not anticipated to have a significant impact on the Distribution Business' financial statements.

4. DEPRECIATION AND AMORTIZATION

Year ended December 31 (millions of Canadian dollars)	**2014**	**2013**
Depreciation of property, plant and equipment	250	235
Amortization of intangible assets	34	26
Asset removal costs	52	51
Amortization of regulatory assets	11	9
	347	321

5. FINANCING CHARGES

Year ended December 31 (millions of Canadian dollars)	**2014**	**2013**
Interest on long-term debt *(Note 18)*	158	150
Other	6	5
Interest on inter-company demand facility *(Note 18)*	1	1
Less: Interest capitalized on construction and development in progress	(15)	(16)
Gain on interest-rate swap agreements	(3)	(3)
	147	137

6. 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)	**2014**	**2013**
Income before provision for PILs	192	282
Canadian Federal and Ontario statutory income tax rate	26.50%	26.50%
Provision for PILs at statutory rate	51	75
Increase (decrease) resulting from:		
Net temporary differences included in amounts charged to customers:		
Capital cost allowance in excess of depreciation and amortization	(25)	(28)
Pension contributions in excess of pension expense	(12)	(10)
Overheads capitalized for accounting but deducted for tax purposes	(6)	(6)
Prior year's adjustment	–	(5)
Interest capitalized for accounting but deducted for tax purposes	(4)	(4)
Environmental expenditures	(3)	(2)
Non-refundable ITCs	(2)	(2)
Post-retirement and post-employment benefit expense in excess of cash payments	2	3
Other	1	2
Net temporary differences	(49)	(52)
Net permanent differences	1	1
Total provision for PILs	3	24
Current provision for (recovery of) PILs	(12)	21
Deferred provision for PILs	15	3
Total provision for PILs	3	24
Effective income tax rate	1.58%	8.51%

The current provision for PILs is remitted to, or received from, the OEFC. At December 31, 2014, $49 million receivable from the OEFC was included in accounts receivable on the Balance Sheet (2013 –$19 million).

The total provision for PILs includes deferred provision for PILs of $15 million (2013 – $3 million) that is not included in the rate-setting process, using the balance sheet liability method of accounting. Deferred PILs balances expected to be included in the rate-setting process are offset by regulatory assets and liabilities to reflect the anticipated recovery or disposition of these balances within future electricity rates.

Deferred Income Tax Assets and Liabilities

Deferred income tax assets and liabilities arise from differences between the carrying amounts and tax bases of the Company's assets and liabilities. At December 31, deferred income tax assets and liabilities consisted of the following:

December 31 (millions of Canadian dollars)	**2014**	**2013**
Deferred income tax liabilities		
Capital cost allowance in excess of depreciation and amortization	(626)	(547)
Regulatory amounts not recognized for tax	(93)	(87)
Goodwill	(9)	(8)
Post-retirement and post-employment benefits expense in excess of cash payments	312	304
Environmental expenses	36	39
Other	1	1
Total deferred income tax liabilities	(379)	(298)
Less: current portion	9	8
	(388)	(306)

During 2014 and 2013, there was no change in the rate applicable to future taxes.

7. ACCOUNTS RECEIVABLE

Year ended December 31 (millions of Canadian dollars)	**2014**	**2013**
Accounts receivable – billed	474	238
Accounts receivable – unbilled	575	647
Accounts receivable, gross	1,049	885
Allowance for doubtful accounts	(64)	(32)
Accounts receivable, net	985	853

The following table shows the movements in the allowance for doubtful accounts for the years ended December 31, 2014 and 2013.

Year ended December 31 (millions of Canadian dollars)	**2014**	**2013**
Allowance for doubtful accounts – January 1	(32)	(20)
Write-offs	24	23
Additions to allowance for doubtful accounts	(56)	(35)
Allowance for doubtful accounts – December 31	(64)	(32)

8. PROPERTY, PLANT AND EQUIPMENT

December 31, 2014 (millions of Canadian dollars)	Property, Plant and Equipment	Accumulated Depreciation	Construction in Progress	Total
Distribution	8,422	2,929	313	5,806
Communication	109	37	3	75
Administration and Service	935	533	10	412
Easements	9	4	–	5
	9,475	3,503	326	6,298

December 31, 2013 (millions of Canadian dollars)	Property, Plant and Equipment	Accumulated Depreciation	Construction in Progress	Total
Distribution	7,939	2,763	307	5,483
Communication	106	29	–	77
Administration and Service	855	483	16	388
Easements	9	4	–	5
	8,909	3,279	323	5,953

Financing charges capitalized on property, plant and equipment under construction were $14 million (2013 – $13 million).

9. INTANGIBLE ASSETS

December 31, 2014 (millions of Canadian dollars)	Intangible Assets	Accumulated Amortization	Development in Progress	Total
Computer applications software	356	178	19	197
Other	1	1	–	–
	357	179	19	197

December 31, 2013 (millions of Canadian dollars)	Intangible Assets	Accumulated Amortization	Development in Progress	Total
Computer applications software	347	144	1	204
Other	1	1	–	–
	348	145	1	204

Financing charges capitalized on intangible assets under development were $1 million (2013 – $3 million). The estimated annual amortization expense for intangible assets is as follows: 2015 – $33 million; 2016 – $33 million; 2017 – $33 million; 2018 – $29 million; and 2019 – $23 million.

10. REGULATORY ASSETS AND LIABILITIES

Regulatory assets and liabilities arise as a result of the rate-making process. The Distribution Business has recorded the following regulatory assets and liabilities:

December 31 (millions of Canadian dollars)	**2014**	**2013**
Regulatory assets:		
Deferred income tax regulatory asset	378	310
Post-retirement and post-employment benefits	154	172
Environmental	135	152
Pension cost variance	79	59
DSC exemption	16	7
OEB cost assessment differential	12	9
Retail settlement variance accounts	7	–
Other	19	11
Total regulatory assets	800	720
Less: current portion	11	15
	789	705

December 31 (millions of Canadian dollars)	**2014**	**2013**
Regulatory liabilities:		
Rider 11	83	54
PST savings deferral	19	14
Deferred income tax regulatory liability	8	7
Retail settlement variance accounts	–	35
Rider 9	–	19
Other	8	7
Total regulatory liabilities	118	136
Less: current portion	8	26
	110	110

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 Distribution Business 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 Distribution Business' provision for PILs would have been recognized using the liability method and there would be no regulatory accounts established for taxes to be reflected in future rates. As a result, the 2014 provision for PILs would have been higher by approximately $48 million (2013 – $53 million).

Post-Retirement and Post-Employment Benefits

The Distribution Business recognizes the net unfunded status of post-retirement and post-employment obligations on the 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, 2014 OCI would have been higher by $18 million (2013 – $8 million).

Environmental

The Distribution Business records a liability for the estimated future expenditures required to remediate past environmental contamination. Because such expenditures are expected to be recoverable in future rates, an equivalent amount was recorded as a regulatory asset. In 2014, the environmental regulatory asset decreased by $25 million (2013 – $3 million) to reflect related changes in the PCB liability, and increased by $12 million (2013 – $18 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 the Distribution Business' actual environmental expenditures. In the absence of rate-regulated accounting, 2014 operation, maintenance and administration expenses would have been lower by 13 million (2013 – higher by 15 million). In addition, 2014 amortization expense would have been lower by $10 million (2013 – $9 million), and 2014 financing charges would have been higher by $6 million (2013 – $6 million).

Pension Cost Variance

A pension cost variance account was established for the Distribution Business 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, 2014 revenue would have been lower by $20 million (2013 – $13 million).

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 identified specific expenditures can be recorded in a deferral account subject to the OEB's review until the next Hydro One Networks' distribution cost-of-service application. This program effectively ended at the end of 2014 with no new principal to be recorded in 2015.

OEB Cost Assessment Differential

In April 2010, the OEB announced its decision regarding the Distribution Business' rate application 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.

Retail Settlement Variance Accounts (RSVA)

Hydro One Networks 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. At December 31, 2014, the RSVA was in a net asset position due to a change in global adjustment.

Rider 11

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. Rider 11 includes amounts previously included as Rider 8.

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 administration 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 the Distribution Business, PST was included in rates between July 1, 2010 and December 31, 2014 and recorded in a deferral account per direction from the OEB.

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.

11. DEBT

Hydro One issues notes for long-term financing under its Medium-Term Note (MTN) Program. The terms of certain issuances are mirrored down to Hydro One Networks through the issuance of inter-company debt, which is then allocated between the Company's transmission and distribution businesses.

The following table presents the outstanding long-term debt of the Distribution Business as at December 31, 2014 and 2013:

December 31 (millions of Canadian dollars)	**2014**	**2013**
Long-term debt	3,381	3,313
Add: Unrealized marked-to-market loss[1]	1	3
Less: Long-term debt payable within one year	(221)	(176)
Long-term debt	3,161	3,140

[1] The unrealized marked-to-market loss relates to $100 million of Distribution Business' $200 million note due 2015 (2013 – $100 million of Distribution Business' $175 million note due 2014 and $100 million of Distribution Business' $200 million note due 2015). The unrealized marked-to-market loss is offset by a $1 million (2013 – $5 million) unrealized marked-to-market gain on the related fixed-to-floating interest-rate swap agreements, which are accounted for as fair value hedges. See Note 12 – Fair Value of Financial Instruments and Risk Management for details of fair value hedges.

The long-term debt is unsecured and denominated in Canadian dollars. The long-term debt is summarized by the number of years to maturity in Note 12 – Fair Value of Financial Instruments and Risk Management.

12. FAIR VALUE OF FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

Fair value is considered to be the exchange price in an orderly transaction between market participants to sell an asset or transfer a liability at the measurement date. The fair value definition focuses on an exit price, which is the price that would be received in the sale of an asset or the amount that would be paid to transfer a liability.

The Company 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 occurs 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, 2014 and 2013, the carrying amounts of accounts receivable, inter-company demand facility, and accounts payable 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 Distribution Business' long-term debt at December 31, 2014 and 2013 are as follows:

December 31 (millions of Canadian dollars)	2014 Carrying Value	2014 Fair Value	2013 Carrying Value	2013 Fair Value
Long-term debt				
$100 million of $175 million notes due 2014[1]	–	–	101	101
$100 million of $200 million notes due 2015[1]	101	101	102	102
Other notes and debentures[2]	3,281	3,820	3,113	3,370
	3,382	3,921	3,316	3,573

[1] The fair value of $100 million of Distribution Business' $175 million notes due 2014 and $100 million of Distribution Business' $200 million notes due 2015 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 other notes and debentures, and the portions of Distribution Business' $175 million and $200 million 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

Hydro One enters into interest-rate swaps agreements with respect to its long-term debt. The terms of these interest-rate swap agreements are mirrored down to Hydro One Networks, and are then allocated between the Company's transmission and distribution businesses.

At December 31, 2014, the Distribution Business' share of the Company's derivative instruments include $100 million (2013 – $200 million) of interest-rate swaps that were used to convert fixed-rate debt to floating-rate debt. These interest-rate swaps are classified as fair value hedges. The Distribution Business' fair value hedge exposure was equal to about 3% (2013 – 6%) of its long-term debt. At December 31, 2014, the Distribution Business' interest-rate swaps designated as fair value hedges were as follows:

- two $50 million fixed-to-floating interest-rate swap agreements to convert $100 million of the $200 million notes maturing September 11, 2015 into three-month variable rate debt.

At December 31, 2014, the Distribution Business' share of interest-rate swaps classified as undesignated contracts consisted of the following:

- a $20 million floating-to-fixed interest-rate swap agreement that locks in the floating rate the Company pays on the $20 million floating-rate MTN Series 22 notes from January 24, 2014 to January 24, 2015.

Fair Value Hierarchy

Fair value hierarchy information for financial assets and liabilities at December 31, 2014 and 2013 was as follows:

December 31, 2014 (millions of Canadian dollars)	Carrying Value	Fair Value	Level 1	Level 2	Level 3
Assets:					
Derivative instruments					
Fair value hedges – interest-rate swaps	1	1	–	1	–
	1	1	–	1	–
Liabilities:					
Inter-company demand facility	225	225	225	–	–
Long-term debt	3,382	3,921	–	3,921	–
	3,607	4,146	225	3,921	–

December 31, 2013 (millions of dollars)	Carrying Value	Fair Value	Level 1	Level 2	Level 3
Assets:					
Inter-company demand facility	47	47	47	–	–
Derivative instruments					
Fair value hedges – interest-rate swaps	3	3	–	3	–
	50	50	47	3	–
Liabilities:					
Long-term debt	3,316	3,573	–	3,573	–
	3,316	3,573	–	3,573	–

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 un-hedged portion of the long-term debt is based on unadjusted period-end market prices for the same or similar debt of the same remaining maturities.

There were no significant transfers between any of the levels during the years ended December 31, 2014 and 2013.

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 Hydro One 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. This could be mirrored in the Company. The Company is exposed to fluctuations in interest rates as the regulated rate of return for its Distribution Business 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 Distribution Business' rate of return would reduce the Distribution Business' 2014 results of operations by approximately $10 million (2013 – $10 million).

Hydro One uses a combination of fixed and variable-rate debt to manage the mix of its debt portfolio. Hydro One also uses derivative financial instruments to manage interest-rate risk. Hydro One 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, Hydro One 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. The Company's derivative instrument policy is consistent with Hydro One. No cash flow hedge agreements were outstanding as at December 31, 2014 or 2013.

A hypothetical 10% increase in the interest rates associated with variable-rate debt would not have resulted in a significant decrease in the Distribution Business' results of operations for the years ended December 31, 2014 or 2013.

Fair Value Hedges

For derivative instruments that are designated and qualify as fair value hedges, the gain or loss on the derivative instruments as well as the offsetting loss or gain on the hedged item attributable to the hedged risk are recognized in the Statements of Operations and Comprehensive Income. The Distribution Business' net unrealized loss (gain) on the hedged debt and the related interest-rate swaps for the years ended December 31, 2014 and 2013 are included in financing charges as follows:

Year ended December 31 (millions of Canadian dollars)	**2014**	**2013**
Unrealized loss (gain) on hedged debt	(1)	(2)
Unrealized loss (gain) on fair value interest-rate swaps	1	2
Net unrealized loss (gain)	–	–

At December 31, 2014, the amount of the Distribution Business' fair value hedges outstanding related to interest-rate swaps was $100 million (2013 – $200 million), with assets at fair value of $1 million (2013 – $3 million). During the years ended December 31, 2014 and 2013, there was no significant impact on the Distribution Business' 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, 2014 and 2013, there were no significant concentrations of credit risk with respect to any class of financial assets. The Distribution Business did not earn a significant amount of revenue from any individual customer. At December 31, 2014 and 2013, there was no significant accounts receivable balance due from any single customer.

At December 31, 2014, the Distribution Business' allowance for doubtful accounts was $64 million (2013 – $32 million). Adjustments and write-offs are determined on the basis of a review of overdue accounts, taking into consideration historical experience. At December 31, 2014, approximately 6% of the Distribution Business' net accounts receivable were aged more than 60 days (2013 – 4%).

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 Hydro One'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, Hydro One establishes credit limits, margining thresholds and collateral requirements for each counterparty. Counterparty credit limits are based on an internal credit review that considers a variety of factors, including the results of a scoring model, leverage, liquidity, profitability, credit ratings and risk management capabilities. The determination of credit exposure for a particular counterparty is the sum of current exposure plus the potential future exposure with that counterparty. The current exposure is calculated as the sum of the principal value of money market exposures and the market value of all contracts that have a positive mark-to-market position on the measurement date. Hydro One would only offset the positive market values against negative values with the same counterparty where permitted by the existence of a legal netting agreement such as an International Swap Dealers Association master agreement. The potential future exposure represents a safety margin to protect against future fluctuations of interest rates, currencies, equities, and commodities. It is calculated based on factors developed by the Bank of International Settlements, following extensive historical analysis of random fluctuations of interest rates and currencies. To the extent that a counterparty's margining thresholds are exceeded, the counterparty is required to post collateral with Hydro One as specified in each agreement. Hydro One monitors current and forward credit exposure to counterparties both on an individual and an aggregate basis. The Company's counterparty credit risk policy is consistent with Hydro One. The Distribution Business' credit risk for accounts receivable is limited to the carrying amounts on its Balance Sheets.

Liquidity Risk

Liquidity risk refers to the Company's ability to meet its financial obligations as they come due. The Company meets its short-term liquidity requirements through the inter-company demand facility with Hydro One and funds from operations. The short-term liquidity available to the Company should be sufficient to fund normal operating requirements.

At December 31, 2014, accounts payable and accrued liabilities in the amount of $670 million (2013 – $651 million) were expected to be settled in cash at their carrying amounts within the next year.

At December 31, 2014, the principal amount of the Distribution Business' long-term debt was $3,381million (2013 – $3,313 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	220	156	2.9
2 years	200	146	4.4
3 years	195	141	5.2
4 years	338	131	2.8
5 years	91	121	1.7
	1,044	695	3.5
6 – 10 years	381	555	3.6
Over 10 years	1,956	1,630	5.4
	3,381	2,880	4.6

13. CAPITAL MANAGEMENT

The Distribution Business' objective is to manage its capital structure consistent with the deemed capital structure for rate-setting purposes as prescribed by the OEB.

The Distribution Business considers its capital structure to consist of excess of assets over liabilities, long-term debt, and the inter-company demand facility. The following table summarizes this capital structure:

December 31 (millions of Canadian dollars)	**2014**	**2013**
Long-term debt payable within one year	221	176
Inter-company demand facility	225	(47)
	446	129
Long-term debt	3,161	3,140
Excess of assets over liabilities	2,595	2,465
Total capital	6,202	5,734

The following table shows the movements in the excess of assets over liabilities for the years ended December 31, 2014 and 2013:

December 31 (millions of Canadian dollars)	**2014**	**2013**
Excess of assets over liabilities, January 1	2,465	2,319
Net income	189	258
Payments to Hydro One to finance dividends	(59)	(112)
Excess of assets over liabilities, December 31	2,595	2,465

14. PENSION AND POST-RETIREMENT AND POST-EMPLOYMENT BENEFITS

Hydro One has a defined benefit pension plan, a supplementary pension plan, and post-retirement and post-employment benefit plans. The defined benefit pension plan (Pension Plan) is contributory and covers all regular employees of Hydro One and its subsidiaries, except Hydro One Brampton Networks Inc. 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 in post-retirement and post-employment benefit liability on the Balance Sheets.

Pension Benefits

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.

Hydro One and employee contributions to the Pension Plan are based on actuarial valuations performed at least every three years. Hydro One's annual Pension Plan contributions for 2014 of $174 million (2013 – $160 million) were based on an actuarial valuation effective December 31, 2013 (2013 – effective December 31, 2011) and the level of 2014 pensionable earnings. Estimated annual Pension Plan contributions for 2015 and 2016 are approximately $174 million and $175 million, respectively, based on an actuarial valuation as at December 31, 2013 and projected levels of pensionable earnings. Future minimum contributions beyond 2016 will be based on an actuarial valuation effective no later than December 31, 2016. Contributions are payable one month in arrears. All of the contributions are expected to be in the form of cash.

At December 31, 2014, based on the December 31, 2013 actuarial valuation, the present value of Hydro One's projected pension benefit obligation was estimated to be $7,535 million (2013 – $6,576 million). The fair value of pension plan assets available for these benefits was $6,299 million (2013 – $5,731 million).

Post-Retirement and Post-Employment Benefits

During the year ended December 31, 2014, the Distribution Business charged $33 million (2013 – $36 million) of post-retirement and post-employment benefit costs to operations, and capitalized $34 million (2013 – $35 million) as part of the cost of property, plant and equipment and intangible assets. Benefits paid in 2014 were $26 million (2013 – $24 million). In addition, the associated post-retirement and post-employment benefits regulatory asset decreased by $18 million (2013 – $8 million).

The Distribution Business presents its post-retirement and post-employment benefit liabilities on its Balance Sheets within the following line items:

December 31 (millions of Canadian dollars)	**2014**	**2013**
Accrued liabilities	25	22
Post-retirement and post-employment benefit liability	844	824
	869	846

15. ENVIRONMENTAL LIABILITIES

The following tables show the movements in environmental liabilities for the years ended December 31, 2014 and 2013:

Year ended December 31, 2014 (millions of Canadian dollars)	**PCB**	**LAR**	**Total**
Environmental liabilities, January 1	117	35	152
Interest accretion	5	1	6
Expenditures	(2)	(8)	(10)
Revaluation adjustment	(25)	12	(13)
Environmental liabilities, December 31	95	40	135
Less: current portion	6	5	11
	89	35	124

Year ended December 31, 2013 (millions of Canadian dollars)	**PCB**	**LAR**	**Total**
Environmental liabilities, January 1	116	24	140
Interest accretion	6	–	6
Expenditures	(2)	(7)	(9)
Revaluation adjustment	(3)	18	15
Environmental liabilities, December 31	117	35	152
Less: current portion	7	6	13
	110	29	139

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

December 31, 2014 (millions of Canadian dollars)	**PCB**	**LAR**	**Total**
Undiscounted environmental liabilities	108	42	150
Less: discounting accumulated liabilities to present value	13	2	15
Discounted environmental liabilities	95	40	135

December 31, 2013 (millions of Canadian dollars)	**PCB**	**LAR**	**Total**
Undiscounted environmental liabilities	136	37	173
Less: discounting accumulated liabilities to present value	19	2	21
Discounted environmental liabilities	117	35	152

At December 31, 2014, the estimated future environmental expenditures were as follows:

(millions of Canadian dollars)	
2015	11
2016	19
2017	19
2018	19
2019	18
Thereafter	64
	150

At December 31, 2014, of the total estimated future environmental expenditures, $108 million relates to PCBs (2013 – $136 million) and $42 million relates to LAR (2013 – $37 million).

The Distribution Business 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 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.

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 2.3% to 6.3%, depending on the appropriate rate for the period when expenditures are expected to be incurred. All factors used in estimating the Distribution Business' 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.

PCBs

The Environment Canada regulations, enacted under the *Canadian Environmental Protection Act,* 1999, govern the management, storage and disposal of PCBs based on certain criteria, including type of equipment, in-use status, and PCB-contamination thresholds. Under current regulations, the Company's PCBs have to be disposed of by the end of 2025, with the exception of specifically exempted equipment. 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 Distribution Business' best estimate of the total estimated future expenditures to comply with current PCB regulations is $108 million. These expenditures are expected to be incurred over the period from 2015 to 2025. As a result of its annual review of environmental liabilities, the Distribution Business recorded a revaluation adjustment in 2014 to reduce the PCB environmental liability by $25 million (2013 – $3 million).

LAR

The Distribution Business' best estimate of the total estimated future expenditures to complete its LAR program is $42 million. These expenditures are expected to be incurred over the period from 2015 to 2023. As a result of its annual review of environmental liabilities, the Distribution Business recorded a revaluation adjustment in 2014 to increase the LAR environmental liability by $12 million (2013 – $18 million).

16. ASSET RETIREMENT OBLIGATIONS

The Company 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 Distribution Business' 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, 2014, the Company had recorded AROs of $4 million (2013 – $4 million), related to its Distribution Business, consisting of the estimated future expenditures associated with the removal and disposal of asbestos-containing materials installed in some of its facilities. The amount of interest recorded is nominal.

17. HYDRO ONE NETWORKS' SHARE CAPITAL

Hydro One Networks has 14,875,720 issued and outstanding cumulative preferred shares and 148,821,741 issued and outstanding common shares. The Company is authorized to issue an unlimited number of preferred shares and common shares.

Hydro One Networks makes common share and preferred share dividend payments to Hydro One. The Distribution Business makes payments to finance its share of the Company's common share and preferred share dividends. During 2014, the Distribution Business' payments to finance these dividends totaled $59 million (2013 – $112 million).

18. RELATED PARTY TRANSACTIONS

The Distribution Business is a separately regulated business of Hydro One Networks which is a subsidiary of Hydro One, and 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 the Distribution Business because they are controlled or significantly influenced by the Province. Transactions between these parties and the Distribution Business are described below.

IESO

In 2014, the Distribution Business purchased power in the amount of $2,172 million (2013 – $2,077 million) from the IESO-administered electricity market.

The Distribution Business receives amounts for rural rate protection from the IESO. 2014 revenues include $125 million (2013 – $125 million) related to this program.

OPA

The OPA funds substantially all of the Company's conservation and demand management programs. The funding includes program costs, incentives, and management fees. In 2014, the Distribution Business received $28 million (2013 – $26 million) from the OPA related to these programs.

OPG

In 2014, the Distribution Business purchased power in the amount of $23 million (2013 – $15 million) from OPG.

The Company has service level agreements with OPG. These services include field and engineering, logistics, corporate, telecommunications and information technology services. Operation, maintenance and administration costs of the Distribution Business related to the purchase of services with respect to these service level agreements were less than $1 million in both 2014 and 2013.

OEFC

In 2014, the Distribution Business purchased power in the amount of $10 million (2013 – $8 million) from power contracts administered by the OEFC.

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. The Distribution Business' allocation of this fee is $1 million.

PILs and payments in lieu of property taxes were paid or payable to the OEFC.

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. In 2014, the Distribution Business incurred $6 million (2013 – $6 million) in OEB fees.

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)	**2014**	**2013**
Accounts receivable	98	56
Accrued liabilities[1]	(180)	(189)

[1] Included in accrued liabilities at December 31, 2014 are amounts owing to the IESO in respect of power purchases of $176 million (2013 – $185 million).

Hydro One and Subsidiaries

The Distribution Business provides services to, and receives services from, Hydro One and its subsidiaries. Amounts due to and from Hydro One and its subsidiaries are settled through the inter-company demand facility.

The Company has entered into various agreements with Hydro One and its other subsidiaries related to the provision of shared corporate functions and services, such as legal, financial and human resources services, and operational services, such as environmental, forestry, and line services. 2014 revenues of the Distribution Business include $2 million (2013 – $3 million) related to the provision of services to Hydro One and its subsidiaries. During year ended December 31, 2014, the Distribution Business provided services to Hydro One and its other subsidiaries totalling $12 million (2013 – $12 million), of which $11 million (2013 – $12 million) was charged to operation, maintenance and administration costs, and $1 million (2013 – $nil) was capitalized.

The Distribution Business' long-term debt is due to Hydro One. In addition, balances payable or receivable under the inter-company demand facility are due to or due from Hydro One. Financing charges include interest expense on the long-term debt in the amount of $158 million (2013 – $150 million), and interest expense on the inter-company demand facility in the amount of $1 million (2013 – $1 million). At December 31, 2014, the Distribution Business had accrued interest payable to Hydro One totalling $38 million (2013 – $38 million).

During 2014, Hydro One Networks paid preferred share dividends in the amount of $20 million (2013 – $20 million) and common share dividends in the amount of $724 million (2013 – $200 million) to Hydro One. The amount allocated to the Distribution Business to finance these dividends was $59 million (2013 – $112 million).

19. 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)	**2014**	**2013**
Accounts receivable	(132)	(75)
Materials and supplies	(1)	1
Other assets	(5)	1
Accounts payable	4	9
Accrued liabilities	16	(4)
Accrued interest	–	3
Long-term accounts payable and other liabilities	–	(12)
Post-retirement and post-employment benefit liability	38	47
	(80)	(30)

Capital Expenditures

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

Year ended December 31 (millions of Canadian dollars)	**2014**	**2013**
Capital investments in property, plant and equipment	(633)	(572)
Capitalized depreciation and net change in accruals included in capital investments in property, plant and equipment	19	9
Capital expenditures – property, plant and equipment	(614)	(563)

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

Year ended December 31 (millions of Canadian dollars)	**2014**	**2013**
Capital investments in intangible assets	(14)	(65)
Net change in accruals included in capital investments in intangible assets	–	(1)
Capital expenditures – intangible assets	(14)	(66)

Supplementary Information

Year ended December 31 (millions of Canadian dollars)	**2014**	**2013**
Net interest paid	155	144
PILs	15	41

20. CONTINGENCIES

The Company is a wholly-owned subsidiary of Hydro One. As such, the assets of the Distribution Business are available for the satisfaction of the debts, contingent liabilities and commitments of both the Company and Hydro One.

21. COMMITMENTS

The Company and Hydro One have numerous commitments. These commitments have not been specifically allocated to the Distribution Business. However, the net assets of the Distribution Business are available to satisfy the commitments of both the Company and Hydro One.

22. SUBSEQUENT EVENT

On February 11, 2015, Hydro One Networks declared preferred share dividends in the amount of $5 million and common share dividends in the amount of $25 million. The amount allocated to the Distribution Business to finance these dividends was $2 million.

HYDRO ONE NETWORKS INC.

DISTRIBUTION BUSINESS

FINANCIAL STATEMENTS

DECEMBER 31, 2015

HYDRO ONE NETWORKS INC.
DISTRIBUTION BUSINESS
INDEPENDENT AUDITORS' REPORT

To the Directors of Hydro One Networks Inc.

We have audited the accompanying carve-out financial statements of the Distribution Business (a business of Hydro One Networks Inc.), which comprise the carve-out balance sheet as at December 31, 2015, the carve-out statements of operations and comprehensive income, and cash flows for the year then ended, and notes, comprising a summary of significant accounting policies and other explanatory information. The carve-out financial statements have been prepared by management in accordance with the basis of accounting in Note 2 to the carve-out financial statements.

Management's Responsibility for the Carve-out Financial Statements

Management of Hydro One Networks Inc. is responsible for the preparation of these carve-out financial statements in accordance with the basis of accounting in Note 2 to the carve-out financial statements; this includes determining that the basis of accounting is an acceptable basis for the preparation of these carve-out financial statements in the circumstances, and for such internal control as management determines is necessary to enable the preparation of carve-out 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 carve-out financial statements based on our audit. We conducted our audit 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 carve-out financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the carve-out financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the carve-out financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity's preparation of the carve-out 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 carve-out financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the carve-out financial statements as at and for the year ended December 31, 2015 are prepared, in all material respects, in accordance with the basis of accounting in Note 2 to the carve-out financial statements.

Basis of Accounting and Restriction of Use

Without modifying our opinion, we draw attention to Note 2 to the carve-out financial statements, which describe the basis of preparation used in these carve-out financial statements. In particular, in preparing the carve-out financial statements, long-term debt, shared functions and service costs, and income taxes have been allocated to the Distribution Business (a business of Hydro One Networks Inc.) using the method of allocation described in Note 2 to the carve-out financial statements. As a result, the carve-out financial statements may not necessarily be identical to the balance sheet, results of operations and cash flows that would have resulted had the Distribution Business (a business of Hydro One Networks Inc.) historically operated on a stand-alone basis. The carve-out financial statements are prepared to assist Hydro One Networks Inc. to comply with its reporting requirements of the Ontario Energy Board. As a result, the carve-out financial statements may not be suitable for another purpose.

Our report is intended solely for the Directors of Hydro One Networks Inc. and the Ontario Energy Board and should not be used by parties other than Hydro One Networks Inc. or the Ontario Energy Board.

KPMG LLP

Chartered Professional Accountants, Licensed Public Accountants

Toronto, Canada
April 26, 2016

HYDRO ONE NETWORKS INC.
DISTRIBUTION BUSINESS
STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME
For the years ended December 31, 2015 and 2014

Year ended December 31 *(millions of Canadian dollars)*	**2015**	**2014**
Revenues		
Energy sales	4,305	4,176
Rural rate protection *(Note 20)*	125	126
Other	45	38
	4,475	4,340
Costs		
Purchased power *(Note 20)*	3,087	2,979
Operation, maintenance and administration *(Note 20)*	574	675
Depreciation and amortization *(Note 5)*	360	347
	4,021	4,001
Income before financing charges and income taxes	**454**	**339**
Financing charges *(Notes 6, 20)*	146	147
Income before income taxes	**308**	**192**
Income taxes *(Notes 7, 20)*	51	3
Net income	**257**	**189**
Other comprehensive income	–	–
Comprehensive income	**257**	**189**

See accompanying notes to Financial Statements.

HYDRO ONE NETWORKS INC.
DISTRIBUTION BUSINESS
BALANCE SHEETS
At December 31, 2015 and 2014

December 31 *(millions of Canadian dollars)*	**2015**	**2014**
Assets		
Current assets:		
Accounts receivable (net of allowance for doubtful accounts – $59; 2014 – $64) *(Notes 8, 20)*	776	985
Regulatory assets *(Note 11)*	28	11
Materials and supplies	4	7
Deferred income tax assets *(Note 7)*	10	9
Derivative instruments *(Note 13)*	–	1
Other	8	13
	826	1,026
Property, plant and equipment *(Note 9)*:		
Property, plant and equipment in service	10,150	9,426
Less: accumulated depreciation	3,794	3,503
	6,356	5,923
Construction in progress	254	326
Future use land, components and spares	53	49
	6,663	6,298
Other long-term assets:		
Regulatory assets *(Note 11)*	829	789
Intangible assets (net of accumulated amortization – $147; 2014 – $179) *(Note 10)*	257	197
Goodwill	113	73
Deferred debt costs	13	13
Other	1	3
	1,213	1,075
Total assets	**8,702**	**8,399**

See accompanying notes to Financial Statements.

HYDRO ONE NETWORKS INC.
DISTRIBUTION BUSINESS
BALANCE SHEETS (continued)
At December 31, 2015 and 2014

December 31 *(millions of Canadian dollars)*	**2015**	**2014**
Liabilities		
Current liabilities:		
Inter-company demand facility *(Notes 13, 14, 20)*	640	225
Accounts payable	59	65
Accrued liabilities *(Notes 7, 15, 16, 20)*	597	605
Accrued interest *(Note 20)*	36	38
Regulatory liabilities *(Note 11)*	10	8
Long-term debt payable within one year *(Notes 12, 13, 14, 20)*	200	221
	1,542	1,162
Long-term debt *(Notes 12, 13, 14, 20)*	2,991	3,161
Other long-term liabilities:		
Post-retirement and post-employment benefit liability *(Note 15)*	862	844
Deferred income tax liabilities *(Note 7)*	426	388
Environmental liabilities *(Note 16)*	99	124
Regulatory liabilities *(Note 11)*	83	110
Net unamortized debt premiums	9	10
Asset retirement obligations *(Note 17)*	4	4
Long-term accounts payable and other liabilities	7	1
	1,490	1,481
Total liabilities	**6,023**	**5,804**

Contingencies and commitments (Notes 22, 23)
Subsequent Events (Note 24)

Excess of assets over liabilities *(Notes 14, 18)*	2,679	2,595
Total liabilities and excess of assets over liabilities	**8,702**	**8,399**

See accompanying notes to Financial Statements.

On behalf of the Board of Directors:

George Cooke
Director

Mayo Schmidt
Director

HYDRO ONE NETWORKS INC.
DISTRIBUTION BUSINESS
STATEMENTS OF CASH FLOWS
For the years ended December 31, 2015 and 2014

Year ended December 31 *(millions of Canadian dollars)*	**2015**	**2014**
Operating activities		
Net income	257	189
Environmental expenditures	(11)	(10)
Adjustments for non-cash items:		
Depreciation and amortization (excluding removal costs)	301	295
Regulatory assets and liabilities	(70)	(58)
Deferred income taxes	(12)	15
Other	3	1
Changes in non-cash balances related to operations *(Note 21)*	240	(80)
Net cash from operating activities	708	352
Financing activities		
Long-term debt issued	30	243
Long-term debt retired	(220)	(175)
Payments to Hydro One Inc. to finance dividends	(240)	(59)
Other	(3)	(1)
Net cash from (used in) financing activities	(433)	8
Investing activities		
Capital expenditures *(Note 21)*		
Property, plant and equipment	(634)	(614)
Intangible assets	(24)	(14)
Transfer of Norfolk Power	(33)	–
Other	1	(4)
Net cash used in investing activities	(690)	(632)
Net change in inter-company demand facility	(415)	(272)
Inter-company demand facility, beginning of year	(225)	47
Inter-company demand facility, end of year	**(640)**	**(225)**

See accompanying notes to Financial Statements.

1. DESCRIPTION OF THE BUSINESS

Hydro One Inc. (Hydro One) was incorporated on December 1, 1998, under the Business Corporations Act (Ontario) and was wholly owned by the Province of Ontario (the Province) until October 31, 2015. On October 31, 2015, Hydro One Limited, a wholly owned subsidiary of the Province, acquired all issued and outstanding shares of Hydro One from the Province. The principal businesses of Hydro One are the transmission and distribution of electricity to customers within Ontario.

Hydro One Networks Inc. (Hydro One Networks or the Company) was incorporated on March 4, 1999 under the *Business Corporations Act* (Ontario) and is a wholly-owned subsidiary of Hydro One. The Company owns and operates Hydro One's regulated transmission and distribution businesses. The regulated distribution business (Distribution Business) operates a low-voltage electrical distribution network that distributes electricity from the transmission system, or directly from generators, to customers within Ontario. The Distribution Business is regulated by the Ontario Energy Board (OEB).

2. SIGNIFICANT ACCOUNTING POLICIES

Basis of Accounting

These Financial Statements are prepared and presented in accordance with the accounting policies summarized below and in Canadian dollars. These policies are consistent with United States (US) Generally Accepted Accounting Principles (GAAP), with the exception that business combinations of entities under common control have been accounted for as of the date of the transfer, such that (1) the Financial Statements were not prepared as though the transfer of entities under common control had occurred at the beginning of the year in which the transfer occurred and (2) the comparative year information has not been retrospectively adjusted.

These Financial Statements have been prepared for the specific use of the OEB. As a result, the financial statements may not be suitable for any other purpose. Consolidated Financial Statements of Hydro One for the year ended December 31, 2015 have been prepared and are publicly available.

These Financial Statements have been prepared on a carve-out basis to provide the financial position, results of operations and cash flows of the Company's regulated Distribution Business on a basis approved by the OEB. The Financial Statements are considered by management to be a reasonable representation, prepared on a rational, systematic and consistent basis, of the financial results of the Company's Distribution Business. As a result of this basis of accounting, these Financial Statements may not necessarily be identical to the financial position and results of operations that would have resulted had the Distribution Business historically operated on a stand-alone basis.

The Financial Statements have been constructed primarily through specific identification of assets, liabilities (other than debt), revenues and expenses that relate to the Distribution Business. The Company's long-term debt is allocated based on the respective borrowing requirements of the Company's transmission and distribution businesses. A portion of the Company's shared functions and services costs is allocated to the Distribution Business on a fully allocated-cost basis, consistent with OEB-approved independent studies. Income tax expense has been recorded at effective rates based on income taxes as reported in the Statements of Operations and Comprehensive Income as though the Distribution Business was a separate taxpaying entity. However, income taxes paid and the deferred tax asset recognized by the Company in relation to the Company losing its exemption from tax under the Federal Tax Regime have been excluded as they represent transactions that are not included in the rate-setting process of the Distribution Business. Certain other amounts presented in these Financial Statements represent allocations subject to review and approval by the OEB.

Hydro One Networks performed an evaluation of subsequent events through to April 26, 2016, the date these Financial Statements were available to be issued, to determine whether any events or transactions warranted recognition and disclosure in these financial statements. See Note 24 – Subsequent Events.

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, 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.

Rate Setting

The OEB has approved the use of US GAAP for rate setting and regulatory accounting and reporting by Hydro One Networks' Distribution Business.

On March 12, 2015, the OEB issued a Decision and Rate Order approving a revenue requirement of $1,326 million for 2015, $1,430 million for 2016 and $1,486 million for 2017. The revenue requirements for 2016 and 2017 are estimates that may change based on 2016 and 2017 Rate Orders. On April 23, 2015, the Final Rate Order for 2015 rates was approved by the OEB.

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 Distribution Business' 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 Distribution Business has recorded regulatory liabilities that generally represent amounts that are refundable to future customers. The Distribution Business 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 Distribution Business 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.

Revenue Recognition

Distribution revenues attributable to the delivery of electricity are based on OEB-approved distribution rates and are recognized on an accrual basis and include billed and unbilled revenues. Billed revenues are based on electricity delivered as measured from customer meters. Unbilled revenues are based on an estimate of electricity delivered determined by historical trends of consumption and are estimated at the end of each month. The unbilled revenue estimate is affected by energy consumption, weather, 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. 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 recorded at their estimated value. Overdue amounts related to regulated billings bear interest at OEB-approved rates. The allowance for doubtful accounts reflects the Distribution Business' best estimate of losses on billed accounts receivable balances. The Distribution Business estimates the allowance for doubtful accounts on customer receivables by applying internally developed loss rates to the outstanding receivable balances by aging category. Loss rates applied to the accounts receivable balances are based on historical overdue balances, customer payments and write-offs. Accounts receivable are written-off against the allowance when they are deemed uncollectible. The existing allowance for doubtful accounts will continue to be affected by changes in volume, prices and economic conditions.

Income Taxes

On October 31, 2015, Hydro One Networks ceased to be exempt from tax under the *Income Tax Act* (Canada) and the *Taxation Act*, 2007 (Ontario) (Federal Tax Regime). Prior to that date, Hydro One Networks was required to make payments in lieu of corporate income taxes (PILs) to the Ontario Electricity Financial Corporation (OEFC) under the *Electricity Act*, 1998 (Ontario) (PILs Regime). These payments were 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. Upon exiting the PILs Regime, Hydro One is required to make corporate income tax payments to the Canada Revenue Agency (CRA) under the Federal Tax Regime.

Current and deferred income taxes are computed based on the tax rates and tax laws enacted as 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 judgment is required to determine recognition thresholds and the related amount of tax benefits to be recognized in the Financial Statements. Management re-evaluates tax positions each period in which new information about recognition or measurement becomes available.

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 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 as at the balance sheet date. Deferred income taxes that are not included in the rate-setting process are charged or credited to the 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 deferred income 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.

Inter-company Demand Facility

Hydro One maintains pooled bank accounts for its use and for the use of its subsidiaries, and implicitly, by the regulated businesses of its subsidiaries. The balance in the inter-company demand facility represents the cumulative net effect of all deposits and withdrawals made by the Distribution Business to and from the pooled bank accounts. Interest is earned on positive inter-company balances based on the average of the bankers' acceptance rate at the beginning and end of the month, less 0.02%. Interest is charged on overdraft inter-company balances based on the same bankers' acceptance rate, plus 0.15%.

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, and any accumulated impairment losses. The cost of additions, including betterments and replacement asset components, is included on the 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 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.

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 fibre optic and microwave radio systems, 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.

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 Distribution Business' 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 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.

Hydro One 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, 2015. 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
Distribution	47 years	1% – 2%	2%
Communication	8 years	1% – 15%	12%
Administration and service	18 years	1% – 7%	6%

The cost of intangible assets is included primarily within the administration and service classification above. Amortization rate for computer applications software assets is 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 and amortization, 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, 2015, based on the qualitative assessment performed as at September 30, 2015, 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, 2015.

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, the Company evaluates whether impairment may exist by estimating 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.

The carrying costs of most of the Distribution Business' 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. As at December 31, 2015 and 2014, no asset impairment had been recorded.

Costs of Arranging Debt Financing

For financial liabilities classified as other than held-for-trading, the Company defers its proportionate share of the relevant Hydro One external transaction costs related to obtaining debt financing and presents such amounts as deferred debt costs on the 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 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 and net income are presented in a single continuous 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 investments; 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 which are measured at the lower of cost or fair value. Accounts receivable are classified as loans and receivables. The Company considers the carrying amount of accounts receivable to be a reasonable estimate 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. All financial instrument transactions are recorded at trade date.

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. Hydro One Networks 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 its risk management policy disclosed in Note 13 – Fair Value of Financial Instruments and Risk Management.

Derivative Instruments and Hedge Accounting

Hydro One closely monitors the risks associated with changes in interest rates on its operations and, where appropriate, uses various derivative 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 hedge relationships. Hydro One's derivative instruments, or portions thereof, are mirrored down to Hydro One Networks, and are allocated between the Company's transmission and distribution businesses. The derivative instruments are classified as fair value hedges or undesignated contracts, consistent with Hydro One's derivative instruments classification.

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 Balance Sheets. For derivative instruments that qualify for hedge accounting, Hydro One may elect to designate such derivative instruments as either cash flow hedges or fair value hedges. Hydro One offsets fair value amounts recognized in its 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 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 Statements of Operations and Comprehensive Income. Additionally, Hydro One 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 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. Hydro One does not engage in derivative trading or speculative activities and had no embedded derivatives at December 31, 2015 or 2014.

Hydro One periodically develops hedging strategies taking into account risk management objectives. At the inception of a hedging relationship where Hydro One 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. Hydro One 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 pension, post-retirement and post-employment benefit plans are recorded over the periods during which employees render service.

Hydro One recognizes the funded status of its defined benefit 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. Defined benefit 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 of Hydro One 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 post-retirement and post-employment benefit plans are unfunded because there are no related plan assets.

Pension benefits

Hydro One has a contributory defined benefit pension plan covering most regular employees of Hydro One and its subsidiaries, including Hydro One Networks. The Hydro One pension plan does not segregate assets in a separate account for individual subsidiaries, nor is the obligation of the pension plan allocated to, or funded separately by, entities within the consolidated group. Accordingly, for purposes of these Financial Statements, the pension plan is accounted for as a defined contribution plan and no pension benefit asset or liability is recorded.

A detailed description of Hydro One pension benefits is provided in Note 15 – Pension and Post-Retirement and Post-Employment Benefits, to the Consolidated Financial Statements of Hydro One for the year ended December 31, 2015.

Post-retirement and post-employment benefits

Hydro One has post-retirement and post-employment benefit plans covering all regular employees of Hydro One and its subsidiaries, including Hydro One Networks. The benefit obligations of these post-retirement and post-employment benefit plans are not segregated, or funded separately, for Hydro One Networks. Accordingly, for purposes of these Financial Statements, the post-retirement and post-employment benefit obligations are allocated to the Company based on base pensionable earnings.

The Company records a regulatory asset equal to its allocated share of Hydro One’s incremental net unfunded projected benefit obligation for post-retirement and post-employment plans 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 absence of regulatory accounting, would be recognized in accumulated OCI (AOCI). A regulatory asset is recognized because management considers it to be probable that post-retirement and post-employment benefit costs will be recovered in the future through the rate-setting process.

Post-retirement and post-employment benefits are recorded and included in rates on an accrual basis. Costs are determined by independent actuaries using the projected benefit method prorated on service and based on assumptions that reflect management's best estimates. Past service costs from plan amendments are amortized to results of operations based on the expected average remaining service period.

For post-retirement benefits, all actuarial gains or losses are deferred using the "corridor" approach. The amount calculated above the "corridor" is amortized to results of operations on a straight-line basis over the expected average remaining service lives of active Hydro One employees in the plan and over the remaining life expectancy of inactive Hydro One 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 associated regulatory asset, to the extent of the remeasurement adjustment.

For post-employment obligations, the actuarial gains and losses that are incurred during the year are recognized immediately to results of operations. The post-employment benefit obligation is remeasured to its fair value at each year end based on an annual actuarial report, with an offset to associated regulatory asset, to the extent of the remeasurement adjustment.

All post-retirement and post-employment future benefit costs are attributed to labour and are either charged to results of operations or capitalized as part of the cost of property, plant and equipment and intangible assets.

A detailed description of Hydro One post-retirement and post-employment benefits is provided in Note 15 – Pension and Post-Retirement and Post-Employment Benefits, to the Consolidated Financial Statements of Hydro One for the year ended December 31, 2015.

Stock-Based Compensation

Hydro One measures share grant plans based on fair value of share grants as estimated based on the grant date Hydro One Limited share price. The costs are recognized in the financial statements using the graded-vesting attribution method for share grant plans that have both a performance condition and a service condition. The Company records a regulatory asset equal to the accrued costs of share grant plans recognized in each period, as management considers it to be probable that such costs will be recovered in the future through the rate-setting process.

Loss Contingencies

Hydro One and its subsidiaries are involved in certain legal and environmental matters that arise in the normal course of business. In the preparation of the Distribution Business' Financial Statements, management makes judgments 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 Distribution Business 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 judgments 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 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 Distribution Business.

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 favorable 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. The Distribution Business records a liability for the estimated future expenditures associated with contaminated land assessment (LAR) and remediation 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. The Company reviews its estimates of future environmental expenditures annually, or more frequently if there are indications that circumstances have changed.

Asset Retirement Obligations

Asset retirement obligations 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 asset retirement obligations 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 asset retirement obligation, 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 asset retirement obligation is recorded, the asset retirement cost is recorded in results of operations.

Some of the Company's distribution assets, particularly those located on unowned easements and rights-of-way, may have asset retirement obligations, 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 Distribution Business expects to use the majority of its facilities in perpetuity, no asset retirement obligations currently exist 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 Distribution Business' 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 certain assets.

3. NEW ACCOUNTING PRONOUNCEMENTS

Recent Accounting Guidance Not Yet Adopted

In January 2015, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) 2015-01, Income Statement – Extraordinary and Unusual Items (Subtopic 225-20): Simplifying Income Statement Presentation by Eliminating the Concept of Extraordinary Items. This ASU eliminates the requirements for reporting entities to consider whether an underlying event or transaction is extraordinary and to show the item separately in the income statement. This ASU is effective for fiscal years, and interim periods within these years, beginning after December 15, 2015. The adoption of this ASU is not anticipated to have an impact on the Distribution Business' financial statements.

In April 2015, the FASB issued ASU 2015-03, Interest – Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs. This ASU requires that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability. The recognition and measurement guidance for debt issuance costs are not affected. This ASU is effective for fiscal years, and interim periods within those years, beginning after December 15, 2015. Upon adoption of this ASU in the first quarter of 2016, the Distribution Business' deferred debt issuance costs that are currently presented under other long-term assets will be reclassified as a deduction from the carrying amount of long-term debt.

In April 2015, the FASB issued ASU 2015-05, Intangibles – Goodwill and Other – Internal-Use Software (Subtopic 350-40): Customer's Accounting for Fees Paid in a Cloud Computing Arrangement. This ASU provides guidance to customers about whether a cloud computing arrangement includes a software license, as well as the related accounting for the arrangement. This ASU is effective for fiscal years, and interim periods within these years, beginning after December 15, 2015. The Distribution Business is currently assessing the impact of adoption of this ASU on its financial statements.

In August 2015, the FASB issued ASU 2015-14, Revenue from Contracts with Customers (Topic 606): Deferral of the Effective Date. This ASU defers by one year the effective date of ASU 2014-09, Revenue from Contracts with Customers (Topic 606) issued by the FASB in May 2014. ASU 2014-09 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. The guidance in ASU 2014-09 is now effective for fiscal years, and interim periods within those years, beginning after December 15, 2017. The Distribution Business is currently assessing the impact of adoption of ASU 2014-09 on its financial statements.

In November 2015, the FASB issued ASU 2015-17, Income Taxes (Topic 740): Balance Sheet Classification of Deferred Taxes. The amendments in this ASU require that all deferred tax assets and liabilities be classified as noncurrent on the balance sheet. This ASU is effective for fiscal years, and interim periods within those years, beginning after December 15, 2016. Upon adoption of this ASU in the first quarter of 2017, the current portions of the Distribution Business' deferred income tax assets and liabilities will be reclassified as noncurrent assets and liabilities on the Balance Sheets.

4. NORFOLK POWER TRANSFER

On August 31, 2015, the common shares of Norfolk Power Distribution Inc. (Norfolk Power) were transferred to Hydro One Networks by Hydro One. The transfer was accounted as a non-monetary transfer, based on Norfolk Power's carrying values at August 31, 2015. On September 1, 2015, Norfolk Power started dissolution proceedings and, as a result, its net assets were transferred to Hydro One Networks.

The following table summarizes the assets and liabilities that were transferred to Hydro One Networks' Distribution Business at September 1, 2015:

(millions of Canadian dollars)	
Property, plant and equipment	55
Goodwill	40
Working capital	9
Other assets	1
Inter-company demand facility	(33)
Derivative instruments	(3)
Other liabilities	(2)
	67

5. DEPRECIATION AND AMORTIZATION

Year ended December 31 *(millions of Canadian dollars)*	**2015**	**2014**
Depreciation of property, plant and equipment	254	250
Amortization of intangible assets	36	34
Asset removal costs	59	52
Amortization of regulatory assets	11	11
	360	347

6. FINANCING CHARGES

Year ended December 31 *(millions of Canadian dollars)*	**2015**	**2014**
Interest on long-term debt *(Note 20)*	154	158
Interest on inter-company demand facility *(Note 20)*	3	1
Other	4	6
Less: Interest capitalized on construction and development in progress	(14)	(15)
Gain on interest-rate swap agreements	(1)	(3)
	146	147

7. INCOME TAXES

Income taxes / provision for PILs differ 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)*	**2015**	**2014**
Income taxes / provision for PILs at statutory rate	82	51
Increase (decrease) resulting from:		
Net temporary differences included in amounts charged to customers:		
Pension contributions in excess of pension expense	(13)	(12)
Overheads capitalized for accounting but deducted for tax purposes	(6)	(6)
Capital cost allowance in excess of depreciation and amortization	(4)	(25)
Interest capitalized for accounting but deducted for tax purposes	(4)	(4)
Environmental expenditures	(3)	(3)
Non-refundable ITCs	(1)	(2)
Post-retirement and post-employment benefit expense in excess of cash payments	–	2
Other	(1)	1
Net temporary differences	(32)	(49)
Net permanent differences	1	1
Total income taxes / provision for PILs	51	3
Current income taxes / provision for (recovery of) PILs	63	(12)
Deferred income taxes / provision for PILs	(12)	15
Total income taxes / provision for PILs	51	3
Effective income tax rate	16.6%	1.6%

The provision for PILs / current income taxes is remitted to, or received from, the OEFC (PILs Regime) and the CRA (Federal Tax Regime). At December 31, 2015, $10 million (2014 – $49 million) due from the OEFC and $1 million due from the CRA were included in accounts receivable (2014 – $nil).

At December 31, 2015, the total income taxes / provision for PILs includes deferred income taxes / recovery of PILs of $12 million (2014 – deferred provision of $15 million) that is not included in the rate-setting process, using the balance sheet liability method of accounting. Deferred PILs balances expected to be included in the rate-setting process are offset by regulatory assets and liabilities to reflect the anticipated recovery or disposition of these balances within future electricity rates.

Deferred Income Tax Assets and Liabilities

Deferred income tax assets and liabilities arise from differences between the carrying amounts and tax basis of the Company's assets and liabilities. At December 31, 2015 and 2014, deferred income tax assets and liabilities consisted of the following:

December 31 *(millions of Canadian dollars)*	**2015**	**2014**
Deferred income tax liabilities		
Capital cost allowance in excess of depreciation and amortization	(686)	(626)
Regulatory amounts not recognized for tax	(112)	(93)
Goodwill	(9)	(9)
Post-retirement and post-employment benefits expense in excess of cash payments	319	312
Environmental expenses	41	36
Non-capital losses	31	–
Other	–	1
Total deferred income tax liabilities	(416)	(379)
Less: current portion	10	9
	(426)	(388)

During 2015 and 2014, there were no changes in the rate applicable to future taxes.

8. ACCOUNTS RECEIVABLE

Year ended December 31 *(millions of Canadian dollars)*	**2015**	**2014**
Accounts receivable – billed	384	474
Accounts receivable – unbilled	451	575
Accounts receivable, gross	835	1,049
Allowance for doubtful accounts	(59)	(64)
Accounts receivable, net	776	985

The following table shows the movements in the allowance for doubtful accounts for the years ended December 31, 2015 and 2014.

Year ended December 31 *(millions of Canadian dollars)*	**2015**	**2014**
Allowance for doubtful accounts – January 1	(64)	(32)
Write-offs	37	24
Additions to allowance for doubtful accounts	(32)	(56)
Allowance for doubtful accounts – December 31	(59)	(64)

9. PROPERTY, PLANT AND EQUIPMENT

December 31, 2015 *(millions of Canadian dollars)*	**Property, Plant and Equipment**	**Accumulated Depreciation**	**Construction in Progress**	**Total**
Distribution	9,083	3,155	236	6,164
Communication	124	65	–	59
Administration and Service	996	574	18	440
	10,203	3,794	254	6,663

December 31, 2014 *(millions of Canadian dollars)*	**Property, Plant and Equipment**	**Accumulated Depreciation**	**Construction in Progress**	**Total**
Distribution	8,431	2,933	313	5,811
Communication	109	37	3	75
Administration and Service	935	533	10	412
	9,475	3,503	326	6,298

Financing charges capitalized on property, plant and equipment under construction were $14 million (2014 – $14 million).

10. INTANGIBLE ASSETS

December 31, 2015 *(millions of Canadian dollars)*	**Intangible Assets**	**Accumulated Amortization**	**Development in Progress**	**Total**
Computer applications software	352	141	17	228
Other	35	6	–	29
	387	147	17	257

December 31, 2014 *(millions of Canadian dollars)*	**Intangible Assets**	**Accumulated Amortization**	**Development in Progress**	**Total**
Computer applications software	356	178	19	197
Other	1	1	–	–
	357	179	19	197

Financing charges capitalized on intangible assets under development were $1 million (2014 – $1 million). The estimated annual amortization expense for intangible assets is as follows: 2016 – $36 million; 2017 – $36 million; 2018 – $36 million; and 2019 – $32 million; and 2020 – $24 million.

11. REGULATORY ASSETS AND LIABILITIES

Regulatory assets and liabilities arise as a result of the rate-making process. The Distribution Business has recorded the following regulatory assets and liabilities:

December 31 *(millions of Canadian dollars)*	**2015**	**2014**
Regulatory assets:		
Deferred income tax regulatory asset	431	378
Post-retirement and post-employment benefits	134	154
Environmental	114	135
Retail settlement variance accounts	113	7
Pension cost variance	23	79
2015-2017 rate rider	20	–
DSC exemption	10	16
Share-based compensation	5	–
OEB cost assessment differential	–	12
Other	7	19
Total regulatory assets	857	800
Less: current portion	28	11
	829	789

December 31 *(millions of Canadian dollars)*	**2015**	**2014**
Regulatory liabilities:		
Green Energy expenditure variance	76	83
Deferred income tax regulatory liability	9	8
PST savings deferral	4	19
Other	4	8
Total regulatory liabilities	93	118
Less: current portion	10	8
	83	110

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 income. The Distribution Business 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 Distribution Business' income tax expense 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 2015 income tax expense would have been higher by approximately $32 million (2014 – $49 million).

Post-Retirement and Post-Employment Benefits

The Distribution Business recognizes the net unfunded status of post-retirement and post-employment obligations on the 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, 2015 OCI would have been higher by $20 million (2014 – $18 million).

Environmental

The Distribution Business records a liability for the estimated future expenditures required to remediate past environmental contamination. Because such expenditures are expected to be recoverable in future rates, an equivalent amount was recorded as a regulatory asset. In 2015, the environmental regulatory asset decreased by $17 million (2014 – $25 million) to reflect related changes in the PCB liability, and increased by $2 million (2014 – $12 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 the Distribution Business' actual environmental expenditures. In the absence of rate-regulated accounting, 2015 operation, maintenance and administration expenses would have been lower by $15 million (2014 – $13 million). In addition, 2015 amortization expense would have been lower by $11 million (2014 – $10 million), and 2015 financing charges would have been higher by $5 million (2014 – $6 million).

Retail Settlement Variance Accounts (RSVA)

Hydro One has deferred certain retail settlement variance amounts (RSVA) under the provisions of Article 490 of the OEB's Accounting Procedures Handbook. RSVA primarily includes variances relating to Power, Global Adjustment, Wholesale Market Service Charge and Transmission Network and Transmission Connection Services. In March 2015, the OEB approved the disposition of the total RSVA balance accumulated from January 2012 to December 2013, including accrued interest, to be recovered through the 2015-2017 Rate Rider. In 2015, the Company revised its method to estimate the unbilled accounts receivable based on new technology implemented to improve the accuracy of the estimation process. This revised method is also in compliance with OEB guidance. At December 31, 2015, the change in estimate reduced unbilled accounts receivable by approximately $121 million, with a corresponding offset to various components of RSVA. The change in estimate had no significant impact on 2015 net income.

Pension Cost Variance

A pension cost variance account was established for the Distribution Business 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, 2015 revenue would have been higher by $3 million (2014 – lower by $20 million).

2015-2017 Rate Rider

In March 2015, as part of its decision on Hydro One Networks' Distribution rate application for 2015-2019 the OEB approved the disposition of certain deferral and variance accounts, including RSVAs and accrued interest. The 2015-2017 Rate Rider account includes the balances approved for disposition by the OEB and will be disposed over a 32-month period in accordance with the OEB decision.

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 identified specific expenditures can be recorded in a deferral account subject to the OEB's review in subsequent Hydro One Network distribution applications. In March 2015, the OEB approved the disposition of the DSC exemption deferral account at December 31, 2013, including accrued interest, which will be recovered through the 2015-2017 Rate Rider. In addition, the OEB also approved Hydro One's request to discontinue this deferral account, and there were no additions to this regulatory account in 2015.

Share-based Compensation

The Distribution Business recognizes costs associated with stock-based compensation in a regulatory asset as management considers it probable that stock-based compensation costs will be recovered in the future through the rate-setting process. At December 31, 2015, the stock-based compensation costs related to the share grant plans are measured at fair value estimated based on grant date Hydro One Limited share price and recognized using the graded-vesting attribution method. In the absence of rate-regulated accounting, 2015 operation, maintenance and administration expenses would have been higher by $2 million (2014 – $nil).

OEB Cost Assessment Differential

In April 2010, the OEB issued its Decision regarding Hydro One Networks' distribution rate application 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. In March 2015, the OEB approved the disposition of the OEB Cost Assessment Differential Account at December 31, 2013, including accrued interest, which will be recovered through the 2015-2017 Rate Rider. In addition, the OEB also approved Hydro One's request to discontinue this deferral account, and there were no additions to this regulatory account in 2015.

Green Energy Expenditure Variance

In April 2010, the OEB requested the establishment of deferral accounts which capture the difference between the revenue recorded on the basis of Green Energy Plan expenditures incurred and the actual recoveries received.

PST Savings Deferral Account

The provincial sales tax (PST) and goods and services tax (GST) were harmonized in July 2010. Unlike the GST, the PST was included in operation, maintenance and administration 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' distribution revenue requirement, PST was included between July 1, 2010 and December 31, 2015 and recorded in a deferral account, as directed by the OEB. In March 2015, the OEB approved the disposition of the PST Savings Deferral account at December 31, 2013, including accrued interest, which will be recovered through the 2015-2017 Rate Rider.

12. DEBT

Hydro One issues notes for long-term financing under its Medium-Term Note (MTN) Program. The terms of certain issuances are mirrored down to Hydro One Networks through the issuance of inter-company debt, which is then allocated between the Company's transmission and distribution businesses.

The following table presents the outstanding long-term debt of the Distribution Business as at December 31, 2015 and 2014:

December 31 *(millions of Canadian dollars)*	**2015**	**2014**
Long-term debt	3,191	3,381
Add: Unrealized marked-to-market loss[1]	–	1
Less: Long-term debt payable within one year	(200)	(221)
Long-term debt	2,991	3,161

[1] At December 31, 2014, the unrealized marked-to-market loss related to $100 million of Distribution Business' $200 million note due 2015. This loss was offset by $1 million unrealized marked-to-market gain on the related fixed-to-floating interest-rate swap agreements, which are accounted for as fair value hedges.

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.

The Company 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 occurs 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, 2015 and 2014, the carrying amounts of accounts receivable, inter-company demand facility, and accounts payable 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 Distribution Business' long-term debt at December 31, 2015 and 2014 are as follows:

December 31 *(millions of Canadian dollars)*	**2015 Carrying Value**	**2015 Fair Value**	**2014 Carrying Value**	**2014 Fair Value**
Long-term debt				
$30 million notes due 2020[1]	30	30	–	–
$100 million of $200 million notes due 2015[1]	–	–	101	101
Other notes and debentures[2]	3,161	3,623	3,281	3,820
	3,191	3,653	3,382	3,921

[1] The fair value of Distribution Business' $30 million notes due 2020 (2014 – $100 million of Distribution Business' $200 million notes due 2015) 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 other notes and debentures, and the portions of Distribution Business' 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

Hydro One enters into interest-rate swaps agreements with respect to its long-term debt. The terms of these interest-rate swap agreements are mirrored down to Hydro One Networks, and are then allocated between the Company's transmission and distribution businesses.

At December 31, 2015, the Distribution Business' share of the Company's derivative instruments include $30 million (2014 – $100 million) of interest-rate swaps that were used to convert fixed-rate debt to floating-rate debt. These interest-rate swaps are classified as fair value hedges. The Distribution Business' fair value hedge exposure was equal to about 1% (2014 – 3%) of its long-term debt. At December 31, 2015, the Distribution Business' interest-rate swaps designated as fair value hedges were as follows:

- $30 million fixed-to-floating interest-rate swap agreements to convert $30 million notes maturing on April 30, 2020 into three-month variable rate debt.

At December 31, 2015, the Distribution Business' had no interest-rate swaps classified as undesignated contracts (2014 – $20 million).

Fair Value Hierarchy

Fair value hierarchy information for financial assets and liabilities at December 31, 2015 and 2014 was as follows:

December 31, 2015 *(millions of Canadian dollars)*	**Carrying Value**	**Fair Value**	**Level 1**	**Level 2**	**Level 3**
Liabilities:					
Inter-company demand facility	640	640	640	–	–
Long-term debt	3,191	3,653	–	3,653	–
	3,831	4,293	640	3,653	

December 31, 2014 *(millions of Canadian dollars)*	**Carrying Value**	**Fair Value**	**Level 1**	**Level 2**	**Level 3**
Assets:					
Derivative instruments					
Fair value hedges – interest-rate swaps	1	1	–	1	–
	1	1	–	1	–
Liabilities:					
Inter-company demand facility	225	225	225	–	–
Long-term debt	3,382	3,921	–	3,921	–
	3,607	4,146	225	3,921	–

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 un-hedged portion of the long-term debt is based on unadjusted period-end market prices for the same or similar debt of the same remaining maturities.

There were no significant transfers between any of the levels during the years ended December 31, 2015 and 2014.

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 costs, foreign exchange rates and interest rates. The Company is exposed to fluctuations in interest rates as its regulated return on equity is derived using a formulaic approach that takes into account anticipated interest rates, but is not currently exposed to material commodity price risk or material foreign exchange risk.

The OEB-approved adjustment formula for calculating return on equity in a deemed regulatory capital structure of 60% debt and 40% equity provides for increases and decreases depending on changes in benchmark rates of return for Government of Canada debt. The Company estimates that a 1% decrease in the forecasted long-term Government of Canada bond yield used in determining the Distribution Business' rate of return would reduce the Distribution Business' 2015 net income by approximately $13 million (2014 – $10 million).

Hydro One uses a combination of fixed and variable-rate debt to manage the mix of its debt portfolio. Hydro One also uses derivative financial instruments to manage interest-rate risk. Hydro One 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.

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 net income for the years ended December 31, 2015 or 2014.

Fair Value Hedges

For derivative instruments that are designated and qualify as fair value hedges, the gain or loss on the derivative instruments as well as the offsetting loss or gain on the hedged item attributable to the hedged risk are recognized in the Statements of Operations and Comprehensive Income. The Distribution Business' net unrealized loss (gain) on the hedged debt and the related interest-rate swaps for the years ended December 31, 2015 and 2014 are included in financing charges as follows:

Year ended December 31 *(millions of Canadian dollars)*	**2015**	**2014**
Unrealized loss (gain) on hedged debt	(1)	(1)
Unrealized loss (gain) on fair value interest-rate swaps	1	1
Net unrealized loss (gain)	–	–

At December 31, 2015, the amount of the Distribution Business' fair value hedges outstanding related to interest-rate swaps was $30 million (2014 – $100 million), with assets at fair value of $nil (2014 – $1 million). During the years ended December 31, 2015 and 2014, there was no significant impact on the Distribution Business' 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, 2015 and 2014, there were no significant concentrations of credit risk with respect to any class of financial assets. The Distribution Business did not earn a significant amount of revenue from any individual customer. At December 31, 2015 and 2014, there was no significant accounts receivable balance due from any single customer.

At December 31, 2015, the Distribution Business' allowance for doubtful accounts was $59 million (2014 – $64 million). Adjustments and write-offs are determined on the basis of a review of overdue accounts, taking into consideration historical experience. At December 31, 2015, approximately 5% of the Distribution Business' net accounts receivable were aged more than 60 days (2014 – 6%).

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 Hydro One'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, Hydro One establishes credit limits, margining thresholds and collateral requirements for each counterparty. Counterparty credit limits are based on an internal credit review that considers a variety of factors, including the results of a scoring model, leverage, liquidity, profitability, credit ratings and risk management capabilities. The determination of credit exposure for a particular counterparty is the sum of current exposure plus the potential future exposure with that counterparty. The current exposure is calculated as the sum of the principal value of money market exposures and the market value of all contracts that have a positive mark-to-market position on the measurement date. Hydro One would only offset the positive market values against negative values with the same counterparty where permitted by the existence of a legal netting agreement such as an International Swap Dealers Association master agreement. The potential future exposure represents a safety margin to protect against future fluctuations of interest rates, currencies, equities, and commodities. It is calculated based on factors developed by the Bank of International Settlements, following extensive historical analysis of random fluctuations of interest rates and currencies. To the extent that a counterparty's margining thresholds are exceeded, the counterparty is required to post collateral with Hydro One as specified in each agreement. Hydro One monitors current and forward credit exposure to counterparties both on an individual and an aggregate basis. The Company's counterparty credit risk policy is consistent with Hydro One. The Distribution Business' credit risk for accounts receivable is limited to the carrying amounts on its Balance Sheets.

Liquidity Risk

Liquidity risk refers to the Company's ability to meet its financial obligations as they come due. The Company meets its short-term liquidity requirements through the inter-company demand facility with Hydro One and funds from operations. The short-term liquidity available to the Company should be sufficient to fund normal operating requirements.

At December 31, 2015, accounts payable and accrued liabilities in the amount of $656 million (2014 – $670 million) were expected to be settled in cash at their carrying amounts within the next 12 months.

At December 31, 2015, the principal amount of the Distribution Business' long-term debt was $3,191 million (2014 – $3,381 million). Principal repayments and related weighted average interest rates are summarized by the number of years to maturity in the following table:

Years to Maturity	**Long-term Debt Principal Repayments** *(millions of Canadian dollars)*	**Weighted Average Interest Rate** *(%)*
1 year	200	4.3
2 years	195	5.2
3 years	338	2.8
4 years	91	1.2
5 years	150	3.9
	974	3.6
6 – 10 years	261	3.2
Over 10 years	1,956	5.4
	3,191	4.7

Interest payments on long-term debt are summarized by year in the following table:

Year	Interest Payments *(millions of Canadian dollars)*
2016	146
2017	141
2018	131
2019	121
2020	118
	657
2021-2025	544
2026 +	1,523
	2,724

14. CAPITAL MANAGEMENT

The Distribution Business' objective is to manage its capital structure consistent with the deemed capital structure for rate-setting purposes as prescribed by the OEB.

The Distribution Business considers its capital structure to consist of excess of assets over liabilities, long-term debt, and the inter-company demand facility. The following table summarizes this capital structure:

December 31 *(millions of Canadian dollars)*	**2015**	**2014**
Long-term debt payable within one year	200	221
Inter-company demand facility	640	225
	840	446
Long-term debt	2,991	3,161
Excess of assets over liabilities	2,679	2,595
Total capital	6,510	6,202

The following table shows the movements in the excess of assets over liabilities for the years ended December 31, 2015 and 2014:

December 31 *(millions of Canadian dollars)*	**2015**	**2014**
Excess of assets over liabilities, January 1	2,595	2,465
Net income	257	189
Payments to Hydro One to finance dividends	(240)	(59)
Transfer of Norfolk Power	67	–
Excess of assets over liabilities, December 31	2,679	2,595

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 most regular employees of Hydro One and its subsidiaries. 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 Balance Sheets.

Pension Benefits

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.

Hydro One and employee contributions to the Pension Plan are based on actuarial valuations performed at least every three years. Hydro One's annual Pension Plan contributions for 2015 of $177 million (2014 – $174 million) were based on an actuarial valuation effective December 31, 2013 and the level of pensionable earnings. Estimated annual Pension Plan contributions for 2016 are approximately $180 million, based on the actuarial valuation as at December 31, 2013 and projected levels of pensionable earnings. Future minimum contributions beyond 2016 will be based on an actuarial valuation effective no later than December 31, 2016. Contributions are payable one month in arrears. All of the contributions are expected to be in the form of cash.

At December 31, 2015, based on the December 31, 2013 actuarial valuation, the present value of Hydro One's projected pension benefit obligation was estimated to be $7,683 million (2014 – $7,535 million). The fair value of pension plan assets available for these benefits was $6,731 million (2014 – $6,299 million).

Post-Retirement and Post-Employment Benefits

During the year ended December 31, 2015, the Distribution Business charged $31 million (2014 – $33 million) of post-retirement and post-employment benefit costs to operations, and capitalized $35 million (2014 – $34 million) as part of the cost of property, plant and equipment and intangible assets. Benefits paid in 2015 were $27 million (2014 – $26 million). In addition, the associated post-retirement and post-employment benefits regulatory asset decreased by $20 million (2014 – $18 million).

The Distribution Business presents its post-retirement and post-employment benefit liabilities on its Balance Sheets within the following line items:

December 31 *(millions of Canadian dollars)*	**2015**	**2014**
Accrued liabilities	26	25
Post-retirement and post-employment benefit liability	862	844
	888	869

16. ENVIRONMENTAL LIABILITIES

The following tables show the movements in environmental liabilities for the years ended December 31, 2015 and 2014:

Year ended December 31, 2015 *(millions of Canadian dollars)*	**PCB**	**LAR**	**Total**
Environmental liabilities, January 1	95	40	135
Interest accretion	4	1	5
Expenditures	(5)	(6)	(11)
Revaluation adjustment	(17)	2	(15)
Environmental liabilities, December 31	77	37	114
Less: current portion	10	5	15
	67	32	99

Year ended December 31, 2014 *(millions of Canadian dollars)*	**PCB**	**LAR**	**Total**
Environmental liabilities, January 1	117	35	152
Interest accretion	5	1	6
Expenditures	(2)	(8)	(10)
Revaluation adjustment	(25)	12	(13)
Environmental liabilities, December 31	95	40	135
Less: current portion	6	5	11
	89	35	124

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

December 31, 2015 *(millions of Canadian dollars)*	**PCB**	**LAR**	**Total**
Undiscounted environmental liabilities	87	38	125
Less: discounting accumulated liabilities to present value	10	1	11
Discounted environmental liabilities	77	37	114

December 31, 2014 *(millions of Canadian dollars)*	**PCB**	**LAR**	**Total**
Undiscounted environmental liabilities	108	42	150
Less: discounting accumulated liabilities to present value	13	2	15
Discounted environmental liabilities	95	40	135

At December 31, 2015, the estimated future environmental expenditures were as follows:

(millions of Canadian dollars)	
2016	15
2017	16
2018	16
2019	17
2020	17
Thereafter	44
	125

The Distribution Business 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 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.

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 2.4% to 6.3%, depending on the appropriate rate for the period when expenditures are expected to be incurred. All factors used in estimating the Distribution Business' 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.

PCBs

The Environment Canada regulations, enacted under the *Canadian Environmental Protection Act*, 1999, govern the management, storage and disposal of PCBs based on certain criteria, including type of equipment, in-use status, and PCB-contamination thresholds. Under current regulations, the Company's PCBs have to be disposed of by the end of 2025, with the exception of specifically exempted equipment. 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 Distribution Business' best estimate of the total estimated future expenditures to comply with current PCB regulations is $87 million. These expenditures are expected to be incurred over the period from 2016 to 2025. As a result of its annual review of environmental liabilities, the Distribution Business recorded a revaluation adjustment in 2015 to reduce the PCB environmental liability by $17 million (2014 – $25 million).

LAR

The Distribution Business' best estimate of the total estimated future expenditures to complete its LAR program is $38 million. These expenditures are expected to be incurred over the period from 2016 to 2023. As a result of its annual review of environmental liabilities, the Distribution Business recorded a revaluation adjustment in 2015 to increase the LAR environmental liability by $2 million (2014 – $12 million).

17. ASSET RETIREMENT OBLIGATIONS

The Company 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 Distribution Business' 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, 2015, the Company had recorded AROs of $4 million (2014 – $4 million), related to its Distribution Business, consisting of the estimated future expenditures associated with the removal and disposal of asbestos-containing materials installed in some of its facilities. The amount of interest recorded is nominal.

18. HYDRO ONE NETWORKS' SHARE CAPITAL

Hydro One Networks is authorized to issue an unlimited number of common and preferred shares. At December 31, 2015, Hydro One Networks had 207,577,181 common shares issued and outstanding and no preferred shares issued and outstanding.

During 2015, Hydro One Networks declared preferred share dividends in the amount of $16 million (2014 – $20 million) and common share dividends in the amount of $875 million (2014 – $724 million) to Hydro One. The amount allocated to and paid by the Distribution Business to finance these dividends was $240 million (2014 – $59 million).

19. STOCK-BASED COMPENSATION

The following compensation plans were established by Hydro One Limited, however they represent components of compensation costs of Hydro One and its subsidiaries, including Hydro One Networks, in current and future periods.

Share Grant Plans

At December 31, 2015, Hydro One Limited had two share grant plans, one for the benefit of certain members of the Power Workers' Union (the PWU Share Grant Plan) and one for the benefit of certain members of The Society of Energy Professionals (the Society Share Grant Plan). These plans are part of the Company's overall compensation strategy. Hydro One and Hydro One Limited entered into an intercompany agreement, such that Hydro One will pay Hydro One Limited for the compensation costs associated with these plans. The agreement requires Hydro One Networks to reimburse Hydro One for the value of shares granted to the Company's eligible employees relating to these plans.

The PWU Share Grant Plan provides for the issuance of common shares of Hydro One Limited from treasury to certain eligible members of the Power Workers' Union annually, commencing on April 1, 2017 and continuing until the earlier of April 1, 2028 or the date an eligible employee no longer meets the eligibility criteria of the PWU Share Grant Plan. To be eligible, an employee must be a member of the Pension Plan on April 1, 2015, be employed on the date annual share issuance occurs and continue to have under 35 years of service. The requisite service period for the PWU share grant plan begins on July 3, 2015, which is the date the share grant plans were ratified by the PWU. The number of common shares issued annually to each eligible employee will be equal to 2.7% of such eligible employee's salary as at April 1, 2015, divided by $20.50, being the price of the common shares of Hydro One Limited in the IPO. The aggregate number of Hydro One Limited common shares issuable under the PWU Share Grant Plan shall not exceed 3,981,763 common shares. In 2015, 2,152,519 Hydro One Limited common shares were granted under the PWU Share Grant Plan relevant to the total share based compensation recognized by the Distribution Business.

The Society Share Grant Plan provides for the issuance of common shares of Hydro One Limited from treasury to certain eligible members of The Society of Energy Professionals annually, commencing on April 1, 2018 and continuing until the earlier of April 1, 2029 or the date an eligible employee no longer meets the eligibility criteria of the Society Share Grant Plan. To be eligible, an employee must be a member of the Pension Plan on September 1, 2015, be employed on the date annual share issuance occurs and continue to have under 35 years of service. Therefore the requisite service period for the Society Share Grant Plan begins on September 1, 2015. The number of common shares issued annually to each eligible employee will be equal to 2.0% of such eligible employee's salary as at September 1, 2015, divided by $20.50, being the price of the common shares of Hydro One Limited in the IPO. The aggregate number of Hydro One Limited common shares issuable under the Society Share Grant Plan shall not exceed 1,434,686 common shares. In 2015, 743,877 Hydro One Limited common shares were granted under the Society Share Grant Plan relevant to the total share based compensation recognized by the Distribution Business.

The fair value of the Hydro One Limited share grants is estimated based on the grant date Hydro One Limited share price of $20.50 and is recognized using the graded-vesting attribution method as the share grant plans have both a performance condition and a service condition. Total fair value of shares granted to employees of Hydro One Networks' Distribution Business in 2015 is $59 million (2014 – $nil). Total share based compensation recognized during 2015 by Hydro One Networks' Distribution Business was $5 million (2014 – $nil) and was recorded as a regulatory asset. The historical turnover rate relating to members of the Power Workers' Union and The Society of Energy Professionals is not believed to be reflective of a future turnover rate due to benefits conferred by the share grant plans. At December 31, 2015, the Company expects all eligible employees to receive the share grants until such time that they no longer meet the eligibility criteria and therefore, a forfeiture rate of 0% is assumed in amounts recognized during 2015. The Company will reevaluate this assumption in subsequent periods based on actual experience.

A summary of the Distribution Business' share grant activity under the Share Grant Plans as of December 31, 2015 is presented below:

Years ended December 31, 2015	Share Grants *(Number)*	Weighted-Average Price
Outstanding – beginning of year	–	–
Granted (non-vested)	2,896,396	$20.50
Outstanding – end of year	2,896,396	–

Employee Share Ownership Plan

Effective December 15, 2015, Hydro One Limited established an Employee Share Ownership Plan (ESOP). Under the ESOP, certain eligible management and non-represented employees may contribute between 1% and 6% of their base salary towards purchasing common shares of Hydro One Limited. Hydro One Networks will match 50% of the employee's contributions, up to a maximum Company contribution of $25,000 per calendar year. No contributions were made under the ESOP during 2015.

Long-term Incentive Plan

Effective August 31, 2015, the Board of Directors of Hydro One Limited adopted a Long-term Incentive Plan (LTIP). Under the LTIP, long-term incentives will be granted to certain executive and management employees of Hydro One Limited and its subsidiaries, and all equity-based awards will be settled in newly-issued shares of Hydro One Limited from treasury, consistent with the provisions of the plan. The aggregate number of shares issuable under the LTIP shall not exceed 11,900,000 shares of Hydro One Limited.

The LTIP provides flexibility to award a range of vehicles, including restricted share units, performance share units, stock options, share appreciation rights, restricted shares, deferred share units and other share-based awards. The mix of vehicles is intended to vary by role to recognize the level of executive accountability for overall business performance. No long-term incentives were awarded during 2015.

20. RELATED PARTY TRANSACTIONS

The Distribution Business is a separately regulated business of Hydro One Networks which is a subsidiary of Hydro One. Hydro One is owned by Hydro One Limited, and the Province is the majority shareholder of Hydro One Limited. The OEFC, IESO, Ontario Power Generation Inc. (OPG), the OEB, and Hydro One Brampton are related parties to Hydro One Networks because they are controlled or significantly influenced by the Province. Transactions between these parties and the Distribution Business are described below.

IESO

- In 2015, the Distribution Business purchased power in the amount of $1,963 million (2014 – $2,172 million) from the IESO-administered electricity market.
- The Distribution Business receives amounts for rural rate protection from the IESO. Revenues in 2015 include $125 million (2014 – $125 million) related to this program.
- The IESO funds substantially all of the Company's conservation and demand management programs. The funding includes program costs, incentives, and management fees. In 2015, the Distribution Business received $63 million (2014 – $28 million) related to these programs.

OPG

- In 2015, the Distribution Business purchased power in the amount of $11 million (2014 – $23 million) from OPG.
- The Company has service level agreements with OPG. These services include field and engineering, logistics, corporate, telecommunications and information technology services. Operation, maintenance and administration costs of the Distribution Business in 2015 and 2014 related to the purchase of services with respect to these service level agreements were not significant.

OEFC

- In 2015, the Distribution Business purchased power in the amount of $6 million (2014 – $10 million) from power contracts administered by the OEFC.
- During 2015, Hydro One paid a $8 million (2014 – $5 million) 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. Hydro One has not made any claims under the indemnity since it was put in place in 1999. Hydro One and the OEFC, with the consent of the Minister of Finance, terminated the indemnity fee effective October 31, 2015. The Distribution Business' allocation of this fee was $1 million.
- PILs and payments in lieu of property taxes were paid to the OEFC.

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. In 2015, the Distribution Business incurred $7 million (2014 – $6 million) in OEB fees.

Hydro One Brampton

- Effective August 31, 2015, Hydro One Brampton is no longer a subsidiary of Hydro One, but is indirectly owned by the Province.

  Subsequent to August 31, 2015, the Distribution Business continues to provide certain management, administrative and smart meter network services to Hydro One Brampton pursuant to certain service level agreements, which are provided at market rates. These agreements will continue until the end of 2016 (except in the case of smart meter network services, which will continue until the end of 2017). Hydro One Brampton has the right to renew these agreements (other than smart meter network services) for additional one-year terms to end no later than December 31, 2019. These agreements will terminate if the Province disposes of its interest in Hydro One Brampton, except in the case of the smart meter network services agreement, which is anticipated to continue for a transition period after the Province disposes of its interest in Hydro One Brampton. From September 1 to December 31, 2015, revenues related to the provision of services with respect to these service level agreements were $1 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)*	**2015**	**2014**
Accounts receivable	60	98
Accrued liabilities[1]	(128)	(180)

[1] Included in accrued liabilities at December 31, 2015 are amounts owing to the IESO in respect of power purchases of $127 million (2014 – $176 million).

Hydro One Limited and Subsidiaries

- The Distribution Business provides services to, and receives services from, Hydro One Limited and its subsidiaries. Amounts due to and from Hydro One Limited and its subsidiaries are settled through the inter-company demand facility.

  The Company has entered into various agreements with Hydro One Limited and its other subsidiaries related to the provision of shared corporate functions and services, including legal, financial and human resources services, and operational services, including environmental, forestry, and line services. 2015 revenues of the Distribution Business include $4 million (2014 – $2 million) related to the provision of services to Hydro One and its subsidiaries. In 2015, services were purchased from Hydro One Limited and its other subsidiaries totalling $16 million (2014 – $12 million), of which $16 million (2014 – $11 million) was expensed and less than $1 million (2014 – $1 million) was capitalized.
- The Distribution Business' long-term debt is due to Hydro One. In addition, balances payable or receivable under the inter-company demand facility are due to or due from Hydro One Limited. Financing charges include interest expense on the long-term debt in the amount of $154 million (2014 – $158 million), and interest expense on the inter-company demand facility in the amount of $3 million (2014 – $1 million). At December 31, 2015, the Distribution Business had accrued interest payable to Hydro One totaling $36 million (2014 – $38 million).
- During 2015, Hydro One Networks declared preferred share dividends in the amount of $16 million (2014 – $20 million) and common share dividends in the amount of $875 million (2014 – $724 million) to Hydro One. The amount allocated to the Distribution Business to finance these dividends was $240 million (2014 – $59 million). The entire amount was paid in 2015 (2014 – entire amount was paid in 2014).
- In 2015, Hydro One Limited established certain stock-based compensation plans, however they represent components of costs of Hydro One and its subsidiaries, including Hydro One Networks in current and future periods. Hydro One and Hydro One Limited entered into an intercompany agreement, such that Hydro One will pay Hydro One Limited for the compensation costs associated with the share grant plans. The agreement requires Hydro One Networks to reimburse Hydro One for the value of shares granted to the Company's eligible employees relating to these plans. At December 31, 2015, Hydro One Networks' Distribution Business had a payable of $5 million (2014 – $nil) to Hydro One associated with these plans. See Note 19 – Stock-based Compensation.

- On August 31, 2015, the common shares of Norfolk Power were transferred to Hydro One Networks by Hydro One. On September 1, 2015, Norfolk Power started dissolution proceedings and, as a result, its assets were transferred to Hydro One Networks. For details, see Note 4 – Norfolk Power Transfer.

21. 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)*	**2015**	**2014**
Accounts receivable	209	(132)
Materials and supplies	3	(1)
Other assets	7	(5)
Accounts payable	(10)	4
Accrued liabilities	(11)	16
Accrued interest	(2)	–
Long-term accounts payable and other liabilities	6	–
Post-retirement and post-employment benefit liability	38	38
	240	(80)

Capital Expenditures

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

Year ended December 31 *(millions of Canadian dollars)*	**2015**	**2014**
Capital investments in property, plant and equipment	(653)	(633)
Capitalized depreciation and net change in accruals included in capital investments in property, plant and equipment	19	19
Capital expenditures – property, plant and equipment	(634)	(614)

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

Year ended December 31 *(millions of Canadian dollars)*	**2015**	**2014**
Capital investments in intangible assets	(26)	(14)
Net change in accruals included in capital investments in intangible assets	2	–
Capital expenditures – intangible assets	(24)	(14)

Supplementary Information

Year ended December 31 *(millions of Canadian dollars)*	**2015**	**2014**
Net interest paid	156	155
Income taxes / PILs paid	21	15

22. CONTINGENCIES

In September 2015, Hydro One and three of its subsidiaries, including Hydro One Networks, were served with a class action suit in which the representative plaintiff is seeking up to $125 million in damages related to allegations of improper billing practices. Hydro One intends to defend the action. Due to the preliminary stage of legal proceedings, an estimate of a possible loss related to this claim cannot be made.

The Company is a wholly-owned subsidiary of Hydro One. As such, the assets of the Distribution Business are available to satisfy the debts, contingent liabilities and commitments of both the Company and Hydro One

23. COMMITMENTS

The Company and Hydro One have numerous commitments. These commitments have not been specifically allocated to the Distribution Business. However, the assets of the Distribution Business are available to satisfy the commitments of both the Company and Hydro One.

24. SUBSEQUENT EVENTS

Long-term Debt

On February 24, 2016, Hydro One issued the following notes under its MTN Program:

- $500 million notes with a maturity date of February 24, 2021 and a coupon rate of 1.84%. This issuance was mirrored down to Hydro One Networks through the issuance of inter-company debt with a coupon rate of 1.86%, of which $250 million was allocated to the Company's Distribution Business;
- $500 million notes with a maturity date of February 24, 2026 and a coupon rate of 2.77%. $490 million of this issuance was mirrored down to Hydro One Networks through the issuance of inter-company debt with a coupon rate of 2.79%, of which $245 million was allocated to the Company's Distribution Business; and
- $350 million notes with a maturity date of February 23, 2046 and a coupon rate of 3.91%. This issuance was mirrored down to Hydro One Networks through the issuance of inter-company debt with a coupon rate of 3.93%, of which $175 million was allocated to the Company's Distribution Business.

On March 3, 2016, Hydro One repaid $450 million of maturing long-term debt notes under its MTN Program. On the same date, Hydro One Networks repaid inter-company debt of $450 million to Hydro One, of which $180 million was allocated to the Company's Distribution Business.

Payments to Finance Dividends

On February 11, 2016, Hydro One Networks declared common share dividends in the amount of $2 million, and a return of stated capital in the amount of $225 million was approved. The amount allocated to the Distribution Business to finance these payments was $114 million, of which $12 million was paid on February 22, 2016.

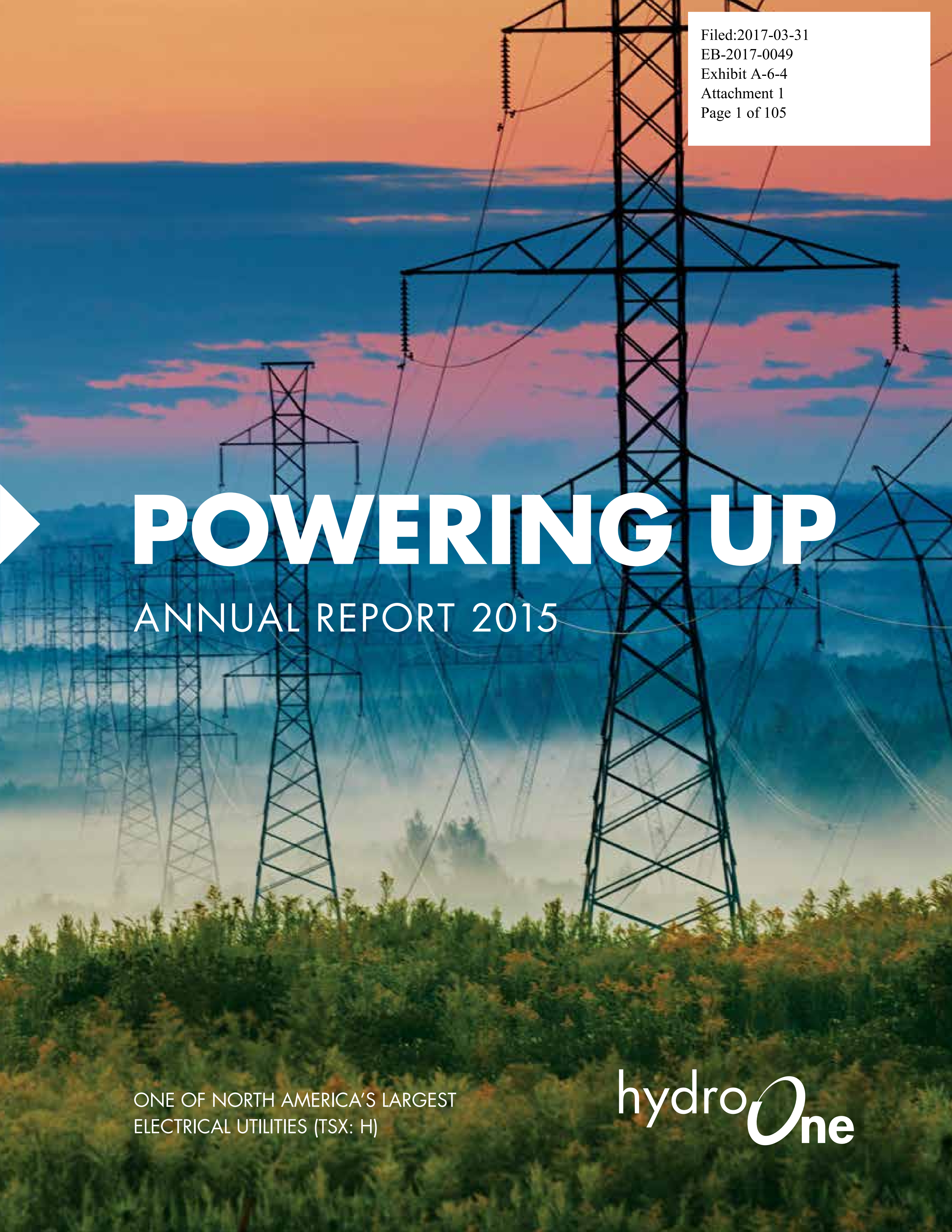
HYDRO ONE NETWORKS INC. DISTRIBUTION PRO FORMA STATEMENT OF INCOME BRIDGE YEAR (2017) AND TEST YEAR (2018) ($ MILLIONS)

Line No.	Particulars	2017	2018
	Revenues		
1	Retail power & energy	1,385	1,468
2	Commodity flow-through	3,439	3,578
3	LV	-	-
4	Other	46	47
5		4,871	5,094
	Costs		
6	OM&A	583	594
7	Cost of power	3,439	3,578
8	Depreciation	384	398
9	Capital tax	-	-
10		4,406	4,571
11	Earnings before interest and income tax	465	522
12	Interest expense	167	177
13	Earnings before income tax	298	345
14	Income tax	45	59
15	Net income	252	286

HYDRO ONE LIMITED - HISTORICAL YEAR ANNUAL REPORT

Included in this exhibit are Hydro One Limited's Annual Reports:

- Attachment 1: 2015 Annual Report
- Attachment 2: 2016 Annual Report – To be filed behind this Tab when it becomes available.

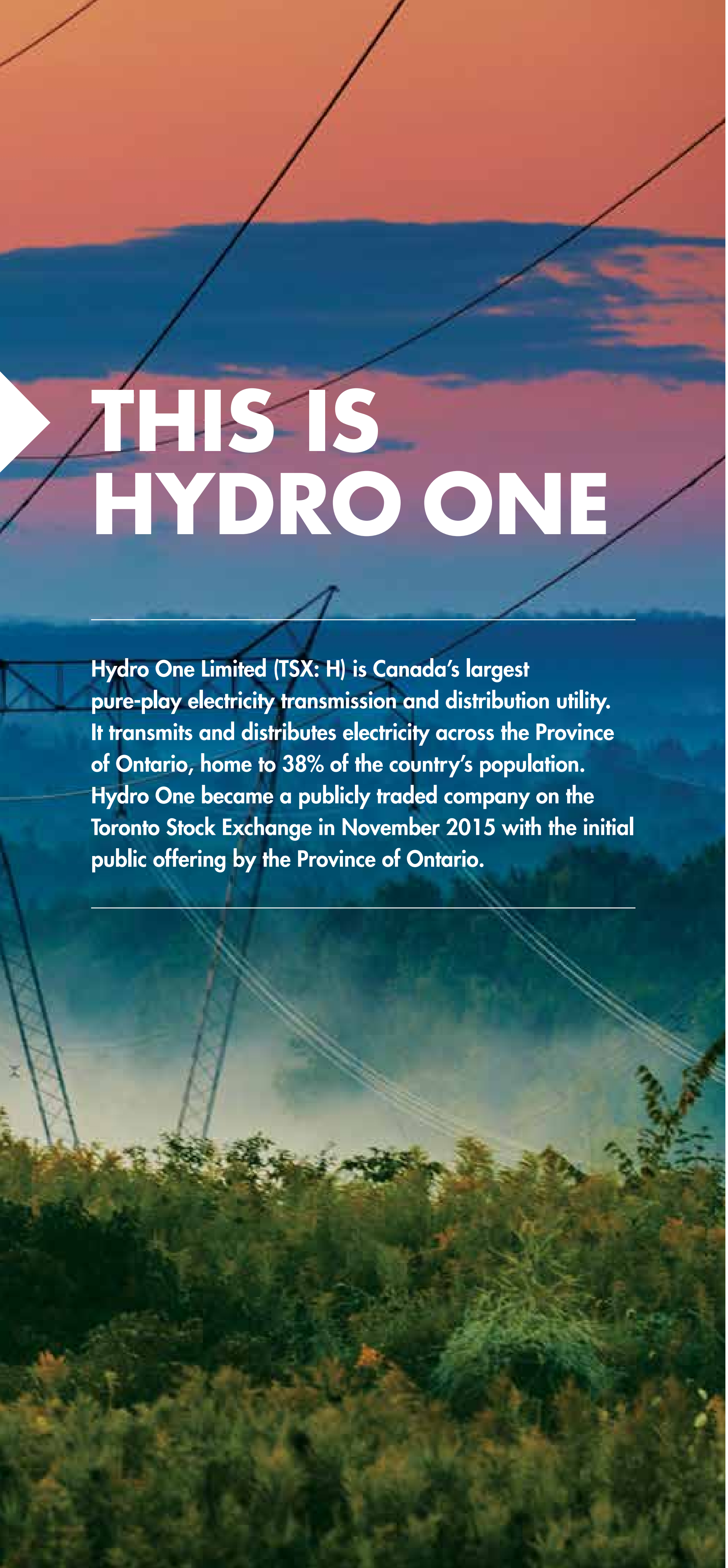


POWERING UP

ANNUAL REPORT 2015

ONE OF NORTH AMERICA'S LARGEST
ELECTRICAL UTILITIES (TSX: H)

hydro One



THIS IS HYDRO ONE

Hydro One Limited (TSX: H) is Canada's largest pure-play electricity transmission and distribution utility. It transmits and distributes electricity across the Province of Ontario, home to 38% of the country's population. Hydro One became a publicly traded company on the Toronto Stock Exchange in November 2015 with the initial public offering by the Province of Ontario.

Hydro One Limited has three reportable segments: the electrical transmission business, the electrical distribution business and a third business segment consisting of the company's telecommunications business and certain corporate activities.

Together, the company's regulated transmission and distribution operations comprise approximately 88% of Hydro One's assets and provide 98% of its net revenues.

Hydro One Telecom leverages the company's telecommunications and tower assets to sell broadband fibre-optic capacity to other carriers, large corporations, government agencies, and healthcare and educational institutions.

A new governance agreement between Hydro One and the Province of Ontario was announced on April 16, 2015. On July 17, 2015 a new independent Board of Directors was appointed to govern Hydro One through its transition into a publicly traded company.

In November 2015, Hydro One Limited completed the initial public offering of 15% of its common shares, with the proceeds of the offering going to the Province of Ontario in the first phase of its previously announced sale of the majority of the company to the public. The common shares are listed and trade on the Toronto Stock Exchange under the symbol "H".

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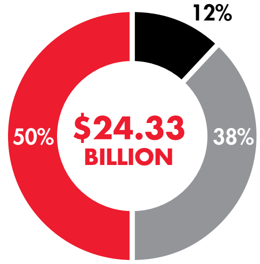
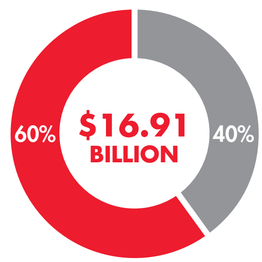
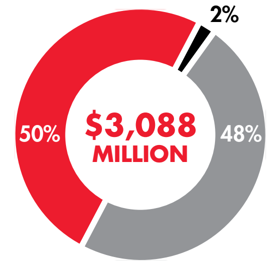
TOTAL ASSETS



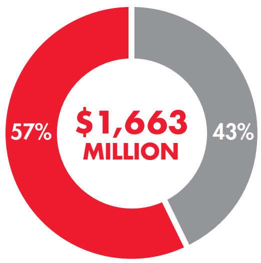
RATE BASE



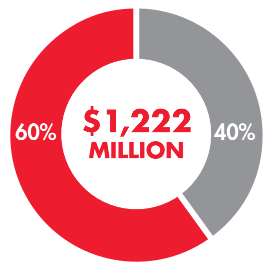
REVENUES (NET OF POWER COSTS)



CAPITAL INVESTMENTS



REGULATED EARNINGS BEFORE FINANCING CHARGES AND INCOME TAXES[1]



Transmission

Distribution

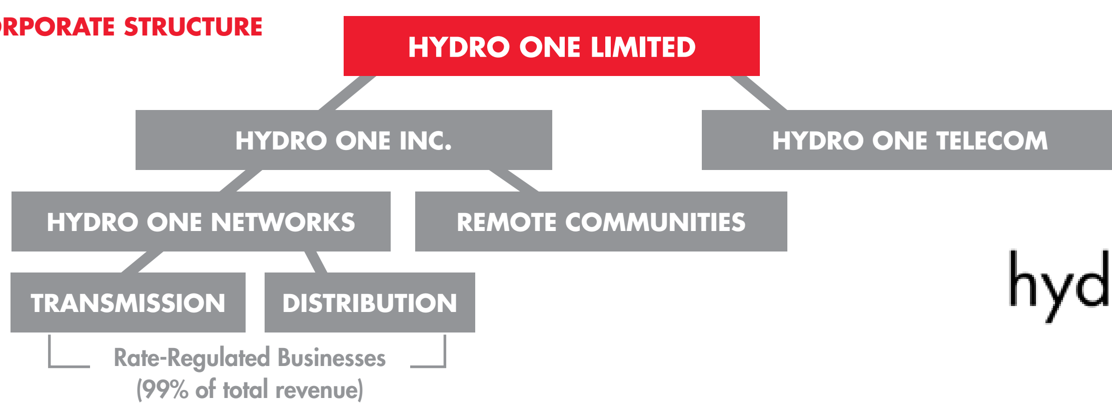
Other

Year ended December 31
(CAD millions, except as otherwise noted)

	2015	2014
Revenues	**6,538**	6,548
Purchased power	**3,450**	3,419
Revenues (net of purchased power)	**3,088**	3,129
Operation, maintenance and administration	**1,135**	1,192
Depreciation and amortization	**759**	722
Income before financing charges and income tax expense	**1,194**	1,215
Financing charges	**376**	379
Income tax expense	**105**	89
Net income attributable to common shareholders of Hydro One	**690**	**731**
Basic and diluted earnings per common share (EPS) *(Canadian dollars)*	**1.39**	1.53
Adjusted basic and diluted EPS *(Canadian dollars)*[2]	**1.16**	**1.23**
Net cash from (used in) operating activities	**(1,253)**	1,256
Adjusted net cash from operating activities[3]	**1,557**	1,256
Funds from (used in) operations (FFO)	**(1,479)**	1,293
Adjusted FFO[3]	**1,331**	1,293
Capital investments	**1,663**	1,530
Transmission – average monthly 60-minute peak demand *(MW)*	**20,344**	20,596
Distribution – average monthly units distributed to customers *(TWh)*	**28.9**	29.8

[1] Distribution and transmission segments
[2] Calculated using the number of common shares outstanding at December 31, 2015
[3] Excludes $2,810 million impact of deferred income tax asset that resulted as a consequence of leaving the payment in lieu of taxes regime and entering the federal tax regime.

CORPORATE STRUCTURE



"Hydro One has a fully independent, diverse and deeply experienced Board of Directors to govern the Company's business, allowing it to execute as an independently controlled and professionally managed commercial entity well positioned to generate growth and value for our shareholders..."

DAVID F. DENISON

Chair of the Board

Dear fellow shareholders,

This was a seminal year of change and movement forward for Hydro One.

The transformative journey began last spring when the Province of Ontario, previously the sole shareholder of Hydro One, made a series of announcements relating to the company, including that it would broaden the ownership through an initial public offering. While the province remains the company's largest shareholder with 84% of the outstanding shares today, it has stated that it intends to make additional tranches of shares available to the public in stages, until it achieves its stated goal of reducing its ownership of Hydro One to 40%.

An integral part of the company's future is a renewed focus on customer service excellence and improved performance. During the past summer, the new Board announced the appointment of Mayo Schmidt as the company's new President and Chief Executive Officer and Michael Vels as its Chief Financial Officer. Both executives have strong track records and demonstrated experience in leading the transformation of large, publicly traded companies into high performance, innovative and customer-focused organizations that enhance customer service, accelerate growth and create significant shareholder value. Together with the technical expertise of the existing Hydro One team, I believe they can help to lead the company forward.

In addition to rolling up their sleeves in their critical new roles, the Hydro One management team led one of the largest and most successful initial public offerings in Canada in more than 15 years. The shares of Hydro One began trading on the Toronto Stock Exchange on November 5th.

To facilitate the change in ownership structure associated with the initial public offering, the province announced a new governance agreement between Hydro One and the province. This agreement ensures that the company is governed as an independent commercial entity going forward, providing confidence that the province is strictly playing the role of shareholder and not manager. Over the ensuing months, the new Board was assembled, drawing upon a diverse and accomplished group of proven leaders to govern Hydro One's transformation with a renewed focus on customer service excellence and improved performance and reliability. My fellow Board members were selected for their independence, commercial experience and strong governance expertise concerning public companies, customer service, the electricity sector and public policy.

As management and the Board work together to put in place a broad strategy to take Hydro One forward, work has already commenced across the company to strengthen customer service and performance excellence while putting in place initiatives to accelerate growth.

I would like to recognize the important foundational work of the previous Chair, Sandra Pupatello, and her Board, and acknowledge the efforts of former President and Chief Executive Officer Carmine Marcello: his contribution and leadership was essential to Hydro One's successful transition in 2015. Finally, I would like to thank the more than 5,500 Hydro One employees who work tirelessly – often around the clock and in hazardous weather and conditions – to ensure that electricity is delivered safely, reliably and cost-effectively to the millions of citizens of Ontario. It is their efforts and commitment that enable this great company to deliver for you – our shareholders, our customers and our communities – and we look forward to taking your company even further in 2016.

Thank you for your support,

David F. Denison, OC

Chair of the Board
Hydro One Limited

"2015 was a year of tremendous positive change for Hydro One. The team is intently focused on transforming this significant North American electrical utility into a high-performance commercial organization with considerable muscle to accelerate growth and consistently deliver on its promises..."

MAYO SCHMIDT

President and CEO

Dear fellow shareholders,

It is clear that 2015 was a pivotal year for your company as Hydro One charted a new course towards becoming a publicly traded, increasingly customer-focused and performance-driven company that offers dependable dividends and robust, predictable growth prospects.

It was a year of tremendous positive change that opened the door to a very bright future.

The size, strength and efficiency of our electrical grid is critical to reliably delivering the electricity that sustains and secures the economic and social well-being of every community in Ontario. This past year, the company made important investments to modernize and bolster the grid, investing approximately $1.7 billion in capital projects across both our transmission and distribution networks. Over the next few years, we will invest in significant infrastructure that is needed to maintain and modernize the critical electrical systems that we all depend on. We are stewards of this system, a mission we take very seriously.

Hydro One is embarking on a journey to take a leadership position in the North American utility landscape. Through building on our strong foundation, we have the opportunity to become a leader in this dynamic and evolving environment. To enable this, we have undertaken a strategic planning process to define our future.

We know that we need to understand the needs of our customers and stakeholders, including First Nations and Métis communities. Serving these needs effectively and efficiently will drive our business decisions. Our strategy will ensure we are ready to adapt to the emerging technology landscape and position our business for success. We will build world-class competencies and position ourselves to grow in the long term.

Hydro One is fortunate to operate in a stable and supportive regulatory environment with a transparent and predictable rate-setting process. The company plays an essential leadership role in the Ontario electricity industry.

We are focused on making life better for our customers. We improve their lives by treating them with respect, by making certain our system is reliable and ready for the future, by managing our costs and thus the cost of our service, and by having highly trained men and women across Ontario who are ready to respond 24/7 when storms and extreme weather disrupt service.

I believe we are uniquely positioned to make the most of the significant opportunities that lie ahead – and transform our business into a great Canadian company that stands out for its commitment to its customers and its performance for its shareholders.

On behalf of our 5,500 employees, thank you for your investment and interest in our progress. I would like to thank the Board of Directors for its support and its confidence in management. I would also like to thank employees across Ontario for embracing Hydro One's transformation and for their unwavering commitment to our customers. The future is bright.

Mayo Schmidt
President and CEO
Hydro One Limited

ELECTRICAL TRANSMISSION OPERATIONS

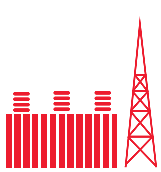
Hydro One's electrical transmission system totals approximately 29,000 circuit kilometres of high-voltage lines, towers and transformers, operating at 500 kV, 230 kV or 115 kV. Hydro One's grid transmits electricity from hydroelectric, nuclear, gas, wind and solar power generation sources to customers across Ontario, including 47 local distribution companies (LDCs), Hydro One's own local distribution systems and 90 large industrial customers directly connected to the transmission system.

The transmission operations service approximately 96% of the Province of Ontario by capacity and represent approximately 50% of the total assets and provide 50% of the net revenues of the company.

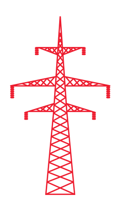
The transmission system is linked to five jurisdictions adjacent to Ontario (Manitoba, Minnesota, Michigan, New York and Quebec) through high-voltage interconnections. The transmission operations are regulated by the Ontario Energy Board (OEB) and the National Energy Board (NEB), together with an operating agreement with the Independent Electricity System Operator (IESO) and the North American Electric Reliability Corporation (NERC). Hydro One is also a partner in the Bruce to Milton Limited Partnership, which is a unique partnership between the company and the Saugeen Ojibway Nation Finance Corporation, operating a 176-kilometre long dual circuit transmission line between the Bruce Nuclear Generating Station and Hydro One's Milton Switching Station.

Our transmission assets can be divided into four functional categories:

1. **Transmission stations:** These facilities are used for the delivery of power, voltage transformation and switching, and serve as connection points for both customers and generators.
2. **Transmission lines:** Bulk transmission lines are main lines delivering power from generating stations or connections to receiving terminal stations. Area supply lines take power from the network and transmit it to customer supply transmission stations at customer load centres.
3. **Network operations:** All transmission assets and many sub-transmission assets are managed from one central location, the Ontario Grid Control Centre.
4. **Telecommunications facilities:** These facilities ensure the company's telecommunications requirements are met, with respect to the protection and operation of the power system as well as voice and administrative data. Our subsidiary Hydro One Telecom sells excess capacity on our fibre-optic network.



TRANSMISSION STATIONS
292

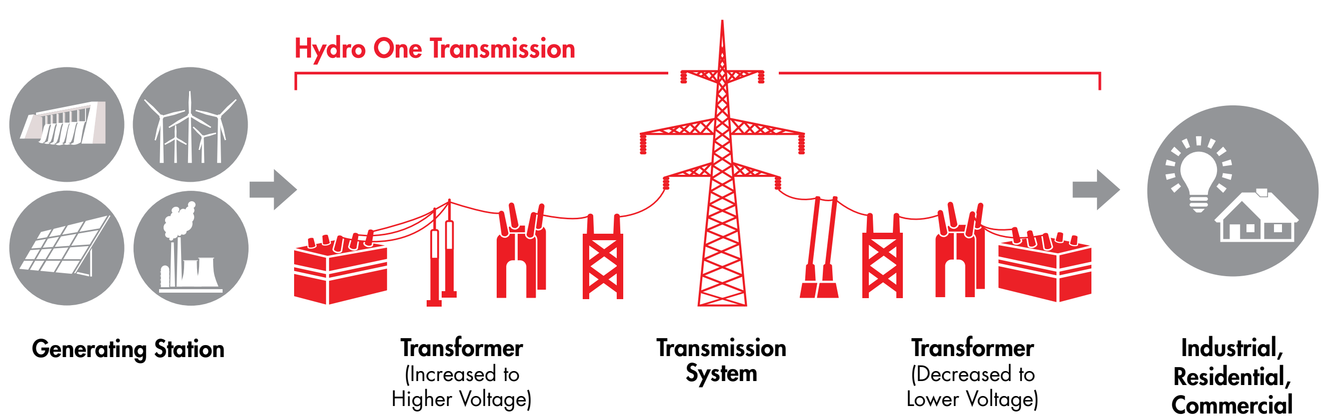


CIRCUIT KILOMETRES OF HIGH-VOLTAGE LINES
29,000

	TRANSMISSION SEGMENT
Customers	47 local distribution companies and 90 large industrial customers connected directly to the transmission network
Assets	292 transmission stations and approximately 29,000 circuit kilometres of high-voltage lines
Current Rate Base	$10.18 billion[1]
Allowed ROE (2016)	9.19%

[1] *Current transmission rate base as at December 31, 2015 includes 100% of B2MLP rate base.*

ONTARIO'S ELECTRICITY SYSTEM



ELECTRICAL DISTRIBUTION OPERATIONS

Hydro One's electrical distribution system totals approximately 123,000 circuit kilometres of lower-voltage power lines, poles and transformers, serving more than 1.3 million customers across Ontario.

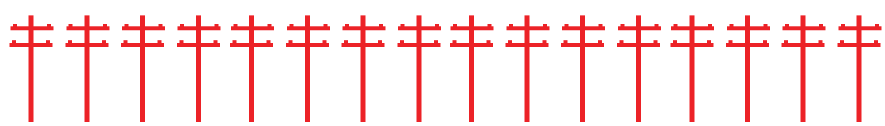
As Hydro One operates in both rural and urban centres across Ontario, customers benefit from our integrated planning and the coordinated operations of our distribution and transmission systems and workforce.

In June 2015, Hydro One announced the closing of its acquisition of Haldimand County Utilities, adding 21,200 customers to its local distribution network. In October, the closing of the acquisition of Woodstock Hydro Holdings Inc., including its wholly-owned subsidiary Woodstock Hydro Services Inc., added 15,800 customers, to be integrated with Hydro One's network in 2016.

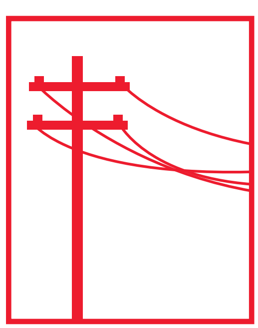
Hydro One Remote Communities Inc. operates and maintains the generation and distribution assets used to supply electricity to 21 remote communities across northern Ontario that are not connected to the electricity transmission grid.

HYDRO ONE HAS A LARGELY RURAL AND SUBURBAN FOOTPRINT

1.3 MILLION CUSTOMERS



1.6 MILLION POLES

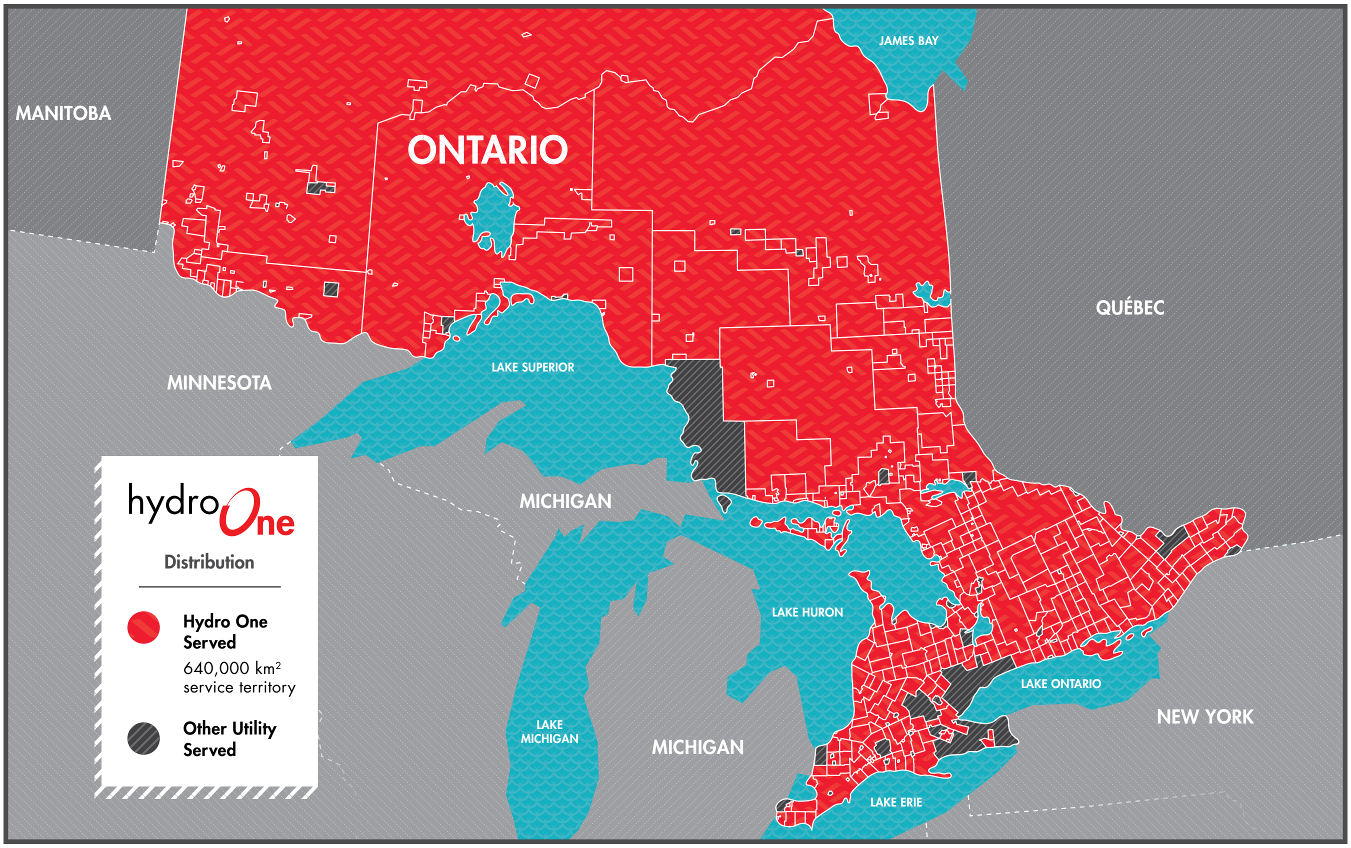


CIRCUIT KILOMETRES OF LOWER-VOLTAGE LINES

123,000

DISTRIBUTION AND REGULATION STATIONS

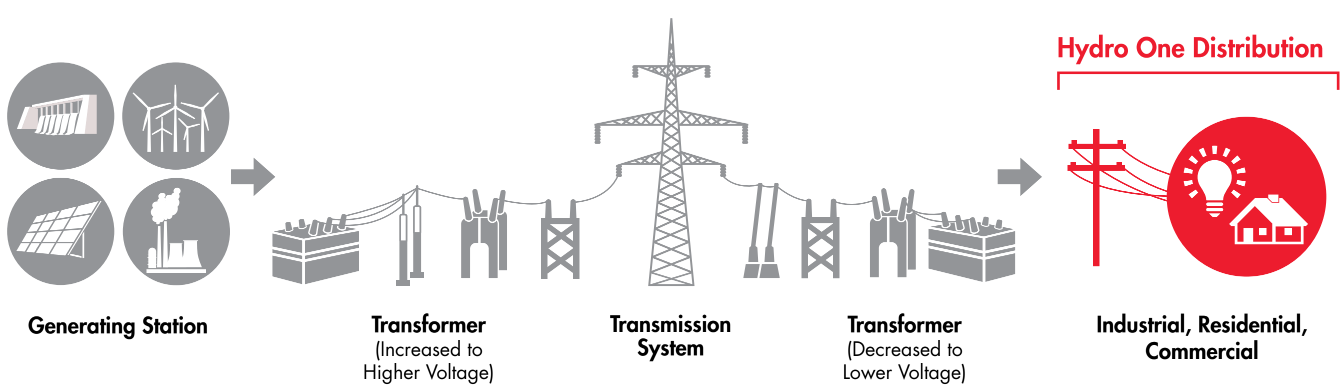
c. 1,000



	DISTRIBUTION SEGMENT
Customers	Approximately 1.3 million residential and business customers located mostly in rural areas, covering approximately 75% of the geographic area of the province, equal to roughly 640,000 square kilometres
Assets	123,000 circuit kilometres of lower-voltage distribution lines and approximately 1,000 distribution and regulating stations
Current Rate Base	$6.74 billion[1]
Allowed ROE (2016)	9.19%

[1] *Current distribution rate base as at December 31, 2015.*

ONTARIO'S ELECTRICITY SYSTEM



SERVING CUSTOMERS

Throughout 2015, Hydro One continued to put customers at the core of its decision-making, planning and execution. Every day the organization is focused on exceeding customer expectations. Whether it's launching new customer-friendly tools or mobilizing hundreds of employees to restore power, Hydro One's future path to success lies with our ability to exceed expectations.

CUSTOMER COMMITMENTS

In 2015, Hydro One was the first utility in Canada to launch Customer Commitments and service level guarantees. Developed with input from more than 40,000 customers and the company's Customer Service Advisory Panel, these five commitments provide assurance to customers about the service they can expect from Hydro One:

1. **We will provide you with a bill you can trust and understand.**
2. **We will provide you with a reliable supply of electricity.**
3. **We will make it easy to do business with us.**
4. **We will courteously and promptly work to resolve any issues you may have.**
5. **We will help you manage your electricity use.**

MOBILE OUTAGE APP

Customer service includes keeping customers connected to the information that is most important to them. The company's mobile outage app – available free to customers on their smartphones – was downloaded more than 60,000 times during 2015, totaling more than 286,000 since its launch in May 2012.

OUTAGE ALERTS

Drawing on the success of the mobile app, Hydro One was the first utility in Canada to launch personalized text and email alerts to customers, proactively informing them of outages that might affect their homes, cottages, farms or small businesses. Customers who register for this service receive alerts and updates on estimated times of restoration when an outage has been reported near their residences. Customers decide when and how they receive messages. To date, more than 7,000 customers have signed up for the service.

OFFICE OF THE OMBUDSMAN

To further support customer service, in October the company's Board of Directors appointed Fiona Crean to the role of Ombudsman for Hydro One. Having most recently served as the City of Toronto's ombudsman, Ms. Crean has worked in the area of complaints investigation and dispute resolution for more than 25 years.

STORM RESPONSE

Wind, snow and rain are a reality of life in Ontario. Across the province, the men and women of Hydro One are available 24 hours a day, seven days a week, to restore power for customers if the lights go out.

From the state-of-the-art Ontario Grid Control Centre, highly trained employees monitor all potential events, including weather, solar storms and geomagnetic disturbances that could affect Hydro One's system. The centre provides Hydro One with the industry-leading ability to remotely monitor and operate transmission equipment, respond to alarms and restore or reroute interrupted power.

When an alert is issued, the entire organization begins mobilizing staff and equipment to ensure power is restored as efficiently as possible. This means moving crews and equipment to where they are needed to make sure that power can be restored safely and quickly. With a workforce trained to the highest standards, crews can travel more than 500 kilometres to aid in restoration.

Working through holidays, in the harshest of conditions and in remote areas of the province, Hydro One employees not only restore power, but restore life back to normal for customers.

SAFETY, COMMUNITY AND THE ENVIRONMENT

SAFETY

The safety of the public, the communities Hydro One serves and the people of Ontario is every employee's responsibility.

From proper job planning to a trained and highly-skilled workforce, Hydro One emphasizes the importance of a safe workplace across every line of business. The result of this focus was seen in 2015 as Hydro One achieved its ambitious health and safety target, recording only 1.68 incidents per 200,000 hours worked.

Hydro One was awarded the Electrical Safety Authority's Powerline Safety Award for its community outreach with the company's mobile Electricity Discovery Centre. More than 30,000 visitors from 26 communities learned about electrical safety, how to conserve energy and the role Hydro One plays in the community.

COMMUNITY

Hydro One believes in the importance of connecting with the communities where we live and work through sponsorships, donations, scholarship programs and volunteering. These charitable giving programs broadly support safety and injury prevention, education and community support. They are an important link to the hundreds of communities that the company serves across the province.

Community Investment

Furthering the company's commitment to First Nations and Métis communities, in February 2015 Hydro One announced a three-year funding extension for Right to Play's Promoting Life-skills in Aboriginal Youth program. Hydro One is investing $100,000 each year to support after-school programming, sport for developmental activities, youth leadership, and health and wellness education.

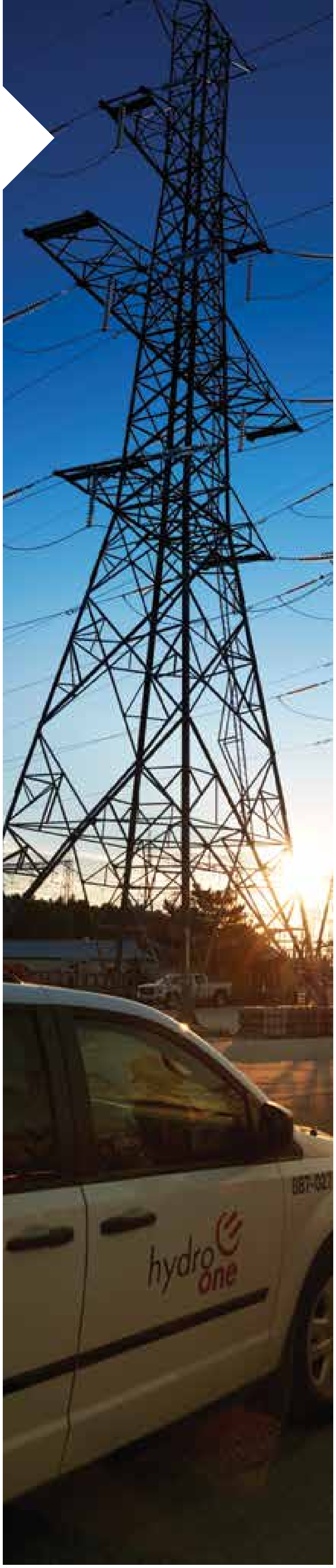
Scholarship Programs

In 2015, 13 female engineering students received Hydro One's Women in Engineering Scholarship for their outstanding achievements in electrical engineering. Winners receive a financial award along with a paid opportunity to work for Hydro One in a developmental student work placement. In celebration of National Aboriginal Day, in June Hydro One awarded 12 students with the Leonard S. (Tony) Mandamin Scholarship, which is granted annually to First Nations, Métis or Inuit post-secondary students.

CORPORATE SOCIAL RESPONSIBILITY

In January, Hydro One was designated as a Sustainable Electricity Company by the Canadian Electricity Association (CEA). This designation established by the CEA for utilities across Canada recognizes success building on the three foundational pillars of sustainability – environmental, social, and economic performance. It requires utilities to establish an Environmental Management System consistent with the ISO 14001 standard; to take the actions and meet the expectations laid out in the ISO 26000 Guidance on Social Responsibility. Hydro One is only the fourth electric utility in Canada to receive this designation.

***For further information on Hydro One's commitments to customers, safety, communities and the environment, please go to:* www.HydroOne.com/OurCommitment.**



CORPORATE GOVERNANCE OVERVIEW

Hydro One and the Board recognize the importance of corporate governance to the effective management of the company. Independence, integrity and accountability are the foundation of the company's approach to corporate governance. It is in the long-term best interests of our shareholders as well as our customers and promotes and strengthens relationships with employees, the communities in which the company operates and other stakeholders of the company.

Hydro One's Board of Directors was appointed on July 17, 2015, drawing upon a diverse and accomplished group of proven business leaders with deep corporate governance experience. The Board's primary role is overseeing corporate performance and the quality, depth and continuity of management required to meet the company's strategic objectives.

Hydro One is committed to best practices that will allow us to honour important fiduciary and oversight responsibilities. The Board regularly reviews and revises the company's governance practices in response to changing governance expectations and regulations. Our practices meet the rules and regulations issued by Canadian Securities Administrators and the Toronto Stock Exchange, including national corporate governance guidelines and related disclosure requirements.

The **Audit Committee** reviews the integrity of the company's financial statements and financial reporting process, internal control over financial reporting, enterprise risk management, disclosure controls and procedures, and compliance with other related legal and regulatory requirements. The committee also assists the Board in fulfilling its oversight responsibilities with respect to financial reporting, including overseeing the independence, qualifications and appointment of external auditors as well as the performance of the company's finance function, auditors (both external and internal) and the auditing, accounting and financial reporting process.

The **Nominating, Corporate Governance, Public Policy and Regulatory Committee** manages and oversees the process of nominating new directors to the Board in accordance with the governance agreement between the company and the Province of Ontario. The committee makes recommendations respecting the Board's approach to corporate governance, overseeing director orientation, education, performance evaluation, compensation and protection. The committee also oversees the company's relationship with shareholders, communities, stakeholders, electricity regulators, customers, the Province of Ontario and the company's approach to corporate social responsibility, including its sponsorship and donation programs.

The **Human Resources Committee** assists the Board in discharging the Board's oversight responsibilities relating to compensation, attraction and retention of key senior management, employee benefits, labour relations and succession planning.

The **Health, Safety, Environment and First Nations and Métis Committee** is responsible for oversight relating to effective occupational health and safety and environmental policies and practices at the company as well as the company's relationships with First Nations and Métis communities.

***For a complete description of Hydro One's corporate governance structure and practices and individual director biographical information, please go to:* www.HydroOne.com/Investors.**

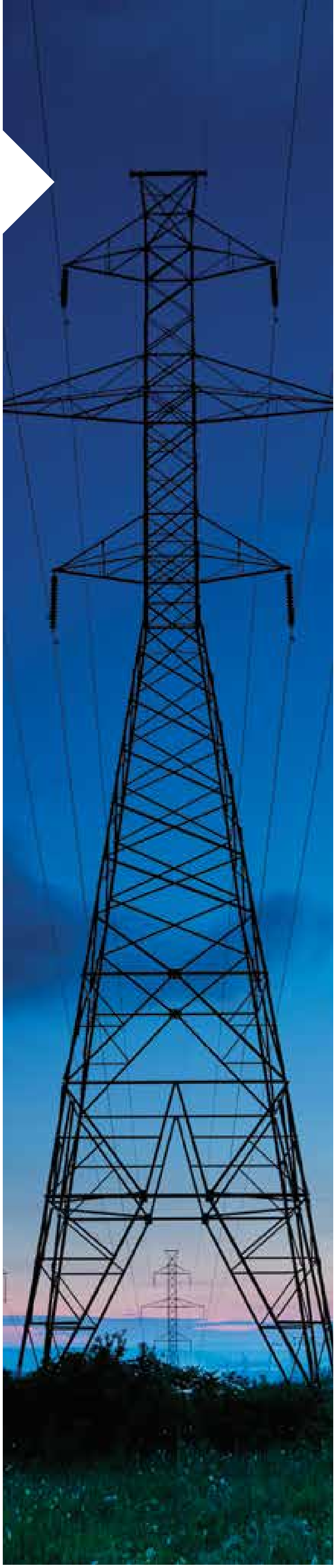
BOARD OF DIRECTORS AND COMMITTEES

★ = CHAIR
▲ = MEMBER

	AUDIT	NOMINATING, CORPORATE GOVERNANCE, PUBLIC POLICY AND REGULATORY	HUMAN RESOURCES	HEALTH, SAFETY, ENVIRONMENT AND FIRST NATIONS AND MÉTIS
David Denison (Chair)				
Mayo Schmidt (President and CEO)				
Ian Bourne		▲	★	
Charles Brindamour	▲		▲	
Marc Caira		▲	▲	
Christie Clark		▲	▲	
George Cooke	▲			▲
Marianne Harris			▲	★
Jim Hinds	▲			▲
Kathryn Jackson		▲		▲
Roberta Jamieson	▲			▲
Frances Lankin	▲	▲		
Philip Orsino	★	▲		
Jane Peverett		★	▲	
Gale Rubenstein			▲	▲

HYDRO ONE GOOD GOVERNANCE PRACTICES

100% Director Independence	Code of Business Conduct and Whistleblower Hotline	Annual Reviews of Board and Committee Performance
Board Education Sessions	Committee Authority to Retain Independent Advisors	Board and Committee In-Camera Discussions
Term Limits for Directors	Director Share Ownership Guidelines	Commitment to Director Diversity



WHY INVEST IN HYDRO ONE?

Opportunities to transition to a customer focused performance culture under Ontario's emerging incentive-based regulation	One of the largest electrical utilities in North America, with significant scale and a leadership position in Canada's most populated province
One of the strongest investment grade balance sheets in the utility sector	Unique combination of electrical transmission and local distribution, with no power generation assets or material exposure to commodity prices
Attractive dividend yield with 70 – 80% target payout ratio and opportunity for growth with rate base expansion	The business operates in a stable, transparent and collaborative rate-regulated environment
2015 IPO was the first phase of the largest-ever privatization by the Province of Ontario providing opportunities for public participation in asset transformation	Predictable growth profile, with consistent rate base growth expected under multi-year approved capital investment program to upgrade aging infrastructure
Strong governance structure and a fully independent Board allow the company to operate autonomously, transform its culture and drive shareholder value creation on multiple fronts	Proven management with demonstrated experience transforming organizations, accelerating performance and creating significant shareholder value

A unique opportunity to participate in the transformation of a premium, large-scale utility

hydroOne

Management's Discussion and Analysis

For the years ended December 31, 2015 and 2014

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 Limited (Hydro One or the Company) for the year ended December 31, 2015. 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 in accordance with National Instrument 51-102 – Continuous Disclosure Obligations of the Canadian Securities Administrators. This MD&A provides information for the year ended December 31, 2015, based on information available to management as of February 11, 2016.

Initial Public Offering

In November 2015, Hydro One and the Province of Ontario (Province) completed an initial public offering (IPO) on the Toronto Stock Exchange of 15% of the Company's 595 million outstanding common shares. Prior to the completion of the IPO, Hydro One and its subsidiary, Hydro One Inc., completed a series of transactions (Pre-Closing Transactions) that resulted in, among other things, the acquisition by Hydro One of all of the issued and outstanding shares of Hydro One Inc. from the Province and the issuance of new common shares and preferred shares of Hydro One to the Province. Both Hydro One and Hydro One Inc. are reporting issuers. See section "Other Developments – Change in Hydro One Ownership Structure" for details relating to the IPO.

Current year information consists of the results of Hydro One Inc. up to October 31, 2015, and the consolidated results of Hydro One and Hydro One Inc. from November 1, 2015 to December 31, 2015. The comparative information consists of the results of Hydro One Inc. as at and for the year ended December 31, 2014.

Consolidated Financial Highlights And Statistics

Year ended December 31 *(millions of Canadian dollars, except as otherwise noted)*	2015	2014	Change
Revenues	6,538	6,548	(0.2%)
Purchased power	3,450	3,419	0.9%
Revenues, net of purchased power	3,088	3,129	(1.3%)
Operation, maintenance and administration costs	1,135	1,192	(4.8%)
Depreciation and amortization	759	722	5.1%
Financing charges	376	379	(0.8%)
Income tax expense	105	89	18.0%
Net income attributable to common shareholders of Hydro One	690	731	(5.6%)
Basic and diluted earnings per common share (EPS)	$1.39	$1.53	(9.2%)
Pro forma adjusted non-GAAP basic and diluted EPS[1]	$1.16	$1.23	(5.6%)
Net cash from (used in) operating activities	(1,253)	1,256	(199.8%)
Adjusted net cash from operating activities[1]	1,557	1,256	24.0%
Funds from (used in) operations (FFO)[1]	(1,479)	1,293	(214.4%)
Adjusted FFO[1]	1,331	1,293	2.9%
Capital investments	1,663	1,530	8.7%
Transmission: Average monthly Ontario 60-minute peak demand *(MW)*	20,344	20,596	(1.2%)
Distribution: Units distributed to Hydro One customers *(TWh)*	28.9	29.8	(3.0%)
Debt to capitalization ratio[2]	50.7%	52.8%	

[1] See section "Non-GAAP Measures" for description and reconciliation of pro forma adjusted non-GAAP basic and diluted EPS, adjusted net cash from operating activities, FFO and adjusted FFO.

[2] Debt to capitalization ratio has been calculated as total debt (includes total long-term debt and short-term borrowings, net of cash) divided by total debt plus total shareholder's equity, including preferred shares but excluding any amounts related to non-controlling interest.

Overview

Hydro One is the largest electricity transmission and distribution company in Ontario. Through its subsidiary, Hydro One Inc., Hydro One owns and operates substantially all of Ontario's electricity transmission network, and is the largest electricity distributor in Ontario. Hydro One has three business segments: (i) Transmission Business; (ii) Distribution Business; and (iii) Other Business (telecommunications).

Transmission Business

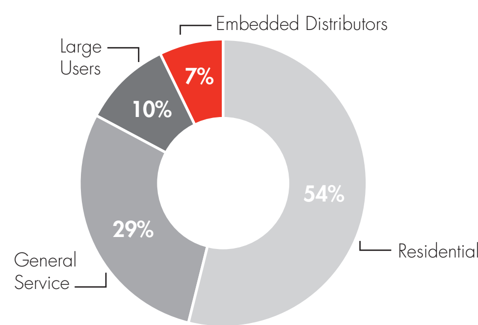
Hydro One's transmission business owns, operates and maintains Hydro One's transmission system, which accounts for approximately 96% of Ontario's transmission capacity. The Transmission Business consists of the transmission system operated by Hydro One Inc.'s subsidiary, Hydro One Networks Inc. (Hydro One Networks), and a 66% interest in B2M Limited Partnership (B2M LP), a limited partnership between Hydro One and the Saugeen Ojibway Nation in respect of the Bruce-to-Milton transmission line. The Company's Transmission Business is a rate-regulated business that earns revenues mainly from charging transmission rates that are approved by the Ontario Energy Board (OEB). The Transmission Business represented approximately 50% of the Company's total assets as at December 31, 2015, and approximately 50% of its total revenues, net of purchased power, in 2015.

	2015	2014
Electricity transmitted *(TWh)*	**137.0**	139.8
Transmission lines spanning the province *(circuit-kilometres)*	**29,355**	29,344
Rate base *(millions of Canadian dollars)*	**10,175**	9,934
Capital investments *(millions of Canadian dollars)*	**943**	845

Note: TWh means terawatt-hours.

Distribution Business

Hydro One's Distribution Business is the largest in Ontario and consists of the distribution system operated by Hydro One Inc.'s subsidiaries Hydro One Networks and Hydro One Remote Communities Inc. The Company's Distribution Business is a rate-regulated business that earns revenues mainly by charging distribution rates that must be approved by the OEB. The Distribution Business represented approximately 38% of the Company's total assets as at December 31, 2015, and approximately 48% of its total revenues, net of purchased power, in 2015.



	2015	2014
Electricity distributed to Hydro One customers *(TWh)*	**28.9**	29.8
Electricity distributed through Hydro One lines *(TWh)*[1]	**40.7**	42.4
Distribution lines spanning the province *(circuit-kilometres)*	**123,425**	123,657
Distribution customers *(number of customers)*	**1,347,231**	1,439,321
Rate base *(millions of Canadian dollars)*	**6,739**	6,415
Capital investments *(millions of Canadian dollars)*	**711**	680

1 Units distributed through Hydro One lines represent total distribution system requirements and include electricity distributed to consumers who purchased power directly from the Independent Electricity System Operator (IESO).

Other Business

Hydro One's Other Business segment consists of the Company's telecommunications business and certain corporate activities. The telecommunications business provides telecommunications support for the Company's Transmission and Distribution Businesses, and also offers communications and IT solutions to organizations with broadband network requirements utilizing Hydro One Telecom Inc.'s (Hydro One Telecom) fibre optic network to provide diverse, secure and highly reliable connectivity. Hydro One's other business segment is not rate-regulated. This segment represented approximately 12% of Hydro One's total assets as at December 31, 2015, and approximately 2% of its total revenues, net of purchased power, in 2015.

Primary Factors Affecting Results Of Operations

Transmission Revenues

Transmission revenues primarily consist of the Company's transmission rates approved by the OEB which are charged based on the monthly peak electricity demand across Hydro One's high-voltage network. Transmission rates are designed to generate revenues necessary to construct, upgrade, extend and support a transmission system with sufficient capacity to accommodate maximum forecasted demand and a regulated return on the Company's investment. Peak electricity demand is primarily influenced by weather and economic conditions. Transmission revenues also include export revenues associated with transmitting electricity to markets outside of Ontario. Ancillary revenues include revenues from providing maintenance services to generators and from third-party land use.

Distribution Revenues

Distribution revenues include the distribution rates approved by the OEB and amounts to recover the cost of purchased power used by the customers of the distribution business. Distribution rates are designed to generate revenues necessary to construct and support local distribution system with sufficient capacity to accommodate existing and new customer demand and a regulated return on the Company's investment. Accordingly, distribution revenues are influenced by distribution rates, the cost of purchased power, and the amount of electricity the Company distributes. Distribution revenues also include ancillary distribution service revenues, such as fees related to the joint use of Hydro One's distribution poles by the telecommunications and cable television industries, as well as miscellaneous charges such as charges for late payments.

Purchased Power Costs

Purchased power costs are incurred by the distribution business and represent the cost of purchased electricity delivered to customers within Hydro One's distribution service territory. These costs comprise the wholesale commodity cost of energy, in addition to wholesale market service and transmission charges levied by the Independent Electricity System Operator (IESO). Hydro One passes the cost of electricity that it delivers to its customers, and is therefore not exposed to wholesale electricity commodity price risk.

Operation, Maintenance and Administration Costs

Operation, maintenance and administration (OM&A) costs are incurred to support the operation and maintenance of the transmission and distribution systems, and other costs such as property taxes related to transmission and distribution lines, stations and buildings. Transmission OM&A costs are incurred to sustain the Company's high-voltage transmission stations, lines and rights-of-way, and include preventive and corrective maintenance costs related to power equipment, overhead transmission lines, transmission station sites, and forestry control to maintain safe distance between line spans and trees. Distribution OM&A costs are required to maintain the Company's low-voltage distribution system, and include costs related to distribution line clearing and forestry control to reduce power outages caused by trees, line maintenance and repair, as well as land assessment and remediation. Hydro One manages its costs through ongoing efficiency and productivity initiatives, while continuing to complete planned work programs associated with the development and maintenance of its transmission and distribution networks.

Depreciation and Amortization

Depreciation and amortization costs relate primarily to depreciation of the Company's property, plant and equipment, and amortization of certain intangible assets and regulatory assets. Depreciation expense also includes the costs incurred to remove property, plant and equipment where no asset retirement obligations have been recorded on the balance sheet.

Financing Charges

Financing charges relate to the Company's financing activities, and include interest expense on the Company's long-term debt, gains and losses on interest rate swap agreements, net of interest earned on short-term and long-term investments. A portion of financing charges incurred by the Company is capitalized to the cost of property, plant and equipment associated with the periods during which such assets are under construction before being placed in-service.

Income Taxes

Hydro One and its subsidiaries were exempt from regular Canadian federal and Ontario income tax (Federal Tax Regime) and instead paid an equivalent amount referred to as payments in lieu of corporate income taxes (PILs) to the Ontario Electricity Financial Corporation (OEFC) under the *Electricity Act* (PILs Regime) until October 2015. Since then, Hydro One and its subsidiaries have been subject to the Federal Tax Regime. See further details in section "Other Developments – PILs Deemed Disposition Rules."

Results of Operations

Net Income

Net income attributable to common shareholders for the year ended December 31, 2015 of $690 million is a decrease of $41 million or 5.6% from the prior year. Significant influences on net income included:

- milder weather in 2015 resulted in a decrease in transmission revenues, mainly due to lower average Ontario peak demand in 2015 compared to 2014, particularly in June, November, and December;
- the effective income tax rate of 12.8% in 2015 compared to an effective tax rate of 10.6% in 2014;
- OM&A costs were lower than the prior year due to:
  - lower costs related to remediating the Company's customer information system, lower customer support expenses and lower bad debt expenses; and
  - lower preventative maintenance related to vegetation management; partially offset by
  - in 2014, insurance proceeds related to 2013 floods at the Company's Richview and Manby transformer stations were recorded as a reduction in 2014 OM&A costs and did not recur in 2015; and
  - during 2015, the Company recorded expenditures related to the integration of acquired local distribution companies.

Revenues

Year ended December 31 *(millions of Canadian dollars, except as otherwise noted)*	2015	2014	Change
Transmission	1,536	1,588	(3.3%)
Distribution	4,949	4,903	0.9%
Other	53	57	(7.0%)
	6,538	6,548	(0.2%)
Transmission: Average monthly Ontario 60-minute peak demand *(MW)*	20,344	20,596	(1.2%)
Distribution: Units distributed to Hydro One customers *(TWh)*	28.9	29.8	(3.0%)

Transmission Revenues

The decrease of $52 million or 3.3% in transmission revenues for the year ended December 31, 2015 was primarily due to lower average monthly Ontario 60-minute peak demand due to industrial customers shifting energy use away from system-wide peaks in the winter months of 2015 and generally milder weather in 2015, which more than offset increased transmission rates for 2015.

Distribution Revenues

The increase of $46 million or 0.9% in distribution revenues for the year ended December 31, 2015 was primarily due to higher OEB-approved distribution rates and higher purchased power costs, partially offset by decreased revenues due to the spin-off of Hydro One Inc.'s subsidiary, Hydro One Brampton Networks Inc. (Hydro One Brampton).

Operation, Maintenance and Administration Costs

Year ended December 31 *(millions of Canadian dollars)*	2015	2014	Change
Transmission	426	394	8.1%
Distribution	633	742	(14.7%)
Other	76	56	35.7%
	1,135	1,192	4.8%

Transmission OM&A Costs

The increase of $32 million or 8.1% in transmission OM&A costs for the year ended December 31, 2015 was primarily due to the following:

- expenses related to write-offs of project and inventory costs due to revisions of asset replacement strategies:
- higher expenditures during 2015 related to work required to adhere to the North American Electric Reliability Corporation (NERC) Critical Infrastructure Protection (Cyber Security) standards; and

- in 2014, insurance proceeds related to 2013 floods at the Company's Richview and Manby transformer stations were recorded as a reduction in 2014 OM&A costs and did not recur in 2015; partially offset by:
- decreased expenditures related to forestry control and line clearing on the Company's transmission rights-of-way.

Distribution OM&A Costs

The decrease of $109 million or 14.7% in distribution OM&A costs for the year ended December 31, 2015 was primarily due to the following:

- a decrease in bad debt expense and lower expenditures related to remediation of the Company's customer information system;
- decreased vegetation management expenditures relating to the distribution line clearing and forestry control; and
- lower volume of work associated with locating and restoring power outages; partially offset by
- increased costs associated with responding to power outages as a result of multiple wind storms during the fourth quarter of 2015.

Other OM&A Costs

The increase of $20 million or 35.7% in other OM&A costs for the year ended December 31, 2015 was primarily due to costs to integrate acquired local distribution companies and increased compensation costs.

Depreciation and Amortization

The increase of $37 million or 5.1% in depreciation and amortization costs for the year ended December 31, 2015 compared to last year was mainly due to the growth in capital assets as the Company continues to place new assets in-service, consistent with its ongoing capital investment program.

Income tax expense

Income tax expense for the year ended December 31, 2015 increased by $16 million compared to 2014, and the Company realized an effective tax rate of approximately 12.8% in 2015, compared to approximately 10.6% realized in 2014. The differences are primarily due to the following:

- lower capital cost allowance in excess of depreciation and amortization; and
- additional tax expense in connection with the spin-off of Hydro One Brampton; partially offset by
- an income tax recovery recorded on the revaluation to fair market value of the tax basis of the assets of Hydro One Inc. and its subsidiaries in excess of the Departure Tax triggered when Hydro One exited the PILs Regime.

Hydro One Brampton

On August 31, 2015, a dividend was paid to the Province by transferring to a company wholly-owned by the Province all of the issued and outstanding shares of Hydro One Brampton and inter-company indebtedness owed to Hydro One Inc. by Hydro One Brampton.

Hydro One's 2015 consolidated results of operations include the results of Hydro One Brampton up to August 31, 2015. The following tables present quarterly results of Hydro One Brampton that are included in consolidated results of Hydro One for the years ended December 31, 2015 and 2014.

Quarter ended *(millions of Canadian dollars)*	Mar. 31, 2015	Jun. 30, 2015	Sept. 30, 2015	Dec. 31, 2015	2015 Total
Revenues	125	129	100	–	354
Purchased power	107	111	88	–	306
OM&A	6	6	4	–	16
Depreciation and amortization	5	4	2	–	11
Income tax expense	–	1	(1)	–	–
Net income	7	7	7	–	21
Capital investments	9	11	8	–	28

Quarter ended *(millions of Canadian dollars)*	Mar. 31, 2014	Jun. 30, 2014	Sept. 30, 2014	Dec. 31, 2014	2014 Total
Revenues	127	115	128	125	495
Purchased power	109	99	109	109	426
OM&A	7	6	5	5	23
Depreciation and amortization	4	3	4	3	14
Income tax expense	–	1	–	2	3
Net income	7	6	10	6	29
Capital investments	2	10	6	9	27

Selected Annual Financial Statistics

Year ended December 31 (millions of Canadian dollars, except per share amounts)	2015	2014	2013
Total revenue	6,538	6,548	6,074
Net income attributable to common shareholders	690	731	785
Basic and diluted EPS	$ 1.39	$ 1.53	$ 1.64
Dividends per common share declared	$ 1.83	$ 0.56	$ 0.42
Dividends per preferred share declared	$ 1.03	$ 1.38	$ 1.38

December 31 (millions of Canadian dollars)	2015	2014	2013
Total assets	24,328	22,550	21,625
Total non-current financial liabilities	8,224	8,373	8,301

Quarterly Results Of Operations

The following table sets forth unaudited quarterly information for 2015 and 2014. This information has been derived from the Company's unaudited interim Consolidated Financial Statements and audited annual Consolidated Financial Statements.

Quarter ended *(millions of Canadian dollars)*	Dec. 31, 2015	Sept. 30, 2015	Jun. 30, 2015	Mar. 31, 2015	Dec. 31, 2014	Sept. 30, 2014	Jun. 30, 2014	Mar. 31, 2014
Total revenues	1,522	1,645	1,563	1,808	1,662	1,556	1,566	1,764
Total revenues, net of purchased power	736	789	725	838	769	776	742	842
Net income attributable to common shareholders	143	188	131	228	216	169	110	236
Basic and diluted EPS	$ 0.26	$ 0.39	$0.27	$0.47	$ 0.45	$ 0.35	$ 0.23	$ 0.50

Non-GAAP Measures

FFO and Adjusted FFO

FFO is defined as net cash from operating activities, adjusted for the following: (i) changes in non-cash balances related to operations, (ii) dividends paid on preferred shares, and (iii) distributions to noncontrolling interest. Adjusted FFO is defined as FFO, adjusted for the impact of the deferred income tax asset that resulted as a consequence of leaving the PILs Regime and entering the Federal Tax Regime. Management believes that FFO and adjusted FFO are helpful as supplemental measures of the Company's operating cash flows as they exclude timing-related fluctuations in non-cash operating working capital and cash flows not attributable to common shareholders, and, in the case of adjusted FFO, the impact of the IPO-related deferred income tax asset. As such, these measures provide a consistent measure of the cash generating performance of the Company's assets.

The following table presents the reconciliation of net cash from operating activities to FFO and adjusted FFO:

Year ended December 31 *(millions of Canadian dollars)*	2015	2014
Net cash from (used in) operating activities	(1,253)	1,256
Changes in non-cash balances related to operations	(208)	55
Preferred dividends	(13)	(18)
Distributions to noncontrolling interest	(5)	–
FFO	(1,479)	1,293
Less: Deferred income tax asset[1]	(2,810)	–
Adjusted FFO	1,331	1,293

[1] Impact of deferred income tax asset that resulted as a consequence of leaving the PILs Regime and entering the Federal Tax Regime

Pro forma Adjusted non-GAAP Basic and Diluted EPS

The following pro forma adjusted non-GAAP basic and diluted EPS has been prepared by management on a supplementary basis which assumes that the total number of common shares outstanding was 595,000,000 in each of the years ended December 31, 2015 and 2014. The supplementary pro forma disclosure is used internally by management subsequent to the IPO to assess the Company's performance and is considered useful because it eliminates the impact of the issuance of common shares to the Province prior to the IPO. Prior to the IPO, the Province was the sole shareholder of Hydro One and disclosure of EPS did not provide meaningful information. EPS is considered an important measure and management believes that presenting it for all periods based on the number of outstanding shares on, and subsequent to, the IPO provides users with a basis to evaluate the operations of the Company with comparable companies and with prior periods.

Year ended December 31	2015	2014
Net income attributable to common shareholders *(millions of Canadian dollars)*	690	731
Pro forma weighted average number of common shares		
Basic	595,000,000	595,000,000
Effect of dilutive share grant plans	94,691	–
Diluted	595,094,691	595,000,000
Pro forma adjusted non-GAAP EPS		
Basic	$1.16	$1.23
Diluted	$1.16	$1.23

Adjusted Net Cash from Operating Activities

Adjusted net cash from operating activities is defined as net cash from operating activities, adjusted for the impact of the deferred income tax asset that resulted as a consequence of leaving the PILs Regime and entering the Federal Tax Regime. Management believes that this measure is helpful as a supplemental measure of the Company's net cash from operating activities as it excludes the impact of the IPO-related deferred income tax asset. As such, adjusted net cash from operating activities provides a consistent measure of the Company's cash from operating activities compared to prior periods.

The following table presents the reconciliation of net cash from operating activities to adjusted net cash from operating activities:

Year ended December 31 *(millions of Canadian dollars)*	2015	2014
Net cash from (used in) operating activities	(1,253)	1,256
Less: Deferred income tax asset[1]	(2,810)	–
Adjusted net cash from operating activities	1,557	1,256

[1] Impact of deferred income tax asset that resulted as a consequence of leaving the PILs Regime and entering the Federal Tax Regime

To the extent that adjusted net income is used in future continuous disclosure documents of Hydro One, it will be defined as net income, adjusted for certain items, including non-recurring items and other one-time items that management does not consider to be reflective of the operating performance of the Company. No such adjustments to net income are presented in this MD&A. Management believes that this measure will be helpful in assessing the Company's financial and operating performance in the future.

FFO, adjusted FFO, pro forma adjusted non-GAAP basic and diluted EPS, adjusted net cash from operating activities, and adjusted net income are not recognized measures under US GAAP and do not have a standardized meaning prescribed by US GAAP. They are therefore unlikely to be directly comparable to similar measures presented by other companies. They should not be considered in isolation nor as a substitute for analysis of the Company's financial information reported under US GAAP.

Summary of Sources and Uses of Cash

Hydro One's primary sources of cash flows are funds generated from operations, capital market debt borrowings and bank financing that are used to satisfy Hydro One's capital resource requirements, including the Company's capital expenditures, servicing and repayment of debt, and dividends.

The following table presents the Company's sources and uses of cash during the years ended December 31, 2015 and 2014:

Year ended December 31 *(millions of Canadian dollars)*	2015	2014
Operating activities		
Net income	713	747
Deferred income taxes	(2,844)	10
Changes in non-cash balances related to operations	208	(55)
Other	670	554
	(1,253)	1,256
Financing activities		
Long-term debt issued	350	628
Long-term debt retired	(585)	(776)
Short-term notes issued	1,491	–
Common shares issued	2,600	–
Dividends paid	(888)	(287)
Amount contributed by (distributed to) noncontrolling interest	(5)	72
Other	(9)	(32)
	2,954	(395)
Investing activities		
Capital expenditures	(1,632)	(1,504)
Capital contributions	62	–
Acquisitions of local distribution companies	(90)	(66)
Investment in Hydro One Brampton	(53)	–
Proceeds from investment	–	250
Other	6	(6)
	(1,707)	(1,326)
Net change in cash and cash equivalents	(6)	(465)

Cash from Operating Activities

Cash used in operations totalled $1,253 million for 2015 compared to cash from operations of $1,256 million in 2014. Cash from operations was affected by changes in deferred income tax assets that resulted as a consequence of leaving the PILs Regime and entering the Federal Tax Regime. Excluding this effect, cash from operations would have been $1,557 million for 2015, an increase of $301 million compared to prior year, mainly due to improved accounts receivable collections in 2015 and changes in regulatory accounts that impact revenue.

Cash from Financing Activities

Cash from financing activities of $2,954 million for 2015 compared to cash used in financing activities of $395 million in 2014. The increase in 2015 was primarily due to cash proceeds from common shares issued, and the issuance of short-term notes and long-term debt, partly offset by payment of dividends and repayment of long-term debt. See section "Liquidity and Financing Strategy" for details of the Company's liquidity and financing strategy.

In 2015, Hydro One issued $350 million of long-term debt under its Medium-Term Note (MTN) Program, compared to $628 million of long-term debt issued in 2014. In 2015, Hydro One repaid $550 million in maturing long-term debt, compared to no long-term debt maturing or repaid in 2014. In addition, long-term debt totalling $35 million assumed as part of the Haldimand County Utilities Inc. (Haldimand Hydro) acquisition and the Woodstock Hydro Holdings Inc. (Woodstock Hydro) acquisition was repaid in 2015.

In 2015, Hydro One paid dividends in the amount of $888 million ($875 million of common share dividends and $13 million of preferred share dividends), compared to dividends totalling $287 million paid in 2014. Included in dividends paid in 2015 was a special dividend paid to the Province prior to the completion of the IPO.

In November 2015, Hydro One issued 2.6 billion common shares to the Province for cash proceeds of $2.6 billion prior to the completion of the IPO.

Cash from Investing Activities

Cash used in investing activities was $1,707 million for 2015 compared to $1,326 million in 2014. The increase in 2015 was mainly due to higher capital investments in 2015 and the sale of an investment in 2014 for $250 million that did not recur in 2015. In 2015, cash totalling $90 million was used to purchase Haldimand Hydro and Woodstock Hydro, compared to cash of $66 million used to purchase Norfolk Power Inc. (Norfolk Power) in 2014. See section "Capital Investments" for details of the Company's capital investments, and section "Other Developments – Acquisitions" for details of the acquisitions of Haldimand Hydro and Woodstock Hydro.

Liquidity and Financing Strategy

Short-term liquidity is provided through funds from operations, Hydro One Inc.'s Commercial Paper Program, and the Company's consolidated credit facilities. Under the commercial paper program, Hydro One Inc. is authorized to issue up to $1.5 billion in short-term notes with a term to maturity of less than 365 days. At December 31, 2015, Hydro One Inc. had $1,491 million in commercial paper borrowings outstanding, compared to no commercial paper borrowings outstanding at December 31, 2014. In addition, the Company and Hydro One Inc. have revolving credit facilities totalling $2,550 million that mature between 2018 and 2020. The Company may use the credit facilities for working capital and general corporate purposes. The short-term liquidity under the Commercial Paper Program, the credit facilities and anticipated levels of funds from operations are expected to be sufficient to fund the Company's normal operating requirements.

At December 31, 2015, all of the Company's long-term debt totalling $8,723 million was issued by Hydro One Inc. under Hydro One Inc.'s MTN Program. At December 31, 2015, the maximum authorized principal amount of medium-term notes issuable under the MTN Program was $3.5 billion, with the entire amount remaining available until January 2018. The long-term debt consists of notes and debentures that mature between 2016 and 2064, and at December 31, 2015, had an average term to maturity of approximately 16.6 years and a weighted average coupon of 4.7%.

At December 31, 2015, Hydro One's corporate credit ratings from approved rating organizations were as follows:

Rating Agency	Corporate Credit Rating
Standard & Poor's Rating Services (S&P)[1]	A

[1] On September 18, 2015, S&P assigned its A corporate credit rating on Hydro One. The outlook is stable.

At December 31, 2015, Hydro One Inc.'s long-term and short-term debt ratings from approved rating organizations were as follows:

Rating Agency	Short-term Debt Rating	Long-term Debt Rating
DBRS Limited (DBRS)[1]	R-1 (low)	A (high)
Moody's Investors Service (Moody's)[2]	Prime-2	A3
S&P[3]	A-1	A

[1] On November 5, 2015, DBRS confirmed Hydro One Inc.'s issuer rating and senior unsecured debenture rating at A (high), downgraded its short-term debt rating to R-1(low) from R-1 (mid), and revised its trend to stable.

[2] On November 5, 2015, Moody's downgraded the senior unsecured ratings of Hydro One Inc. to A3 from A2, downgraded its short term debt rating to Prime-2 from Prime-1, and revised its outlook on the Company to stable from negative.

[3] On September 18, 2015, S&P affirmed its ratings on Hydro One Inc., including its A long-term corporate credit rating on the company.

At December 31, 2015, Hydro One and Hydro One Inc. were in compliance with all financial covenants and limitations associated with the outstanding borrowings and credit facilities.

Effect of Interest Rates

The Company is exposed to fluctuations in interest rates as its regulated return on equity is derived using a formulaic approach that takes into account anticipated interest rates. See section "Risk Management and Risk Factors – Risks Relating to Hydro One's Business – Market, Financial Instrument and Credit Risk" for more details.

Pension Plan

In 2015, Hydro One contributed approximately $177 million to its pension plan, compared to contributions of approximately $174 million in 2014, and incurred $163 million in net periodic pension benefit costs, compared to $158 million incurred in 2014. The Company estimates that total pension contributions for 2016 will be approximately $180 million.

The Company's pension benefits obligation is impacted by various assumptions and estimates, such as discount rate, rate of return on plan assets, rate of cost of living increase, and mortality assumptions. A full discussion of the significant assumptions and estimates can be found in the section "Critical Accounting Estimates – Employee Future Benefits."

Capital Investments

The Company makes capital investments to maintain the safety, reliability and integrity of its transmission and distribution assets and to provide for the ongoing growth and modernization required to meet the expanding and evolving needs of its customers and the electricity market. This is achieved through a combination of sustaining capital investments, which are required to support the continued operation of Hydro One's existing assets, and development capital investments, which involve both additions to existing assets and large scale projects such as new transmission lines and transmission stations.

In 2015, the Company made capital investments totalling $1,663 million and placed $1,476 million of new assets in-service, including replacements of end-of-life wood poles, new load connections, and the completion of two transformer replacements at the Hanmer Transmission Station, compared to $1,530 million of capital investments and $1,574 million of new assets placed in-service in 2014.

The following table presents Hydro One's 2015 and 2014 capital investments:

Year ended December 31 *(millions of Canadian dollars)*	2015	2014	Change
Transmission			
Sustaining	706	625	13.0%
Development	166	132	25.8%
Other	71	88	(19.3%)
Total Transmission Capital Investments	943	845	11.6%
Distribution			
Sustaining	398	356	11.8%
Development	220	236	(6.8%)
Other	93	88	5.7%
Total Distribution Capital Investments	711	680	4.6%
Other Capital Investments	9	5	80.0%
Total Capital Investments	1,663	1,530	8.7%

Transmission Capital Investments

The increase of $98 million or 11.6% in transmission capital investments in 2015 was primarily due to the following:

- several system re-investments, including various end-of-life equipment replacements at certain transmission stations, including the Bruce, Richview, Larchwood and Wiltshire Transmission Stations, as well as the completion of two transformer replacements at the Hanmer Transmission Station;
- the continued work on some of the Company's major inter-area network and local area supply projects, such as the Clarington Transmission Station and Guelph Area Transmission Refurbishment projects;
- increased work on overhead lines refurbishment and replacement projects and programs;
- increased volume of work related to station security upgrades to prevent unauthorized entry to stations and enhance safety, and increased cyber system replacements, including firewall infrastructure, auxiliary equipment and management software, to adhere to the NERC Cyber Security standards; and
- increased volume of demand equipment replacements, as well as spare transformer equipment purchases to ensure readiness for unplanned transformer replacements; partially offset by
- decreased expenditures related to underground lines system replacements, as the end-of-life underground transmission cables between the Strachan Transformer Station and Riverside Junction were replaced and placed in-service in 2014.

Distribution Capital Investments

The increase of $31 million or 4.6% in distribution capital investments in 2015 was primarily due to the following:

- increased capital lines work, primarily related to multiple sustainment initiatives programs and higher volume of component replacements;
- increased work related to station refurbishment programs due to a larger volume of transformer purchases and more refurbishments accomplished during 2015; and
- increased storm restoration work as a result of multiple wind storms which occurred during the fourth quarter of 2015, as well as related power quality-related issues; partially offset by
- decreased expenses in 2015 due to completion of a smart meter installation project in 2014.

Major Transmission Projects

The following table summarizes the status of certain of Hydro One's major transmission projects at December 31, 2015:

Project Name	Location	Type	Anticipated In-Service Date	Estimated Cost	Capital Cost To-Date	Status
Toronto Midtown Transmission Reinforcement	Toronto Southwestern Ontario	New transmission line	2016	$123 million	$121 million	In progress
Guelph Area Transmission Refurbishment	Guelph area Southwestern Ontario	Transmission line upgrade	2016	$103 million	$67 million	In progress
Clarington Transmission Station	Oshawa area Eastern GTA	New transmission station	2018/2019	$297 million	$97 million	In progress
Supply to Essex County Transmission Reinforcement	Windsor-Essex area Southwestern Ontario	New transmission line and station	2018	To be determined	–	OEB decision received in July 2015
Northwest Bulk Transmission Line	Thunder Bay Northwestern Ontario	New transmission line	As early as 2020	To be determined	–	Development work is in progress

Future Capital Investments

Hydro One anticipates that it will spend an average of over $1.6 billion per year over the next five years on total capital investments, with sustaining capital investments representing an average of approximately 60% of total capital investments in each year. The Company anticipates that these investments will contribute to improved reliability, customer service and operating efficiencies.

The following table summarizes Hydro One's annual projected capital investments for 2016 to 2020, by business segment:

(millions of Canadian dollars)	2016	2017	2018	2019	2020
Transmission	937	920	978	1,021	989
Distribution	706	692	690	729	663
Other	8	8	7	7	7
Total capital investments	1,651	1,620	1,675	1,757	1,659

The following table summarizes Hydro One's annual projected capital investments for 2016 to 2020, by category:

(millions of Canadian dollars)	2016	2017	2018	2019	2020
Sustaining	999	998	1,098	1,006	1,001
Development	416	435	360	479	480
Other	236	187	217	272	178
Total capital investments	1,651	1,620	1,675	1,757	1,659

Note: "Other" capital expenditures consist of special projects, such as those relating to information technology.

Other Obligations

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 the Company's 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 Hydro One's debt and other major contractual obligations, as well as other major commercial commitments:

December 31, 2015 *(millions of Canadian dollars)*	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
Contractual obligations *(due by year)*					
Long-term debt – principal repayments	8,723	500	1,350	878	5,995
Long-term debt – interest payments	7,368	397	741	654	5,576
Short-term notes payable	1,491	1,491	–	–	–
Pension contributions[1]	197	180	17	–	–
Environmental and asset retirement obligations[2]	248	22	51	58	117
Outsourcing agreements[3]	523	167	244	101	11
Operating lease commitments	45	11	19	12	3
Other	90	17	34	33	6
Total contractual obligations	18,685	2,785	2,456	1,736	11,708
Other commercial commitments *(by year of expiry)*					
Bank line[4]	2,550	–	800	1,750	–
Letters of credit[5]	154	154	–	–	–
Guarantees[5]	330	330	–	–	–
Total other commercial commitments	3,034	484	800	1,750	–

1 Contributions to the Hydro One Pension Fund are generally made one month in arrears. The 2016 minimum pension contributions are based on an actuarial valuation as at December 31, 2013 and projected levels of pensionable earnings. Pension contributions beyond 2016 are not estimable at this time.

2 Hydro One records 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 owned by the Company. Hydro One also records a liability for asset retirement obligations associated with the removal and disposal of asbestos-containing materials installed in some of its facilities. The forecasted expenditure pattern reflects the Company's planned work programs for the periods.

3 Inergi LP (Inergi), an affiliate of Capgemini Canada Inc., provides services to Hydro One, including settlements, source to pay services, pay operations services, information technology, finance and accounting services. The agreement with Inergi for these services expires in December 2019. In addition, Inergi provides customer service operations outsourcing services to Hydro One. The agreement for these services expires in February 2018. Brookfield Global Integrated Solutions (formerly Brookfield Johnson Controls Canada LP) (Brookfield) provides services to Hydro One, including facilities management and execution of certain capital projects as deemed required by the Company. The current agreement with Brookfield expires in December 2024. The contractual amounts disclosed include an estimated contractual annual inflation adjustment in the range of 1.9% to 2.1%. Payments in respect of the Company's outsourcing agreements are recorded in OM&A costs on the Company's Consolidated Statements of Operations and Comprehensive Income or as a cost of capital programs.

4 The Company and Hydro One Inc. have revolving credit facilities totalling $2,550 million that expire between 2018 and 2020.

5 Hydro One Inc. currently has outstanding bank letters of credit of $139 million relating to retirement compensation arrangements. Hydro One Inc. provides 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, 2015, Hydro One Inc. has provided a letter of credit to the IESO in the amount of $15 million to meet its current prudential requirements. Hydro One Inc. has also provided prudential support to the IESO on behalf of its subsidiaries as required by the IESO's Market Rules, using parental guarantees of $329 million, and on behalf of a distributor using total guarantees of $1 million.

Regulation

The OEB approves both the revenue requirements of and the rates charged by Hydro One's regulated transmission and distribution businesses. The rates are designed to permit the Company's transmission and distribution businesses to recover the allowed costs and to earn a formula-based annual rate of return on its equity invested in the regulated businesses. This is done by applying a specified equity risk premium to forecasted interest rates on long-term bonds. In addition, the OEB approves rate riders to allow for the recovery or disposition of specific regulatory deferral accounts over specified timeframes.

The following table summarizes Hydro One's major regulatory proceedings:

Application	Year(s)	Type	Status
Electricity Rates			
Hydro One Networks	2015-2016	Transmission – Cost-of-service	OEB decision received
Hydro One Networks	2015-2017	Distribution – Custom	OEB decision received
B2M LP	2015	Transmission – Interim	OEB decision received
B2M LP	2015-2019	Transmission – Cost-of-service	OEB decision received
Mergers Acquisitions Amalgamations and Divestitures			
Haldimand Hydro	n/a	Acquisition	OEB decision received
Woodstock Hydro	n/a	Acquisition	OEB decision received
Leave to Construct			
Supply to Essex County Transmission Reinforcement Project	n/a	Section 92	OEB decision received

Hydro One has secured rate orders for Hydro One Networks' transmission business through 2016, for B2M LP through 2019, and for Hydro One Networks' distribution business to the end of 2017.

The following table summarizes the status of Hydro One's electricity rate applications.

Application	Date of Rate Application Approval	Year	ROE Allowed (A) or Forecast (F)	Rate Base	Date of Rate Order Filing	Rate Order Status
Transmission:						
Hydro One Networks	January 2015	2015	9.30% (A)	$9,651 million	January 2015	Approved
		2016	9.19% (A)	$10,040 million	November 2015	Approved
B2M LP	December 2015	2015	9.30% (A)	$523 million	December 2014	Approved
		2016	9.19% (A)	$516 million	January 2016	Approved
		2017	9.71% (F)	$509 million	–	To be filed 2016 Q4
		2018	9.96% (F)	$502 million	–	To be filed 2017 Q4
		2019	10.01% (F)	$496 million	–	To be filed 2018 Q4
Distribution:						
Hydro One Networks	March 2015	2015	9.30% (A)	$6,552 million	April 2015	Approved
		2016	9.19% (A)	$6,863 million	January 2016	Approved
		2017	9.71% (F)	$7,190 million	–	To be filed 2016 Q4

Hydro One Networks

Hydro One Networks' transmission 2016 revenue requirement of $1,480 million is reflected in the Uniform Transmission Rates (UTR) Decision and Order. Hydro One Networks plans to submit a transmission application for 2017-2018 rates in the second quarter of 2016.

The Hydro One Distribution forecast for 2017 will be subject to adjustments for cost of capital parameters. Hydro One Networks plans to submit a distribution application for 2018-2022 rates in the first quarter of 2017.

B2M LP

On December 29, 2015, the OEB issued a Decision and Order approving the five-year revenue requirement for years 2015-2019 inclusive, approving the recovery of $8 million start-up costs in rates, and the establishment of a deferral account to capture costs of Tax Rate and Rule changes. The January 14, 2016, Decision and Rate Order approved the B2M LP revenue requirement recovery through the 2016 UTRs.

Supply to Essex County Transmission Reinforcement Project

On July 16, 2015, the OEB issued a Decision and Order granting Hydro One Networks Leave to Construct a new 13-kilometre 230 kV double-circuit transmission line in the Windsor-Essex region. The Decision and Order includes standard conditions of adherence to the system impact assessment and the connection impact assessment, and requires construction to commence within twelve months. In addition, on August 28, 2015, the OEB issued a letter stating that given the complexities and implications of the issues relating to cost allocation, including potential changes to the provisions in the Distribution System Code and the Transmission System Code, the OEB will not proceed with cost allocation through an adjudicative process, but will review these issues from a policy perspective.

On January 7, 2016, the OEB initiated its policy review. In the southeast Essex County, a number of large distribution-connected customers are a factor driving the need for new transmission capacity, such as the new Leamington transmission station. Three other distributors embedded in Hydro One's distribution area will also benefit from this investment. Therefore, Hydro One has proposed that its share of this transmission investment be shared proportionately between Hydro One and the other identified beneficiaries in the area. The OEB consultation will review the concept of proportional benefit and its application, as the policy and regulatory framework to flow transmission costs through to identified distribution-connected customers is not in place.

Other Regulatory Developments

Time-of-Use (TOU) Pricing Decision and Order

On March 26, 2015, the OEB issued a Decision and Order to amend Hydro One Networks' distribution license to include an exemption from the requirement to apply TOU pricing to approximately 170,000 Regulated Price Plan customers that are outside the smart meter telecommunications infrastructure. The exemption expires December 31, 2019.

Distribution System Code Requirements

In April 2015, the OEB introduced a Notice of Amendment to the Distribution System Code requiring electricity distributors to issue monthly bills to non-seasonal residential and certain general service customers by the end of 2016. In addition, the OEB amended the Distribution System Code imposing a 98% billing accuracy requirement, and provisions allowing a local distribution company to issue a bill based on estimated consumption only twice every twelve months to these customers. In September 2015, the OEB issued its Decision and Order amending Hydro One Networks' electricity distribution licence to include an exemption from the requirement for estimated billing and billing accuracy for the 170,000 hard-to-reach customers that are currently exempt from TOU billing, for a term ending on December 31, 2019.

On December 31, 2015, Hydro One submitted a report to the OEB summarizing that as of November 2015, approximately only 101,000 "hard-to-reach" customers received estimated bills in 2015 and significant improvements were realized in estimated billing accuracy due to the availability of better customer-specific historical usage data on which the estimation algorithms are based.

Conservation and Demand Management

In accordance with a directive from the Minister of Energy and Infrastructure dated March 31, 2010, as a condition of licence, certain licensed electricity distributors must meet the IESO established targets for the reduction of electricity consumption and peak provincial electricity demand. On September 30, 2015, Hydro One Networks filed its annual Conservation and Demand Management (CDM) Report with the OEB. In 2014, Hydro One Networks achieved 167.4 MW in peak demand savings and 898.4 GWh in energy savings, which represent 78.4% and 79.5% of its peak demand and energy reduction targets, respectively. Although Hydro One Networks did not meet its peak demand reduction target, no punitive action will be taken against the Company.

Rate Design (previously Revenue Decoupling for Distributors)

In April 2015, the OEB issued a report, *"Board Policy: A New Distribution Rate Design for Residential Electricity Customers"*, outlining its new policy on fully fixed distribution charges for residential customers. The current distribution charges are a combination of fixed and variable rates. Under the new policy, electricity distributors will structure their residential rates such that all distribution service costs will be collected through a fixed monthly charge only. The new policy will be implemented gradually over a four year period, with increases in the fixed rate and decreases in the variable rate, resulting in a fixed rate only by 2019. The new rate design will enable residential customers to leverage new technologies, manage costs through conservation, and better understand the value of distribution services. It will also provide greater revenue stability for distributors, including Hydro One.

In its December 22, 2015 Decision, the OEB has increased the transition period for Hydro One Networks' certain customer classes to eight years to mitigate excessive bill impacts.

In January 2016, the OEB issued a Decision and Rate Order for the area formerly served by Norfolk Power approving Hydro One's implementation plan to transition residential customers to fixed rates over a four year period. Although Norfolk Power customers' rates are frozen for five years, the OEB Order approved Tariffs of Rates and Charges for 2016 only.

In 2015, Hydro One Networks filed applications with the OEB with respect to the new rate design for residential customers in the service areas formerly served by Haldimand Hydro and Woodstock Hydro that include fixed rates for five years and implementation plans to transition to fixed distribution rates. Approvals for these applications are pending.

Performance Measurement for Electricity Distributors

On September 18, 2015, Hydro One Networks submitted its 2014 Performance Scorecard to the OEB. In addition to ongoing operations, a major focus in 2014 was investing in improvements to the Company's customer call centre and billing operations. Hydro One plans to continue developing targeted products and services that respond to its customers' unique needs, including realizing value from the new customer information system, simplifying and shortening timeframes for the delivery of services, and enhancing accessibility to allow effective self-service for simple transactions. The Company is also committed to delivering programs to help its customers manage their energy consumption. Hydro One Networks' 2014 Scorecard was posted on the Hydro One and the OEB websites.

Renewed Regulatory Framework for Transmitters

In 2015, the OEB initiated a discussion to develop a framework for the application of Renewed Regulatory Framework principles to transmitters, and in January 2016, issued a new set of draft filing requirements for transmitters for discussion.

Transmitter Consolidations

On January 19, 2016, the OEB issued the *Handbook for Electricity Distributor and Transmitter Consolidations* (the "handbook") to provide guidance on applications for approval of electricity utility consolidations by way of mergers, acquisitions, amalgamations and divestitures and subsequent rate applications. The handbook is intended to provide guidance on the process for review of consolidation applications by the OEB and affirms the OEB's policy of using the "no harm" test in reviewing consolidation applications. This test requires applicants to demonstrate that the costs to serve acquired customers post-consolidation will be no higher than they otherwise would be without consolidation. In addition the OEB will consider whether any price premium paid on the acquisition is financially burdensome to the applicant, as any premium paid over historic asset value is not recoverable in rates. The handbook will allow applicants to defer rebasing of the acquired utility for up to a 10 year period with the view of permitting the applicant to fully realize the anticipated efficiency gains and offset the overall costs of the transaction.

Other Developments

Change in Hydro One Ownership Structure

During the fourth quarter of 2015, Hydro One and Hydro One Inc. completed a series of Pre-Closing Transactions that resulted in, among other things, the acquisition by Hydro One of all of the issued and outstanding shares of Hydro One Inc. and the issuance of new common shares and preferred shares of Hydro One to the Province. On November 5, 2015, Hydro One and the Province concluded the IPO of Hydro One on the Toronto Stock Exchange, whereby 81.1 million of the 595 million outstanding common shares of Hydro One were sold to the public. On November 12, 2015, the underwriters of the IPO exercised their option to purchase an additional 8.15 million common shares of Hydro One from the Province. All proceeds from the IPO were received by the Province. All of the regulated business and outstanding notes and debentures of Hydro One at the time of the IPO remain at Hydro One Inc. The final prospectus associated with the IPO, which contains details of the IPO, recapitalization and corporate structure, is posted on www.sedar.com.

PILs Deemed Disposition Rules

In connection with the IPO, upon ceasing to be exempt from tax under the Federal Tax Regime in October 2015, Hydro One and its subsidiaries were deemed to dispose of their assets for proceeds equal to their fair market value, triggering a PILs liability of $2.6 billion (Departure Tax). The Departure Tax amount was confirmed in writing by the Minister of Finance and was paid to the OEFC in 2015. To enable Hydro One and its subsidiaries to pay the Departure Tax, the Province made an equity injection of $2.6 billion in Hydro One and received 2.6 billion common shares of Hydro One. The revaluation of the tax basis of the assets of Hydro One Inc. and its subsidiaries to fair market value resulted in a net deferred tax recovery of $2,619 million recorded in 2015.

Class Action Lawsuit

In September 2015, Hydro One and three of its subsidiaries were served with a class action suit in which the representative plaintiff is seeking up to $125 million in damages related to allegations of improper billing practices. Hydro One intends to defend the action. Due to the preliminary stage of legal proceedings, an estimate of a possible loss related to this claim cannot be made.

Acquisitions

Integration of Norfolk Power

The Company acquired Norfolk Power in August 2014. The purchase price for Norfolk Power, adjusted for working capital and other closing adjustments, was approximately $68 million. Due to this acquisition, approximately 18,000 new customers were added to Hydro One's Distribution Business. In September 2015, the Company completed the integration of Norfolk Power, including the integration of employees, customers, business processes, information and operations. This successful integration will allow the Company to standardize processes and leverage key lessons learned to drive efficiency and improvements when integrating other acquisitions in the future.

Acquisition of Haldimand Hydro

In June 2015, Hydro One completed the acquisition of Haldimand Hydro, an electricity distribution company located in southwestern Ontario, following approval of the acquisition by the OEB in March 2015. The purchase price for Haldimand Hydro, adjusted for working capital and other closing adjustments of approximately $8 million, was approximately $73 million. The goodwill of approximately $33 million arising from the Haldimand Hydro acquisition consists largely of the synergies and economies of scale expected from combining the operations of Hydro One and Haldimand Hydro. Due to this acquisition, approximately 21,000 new customers were added to Hydro One's Distribution Business. Integration of Haldimand Hydro is ongoing.

Acquisition of Woodstock Hydro

In October 2015, Hydro One completed the acquisition of Woodstock Hydro, an electricity distribution company located in southwestern Ontario, following approval of the acquisition by the OEB in September 2015. The purchase price for Woodstock Hydro, adjusted for preliminary working capital and other closing adjustments, was approximately $32 million. The preliminary goodwill of approximately $17 million arising from the Woodstock Hydro acquisition consists largely of the synergies and economies of scale expected from combining the operations of Hydro One and Woodstock Hydro. Due to this acquisition, approximately 16,000 new customers were added to Hydro One's Distribution Business. Integration of Woodstock Hydro is ongoing.

Great Lakes Power Transmission Purchase Agreement

On January 28, 2016, Hydro One reached an agreement to acquire from Brookfield Infrastructure various entities that own and control Great Lakes Power Transmission LP, an Ontario regulated electricity transmission business operating along the eastern shore of Lake Superior, north and east of Sault Ste. Marie, Ontario, for $222 million in cash, subject to customary adjustments, plus the assumption of approximately $151 million in outstanding indebtedness. The acquisition is pending a *Competition Act* approval as well as regulatory approval from the OEB.

Hydro One Workforce

Hydro One has a skilled and flexible work force of over 5,500 regular employees and over 2,000 non-regular employees province-wide, comprising a mix of skilled trades, lines staff, engineering, professional, managerial and executive personnel. Hydro One's regular employees are supplemented primarily by accessing a large external labour force available through arrangements with the Company's trade unions for variable workers, sometimes referred to as "hiring halls", and also by access to contract personnel. The hiring halls offer Hydro One the ability to access highly trained and appropriately skilled workers on a project-by-project and seasonal basis.

The following table sets out the number of Hydro One employees as at December 31, 2015.

	Regular Employees	Non-Regular Employees	Total
Power Workers' Union (PWU)	3,419	636[1]	4,055
The Society of Energy Professionals (Society)	1,394	57	1,451
Canadian Union of Skilled Workers (CUSW) and construction building trade unions[2]	–	1,346	1,346
International Brotherhood of Electrical Workers (IBEW)	63	4	67
Total employees represented by unions	4,876	2,043	6,919
Management and non-represented employees	640	34	674
Total employees	5,516	2,077	7,593

1 Includes 475 non-regular "hiring hall" employees covered by PWU agreement.

2 Employees are jointly represented by both unions. The construction building trade unions have collective agreements with the Electrical Power Systems Construction Association (EPSCA).

Collective Agreements

The PWU represents the majority of the skilled trade personnel employed by Hydro One. In April 2015, Hydro One reached an agreement with the PWU for a renewal of the collective agreement. The agreement is for a three-year term, covering April 1, 2015 to March 31, 2018. The agreement was ratified by the PWU and the Hydro One Board of Directors in July 2015.

The Society represents professional and certain first-level supervisory staff employed by Hydro One. In July 2015, Hydro One reached an agreement with the Society for an early renewal of the collective agreement. The agreement is for a three-year term, covering April 1, 2016 to March 31, 2019. The agreement was ratified by the Society and the Hydro One Board of Directors in August 2015.

In July 2015, Hydro One reached an agreement with the CUSW for a renewal of the collective agreement. The agreement is for a three-year term, covering May 1, 2014 to April 30, 2017. The agreement was ratified by CUSW in September 2015 and the Hydro One Board of Directors in August 2015.

The EPSCA is an employers' association of which Hydro One is a member. A number of the EPSCA construction collective agreements, which bind Hydro One, expired in April 2015. Ratified five-year renewal collective agreements, covering May 1, 2015 to April 30, 2020, have been reached with The United Association of Plumbers and Pipefitters, The Ironworkers, The Rodmen, The Boilermakers, The Insulators, The Sheet Metal Workers, The Roofers, the Labourers International Union of North America (LIUNA), the Operating Engineers (OE) and the Teamsters.

Share-based Compensation

Share Grant Plans

At December 31, 2015, Hydro One had two share grant plans, one for the benefit of certain members of the Power Workers' Union (the PWU Share Grant Plan) and one for the benefit of certain members of The Society of Energy Professionals (the Society Share Grant Plan).

The PWU Share Grant Plan provides for the issuance of common shares of Hydro One from treasury to certain eligible members of the PWU annually, commencing on April 1, 2017 and continuing until the earlier of April 1, 2028 or the date an eligible employee no longer meets the eligibility criteria of the PWU Share Grant Plan. The number of common shares granted annually to each eligible employee will be equal to 2.7% of such eligible employee's salary as at April 1, 2015, divided by the price of the common shares of Hydro One in the IPO. The aggregate number of common shares issuable under the PWU Share Grant Plan shall not exceed 3,981,763 common shares.

The Society Share Grant Plan provides for the issuance of common shares of Hydro One from treasury to certain eligible members of the Society annually, commencing on April 1, 2018 and continuing until the earlier of April 1, 2029 or the date an eligible employee no longer meets the eligibility criteria of the Society Share Grant Plan. The number of common shares granted annually to each eligible employee will be equal to 2.0% of such eligible employee's salary as at September 1, 2015, divided by the price of the common shares of Hydro One in the IPO. The aggregate number of common shares issuable under the Society Share Grant Plan shall not exceed 1,434,686 common shares.

Directors' Deferred Share Unit (DSU) Plan

Under the Company's Directors' DSU Plan, directors can elect to receive credit for their annual cash retainer in a notional account of DSUs in lieu of cash. Hydro One's Board of Directors may also determine from time to time that special circumstances exist that would reasonably justify the grant of DSUs to a director as compensation in addition to any regular retainer or fee to which the director is entitled.

Employee Share Ownership Plan

Effective December 15, 2015, Hydro One established an Employee Share Ownership Plan (ESOP). Under the ESOP, certain eligible management and non-represented employees may contribute between 1% and 6% of their base salary towards purchasing common shares of Hydro One. The Company will match 50% of the employee's contributions, up to maximum Company contribution of $25,000 per calendar year. No contributions were made under the ESOP during 2015.

Long-term Incentive Plan

The Board of Directors of Hydro One adopted a Long-term Incentive Plan effective August 31, 2015. Under the Long-term Incentive Plan, long-term incentives will be granted to certain executive and management employees, and all equity-based awards will be settled in newly-issued shares of Hydro One from treasury, consistent with the provisions of the plan.

The mix of long-term incentive vehicles has not yet been determined and, accordingly, the Long-term Incentive Plan provides flexibility to award a range of vehicles, including restricted share units, performance share units, stock options, share appreciation rights, restricted shares, deferred share units and other share-based awards. The mix of vehicles is intended to vary by role to recognize the level of executive accountability for overall business performance. It is expected that the specific incentive vehicles and performance targets associated with the Long-term Incentive Plan will be decided in early 2016, after which the incentive grants will commence. No long-term incentive payments were awarded during 2015.

Related Party Transactions

The Province is the majority shareholder of Hydro One. The OEFC, IESO, Ontario Power Generation Inc. (OPG), the OEB, and Hydro One Brampton are related parties to Hydro One because they are controlled or significantly influenced by the Province. The following is a summary of the Company's related party transactions during the year ended December 31, 2015:

The Province

- During 2015, Hydro One paid dividends to the Province totalling $888 million (2014 – $287 million). In addition, on August 31, 2015, Hydro One declared a dividend in-kind on its common shares payable in all of the issued and outstanding shares of Hydro One Brampton.
- On November 4, 2015, Hydro One issued 2.6 billion common shares to the Province for proceeds of $2.6 billion.
- In 2015, Hydro One Inc. incurred certain IPO related expenses totaling $7 million which will be reimbursed to the Company by the Province and reimbursed by the Company to Hydro One Inc.

IESO

- During 2015, Hydro One purchased power in the amount of $2,318 million from the IESO-administered electricity market, compared to $2,601 million purchased in 2014.
- Hydro One receives revenues for transmission services from the IESO, based on OEB-approved Uniform Transmission Rates. The Company's 2015 transmission revenues include $1,548 million related to these services, compared to $1,556 million in 2014.
- Hydro One receives amounts for rural rate protection from the IESO. The Company's 2015 distribution revenues include $127 million related to this program, compared to $127 million in 2014.
- Hydro One receives revenues related to the supply of electricity to remote northern communities from the IESO. The Company's 2015 distribution revenues include $32 million related to these services, compared to $32 million in 2014.
- The IESO (Ontario Power Authority prior to January 1, 2015) funds substantially all of Hydro One's CDM programs. The funding includes program costs, incentives, and management fees. During 2015, the Company received $70 million related to these programs, compared to $33 million received in 2014.

OPG

- During 2015, Hydro One purchased power in the amount of $11 million from the OPG, compared to $23 million purchased in 2014.
- Hydro One has service level agreements with OPG. These services include field, engineering, logistics and telecommunications services. The Company's other 2015 revenues include $7 million related to these service level agreements, compared to $12 million in 2014. OM&A costs related to the purchase of services with respect to these service level contracts were not significant in 2015 and 2014.

OEFC

- During 2015, Hydro One made PILs to the OEFC totalling $2.9 billion, including Departure Tax of $2.6 billion, compared to payments of $86 million made in 2014.
- During 2015, Hydro One purchased power in the amount of $6 million from power contracts administered by the OEFC, compared to $9 million purchased in 2014.
- In 2015, the Company paid $8 million to the OEFC, compared to $5 million paid in 2014, 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. Hydro One has not made any claims under the indemnity since it was put in place in 1999. Hydro One and the OEFC, with the consent of the Minister of Finance, have agreed to terminate the indemnity effective October 31, 2015.

OEB

- Under the *OEB Act*, the OEB is required to recover all of its annual operating costs from gas and electricity distributors and transmitters. During 2015, Hydro One incurred $12 million in OEB fees, compared to $12 million incurred in 2014.

Hydro One Brampton

- Effective August 31, 2015, Hydro One Brampton is no longer a subsidiary of Hydro One Inc., but is indirectly owned by the Province. Subsequent to August 31, 2015, Hydro One continues to provide certain management, administrative and smart meter network services to Hydro One Brampton pursuant to certain service level agreements, which are provided at market rates. During 2015, revenues related to the provision of services with respect to these service level agreements were $1 million.

At December 31, 2015, the amounts due from and due to related parties as a result of the transactions described above were $191 million and $138 million, compared to $224 million and $227 million at December 31, 2014, respectively. At December 31, 2015, included in amounts due to related parties were amounts owing to the IESO in respect of power purchases of $134 million, compared to $214 million at December 31, 2014.

Risk Management and Risk Factors

Risks Relating to Hydro One's Business

Regulatory Risks and Risks Relating to Hydro One's Revenues

Risks Relating to Obtaining Rate Orders

The Company is subject to the risk that the OEB will not approve the Company's transmission and distribution revenue requirements requested in future applications for rates. Rate applications for revenue requirements are subject to the OEB's review process, usually involving participation from intervenors and a public hearing process. There can be no assurance that resulting decisions or rate orders issued by the OEB will permit Hydro One to recover all costs actually incurred, including operations, maintenance and administration costs, costs accumulated in other regulatory accounts (including, for instance, deferral and variance accounts), costs of debt and income taxes, or to earn a particular return on equity. A failure to obtain acceptable rate orders, or approvals of appropriate returns on equity and costs actually incurred, may materially adversely affect: Hydro One's transmission or distribution businesses, the undertaking or timing of capital expenditures, ratings assigned by credit rating agencies, the cost and issuance of long-term debt, and other matters, any of which may in turn have a material adverse effect on the Company. In addition, there is no assurance that the Company will receive regulatory decisions in a timely manner and, therefore, costs may be incurred prior to having an approved revenue requirement.

Risks Relating to Actual Performance Against Forecasts

The Company's ability to recover the actual costs of providing service and earn the allowed return on equity depends on the Company achieving its forecasts established and approved in the rate-setting process. Actual costs could exceed the approved forecasts if, for example, the Company incurs operations, maintenance and administration costs above those included in the Company's approved revenue requirement, higher capital expenditures than those approved in rate decisions, or additional financing charges because of increased debt amounts or higher interest rates. The inability to obtain acceptable rate decisions or to otherwise recover any significant difference between forecast and actual expenses could materially adversely affect the Company's financial condition and results of operations.

Further, the OEB approves the Company's transmission and distribution rates based on projected electricity load and consumption levels, among other factors. If actual load or consumption materially falls below projected levels, the Company's revenue and net income for either, or both, of these businesses could be materially adversely affected. Also, the Company's current revenue requirements for these businesses are based on cost and other 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 the Company's costs.

The Company is subject to risk of revenue loss from other factors, such as economic trends and weather conditions that influence the demand for electricity. The Company's overall operating results may fluctuate substantially on a seasonal and year-to-year basis based on these trends and weather conditions. For instance, a cooler than normal summer or warmer than normal winter may reduce demand for electricity below that forecast by the Company, causing a decrease in the Company's revenues from the same period of the previous year. The Company's load could also be negatively affected by successful CDM programs whose results exceed forecasted expectations.

Risks Relating to Rate-Setting Models for Transmission and Distribution

The OEB's rate-setting model for distributors requires that the term of a custom rate application (distribution business) be a minimum five-year period. There are risks associated with forecasting over such a long period. For instance, if unanticipated capital expenditures arise that were not contemplated in the Company's most recent rate decision, the Company may be required to incur costs that may not be recoverable until a future period or not recoverable at all in future rates. This could have a material adverse effect on the Company.

The OEB has stated its intention to examine the policies that may apply to transmission rate setting, and this may result in changes to the rate-setting model for transmission services. A change to the rate-setting model for transmission services, such as the introduction of an asymmetrical earnings sharing mechanism, could result in a decrease in the Company's revenues or financial performance.

The OEB approves and periodically, generally on an annual basis, changes the return on equity for transmission and distribution businesses. The OEB may in the future decide to reduce its allowed return on equity for either of these businesses, modify the formula or methodology it uses to determine the return on equity, or reduce the weighting of the equity component of the deemed capital structure. Any such reduction could reduce the net income of the Company.

Risks Relating to Capital Expenditures

In order to be recoverable, capital expenditures require the approval of the OEB, either through the approval of capital expenditure plans, rate base or revenue requirements for the purposes of setting transmission and distribution rates, which include the impact of capital expenditures on rate base or cost of service. There can be no assurance that all capital expenditures incurred by Hydro One will be approved by the OEB. Capital cost overruns may not be recoverable in transmission or distribution rates. The Company could incur unexpected capital expenditures in maintaining or improving its assets, particularly given that new technology is required to support renewable generation and unforeseen technical issues may be identified through implementation of projects. There is risk that the OEB may not allow full recovery of such expenditures in the future. To the extent possible, Hydro One aims 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 the Company expects all of its expenditures and regulatory assets to be fully recoverable after OEB review, any future regulatory decision to disallow or limit the recovery of such costs would lead to a lower than expected approved revenue requirement or rate base, potential asset impairment or charges to the Company's results of operations, any of which could have a material adverse effect on the Company.

Risks Relating to Deferred Tax Asset

As a result of leaving the PILs Regime and entering the Federal Tax Regime, Hydro One recorded a deferred tax asset due to the revaluation of the tax basis of Hydro One's fixed assets at their fair market value and recognition of eligible capital expenditures. Management believes this will result in annual net cash savings over the next five years due to the reduction of cash taxes payable by Hydro One associated primarily with a higher capital cost allowance. There is a risk that, in future rate applications, the OEB will reduce the Company's revenue requirement by all or a portion of those net cash savings. If the OEB were to reduce the Company's revenue requirement in this manner, it could have a material adverse effect on the Company.

Risks Relating to Other Applications to the OEB

The Company is also subject to the risk that it will not obtain required regulatory approvals for other matters, such as leave to construct applications, applications for mergers, acquisitions, amalgamations and divestitures, and environmental approvals. Decisions to acquire or divest other regulated businesses licensed by the OEB are subject to OEB approval. Accordingly, there is the risk that such matters may not be approved or that unfavourable conditions will be imposed by the OEB.

First Nations and Métis Claims Risk

Some of the Company's current and proposed transmission and distribution assets are or may be located on Reserve (as defined in the *Indian Act* (Canada)) lands, and lands over which First Nations and Métis have Aboriginal, treaty or other legal claims. Although the Company has a recent history of successful negotiations and engagement with First Nations and Métis communities in Ontario, some First Nations and Métis leaders, communities and their members have made assertions related to sovereignty and jurisdiction over Reserve lands and traditional territories and are increasingly willing to assert their claims through the courts, tribunals, or by direct action. These claims could have a material adverse effect on the Company or otherwise materially adversely impact the Company's operations, including the development of current and future projects.

The Company's operations and activities may, on occasion, give rise to the Crown's duty to consult and potentially accommodate First Nations and Métis communities. Procedural aspects of the duty to consult may be delegated to the Company by the Province or the federal government. A perceived failure by the Crown to sufficiently consult a First Nations or Métis community, or a perceived failure by the Company in relation to delegated consultation obligations, could result in legal challenges against the Crown or the Company, including judicial review or injunction proceedings, or could potentially result in direct action against the Company by a community or its members. If this occurs, it could disrupt or delay the Company's operations and activities, including current and future projects, and have a material adverse effect on the Company.

Risk from Transfer of Assets Located on Reserves

The transfer orders by which the Company acquired certain of Ontario Hydro's businesses as of April 1, 1999 did not transfer title to assets located on Reserves. The transfer of title to these assets did not occur because authorizations originally granted by the federal government for the construction and operation of these assets on Reserves could not be transferred without required consent. In several cases, the authorizations had either expired or had never been issued.

Currently, the Ontario Electricity Financial Corporation holds legal title to these assets and it is expected that the Company will manage them until it has obtained permits to complete the title transfer. To occupy Reserves, the Company must have valid permits issued by Her Majesty the Queen in the Right of Canada. For each permit, the Company must negotiate an agreement (in the form of a memorandum of understanding) with the First Nation, the Ontario Electricity Financial Corporation and any members of the First Nation who have occupancy rights. The agreement includes provisions whereby the First Nation consents to the federal government (presently Indigenous Affairs and Northern Development Canada) issuing a permit. For transmission assets, the Company must negotiate terms of payment. It is difficult to predict the aggregate amount that the Company may have to pay, either on an annual or one-time basis, to obtain the required agreements from First Nations. If the Company cannot reach satisfactory agreements with the relevant First Nation to obtain federal permits, it 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 the Company if the costs are not recoverable in future rate orders.

Compliance with Laws and Regulations

Hydro One must comply with numerous laws and regulations affecting its business, including requirements relating to transmission and distribution companies, environmental laws, employment laws and health and safety laws. The failure of the Company to comply with these laws could have a material adverse effect on the Company's business. See also "– Health, Safety and Environmental Risk".

For instance, Hydro One's licensed transmission and distribution businesses are required to comply with the terms of their licenses, with codes and rules issued by the OEB, and with other regulatory requirements, including regulations of the National Energy Board. In Ontario, the Market Rules issued by the IESO require the Company to, among other things, comply with the reliability standards established by the NERC and Northeast Power Coordinating Council, Inc. (NPCC). The incremental costs associated with compliance with these reliability standards are expected to be recovered through rates, but there can be no assurance that the OEB will approve the recovery of all of such incremental costs. Failure to obtain such approvals could have a material adverse effect on the Company.

There is the risk that new legislation, regulations or policies will be introduced in the future. These may require Hydro One to incur additional costs, which may or may not be recovered in future transmission and distribution rates.

Risk of Natural and Other Unexpected Occurrences

The Company's facilities are exposed to the effects of severe weather conditions, natural disasters, man-made events including but not limited to cyber and physical terrorist type attacks, events which originate from third party connected systems, or any other potentially catastrophic events. Although constructed, operated and maintained to industry standards, the Company's facilities may not withstand occurrences of this type in all circumstances. The Company does not have insurance for damage to its transmission and distribution wires, poles and towers located outside its transmission and distribution stations resulting from these or other events. Losses from lost revenues and repair costs could be substantial, especially for many of the Company's facilities that are located in remote areas. The Company could also be subject to claims for damages caused by its failure to transmit or distribute electricity. Hydro One's risk is partly mitigated because its 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, Hydro One 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 the Company.

Risk Associated with Information Technology Infrastructure and Data Security

The Company's ability to operate effectively in the Ontario electricity market is, in part, dependent upon it developing, maintaining and managing complex information technology systems which are employed to operate and monitor its transmission and distribution facilities, financial and billing systems and other business systems. The Company's increasing reliance on information systems and expanding data networks increases its exposure to information security threats. The Company's transmission business is required to comply with various rules and standards for transmission reliability, including mandatory standards established by the NERC and the NPCC. These include standards relating to cyber-security and information technology, which only apply to certain of the Company's assets (generally being those whose failure could impact the functioning of the bulk electricity system). The Company may maintain different or lower levels of information technology security for its assets that are not subject to these mandatory standards. Unauthorized access to corporate and information technology systems or cyber-attacks could result in service disruptions and system failures, which could have a material adverse effect on the Company, including as a result of a failure to provide electricity to customers. In addition, in the normal course of its operations, the Company may collect, process or retain access to confidential customer, supplier, counterparty or employee information, which could be exposed in the event of a cyber security incident.

Hydro One mitigates these risks, including through the use of security event management tools on its power and business systems, by separating its transmission and distribution system networks from its other business system networks, by performing scans of its systems for known cyber threats and by providing company-wide awareness training to Hydro One personnel. Hydro One also engages the services of external experts to evaluate the security of its information technology infrastructure and controls. Hydro One performs vulnerability assessments on its critical cyber assets and it ensures security and privacy controls are incorporated into new information technology capabilities. Although these security and system disaster recovery controls are in place, there can be no assurance that there will not be system failures or security breaches or that such threats would be detected or mitigated on a timely basis. Upon occurrence and detection, 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 the Company.

Workforce Demographic Risk

By the end of 2015, approximately 17% of the Company's employees were eligible for retirement and by the end of 2016, up to approximately 21% could be eligible. These percentages are not evenly spread across the Company's workforce, but tend to be most significant in the most senior levels of the Company's staff and especially among management staff. During each of 2015 and 2014, approximately 3% of the Company's workforce elected to retire. Accordingly, the Company's continued success will be tied to its ability to attract and retain sufficient qualified staff to replace the capability lost through retirements and to meet the demands of the Company's work programs.

In addition, the Company expects the skilled labour market for its industry to be highly competitive in the future. Many of the Company's current employees and many of the potential employees it would seek in the future possess skills and experience that would also be highly sought after by other organizations inside and outside the electricity sector. The failure to attract and retain qualified personnel for Hydro One's business could have a material adverse effect on the Company.

Labour Relations Risk

The substantial majority of the Company's employees are represented by either the Power Workers' Union or The Society of Energy Professionals. Over the past several years, significant effort has been expended to increase Hydro One's flexibility to conduct operations in a more cost efficient manner. Although the Company has achieved improved flexibility in its collective agreements, the Company may not be able to achieve further improvements. The Company recently reached an agreement with the Power Workers' Union for a renewal collective agreement with a three-year term, covering the period from April 1, 2015 to March 31, 2018 and an early renewal collective agreement with The Society of Energy Professionals with a three-year term, covering the period from April 1, 2016 to March 31, 2019. The Company also reached a renewal collective agreement with the

Canadian Union of Skilled Workers for a three-year term, covering the period from May 1, 2014 to April 30, 2017. Additionally, the Electrical Power Systems Construction Association ("EPSCA") and a number of construction unions have reached renewal agreements, to which Hydro One is bound, for a 5-year period covering May 1, 2015 to April 30, 2020. However, there can be no assurance that future collective agreement renewals with these unions or that collective agreements with the other unions with which Hydro One has contractual relationships, will be renewed on acceptable terms. The Company faces financial risks related to its ability to negotiate collective agreements consistent with its rate orders. In addition, in the event of a labour dispute, the Company could face operational risk related to continued compliance with its license requirements of providing service to customers. Any of these could have a material adverse effect on the Company.

Risk Associated with Arranging Debt Financing

The Company expects to borrow to repay its existing indebtedness and to fund a portion of capital expenditures. Hydro One Inc. has substantial amounts of existing debt, including $500 million maturing in 2016, $600 million maturing in 2017, and $750 million maturing in 2018. In addition, from time to time, the Company may draw on its syndicated bank lines and or issue short-term debt under Hydro One Inc.'s $1.5 billion commercial paper program which would need to be paid down. The Company also plans to incur capital expenditures of over $1.6 billion for each of 2016 and 2017. Cash generated from operations, after the payment of expected dividends, will not be sufficient to fund the repayment of the Company's existing indebtedness and capital expenditures. The Company's ability to arrange sufficient and cost-effective debt financing could be materially adversely affected by numerous factors, including the regulatory environment in Ontario, the Company's results of operations and financial position, market conditions, the ratings assigned to its debt securities by credit rating agencies and general economic conditions. A downgrade in the Company's credit ratings could restrict the Company's ability to access debt capital markets and increase the Company's cost of debt. Any failure or inability on the Company's part to borrow the required amounts of debt on satisfactory terms could impair its 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 the Company.

Market, Financial Instrument and Credit Risk

Market risk refers primarily to the risk of loss that results from changes in costs, foreign exchange rates and interest rates. The Company is exposed to fluctuations in interest rates as its regulated return on equity is derived using a formulaic approach that takes into account anticipated interest rates, but is not currently exposed to material commodity price risk or material foreign exchange risk.

The OEB-approved adjustment formula for calculating return on equity in a deemed regulatory capital structure of 60% debt and 40% equity provides for increases and decreases depending on changes in benchmark rates of return for Government of Canada debt. The Company estimates that a 1% decrease in the forecasted long-term Government of Canada bond yield used in determining its rate of return would reduce the Company's transmission business' 2017 net income by approximately $22 million and its distribution business' 2017 net income by approximately $14 million. The Company's net income is adversely impacted by rising interest rates as the Company's maturing debt is refinanced at market rates. The Company periodically utilizes 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. Hydro One monitors and minimizes credit risk through various techniques, including dealing with highly-rated counterparties, limiting total exposure levels with individual counterparties, entering into master agreements which enable net settlement, and by monitoring the financial condition of counterparties. The Company does not trade in any energy derivatives. Currently, there are no significant concentrations of credit risk with respect to any class of financial assets. The Company is required to procure electricity on behalf of competitive retailers and certain local distribution companies 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 the Company's service agreements with these retailers in accordance with the OEB's Retail Settlement Code.

The failure to properly manage these risks could have a material adverse effect on the Company.

Risks Relating to Asset Condition and Capital Projects

The Company continually incurs sustainment and development capital expenditures and monitors the condition of its transmission assets to manage the risk of equipment failures and to determine the need for and timing of major refurbishments and replacements of its transmission and distribution infrastructure. However the lack of real time monitoring of distribution assets increases the risk of distribution equipment failure. The connection of large amounts of distributed generation on the distribution network has resulted in more equipment operations than in the past for the Company. This increases maintenance requirements and may accelerate the aging of the Company's assets.

Execution of the Company's capital expenditure programs, particularly for development capital expenditures, is partially dependent on external factors, such as environmental approvals, municipal permits, equipment outage schedules that accommodate the IESO, generators and transmission-connected customers, and supply chain availability for equipment suppliers and consulting services. There may also be a need for, among other things, *Environmental Assessment Act* (Ontario) approvals, approvals which require public meetings, appropriate engagement with First Nations and Métis communities, OEB approvals of expropriation or early access to property, and other activities. Obtaining approvals and carrying out these processes may also be impacted by opposition to the proposed site of the capital investments. Delays in obtaining required approvals or failure to complete capital projects on a timely basis could materially adversely affect transmission reliability or customers' service quality or increase maintenance costs which could have a material adverse effect on the Company. External factors are considered in the Company's planning process. However, if the Company is unable to carry out capital expenditure plans in a timely manner, equipment performance may degrade, which may reduce transmission capacity, compromise the reliability of the Company's transmission system or increase the costs of operating and maintaining these assets. Any of these consequences could have a material adverse effect on the Company.

Increased competition for the development of large transmission projects and legislative changes relating to the selection of transmitters could impact the Company's ability to expand its existing transmission system, which may have an adverse effect on the Company. To the extent that other parties are selected to construct, own and operate new transmission assets, the Company's share of Ontario's transmission network would be reduced.

Health, Safety and Environmental Risk

Hydro One's 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 the Board of Directors that has governance over health, safety and environmental matters. However, given the expansive territory that the Company's system encompasses and the amount of equipment that it owns, the Company cannot guarantee that all such risks will be identified and mitigated without significant cost and expense to the Company. The following are some of the areas that may have a significant impact on the Company's operations.

The Company is subject to extensive Canadian federal, provincial and municipal environmental regulation. Failure to comply could subject the Company to fines or other penalties. In addition, the presence or release of hazardous or other harmful substances could lead to claims by third parties or governmental orders requiring the Company to take specific actions such as investigating, controlling and remediating the effects of these substances. Hydro One currently has a voluntary land assessment and remediation program for off-site migration in place to identify and, where necessary, remediate historical contamination that has resulted from past operational practices and uses of certain long-lasting chemicals at the Company's facilities. Any contamination of the Company's properties could limit its ability to sell or lease these assets in the future.

In addition, actual future environmental expenditures may vary materially from the estimates used in the calculation of the environmental liabilities on the Company's balance sheet. The Company does not have insurance coverage for these environmental expenditures.

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.

Although Hydro One is not a large emitter of greenhouse gases, the Company monitors all of these emissions and has a management plan in place to track and report on all sources, including sulphur hexafluoride or "SF6". In addition, the Company recognizes the risks associated with potential climate change and has developed plans to respond as appropriate.

The Company anticipates that all of its future environmental expenditures will continue to be recoverable in future rates. However, any future regulatory decision to disallow or limit the recovery of such costs could have a material adverse effect on the Company.

Pension Plan Risk

Hydro One has the Hydro One Defined Benefit Pension Plan in place for the majority of its 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, 2013, and was filed in June 2014, covering a three year period from 2014 to 2016. Hydro One contributed approximately $174 million in respect of 2014, approximately $177 million in respect of 2015, and is expected to contribute approximately $180 million by the end of 2016 to its pension plan to satisfy minimum funding requirements. Contributions beyond 2016 are expected to continue to be significant; actual amounts will depend on investment returns, interest rates, changes in benefits and actuarial assumptions, and may include additional voluntary contributions by the Company from time to time. A determination by the OEB that some of the Company's pension expenditures are not recoverable through rates could have a material adverse effect on the Company, and this risk may be exacerbated if the amount of required pension contributions increases.

The OEB has begun a consultation process that will examine pensions and other post-employment benefits in regulated utilities. See "– Other Post-Employment and Post-Retirement Benefits Risks". The outcome of this consultation process is uncertain and the Company is unable to assess the impact of the potential changes stemming from the review at this time.

Risk of Recoverability of Total Compensation Costs

The Company manages all of its total compensation costs, including pension and other post-employment and post-retirement benefits, subject to restrictions and requirements imposed by the collective bargaining process. Should any element of total compensation costs be disallowed in whole or part by the OEB and not be recoverable from customers in rates, the costs could be material and could lead to changes to the Company's results of operations and decrease net income, which could have a material adverse effect on the Company.

Other Post-Employment and Post-Retirement Benefits Risks

The Company provides other post-employment and post-retirement benefits, including workers compensation benefits and long-term disability benefits to qualifying employees. The OEB has begun a consultation process that will examine pensions and other post-employment benefits in regulated utilities. The objectives of the consultation are to develop standard principles to guide the OEB's review of pension and other post-employment and post-retirement benefits costs in the future, to establish specific information requirements for application and to establish appropriate regulatory mechanisms for cost recovery which can be applied consistently across the gas and electricity sectors for rate-regulated utilities. The outcome of this consultation process is uncertain and the Company is unable to assess the impact of the potential changes stemming from the review at this time. A determination that some of the Company's post-employment and post-retirement benefit costs are not recoverable could have a material adverse effect on the Company.

Risk Associated with Outsourcing Arrangements

Consistent with Hydro One's strategy of reducing operating costs, it has entered into an outsourcing arrangement with Inergi for the provision of back office services and call centre services. If the outsourcing arrangement or statements of work thereunder are terminated for any reason or expire before a new supplier is selected, the Company could be required to incur significant expenses to transfer to another service provider or insource, which could have a material adverse effect on the Company's business, operating results, financial condition or prospects.

Risk from Provincial Ownership of Transmission Corridors

The Province owns some of the corridor lands underlying the Company's transmission system. Although the Company has the statutory right to use these transmission corridors, the Company may be limited in its options to expand or operate its systems. Also, other uses of the transmission corridors by third parties in conjunction with the operation of the Company's systems may increase safety or environmental risks, which could have a material adverse effect on the Company.

Litigation Risks

In the normal course of the Company's operations, it may become involved in, be named as a party to or be the subject of, various legal proceedings, including regulatory proceedings, tax proceedings and legal actions, relating to actual or alleged violations of law, common law damages claims, personal injuries, property damage, property taxes, land rights, the environment and contract disputes. The outcome of outstanding, pending or future proceedings cannot be predicted with certainty and may be determined adversely to the Company, which could have a material adverse effect on the Company. Even if the Company prevails in any such legal proceeding, the proceedings could be costly and time-consuming and would divert the attention of management and key personnel from the Company's business operations, which could adversely affect the Company.

Risks Relating to the Company's Relationship with the Province

Ownership by the Province and Voting Power; Share Ownership Restrictions

The Province currently owns approximately 84% of the common shares of Hydro One. The *Electricity Act* restricts the Province from selling voting securities of Hydro One (including common shares) of any class or series if it would own less than 40% of the outstanding number of voting securities of that class or series after the sale and in certain circumstances also requires the Province to take steps to maintain that level of ownership. Accordingly, the Province is expected to continue to maintain a significant ownership interest in voting securities of Hydro One for an indefinite period.

As a result of its significant ownership of the common shares of Hydro One, the Province has, and is expected indefinitely to have, the ability to determine or significantly influence the outcome of shareholder votes, subject to the restrictions in the governance agreement entered into between Hydro One and the Province dated November 5, 2015 ("Governance Agreement"; available on SEDAR at www.sedar.com). While, with respect to its ownership interest in Hydro One, the Province has agreed to engage in the business and affairs of Hydro One only as an investor and not as a manager, and has stated its intention to achieve its policy objectives through legislation and regulation as it would with respect to any other utility operating in Ontario, the Governance Agreement preserves the Province's right to vote its common shares in its sole interest, which may not be aligned with the interests of the Company's other shareholders.

The share ownership restrictions in the *Electricity Act* ("Share Ownership Restrictions") and the Province's significant ownership of common shares of Hydro One together effectively prohibit one or more persons acting together from acquiring control of Hydro One. They also may limit or discourage transactions involving other fundamental changes to Hydro One and the ability of other shareholders to successfully contest the election of the directors proposed for election pursuant to the Governance Agreement. The Share Ownership Restrictions may also discourage trading in, and may limit the market for, the common shares and other voting securities.

Continued Influence by the Province

Despite the terms of the Governance Agreement in which the Province has agreed to engage in the business and affairs of the Company as an investor and not as a manager, there is a risk that the Province's engagement in the business and affairs of the Company as an investor will be informed by its own policy objectives and may influence the conduct of the business and affairs of the Company in ways that may not be aligned with the interests of other shareholders.

Nomination of Directors and Confirmation of Chief Executive Officer and Chair

Although director nominees are required to be independent of both the Company and the Province pursuant to the Governance Agreement, there is a risk that the Province will nominate or confirm individuals who satisfy the independence requirements but who it considers are disposed to support and advance its policy objectives and give disproportionate weight to the Province's interests in exercising their business judgment and balancing the interests of the stakeholders of Hydro One. This, combined with the fact certain matters require a two-thirds vote of the Board of Directors, could allow the Province to unduly influence certain Board actions such as confirmation of the Chair and confirmation of the Chief Executive Officer.

Board Removal Rights

Under the Governance Agreement, the Province has the right to withhold from voting in favour of all director nominees and has the right to seek to remove and replace the entire Board of Directors, including in each case its own director nominees but excluding the Chief Executive Officer and, at the Province's discretion, the Chair. In exercising these rights in any particular circumstance, the Province is entitled to vote in its sole interest, which may not be aligned with the interests of other shareholders.

More Extensive Regulation

Although under the Governance Agreement, the Province has agreed to engage in the business and affairs of Hydro One as an investor and not as a manager and has stated that its intention is to achieve its policy objectives through legislation and regulation as it would with respect to any other utility operating in Ontario, there is a risk that the Province will exercise its legislative and regulatory power to achieve policy objectives in a manner that has a material adverse effect on the Company.

Prohibitions on Selling the Company's Transmission or Distribution Business

The *Electricity Act* prohibits the Company from selling all or substantially all of the business, property or assets related to its transmission system or distribution system that is regulated by the OEB. There is a risk that these prohibitions may limit the ability of the Company to engage in sale transactions involving a substantial portion of either system, even where such a transaction may otherwise be considered to provide substantial benefits to the Company and the holders of the common shares.

Future Sales of Common Shares by the Province

The Province has indicated that it currently intends to sell further common shares of Hydro One over time, until it holds approximately 40% of the common shares, subject to the selling restrictions agreed with the Underwriters. The registration rights agreement between Hydro One and the Province dated November 5, 2015 (available on SEDAR at www.sedar.com) also grants the Province the right to request that Hydro One file one or more prospectuses and take other procedural steps to facilitate secondary offerings by the Province of the common shares of Hydro One. Future sales of common shares of Hydro One by the Province, or the perception that such sales could occur, may materially adversely affect market prices for these common shares and impede Hydro One's ability to raise capital through the issuance of additional common shares, including the number of common shares that Hydro One may be able to sell at a particular time or the total proceeds that may be realized.

Limitations on Enforcing the Governance Agreement

The Governance Agreement includes commitments by the Province restricting the exercise of its rights as a holder of voting securities, including with respect to the maximum number of directors that the Province may nominate and on how the Province will vote with respect to other director nominees. Hydro One's ability to obtain an effective remedy against the Province, if the Province were not to comply with these commitments, is limited as a result of the *Proceedings Against the Crown Act* (Ontario). This legislation provides that the remedies of injunction and specific performance are not available against the Province, although a court may make an order declaratory of the rights of the parties, which may influence the Province's actions. A remedy of damages would be available to Hydro One, but damages may not be an effective remedy, depending on the nature of the Province's non-compliance with the Governance Agreement.

Critical Accounting Estimates

The preparation of Hydro One Consolidated Financial Statements requires the Company to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and costs, and related disclosures of contingencies. Hydro One bases its estimates and judgments 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 judgments about the carrying values of assets and liabilities, as well as identifying and assessing the Company's accounting treatment with respect to commitments and contingencies. Actual results may differ from these estimates and judgments. Hydro One has identified the following critical accounting estimates used in the preparation of its Consolidated Financial Statements:

Revenues

Distribution revenues are recognized on an accrual basis and include billed and unbilled revenues. Unbilled revenues are based on an estimate of electricity delivered determined by historical trends of consumption and are estimated at the end of each month. The unbilled revenue estimate is affected by energy consumption, weather, and changes in the composition of customer classes.

Accounts Receivable and Allowance for Doubtful Accounts

In 2015, the Company revised its method to estimate the unbilled accounts receivable based on new technology implemented to enhance the estimation process. This change has been accounted for on a prospective basis in the consolidated financial statements at December 31, 2015. At December 31, 2015, the change in estimate reduced unbilled accounts receivable by approximately $121 million, with a corresponding offset to various components of the retail settlement variance accounts (RSVA) regulatory asset. The change in estimate had no impact on 2015 revenues or net income.

The allowance for doubtful accounts reflects the Company's best estimate of losses on billed accounts receivable balances. The Company estimates the allowance for doubtful accounts on customer receivables by applying internally developed loss rates to the outstanding receivable balances by aging category. Loss rates applied to the accounts receivable balances are based on historical overdue balances, customer payments and write-offs.

Regulatory Assets and Liabilities

Hydro One's regulatory assets represent certain amounts receivable from future electricity customers and costs that have been deferred for accounting purposes because it is probable that they will be recovered in future rates. The regulatory assets mainly include costs related to the pension benefit liability, deferred income tax liabilities, post-retirement and post-employment benefit liability, share-based compensation costs, and environmental liabilities. The Company's 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 electricity 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 electricity rates, the applicable carrying amount of the regulatory asset or liability will be reflected in results of operations in the period that the judgment is made by management.

Environmental Liabilities

Hydro One records a liability for the estimated future expenditures associated with the removal and destruction of PCB-contaminated insulating oils and related electrical equipment, and for the assessment and remediation of chemically-contaminated lands. There are uncertainties in estimating future environmental costs due to potential external events such as changes in legislation or regulations and advances in remediation technologies. 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.

Employee Future Benefits

Hydro One's employee future benefits consist of pension and post-retirement and post-employment plans, and include pension, group life insurance, health care, and long-term disability benefits provided to the Company's current and retired employees. Employee future benefits costs are included in Hydro One's 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 affect the benefit obligation of the employee future benefits and the amounts that will be charged to results of operations or capitalized in future years. The following significant assumptions and estimates are used to determine employee future benefit costs and obligations:

Weighted Average Discount Rate

The weighted average discount rate used to calculate the employee future benefits obligation is determined at 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 rate at December 31, 2015 remained at 4.00% for pension benefits whereas it increased to 4.10% (from 4.00% used at December 31, 2014) for the post-retirement and post-employment plans. The increase in the discount rate has resulted in a corresponding decrease in employee future benefits liabilities for the post-retirement and post-employment plans for accounting purposes. The liabilities are determined by independent actuaries using the projected benefit method prorated on service and based on assumptions that reflect management's best estimates.

Expected Rate of Return on Plan Assets

The expected rate of return on pension plan assets is based on expectations of long-term rates of return at the beginning of the year and reflects a pension asset mix consistent with the pension plan's current investment policy.

Rates of return on the respective portfolios are determined with reference to respective published market indices. The expected rate of return on pension plan assets reflects the Company's long-term expectations. We believe that this assumption is reasonable because, with the pension plan'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 lower return than might be expected by investing in equities alone. In the short term, the pension plan can experience fluctuations in actual rates of return.

Rate of Cost of Living Increase

The rate of cost of living increase is determined by considering differences between long-term Government of Canada nominal bonds and real return bonds, which decreased from 1.70% per annum as at December 31, 2014 to approximately 1.50% per annum as at December 31, 2015. Given the Bank of Canada's commitment to keep long-term inflation between 1.00% and 3.00%, management believes that the current rate is reasonable to use as a long-term assumption and as such, has used a 2.0% per annum inflation rate for employee future benefits liability valuation purposes as at December 31, 2015.

Mortality Assumptions

The Company's employee future benefits liability is also impacted by changes in life expectancies used in mortality assumptions. Increases in life expectancies of plan members result in increases in the employee future benefits liability. The mortality assumption at December 31, 2015 is based on the final tables issued by the Canadian Institute of Actuaries (for public sector, with projection scale CPM-B and no adjustment due to pension size). This is the same assumption as was used as of December 31, 2014.

Rate of Increase in Health Care Cost Trends

The costs of post-retirement and post-employment benefits are determined at the beginning of the year and 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 a $22 million increase in 2015 interest cost plus service cost, and a $252 million increase in the year-end 2015 benefit liability.

Asset Impairment

Within Hydro One's regulated businesses, the carrying costs of most of the long-lived assets are included in the rate base where they earn an OEB-approved rate of return. Asset carrying values and the related return are recovered through OEB-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 the

Company's unregulated Hydro One Telecom subsidiary for indications of impairment. As at December 31, 2015, no asset impairment had been recorded for assets within Hydro One's regulated or unregulated businesses.

Goodwill is evaluated for impairment on an annual basis, or more frequently if circumstances require. Hydro One has concluded that goodwill was not impaired at December 31, 2015. 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.

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.

In compliance with the requirements of National Instrument 52-109, the Company's Certifying Officers have reviewed and certified the Consolidated Financial Statements for the year ended December 31, 2015, together with other financial information included in the Company's securities filings. The Certifying Officers have also certified that disclosure controls and procedures (DC&P) have been designed to provide reasonable assurance that material information relating to the Company is made known within the Company. Further, the 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 the Company's DC&P and ICFR, the Certifying Officers concluded that the Company's DC&P and ICFR were effective as at December 31, 2015.

New Accounting Pronouncements

In January 2015, the Financial Accounting Standards Board (FASB) issued an accounting standards update that eliminates the requirements for reporting entities to consider whether an underlying event or transaction is extraordinary and to show the item separately in the income statement. This update is applicable to Hydro One for the years and interim periods beginning on January 1, 2016. The Company does not anticipate that the adoption of this update will have a significant impact on its consolidated financial statements.

In February 2015, the FASB issued an accounting standards update that provides guidance about the analysis that a reporting entity must perform to determine whether it should consolidate certain types of legal entities. This update is applicable to Hydro One for the years and interim periods beginning on January 1, 2016. The Company does not anticipate that the adoption of this update will have a significant impact on its consolidated financial statements.

In April 2015, the FASB issued an accounting standards update that requires debt issuance costs related to a recognized debt liability to be presented on the balance sheet as a direct deduction from the carrying amount of that debt liability. The recognition and measurement guidance for debt issuance costs are not affected. This update is applicable to Hydro One for the years and interim periods beginning on January 1, 2016. Upon adoption of this update in the first quarter of 2016, the Company's deferred debt issuance costs that are currently presented under other long-term assets will be reclassified as a deduction from the carrying amount of long-term debt.

In April 2015, the FASB issued an accounting standards update that permits an entity with a fiscal year-end that does not coincide with a month-end and an entity that has a significant event in an interim period that calls for a remeasurement of defined benefit plan assets and obligations to measure the defined benefit plan assets and obligations using the month-end that is closest to the entity's fiscal year-end. This update is applicable to Hydro One for the years and interim periods beginning on January 1, 2016. The Company does not anticipate that the adoption of this update will have a significant impact on its consolidated financial statements.

In April 2015, the FASB issued an accounting standards update that provides guidance to customers about whether a cloud computing arrangement includes a software license, as well as the related accounting for the arrangement. This update is applicable to Hydro One for the years and interim periods beginning on January 1, 2016. The Company is currently assessing the impact of adoption of this update on its consolidated financial statements.

In August 2015, the FASB issued an accounting standards update that defers by one year the effective date of a revenue recognition standard issued in 2014 to January 1, 2018. The standard 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. The Company is currently assessing the impact of adoption of this update on its consolidated financial statements.

In September 2015, the FASB issued an accounting standards update that requires an acquirer to recognize adjustments to provisional amounts that are identified during the measurement period of a business combination in the reporting period in which the adjustment amounts are determined. This update is applicable to Hydro One for the years and interim periods beginning on January 1, 2016 for measurement adjustments related to business combinations.

In November 2015, the FASB issued an accounting standards update that requires all deferred tax assets and liabilities to be classified as noncurrent on the balance sheet. This update is applicable to Hydro One for the years and interim periods beginning on January 1, 2017. Upon adoption of this update in the first quarter of 2017, the current portions of the Company's deferred income tax assets and liabilities will be reclassified as long-term assets and liabilities on the consolidated Balance Sheets.

In January 2016, the FASB issued an accounting standards update that requires equity investments to be measured at fair value with changes in fair value recognized in net income, and requires enhanced disclosures and presentation of financial assets and liabilities in the financial statements. This update also simplifies the impairment assessment of equity investments without readily determinable fair values by requiring a qualitative assessment to identify impairment. This update is applicable to Hydro One for the years and interim periods beginning on January 1, 2018. The Company is currently assessing the impact of adoption of this update on its consolidated financial statements.

Other Matters

Appointment of New Board of Directors

In 2015, the Province appointed a fully independent Board of Directors to govern Hydro One as a publicly traded company, with a renewed focus on customer service excellence, improved performance and reliability, and growing shareholder value. Each of the directors, including Canadian business leaders, electricity sector experts, corporate directors and a former provincial Ombudsman, was selected based upon their independence, commercial experience, and specific expertise.

Appointment of President and Chief Executive Officer

In August 2015, the Company's Board of Directors announced the appointment of Mayo Schmidt as Hydro One's new President and Chief Executive Officer, effective September 3, 2015. Mr. Schmidt was most recently the Chief Executive Officer of Viterra Inc.

Appointment of Chief Financial Officer

In June 2015, Mr. Michael Vels was appointed to the position of Chief Financial Officer of Hydro One, effective July 1, 2015. Mr. Vels was most recently the Chief Financial Officer at Maple Leaf Foods Inc.

Appointment of Hydro One Ombudsman

In October 2015, the Hydro One Board of Directors announced the appointment of Fiona Crean to the role of Ombudsman for Hydro One, effective November 17, 2015. Ms. Crean most recently served as the City of Toronto's Ombudsman, and has worked in the area of dispute resolution and complaints investigation for more than 25 years. Ms. Crean will report directly to the Hydro One Board of Directors.

Summary of Fourth Quarter Results of Operations

Quarter ended December 31 *(millions of Canadian dollars, except per share amounts)*	2015	2014	Change
Revenues			
Distribution	1,148	1,268	(9.5%)
Transmission	361	382	(5.5%)
Other	13	12	8.3%
	1,522	1,662	(8.4%)
Costs			
Purchased power	786	893	(12.0%)
OM&A			
Distribution	146	148	(1.4%)
Transmission	128	86	48.8%
Other	27	13	107.7%
	301	247	21.9%
Depreciation and amortization	193	190	1.6%
	1,280	1,330	(3.8%)
Income before financing charges and income taxes	242	332	(27.1%)
Financing charges	94	98	(4.1%)
Income before income taxes	148	234	(36.8%)
Income tax expense	1	15	(93.3%)
Net income	147	219	(32.9%)
Net income attributable to common shareholders of Hydro One	143	216	(33.8%)
Basic and diluted EPS	$ 0.26	$ 0.45	(42.2%)
Capital investments			
Distribution	198	211	(6.2%)
Transmission	251	265	(5.3%)
Other	2	2	–
	451	478	(5.6%)

Net Income and EPS

The changes to net income and EPS were primarily due to the following:

- Milder weather resulted in a decrease in transmission revenues, mainly due to lower average monthly Ontario 60-minute peak demand, and lower net distribution revenues; and
- Although expenses related to stabilization of the Company's customer information system were significantly lower than last year, OM&A costs increased from last year, primarily due to:
  - expenses related to write-offs of project and inventory costs due to revisions of asset replacement strategies;
  - higher storm restoration efforts due to multiple windstorms in the fourth quarter of 2015;
  - timing of preventative maintenance on grid infrastructure;
  - insurance proceeds receipts in 2014 that did not re-occur in 2015; and
  - expenditures related to integration of acquired local distribution companies.

Income tax expense for the quarter was reduced by an income tax recovery of $19 million due to tax benefits related to the IPO.

Excluding this effect, the fourth quarter 2015 effective tax rate would have been approximately 13.8% compared to the fourth quarter 2014 effective tax rate of approximately 6.6%.

Revenues

The quarterly decrease of $21 million or 5.5% in transmission revenues was primarily due to lower average monthly Ontario 60-minute peak demand associated with unseasonably warm weather during the fourth quarter of 2015.

The quarterly decrease of $120 million or 9.5% in distribution revenues was primarily due to lower purchased power costs, the spin-off of Hydro One Brampton, and lower consumption due primarily to milder weather, partially offset by higher OEB-approved distribution rates.

OM&A Costs

The quarterly increase of $42 million or 48.8% in transmission OM&A costs was primarily due to the following:

- expenses related to write-offs of project and inventory costs due to revisions of asset replacement strategies;
- higher volumes of preventative and corrective station maintenance on power equipment;
- insurance proceeds received in the fourth quarter of 2014 related to 2013 floods at the Company's Richview and Manby transformer stations which were recorded as a reduction in 2014 OM&A costs;
- higher expenditures during 2015 related to work required to adhere to the NERC Cyber Security standards; and
- increased expenditures related to forestry control and line clearing on the Company's transmission rights-of-way.

The decrease of $2 million or 1.4% in distribution OM&A costs during the fourth quarter of 2015 was primarily due to the following:

- a decrease in bad debt expense and lower expenditures related to remediation of the Company's customer information system; and
- decreased vegetation management expenditures relating to distribution line clearing and forestry control; partially offset by
- increased costs associated with responding to power quality-related issues and outages as a result of multiple wind storms which occurred during the fourth quarter of 2015.

Depreciation and Amortization

The increase of $3 million or 1.6% in depreciation and amortization costs during the fourth quarter of 2015 compared to last year was mainly due to the growth in capital assets as the Company continues to place new assets in-service, consistent with its multi-year capital investment program.

Income Taxes

The decrease of $14 million in income tax expense for the fourth quarter of 2015 compared to 2014 was due to lower income before taxes, in addition to the positive effect of an income tax recovery associated with the step-up of the tax basis of the assets of Hydro One Inc. and its subsidiaries to fair market value in excess of the Departure Tax incurred when Hydro One exited the PILs Regime.

For the fourth quarter of 2015, the Company realized an effective tax rate of approximately 0.7%, compared to approximately 6.6% realized for the fourth quarter of 2014. The difference in the effective tax rates is due primarily to the income tax recovery on the revaluation of the assets of Hydro One on exiting the PILs Regime, partially offset by a decrease in accelerated capital cost allowance over depreciation recognized in 2014 for certain classes of assets.

Capital Investments

During the fourth quarter of 2015, the Company made capital investments totalling $451 million and placed $607 million of new assets in-service. Capital investments in the transmission system during the fourth quarter included equipment replacements at the Bruce, Richview and Pickering Transmission Stations, and continued work on the Company's major inter-area network and local area supply projects, including the Clarington Transmission Station and Guelph Area Transmission Refurbishment projects.

Capital investments in the distribution system during the fourth quarter included capital work related to station refurbishment programs and wood utility pole replacements, continued investments in new customer connections and upgrades, and increased storm restoration work as a result of two significant wind storms during the fourth quarter of 2015.

Forward-looking Statements And Information

The Company's oral and written public communications, including this document, often contain forward-looking statements that are based on current expectations, estimates, forecasts and projections about the Company's business and the industry in which it operates, and include beliefs and assumptions made by the management of the Company. Such statements include, but are not limited to: expectations regarding energy-related revenues and profit and their trend; statements regarding the Company's transmission and distribution rates resulting from rate applications; statements about

CDM; statements regarding the Company's liquidity and capital resources and operational requirements; statements about the standby credit facilities; expectations regarding the Company's financing activities; statements regarding the Company's maturing debt; statements regarding ongoing and planned projects and/or initiatives including the expected results of these projects and/or initiatives and their completion dates; expectations regarding the recoverability of large capital investments; statements regarding expected future capital and development investments, the timing of these expenditures and the Company's investment plans; statements regarding contractual obligations and other commercial commitments; statements related to the OEB; statements regarding future pension contributions, the pension plan and actuarial valuation; expectations related to workforce demographics; statements about the outsourcing arrangements with Inergi and Brookfield; expectations regarding work and costs of compliance with environmental and health and safety regulations; statements related to critical accounting estimates, including employee future benefits and expectations regarding regulatory assets and liabilities; statements about non-GAAP measures; statements regarding recent accounting-related guidance; statements about internal controls; expectations about effect of interest rates; statements related to Hydro One Brampton; statements about collective agreements; expectations regarding taxes; statements related to future sales of shares of Hydro One; statements related to the Company's relationship with the Province; statements about share-based compensation; statements related to claims; statements regarding the role of Hydro One's Ombudsman; and statements related to the Company's acquisitions and integrations, including statements about Great Lakes Power Transmission LP, Woodstock Hydro, Haldimand Hydro, and 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. Hydro One does not intend, and it disclaims 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 and future rate and other applications; no unexpected delays in obtaining the required approvals; no unforeseen changes in rate orders or rate setting methodologies for the Company's 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 the Company, including information obtained from third party sources. Actual results may differ materially from those predicted by such forward-looking statements. While Hydro One does not know what impact any of these differences may have, the Company's business, results of operations, financial condition and 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:

- risks associated with the Province's significant share ownership of Hydro One and other relationships with the Province, including potential conflicts of interest that may arise between Hydro One, the Province and related parties;
- regulatory risks and risks relating to Hydro One's revenues, including risks relating to rate orders, actual performance against forecasts and capital expenditures;
- the risk that previously granted regulatory approvals may be subsequently challenged, appealed or overturned;
- the risk that the Company may be unable to comply with regulatory and legislative requirements or that the Company may incur additional costs for compliance that are not recoverable through rates;
- the risk of exposure of the Company's facilities to the effects of severe weather conditions, natural disasters or other unexpected occurrences for which the Company is uninsured or for which the Company could be subject to claims for damage;
- public opposition to and delays or denials of the requisite approvals and accommodations for the Company's planned projects;
- the risk that Hydro One may incur significant costs associated with transferring assets located on Reserves (as defined in the Indian Act (Canada));
- the risks associated with information system security and with maintaining a complex information technology system infrastructure;
- the risks related to the Company's workforce demographic and its potential inability to attract and retain qualified personnel;
- the risk of labour disputes and inability to negotiate appropriate collective agreements on acceptable terms consistent with the Company's rate decisions;
- risk that the Company is not able to arrange sufficient cost-effective financing to repay maturing debt and to fund capital expenditures;

- risks associated with fluctuations in interest rates and failure to manage exposure to credit risk;
- the risk that the Company may not be able to execute plans for capital projects necessary to maintain the performance of the Company's assets or to carry out projects in a timely manner;
- the risk of non-compliance with environmental regulations or failure to mitigate significant health and safety risks and inability to recover environmental expenditures in rate applications;
- the risk that assumptions that form the basis of the Company's recorded environmental liabilities and related regulatory assets may change;
- changes in benefits and changes in actuarial assumptions;
- the risk of not being able to recover the Company's pension expenditures in future rates and uncertainty regarding the future regulatory treatment of pension, other post-employment benefits and post-retirement benefits costs;
- the potential that Hydro One may incur significant expenses to replace some or all of the functions currently outsourced if either of the Company's agreements with Inergi or Brookfield are terminated or expire before a new service provider is selected;
- the risks associated with economic uncertainty and financial market volatility;
- the inability to prepare financial statements using US GAAP; and
- the impact of the ownership by the Province of lands underlying the Company's transmission system.

Hydro One cautions 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.

In addition, Hydro One cautions the reader that information provided in this MD&A regarding the Company's outlook on certain matters, including potential future expenditures, is provided in order to give context to the nature of some of the Company's future plans and may not be appropriate for other purposes.

Additional information about Hydro One is available on SEDAR at www.sedar.com.

Management's Report

The Consolidated Financial Statements, Management's Discussion and Analysis (MD&A) and related financial information have been prepared by the management of Hydro One Limited (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.

The preparation of the Consolidated Financial Statements and information in the MD&A involves the use of estimates and assumptions based on management's judgment, 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 11, 2016.

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 (2013), 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, 2015. The effectiveness of these internal controls is reported to the Audit Committee of the Hydro One Board of Directors, as required.

The Consolidated Financial Statements have been audited by KPMG LLP, independent external auditors appointed by the shareholders of the Company. 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 Committee, is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal controls. The Audit 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 Committee, with and without the presence of management, to discuss their audit findings.

The President and Chief Executive Officer and the 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's management:

Mayo Schmidt
President and Chief
Executive Officer

Michael Vels
Chief Financial Officer

Independent Auditors' Report

To the Shareholders of Hydro One Limited

We have audited the accompanying Consolidated Financial Statements of Hydro One Limited, which comprise the consolidated balance sheets as at December 31, 2015 and December 31, 2014, the consolidated statements of operations and comprehensive income, changes in 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 judgment, including the assessment of the risks of material misstatement of the Consolidated Financial Statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity's preparation and fair presentation of the Consolidated Financial Statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the Consolidated Financial Statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the Consolidated Financial Statements present fairly, in all material respects, the consolidated financial position of Hydro One Limited as at December 31, 2015 and December 31, 2014, 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 11, 2016

Consolidated Statements of Operations and Comprehensive Income

For the years ended December 31, 2015 and 2014

Year ended December 31 (millions of Canadian dollars, except per share amounts)	2015	2014
Revenues		
Distribution (includes $159 related party revenues; 2014 – $159) *(Note 23)*	4,949	4,903
Transmission (includes $1,554 related party revenues; 2014 – $1,567) *(Note 23)*	1,536	1,588
Other	53	57
	6,538	6,548
Costs		
Purchased power (includes $2,335 related party costs; 2014 – $2,633) *(Note 23)*	3,450	3,419
Operation, maintenance and administration *(Note 23)*	1,135	1,192
Depreciation and amortization *(Note 5)*	759	722
	5,344	5,333
Income before financing charges and income taxes	1,194	1,215
Financing charges *(Note 6)*	376	379
Income before income taxes	818	836
Income taxes *(Notes 7, 23)*	105	89
Net income	713	747
Other comprehensive income	1	–
Comprehensive income	714	747
Net income attributable to:		
Noncontrolling interest *(Note 22)*	10	(2)
Preferred shareholders	13	18
Common shareholders	690	731
	713	747
Comprehensive income attributable to:		
Noncontrolling interest *(Note 22)*	10	(2)
Preferred shareholders	13	18
Common shareholders	691	731
	714	747
Earnings per common share *(Note 20)*		
Basic	$ 1.39	$ 1.53
Diluted	$ 1.39	$ 1.53
Dividends per common share declared *(Note 19)*	$ 1.83	$ 0.56

See accompanying notes to Consolidated Financial Statements.

Consolidated Balance Sheets

At December 31, 2015 and 2014

December 31 (millions of Canadian dollars)	2015	2014
Assets		
Current assets:		
Cash and cash equivalents *(Note 13)*	94	100
Accounts receivable (net of allowance for doubtful accounts – $61; 2014 – $66) *(Note 8)*	776	1,016
Due from related parties *(Note 23)*	191	224
Regulatory assets *(Note 11)*	36	31
Materials and supplies	21	23
Deferred income tax assets *(Note 7)*	19	19
Derivative instruments *(Note 13)*	–	2
Prepaid expenses and other assets	29	35
	1,166	1,450
Property, plant and equipment *(Note 9)*:		
Property, plant and equipment in service	26,070	25,356
Less: accumulated depreciation	9,414	9,134
	16,656	16,222
Construction in progress	1,155	1,025
Future use land, components and spares	157	154
	17,968	17,401
Other long-term assets:		
Regulatory assets *(Note 11)*	3,015	3,200
Deferred income tax assets *(Note 7)*	1,636	7
Intangible assets (net of accumulated amortization – $274; 2014 – $305) *(Note 10)*	336	276
Goodwill *(Note 4)*	163	173
Deferred debt issuance costs	34	36
Derivative instruments *(Note 13)*	1	–
Other	9	7
	5,194	3,699
Total assets	24,328	22,550

See accompanying notes to Consolidated Financial Statements.

CONSOLIDATED FINANCIAL STATEMENTS

Consolidated Balance Sheets (continued)

At December 31, 2015 and 2014

December 31 (millions of Canadian dollars, except number of shares)	2015	2014
Liabilities		
Current liabilities:		
Bank indebtedness *(Note 13)*	–	2
Short-term notes payable *(Notes 12, 13)*	1,491	–
Accounts payable	155	173
Accrued liabilities *(Notes 15, 16)*	598	611
Due to related parties *(Note 23)*	138	227
Accrued interest	96	100
Regulatory liabilities *(Note 11)*	19	47
Derivative instruments *(Note 13)*	–	3
Long-term debt payable within one year (includes $nil measured at fair value; 2014 – $252) *(Notes 12, 13)*	500	552
	2,997	1,715
Long-term debt (includes $51 measured at fair value; 2014 – $nil) *(Notes 12, 13)*	8,224	8,373
Other long-term liabilities:		
Post-retirement and post-employment benefit liability *(Note 15)*	1,560	1,533
Pension benefit liability *(Note 15)*	952	1,236
Regulatory liabilities *(Note 11)*	236	168
Deferred income tax liabilities *(Note 7)*	207	1,313
Environmental liabilities *(Note 16)*	185	221
Net unamortized debt premiums	17	18
Asset retirement obligations *(Note 17)*	9	9
Long-term accounts payable and other liabilities	17	17
	3,183	4,515
Total liabilities	14,404	14,603
Contingencies and Commitments (Notes 25, 26)		
Subsequent Events (Note 28)		
Preferred shares *(Notes 18, 19)*	–	323
Noncontrolling interest subject to redemption *(Note 22)*	23	21
Equity		
Common shares *(Notes 18, 19)*	5,623	3,314
Preferred shares *(Notes 18, 19)*	418	–
Additional paid-in capital *(Note 21)*	10	–
Retained earnings	3,806	4,249
Accumulated other comprehensive loss	(8)	(9)
Total Hydro One shareholders' equity	9,849	7,554
Noncontrolling interest *(Note 22)*	52	49
Total equity	9,901	7,603
	24,328	22,550

See accompanying notes to Consolidated Financial Statements.

On behalf of the Board of Directors:

David Denison
Chair

Philip Orsino
Chair, Audit Committee

Consolidated Statements of Changes in Equity

For the years ended December 31, 2015 and 2014

Year ended December 31, 2015 *(millions of Canadian dollars)*	Common Shares	Preferred Shares	Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Total Hydro One Shareholders' Equity	Non-controlling Interest *(Note 22)*	Total Equity
January 1, 2015	3,314	–	–	4,249	(9)	7,554	49	7,603
Net income	–	–	–	703	–	703	7	710
Other comprehensive income	–	–	–	–	1	1	–	1
Distributions to noncontrolling interest	–	–	–	–	–	–	(4)	(4)
Dividends on preferred shares	–	–	–	(13)	–	(13)	–	(13)
Dividends on common shares	–	–	–	(875)	–	(875)	–	(875)
Hydro One Brampton spin-off *(Note 4)*	(196)	–	–	(258)	–	(454)	–	(454)
Pre-IPO Transactions *(Notes 1, 18)*	2,505	418	–	–	–	2,923	–	2,923
Stock-based compensation *(Note 21)*	–	–	10	–	–	10	–	10
December 31, 2015	5,623	418	10	3,806	(8)	9,849	52	9,901

Year ended December 31, 2014 *(millions of Canadian dollars)*	Common Shares	Preferred Shares	Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Total Hydro One Shareholders' Equity	Non-controlling Interest *(Note 22)*	Total Equity
January 1, 2014	3,314	–	–	3,787	(9)	7,092	–	7,092
Net income	–	–	–	749	–	749	(1)	748
Other comprehensive income	–	–	–	–	–	–	–	–
Amount contributed by noncontrolling interest	–	–	–	–	–	–	50	50
Dividends on preferred shares	–	–	–	(18)	–	(18)	–	(18)
Dividends on common shares	–	–	–	(269)	–	(269)	–	(269)
December 31, 2014	3,314	–	–	4,249	(9)	7,554	49	7,603

See accompanying notes to Consolidated Financial Statements.

Consolidated Statements of Cash Flows

For the years ended December 31, 2015 and 2014

Year ended December 31 (millions of Canadian dollars)	2015	2014
Operating activities		
Net income	713	747
Environmental expenditures	(19)	(18)
Adjustments for non-cash items:		
Depreciation and amortization (excluding removal costs)	668	641
Regulatory assets and liabilities	(3)	(69)
Deferred income taxes *(Note 7)*	(2,844)	10
Other	24	–
Changes in non-cash balances related to operations *(Note 24)*	208	(55)
Net cash from (used in) operating activities	(1,253)	1,256
Financing activities		
Long-term debt issued	350	628
Long-term debt retired	(585)	(776)
Short-term notes issued	1,491	–
Common shares issued	2,600	–
Dividends paid	(888)	(287)
Amount contributed by noncontrolling interest *(Note 22)*	–	72
Distributions paid to noncontrolling interest	(5)	–
Change in bank indebtedness	(2)	(29)
Other	(7)	(3)
Net cash from (used in) financing activities	2,954	(395)
Investing activities		
Capital expenditures *(Note 24)*		
Property, plant and equipment	(1,595)	(1,481)
Intangible assets	(37)	(23)
Capital contributions received *(Note 24)*	62	–
Acquisition of Haldimand Hydro *(Note 4)*	(66)	–
Acquisition of Woodstock Hydro *(Note 4)*	(24)	–
Investment in Hydro One Brampton *(Note 4)*	(53)	–
Acquisition of Norfolk Power *(Note 4)*	–	(66)
Proceeds from investment	–	250
Other	6	(6)
Net cash used in investing activities	(1,707)	(1,326)
Net change in cash and cash equivalents	(6)	(465)
Cash and cash equivalents, beginning of year	100	565
Cash and cash equivalents, end of year	94	100

See accompanying notes to Consolidated Financial Statements.

Notes to Consolidated Financial Statements

For the years ended December 31, 2015 and 2014

1. Description of The Business

Hydro One Limited (Hydro One or the Company) was incorporated on August 31, 2015, under the *Business Corporations Act* (Ontario).

On October 31, 2015, the Company acquired Hydro One Inc., a company previously wholly-owned by the Province of Ontario (Province). The acquisition of Hydro One Inc. by Hydro One was accounted for as a common control transaction and Hydro One is a continuation of business operations of Hydro One Inc. The principal businesses of Hydro One are the transmission and distribution of electricity to customers within Ontario.

In November 2015, Hydro One and the Province completed an initial public offering (IPO) on the Toronto Stock Exchange of 15% of its 595 million outstanding common shares. The proceeds of the offering were received by the Province. All of the regulated business and outstanding publicly issued notes and debentures of Hydro One remain at the Company's wholly owned subsidiary Hydro One Inc. At December 31, 2015, the Province owns 84% of Hydro One. See Note 18 for further details regarding the reorganization of Hydro One.

2. Significant Accounting Policies

Basis of Consolidation and Preparation

These Consolidated Financial Statements have been presented in a manner similar to the pooling-of-interests method. The financial statements consist of the results of operations of Hydro One Inc. prior to October 31, 2015, and the consolidated results of operations of Hydro One from the date of incorporation on August 31, 2015 to December 31, 2015, which include the results of Hydro One Inc. subsequent to its acquisition on October 31, 2015. All periods have been combined using historical amounts. The comparative information consists of the results of Hydro One Inc. as at and for the year ended December 31, 2014. In addition, Hydro One's issued and outstanding common shares prior to October 31, 2015 have been retroactively adjusted for the purposes of presentation to reflect the effects of the acquisition of Hydro One Inc. using the exchange ratio established for the acquisition. The accompanying combined consolidated and consolidated financial statements are referred to as "consolidated" for all periods presented. Intercompany transactions and balances have been eliminated.

On August 31, 2015, Hydro One Inc. completed the spin-off of its subsidiary, Hydro One Brampton Networks Inc. (Hydro One Brampton) to the Province. See note 4 – Business Combinations. These Consolidated Financial Statements include the results of operations of Hydro One Brampton up to August 31, 2015.

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.

Hydro One performed an evaluation of subsequent events through to February 11, 2016, 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 28 – Subsequent Events.

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, 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.

Rate Setting

The Company's Transmission Business consists of the transmission business of Hydro One Inc., which includes the transmission business of its subsidiary, Hydro One Networks Inc. (Hydro One Networks), as well as its 66% interest in B2M Limited Partnership (B2M LP). The

Company's Distribution Business consists of the distribution business of Hydro One Inc., which includes the distribution businesses of Hydro One Networks, Haldimand County Utilities Inc. (Haldimand Hydro), Hydro One Remote Communities Inc. (Hydro One Remote Communities), and Woodstock Hydro Holdings Inc. (Woodstock Hydro).

The Ontario Energy Board (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.

Transmission

On January 8, 2015, pursuant to an application filed with the OEB, the OEB approved the 2015 Hydro One transmission rates revenue requirement, excluding the B2M LP revenue requirement, of $1,477 million.

On June 30, 2015, B2M LP updated its application (originally filed March 30, 2015) with the OEB for 2015-2019 transmission rates, requesting approval of revenue requirement of $39 million, $36 million, $37 million, $38 million and $37 million for the respective years. On December 29, 2015, the OEB issued a Decision and Order approving the 2015-2019 rates revenue requirement, and on January 14, 2016, the OEB approved the B2M LP revenue requirement recovery through the 2016 Uniform Transmission Rates, and the establishment of a deferral account to capture costs of Tax Rate and Rule changes.

Distribution

On March 12, 2015, the OEB issued a Decision and Rate Order approving a revenue requirement of $1,326 million for 2015, $1,430 million for 2016 and $1,486 million for 2017. The revenue requirements for 2016 and 2017 are estimates that may change based on 2016 and 2017 Rate Orders. On April 23, 2015, the Final Rate Order for 2015 rates was approved by the OEB.

On September 24, 2014, Hydro One Remote Communities filed an Incentive Regulation Mechanism application with the OEB for 2015 rates, seeking approval for increased base rates for the distribution and generation of electricity of 1.7%. On March 19, 2015, the OEB approved an increase of approximately 1.6% to basic rates for the distribution and generation of electricity, with an effective date of May 1, 2015.

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 attributable to the delivery of electricity are based on OEB-approved distribution rates and are recognized on an accrual basis and include billed and unbilled revenues. Billed revenues are based on electricity delivered as measured from customer meters. Unbilled revenues are based on an estimate of electricity delivered determined by historical trends of consumption and are estimated at the end of each month. The unbilled revenue estimate is affected by energy consumption, weather, 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.

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 recorded at their estimated value. 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 Company estimates the allowance for doubtful accounts on customer receivables by applying internally developed loss rates to the outstanding receivable balances by aging category. Loss rates applied to the accounts receivable balances are based on historical overdue balances, customer payments and write-offs. Accounts receivable are written-off against the allowance when they are deemed uncollectible. The existing allowance for doubtful accounts will continue to be affected by changes in volume, prices and economic conditions.

Noncontrolling interest

Noncontrolling interest represents the portion of equity ownership in subsidiaries that is not attributable to shareholders of Hydro One. Noncontrolling interest is initially recorded at fair value and subsequently the amount is adjusted for the proportionate share of net income (loss) and other comprehensive income (loss) attributable to the noncontrolling interest and any dividends or distributions paid to the noncontrolling interest.

If a transaction results in the acquisition of all, or part, of a noncontrolling interest in a subsidiary, the acquisition of the noncontrolling interest is accounted for as an equity transaction. No gain or loss is recognized in consolidated net income or comprehensive income as a result of changes in the noncontrolling interest, unless a change results in the loss of control by the Company.

Income Taxes

By virtue of being wholly owned by the Province, Hydro One was exempt from tax under the *Income Tax Act* (Canada) and the *Taxation Act, 2007* (Ontario) (Federal Tax Regime). However, under the *Electricity Act*, Hydro One was required to make payments in lieu of tax (PILs) to the Ontario Electricity Financial Corporation (OEFC) (PILs Regime). The PILs were, in general, based on the amount of tax that Hydro One would otherwise be liable to pay under the Federal Tax Regime if it was not exempt from taxes under those statutes.

In connection with the IPO of Hydro One, Hydro One's exemption from tax under the Federal Tax Regime ceased to apply. Upon exiting the PILs Regime, Hydro One is required to make corporate income tax payments to the Canada Revenue Agency (CRA) under the Federal Tax Regime.

Current and deferred income taxes are computed based on the tax rates and tax laws enacted as 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 judgment 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.

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 as 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 deferred income 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, 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 fibre optic and microwave radio systems, 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 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 financing costs are a reduction of 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, 2015. A summary of average service lives and depreciation and amortization rates for the various classes of assets is included below:

	Average Service Life	Rate	
		Range	Average
Transmission	56 years	1% – 2%	2%
Distribution	46 years	1% – 7%	2%
Communication	16 years	1% – 15%	6%
Administration and service	18 years	1% – 20%	6%

The cost of intangible assets is included primarily within the administration and service classification above. Amortization rate for computer applications software and other intangible assets is 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 asset retirement obligations have 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, 2015, based on the qualitative assessment performed as at September 30, 2015, 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, 2015.

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, the Company evaluates whether impairment may exist by estimating 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, 2015 and 2014, 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 issuance costs on the Consolidated Balance Sheets. Deferred debt issuance 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). 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. All financial instrument transactions are recorded at trade date.

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.

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 on 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 Statements 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 which 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, 2015 or 2014.

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 defined benefit 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. Defined benefit 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 post-retirement and post-employment benefit plans are unfunded because there are no related plan assets.

Pension benefits

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.

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.

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

Former employees of Haldimand Hydro and Woodstock Hydro participate in the Ontario Municipal Employees Retirement System Fund (OMERS Plan), a multiemployer, contributory, defined benefit public sector pension fund. Former employees of Norfolk Power Inc. (Norfolk Power) ceased to contribute to the OMERS Plan upon integration of Norfolk Power into Hydro One Networks in September 2015. These employees are now included in Hydro One's defined benefit pension plan. OMERS Plan provides retirement pension payments based on members' length of service and salary. Both the 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. The OMERS Plan is registered with the Financial Services Commission of Ontario under Registration #0345983.

The OMERS Plan is accounted for as a defined contribution plan by Hydro One because it is not practicable to determine the present value of the Company's obligation, the fair value of plan assets or the related current service cost applicable to employees of Haldimand Hydro and Woodstock Hydro. 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.

Stock-Based Compensation

Hydro One measures share grant plans based on fair value of share grants as estimated based on the grant date share price. The costs are recognized in the financial statements using the graded-vesting attribution method for share grant plans that have both a performance condition and a service condition. The Company records a regulatory asset equal to the accrued costs of share grant plans recognized in each period, as management considers it to be probable that such costs will be recovered in the future through the rate-setting process.

The Company also records the liabilities associated with its Directors' Deferred Share Unit (DSU) Plan at fair value at each reporting date until settlement, recognizing compensation expense over the vesting period on a straight-line basis. The fair value of the DSU liability is based on the Company's common share closing price at the end of each reporting period.

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 judgments 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 judgments 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 contaminated land assessment and remediation 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

Asset retirement obligations 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 asset retirement obligations 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 asset retirement obligation, 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 asset retirement obligation 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 asset retirement obligations, 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 asset retirement obligations currently exist 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 asset retirement obligation exists. In such a case, an asset retirement obligation would be recorded at that time.

The Company's asset retirement obligations 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

Recent Accounting Guidance Not Yet Adopted

In January 2015, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) 2015-01, Income Statement – Extraordinary and Unusual Items (Subtopic 225-20): Simplifying Income Statement Presentation by Eliminating the Concept of Extraordinary Items. This ASU eliminates the requirements for reporting entities to consider whether an underlying event or transaction is extraordinary and to show the item separately in the income statement. This ASU is effective for fiscal years, and interim periods within these years, beginning after December 15, 2015. The adoption of this ASU is not anticipated to have an impact on the Company's consolidated financial statements.

In February 2015, the FASB issued ASU 2015-02, Consolidation (Topic 810): Amendments to the Consolidation Analysis. This ASU provides guidance about the analysis that a reporting entity must perform to determine whether it should consolidate certain types of legal entities. This ASU is effective for fiscal years, and interim periods within those years, beginning after December 15, 2015. The adoption of this ASU is not anticipated to have an impact on the Company's consolidated financial statements.

In April 2015, the FASB issued ASU 2015-03, Interest – Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs. This ASU requires that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability. The recognition and measurement guidance for debt issuance costs are not affected. This ASU is effective for fiscal years, and interim periods within those years, beginning after December 15, 2015. Upon adoption of this ASU in the first quarter of 2016, the Company's deferred debt issuance costs that are currently presented under other long-term assets will be reclassified as a deduction from the carrying amount of long-term debt.

In April 2015, the FASB issued ASU 2015-04, Compensation – Retirement Benefits (Topic 715): Practical Expedient for the Measurement Date of an Employer's Defined Benefit Obligation and Plan Assets. This ASU permits an entity with a fiscal year-end that does not coincide with a month-end and an entity that has a significant event in an interim period that calls for a remeasurement of defined benefit plan assets and obligations to measure the defined benefit plan assets and obligations using the month-end that is closest to the entity's fiscal year-end. This ASU is effective for fiscal years, and interim periods within these years, beginning after December 15, 2015. The adoption of this ASU is not anticipated to have an impact on the Company's consolidated financial statements.

In April 2015, the FASB issued ASU 2015-05, Intangibles – Goodwill and Other – Internal-Use Software (Subtopic 350-40): Customer's Accounting for Fees Paid in a Cloud Computing Arrangement. This ASU provides guidance to customers about whether a cloud computing arrangement includes a software license, as well as the related accounting for the arrangement. This ASU is effective for fiscal years, and interim periods within these years, beginning after December 15, 2015. The Company is currently assessing the impact of adoption of this ASU on its consolidated financial statements.

In August 2015, the FASB issued ASU 2015-14, Revenue from Contracts with Customers (Topic 606): Deferral of the Effective Date. This ASU defers by one year the effective date of ASU 2014-09, Revenue from Contracts with Customers (Topic 606) issued by the FASB in May 2014. ASU 2014-09 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. The guidance in ASU 2014-09 is now effective for fiscal years, and interim periods within those years, beginning after December 15, 2017. The Company is currently assessing the impact of adoption of ASU 2014-09 on its consolidated financial statements.

In September 2015, the FASB issued ASU 2015-16, Business Combinations (Topic 805): Simplifying the Accounting for Measurement-Period Adjustments. The amendments in this ASU require that an acquirer recognize adjustments to provisional amounts that are identified during the measurement period of a business combination in the reporting period in which the adjustment amounts are determined. The amendments in this update require that the acquirer to present separately on the face of the income statement or disclose in the notes the portion of the amount recorded in current-period earnings by line item that would have been recorded in previous reporting periods if the adjustment to the provisional amounts had been recognized as of the acquisition date. This ASU is effective for fiscal years, and interim periods within those years, beginning after December 15, 2015. Upon adoption of this ASU in the first quarter of 2016, the Company will apply the guidance in this ASU to future measurement adjustments related to business combinations, as applicable.

In November 2015, the FASB issued ASU 2015-17, Income Taxes (Topic 740): Balance Sheet Classification of Deferred Taxes. The amendments in this ASU require that all deferred tax assets and liabilities be classified as noncurrent on the balance sheet. This ASU is effective for fiscal years, and interim periods within those years, beginning after December 15, 2016. Upon adoption of this ASU in the first quarter of 2017, the current portions of the Company's deferred income tax assets and liabilities will be reclassified as noncurrent assets and liabilities on the consolidated Balance Sheets.

In January 2016, the FASB issued ASU 2016-01, Financial Instruments – Overall (Subtopic 825-10): Recognition and Measurement of Financial Assets and Financial Liabilities. This ASU requires equity investments to be measured at fair value with changes in fair value recognized in net income, and requires enhanced disclosures and presentation of financial assets and liabilities in the financial statements. This ASU also simplifies the impairment assessment of equity investments without readily determinable fair values by requiring a qualitative assessment to identify impairment. This ASU is effective for fiscal years, and interim periods within those years, beginning after December 15, 2017. The Company is currently assessing the impact of adoption of this ASU on its consolidated financial statements.

4. Business Combinations

Acquisition of Woodstock Hydro

On October 31, 2015, Hydro One acquired 100% of the common shares of Woodstock Hydro, an electricity distribution company located in southwestern Ontario. The total purchase price for Woodstock Hydro was approximately $32 million.

The following table summarizes the preliminary determination of the fair value of the assets acquired and liabilities assumed:

(millions of Canadian dollars)	
Cash and cash equivalents	3
Working capital	4
Property, plant and equipment	28
Intangible assets	1
Deferred income tax assets	2
Goodwill	17
Long-term debt	(17)
Other long-term liabilities	(2)
Post-retirement and post-employment benefit liability	(1)
Derivative instruments	(3)
	32

The preliminary determination of the fair value of assets acquired and liabilities assumed has been based upon management's preliminary estimates and certain assumptions with respect to the fair values of the assets acquired and liabilities assumed. Due to the timing of the transaction, the Company has not yet completed the final fair value measurements as at December 31, 2015. In addition, the purchase agreement provides for final purchase price adjustments based on agreed working capital and other balances at the acquisition date which have not yet been finalized. The Company will continue to review information and perform further analysis prior to finalizing the total purchase price and the fair values of the assets acquired and liabilities assumed. The actual total purchase price and the fair values of the assets acquired and liabilities assumed may differ from the amounts above.

Goodwill of approximately $17 million arising from the Woodstock Hydro acquisition consists largely of the synergies and economies of scale expected from combining the operations of Hydro One and Woodstock Hydro. All of the goodwill was assigned to Hydro One's Distribution Business segment. Woodstock Hydro contributed revenues of $12 million and net income of $2 million to the Company's consolidated financial results for the year ended December 31, 2015. All costs related to the acquisition have been expensed through the Consolidated Statements of Operations and Comprehensive Income. Woodstock Hydro's financial information is not material to the Company's consolidated financial results for the year ended December 31, 2015 and therefore, has not been disclosed on a pro forma basis.

Hydro One Brampton Spin-off

On August 31, 2015, Hydro One completed the spin-off of its subsidiary, Hydro One Brampton. The spin-off was accounted as a non-monetary, nonreciprocal transfer with the Province, based on its carrying values at August 31, 2015. Transactions that immediately preceded the spin-off as well as the spin-off were as follows:

- Hydro One subscribed for 357 common shares of Hydro One Brampton for an aggregate subscription price of $53 million;
- Hydro One transferred to a company wholly owned by the Province all the issued and outstanding shares of Hydro One Brampton as a dividend-in-kind; and all of the long-term intercompany debt in aggregate principal amount of $193 million plus accrued interest of $3 million owed by Hydro One Brampton to Hydro One as a return of stated capital of $196 million on its common shares.

In connection with the Hydro One Brampton spin-off, the following assets and liabilities of Hydro One Brampton were transferred:

(millions of Canadian dollars)	
Working capital	33
Property, plant and equipment and intangibles (net)	360
Other long-term assets	6
Long-term liabilities	(205)

As a result of the spin-off, goodwill related to Hydro One Brampton of $60 million was eliminated from the Consolidated Balance Sheet.

Acquisition of Haldimand Hydro

On June 30, 2015, Hydro One acquired 100% of the common shares of Haldimand Hydro, an electricity distribution company located in southwestern Ontario. The final total purchase price for Haldimand Hydro was approximately $73 million.

The following table summarizes the determination of the fair value of the assets acquired and liabilities assumed:

(millions of Canadian dollars)	
Cash and cash equivalents	3
Working capital	5
Property, plant and equipment	52
Deferred income tax assets	1
Goodwill	33
Long-term debt	(18)
Regulatory liabilities	(3)
	73

The determination of the fair value of assets acquired and liabilities assumed has been based upon management's estimates and certain assumptions with respect to the fair values of the assets acquired and liabilities assumed.

Goodwill of approximately $33 million arising from the Haldimand Hydro acquisition consists largely of the synergies and economies of scale expected from combining the operations of Hydro One and Haldimand Hydro. All of the goodwill was assigned to Hydro One's Distribution Business segment. Haldimand Hydro contributed revenues of $32 million and net income of $6 million to the Company's consolidated financial results for the year ended December 31, 2015. All costs related to the acquisition have been expensed through the Consolidated Statements of Operations and Comprehensive Income. Haldimand Hydro's financial information is not material to the Company's consolidated financial results for the year ended December 31, 2015 and therefore, has not been disclosed on a pro forma basis.

Acquisition of Norfolk Power

On August 29, 2014, Hydro One acquired 100% of the common shares of Norfolk Power an electricity distribution and telecom company located in southwestern Ontario. Norfolk Power was a holding company for two subsidiaries, Norfolk Power Distribution Inc. (NPDI) and Norfolk Energy Inc. The total purchase price for Norfolk Power, net of the long-term debt assumed, was approximately $68 million. The purchase price was finalized in 2015, with no adjustments to the preliminary purchase price allocation as disclosed at December 31, 2014.

The following table summarizes the determination of the fair value of the assets acquired and liabilities assumed:

(millions of Canadian dollars)	
Working capital	6
Property, plant and equipment	56
Deferred income tax assets	1
Goodwill	40
Bank indebtedness	(3)
Derivative instruments	(3)
Long-term debt	(26)
Post-retirement and post-employment benefit liability	(1)
Environmental liability	(1)
Long-term accounts payable and other liabilities	(1)
	68

The determination of the fair values of assets acquired and liabilities assumed has been based upon management's estimates and certain assumptions with respect to the fair values of the assets acquired and liabilities assumed.

Goodwill of approximately $40 million arising from the Norfolk Power acquisition consists largely of the synergies and economies of scale expected from combining the operations of Hydro One and Norfolk Power. All of the goodwill was assigned to Hydro One's Distribution Business segment. Norfolk Power contributed revenues of $18 million and net income of less than $1 million to the Company's consolidated financial results for the year ended December 31, 2014. All costs related to the acquisition have been expensed through the Consolidated Statements of Operations and Comprehensive Income. Norfolk Power's financial information was not material to the Company's consolidated financial results for the year ended December 31, 2014 and therefore, has not been disclosed on a pro forma basis.

5. Depreciation And Amortization

Year ended December 31 *(millions of Canadian dollars)*	2015	2014
Depreciation of property, plant and equipment	595	565
Amortization of intangible assets	54	53
Asset removal costs	91	81
Amortization of regulatory assets	19	23
	759	722

6. Financing Charges

Year ended December 31 *(millions of Canadian dollars)*	2015	2014
Interest on long-term debt	417	432
Other	16	12
Less: Interest capitalized on construction and development in progress	(52)	(49)
Gain on interest-rate swap agreements	(2)	(10)
Interest earned on investments	(3)	(6)
	376	379

7. Income Taxes

Income taxes / 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)*	2015	2014
Income taxes / provision for PILs at statutory rate	217	222
Increase (decrease) resulting from:		
Net temporary differences included in amounts charged to customers:		
Capital cost allowance in excess of depreciation and amortization	(37)	(72)
Pension contributions in excess of pension expense	(25)	(24)
Overheads capitalized for accounting but deducted for tax purposes	(15)	(15)
Interest capitalized for accounting but deducted for tax purposes	(13)	(13)
Environmental expenditures	(5)	(5)
Non-refundable investment tax credits	(2)	(3)
Post-retirement and post-employment benefit expense in excess of cash payments	(1)	3
Prior year's adjustments	(1)	(4)
Other	(2)	(1)
Net temporary differences	(101)	(134)
Net tax benefit resulting from transition from PILs Regime to Federal Tax Regime	(19)	–
Hydro One Brampton spin-off	7	–
Net permanent differences	1	1
Total income taxes / provision for PILs	105	89

The major components of income tax expense are as follows:

Year ended December 31 *(millions of Canadian dollars)*	2015	2014
Current income taxes / provision for PILs	2,949	79
Deferred income taxes / provision for (recovery of) PILs	(2,844)	10
Total income taxes / provision for PILs	105	89
Effective income tax rate	12.84%	10.63%

The provision for PILs / current income taxes is remitted to, or received from, the OEFC (PILs Regime) and the CRA (Federal Tax Regime). At December 31, 2015, $12 million (2014 – $39 million) due from the OEFC was included in due from related parties and $1 million (2014 – $nil) due from the CRA was included in prepaid expenses and other assets on the Consolidated Balance Sheet.

In connection with the IPO, Hydro One's exemption from tax under the Federal Tax Regime ceased to apply. Under the PILs Regime, Hydro One was deemed to have disposed of its assets immediately before it lost its tax exempt status under the Federal Tax Regime, resulting in Hydro One making payments in lieu of tax (Departure Tax) totalling $2.6 billion. To enable Hydro One to make the Departure Tax payment, the Province subscribed for common shares of Hydro One for $2.6 billion (See Note 18 – Share Capital). Hydro One used the proceeds of this share subscription to pay the Departure Tax.

At December 31, 2015, the total income taxes / provision for PILs includes deferred income taxes / recovery of PILs of $2,844 million (2014 – deferred provision of $10 million), including $2,810 million (2014 – $nil) resulting from transition from the PILs Regime to the Federal Tax Regime, that is not included in the rate-setting process, using the liability method of accounting. Deferred income taxes / 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 basis of the Company's assets and liabilities. At December 31, 2015 and 2014, deferred income tax assets and liabilities consisted of the following:

December 31 *(millions of Canadian dollars)*	2015	2014
Deferred income tax assets		
Depreciation and amortization in excess of capital cost allowance	937	(4)
Post-retirement and post-employment benefits expense in excess of cash payments	578	8
Environmental expenditures	75	4
Non-capital losses	62	–
Other	3	(1)
Total deferred income tax assets	1,655	7
Less: current portion	19	–
	1,636	7

December 31 *(millions of Canadian dollars)*	2015	2014
Deferred income tax liabilities		
Regulatory amounts that are not recognized for tax purposes	(153)	(140)
Partnership interest	(41)	(38)
Goodwill	(10)	(21)
Capital cost allowance in excess of depreciation and amortization	(1)	(1,713)
Post-retirement and post-employment benefits expense in excess of cash payments	–	559
Environmental expenditures	–	59
Other	(2)	–
Total deferred income tax liabilities	(207)	(1,294)
Less: current portion	–	19
	(207)	(1,313)

During 2015 and 2014, there were no changes in the rate applicable to future taxes. The Company has recorded a valuation allowance in the amount of $278 million (2014 – $nil) in respect of non-depreciable capital property.

8. Accounts Receivable

December 31 *(millions of Canadian dollars)*	2015	2014
Accounts receivable – billed	379	496
Accounts receivable – unbilled	458	586
Accounts receivable, gross	837	1,082
Allowance for doubtful accounts	(61)	(66)
Accounts receivable, net	776	1,016

In 2015, the Company revised the method to estimate the unbilled accounts receivable by using new technology that improved the estimation process. This change has been accounted for on a prospective basis in the consolidated financial statements at December 31, 2015. At December 31, 2015, the change in estimation technology resulted in a reduction in unbilled accounts receivable of approximately $121 million, with a corresponding offset to various components of the retail settlement variance accounts (RSVA). The change in estimate had no significant impact on 2015 net income.

The following table shows the movements in the allowance for doubtful accounts for the years ended December 31, 2015 and 2014:

Year ended December 31 *(millions of Canadian dollars)*	2015	2014
Allowance for doubtful accounts – January 1	(66)	(36)
Write-offs	37	24
Additions to allowance for doubtful accounts	(32)	(54)
Allowance for doubtful accounts – December 31	(61)	(66)

9. Property, Plant And Equipment

December 31, 2015 *(millions of Canadian dollars)*	Property, Plant and Equipment	Accumulated Depreciation	Construction in Progress	Total
Transmission	13,803	4,625	853	10,031
Distribution	9,205	3,177	238	6,266
Communication	1,165	704	28	489
Administration and service	1,531	848	36	719
Easements	523	60	–	463
	26,227	9,414	1,155	17,968

December 31, 2014 *(millions of Canadian dollars)*	Property, Plant and Equipment	Accumulated Depreciation	Construction in Progress	Total
Transmission	13,209	4,416	626	9,419
Distribution	9,076	3,225	320	6,171
Communication	1,100	615	56	541
Administration and service	1,502	793	23	732
Easements	623	85	–	538
	25,510	9,134	1,025	17,401

Financing charges capitalized on property, plant and equipment under construction were $50 million in 2015 (2014 – $48 million).

10. Intangible Assets

December 31, 2015 *(millions of Canadian dollars)*	Intangible Assets	Accumulated Amortization	Development in Progress	Total
Computer applications software	579	270	24	333
Other	7	4	–	3
	586	274	24	336

December 31, 2014 *(millions of Canadian dollars)*	Intangible Assets	Accumulated Amortization	Development in Progress	Total
Computer applications software	573	303	3	273
Other	5	2	–	3
	578	305	3	276

Financing charges capitalized to intangible assets under development were $1 million in 2015 (2014 – $1 million). The estimated annual amortization expense for intangible assets is as follows: 2016 – $57 million; 2017 – $57 million; 2018 – $57 million; 2019 – $47 million; and 2020 – $30 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)*	2015	2014
Regulatory assets:		
Deferred income tax regulatory asset	1,445	1,327
Pension benefit regulatory asset	952	1,236
Post-retirement and post-employment benefits	240	273
Environmental	207	239
RSVA	110	11
Pension cost variance	37	90
2015-2017 rate rider	20	–
DSC exemption	10	16
Share-based compensation	10	–
B2M LP start-up costs	8	–
OEB cost assessment differential	–	12
Other	12	27
Total regulatory assets	3,051	3,231
Less: current portion	36	31
	3,015	3,200
Regulatory liabilities:		
External revenue variance	87	54
Green Energy expenditure variance	76	83
CDM deferral variance	53	25
Deferred income tax regulatory liability	23	21
PST savings deferral	4	19
Other	12	13
Total regulatory liabilities	255	215
Less: current portion	19	47
	236	168

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 income. 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 income tax expense 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 2015 income tax expense would have been higher by approximately $101 million (2014 – $132 million).

Pension Benefit Regulatory Asset

In accordance with OEB 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). 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, 2015 OCI would have been higher by $284 million (2014 – lower by $391 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, 2015 OCI would have been higher by $33 million (2014 – $35 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 2015, the environmental regulatory asset decreased by $24 million (2014 – $33 million) to reflect related changes in the Company's PCB liability, and increased by $1 million (2014 – $13 million) due to changes in the land assessment and remediation 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, 2015 operation, maintenance and administration expenses would have been lower by $23 million (2014 – $20 million). In addition, 2015 amortization expense would have been lower by $19 million (2014 – $18 million), and 2015 financing charges would have been higher by $10 million (2014 – $11 million).

RSVA

Hydro One has deferred certain retail settlement variance amounts under the provisions of Article 490 of the OEB's Accounting Procedures Handbook. In March 2015, the OEB approved the disposition of the total RSVA balance accumulated from January 2012 to December 2013, including accrued interest, to be recovered through the 2015-2017 Rate Rider. In 2015, the Company revised its method to estimate the unbilled accounts receivable based on new technology implemented to improve the accuracy of the estimation process. At December 31, 2015, the change in estimate reduced unbilled accounts receivable by approximately $121 million, with a corresponding offset to various components of RSVA. The change in estimate had no significant impact on 2015 net income.

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 expenses 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 March 2015, the OEB approved the disposition of the distribution business portion of the total pension cost variance account at December 31, 2013, including accrued interest, which will be recovered through the 2015-2017 Rate Rider. In the absence of rate-regulated accounting, 2015 revenue would have been lower by $6 million (2014 – $10 million).

2015-2017 Rate Rider

In March 2015, as part of its decision on Hydro One Networks' Distribution rate application for 2015-2019 the OEB approved the disposition of certain deferral and variance accounts, including RSVAs and accrued interest. The 2015-2017 Rate Rider account includes the balances approved for disposition by the OEB and will be disposed over a 32-month period in accordance with the OEB decision.

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 identified specific expenditures can be recorded in a deferral account subject to the OEB's review in subsequent Hydro One Network distribution applications. In March 2015, the OEB approved the disposition of the DSC exemption deferral account at December 31, 2013, including accrued interest, which will be recovered through the 2015-2017 Rate Rider. In addition, the OEB also approved Hydro One's request to discontinue this deferral account, and there were no additions to this regulatory account in 2015.

Share-based Compensation

The Company recognizes costs associated with stock-based compensation in a regulatory asset as management considers it probable that stock-based compensation costs will be recovered in the future through the rate-setting process. At December 31, 2015 the stock-based compensation costs relate to the share grant plans, are measured at fair value estimated based on grant date share price and recognized using the graded-vesting attribution method. In the absence of rate-regulated accounting 2015 operation, maintenance and administration expenses would have been higher by $5 million (2014 – $nil).

B2M LP Start-up Costs

In December 2015, OEB issued its decision on B2M LP's application for 2015-2019 and as part of the decision approved the recovery of $8 million of start-up costs relating to B2M LP. The costs will be recovered over a 4 year period beginning in 2016, in accordance with the OEB decision.

OEB Cost Assessment Differential

In April 2010, the OEB issued its Decision regarding Hydro One Networks' distribution rate application 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. In March 2015, the OEB approved the disposition of the OEB Cost Assessment Differential Account at December 31, 2013, including accrued interest, which will be recovered through the 2015-2017 Rate Rider. In addition, the OEB also approved Hydro One's request to discontinue this deferral account, and there were no additions to this regulatory account in 2015.

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.

Green Energy Expenditure Variance

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.

CDM Deferral Variance Account

As part of Hydro One Networks' application for 2013 and 2014 transmission rates, Hydro One agreed to establish a new regulatory deferral variance account to track the impact of actual Conservation and Demand Management (CDM) and demand response results on the load forecast compared to the estimated load forecast included in the revenue requirement. At December 31, 2014, the balance in the CDM deferral variance account relates to the actual 2013 CDM compared to the amounts included in 2013 revenue requirement. At December 31, 2015, the balance also includes the difference between the actual 2014 CDM compared to the amounts included in 2014 revenue requirement. The OEB rate order specifically states that the IESO (Ontario Power Authority (OPA) prior to January 1, 2015) data used to calculate the difference between forecasted and actual savings will be provided one year in arrears, and as a result, no amount should be recorded in advance of notification from the IESO of actual results.

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 administration 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, 2015 and recorded in a deferral account, as directed by the OEB. In March 2015, the OEB approved the disposition of the PST Savings Deferral account at December 31, 2013, including accrued interest, which will be recovered through the 2015-2017 Rate Rider.

12. Debt And Credit Agreements

Short-Term Notes and Credit Facilities

Hydro One meets its short-term liquidity requirements in part through the issuance of commercial paper under Hydro One Inc.'s Commercial Paper Program which has a maximum authorized amount of $1.5 billion. These short-term notes are denominated in Canadian dollars with varying maturities not exceeding 365 days. The Commercial Paper Program is supported by Hydro One Inc.'s committed revolving credit facilities totalling $2.3 billion. At December 31, 2015, Hydro One Inc. had $1,491 million in commercial paper borrowings outstanding (December 31, 2014 – $nil).

At December 31, 2015, Hydro One's consolidated committed, unsecured and unused credit facilities totalling $2,550 million consisted of the following:

(millions of Canadian dollars)	Maturity	Amount
Hydro One Inc.		
Revolving standby credit facility	June 2020	1,500
Three-year senior, revolving term credit facility	October 2018	800
Hydro One		
Five-year senior, revolving term credit facility	November 2020	250
Total		2,550

The Company may use the credit facilities for working capital and general corporate purposes. If used, interest on the credit facilities would apply based on Canadian benchmark rates. The obligation of each lender to make any credit extension 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

At December 31, 2015, all of the Company's long-term debt was issued by Hydro One Inc. under Hydro One Inc.'s Medium-Term Note (MTN) Program. The maximum authorized principal amount of notes issuable by Hydro One Inc. under this program is $3.5 billion. At December 31, 2015, $3.5 billion remained available for issuance until January 2018.

The following table presents Hydro One Inc.'s outstanding long-term debt at December 31, 2015 and 2014:

December 31 (millions of Canadian dollars)	2015	2014
2.95% Series 21 notes due 2015[1]	–	500
Floating-rate Series 22 notes due 2015[2]	–	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	750
Floating-rate Series 31 notes due 2019[2]	228	228
4.40% Series 20 notes due 2020	300	300
1.62% Series 33 notes due 2020[1]	350	–
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	435
4.17% Series 32 notes due 2044	350	350
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
4.29% Series 30 notes due 2064	50	50
	8,723	8,923
Add: Unrealized mark-to-market loss[1]	1	2
Less: Long-term debt payable within one year	(500)	(552)
Long-term debt	8,224	8,373

[1] The unrealized mark-to-market loss relates to $50 million of the Series 33 notes due 2020 (2014 – $250 million of the Series 21 notes due 2015). The unrealized mark-to-market loss is offset by a $1 million (2014 – $2 million) unrealized mark-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 2015, Hydro One Inc. issued $350 million (2014 – $628 million) of long-term debt under the MTN Program, and repaid $550 million of long-term debt MTN Program notes (2014 – $750 million).

Long-term debt totalling $35 million assumed by Hydro One Inc. as part of the Haldimand Hydro and Woodstock Hydro acquisitions was repaid in 2015.

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, 2015 and 2014, the Company's carrying amounts of accounts receivable, due from related parties, cash and cash equivalents, bank indebtedness, short-term notes payable, 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, 2015 and 2014 are as follows:

December 31 *(millions of Canadian dollars)*	2015 Carrying Value	2015 Fair Value	2014 Carrying Value	2014 Fair Value
Long-term debt				
$250 million of MTN Series 21 notes[1]	–	–	252	252
$50 million of MTN Series 33 notes[1]	51	51	–	–
Other notes and debentures[2]	8,673	9,942	8,673	10,159
	8,724	9,993	8,925	10,411

[1] The fair value of the $50 million MTN Series 33 notes and $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).

[2] The fair value of other notes and debentures, and the portion of 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, 2015, Hydro One Inc. had an interest-rate swap in the amount of $50 million (2014 – $250 million) that was used to convert fixed-rate debt to floating-rate debt. This swap is classified as a fair value hedge. Hydro One Inc.'s fair value hedge exposure was equal to about 1% (2014 – 3%) of its total long-term debt of $8,724 million (2014 – $8,925 million). At December 31, 2015, Hydro One Inc.'s interest-rate swap designated as a fair value hedge was as follows:

- a $50 million fixed-to-floating interest-rate swap agreement to convert $50 million of the $350 million MTN Series 33 notes maturing April 30, 2020 into three-month variable rate debt.

At December 31, 2015, the Company had no interest-rate swaps classified as undesignated contracts (2014 – $409 million).

As part of the Norfolk Power and Woodstock Hydro acquisitions, Hydro One Inc. assumed liabilities associated with unrealized losses on derivative instruments (interest-rate swaps) totalling $6 million. Hydro One Inc. extinguished the interest rate swaps and repaid these liabilities in 2015.

Fair Value Hierarchy

The fair value hierarchy of financial assets and liabilities at December 31, 2015 and 2014 is as follows:

December 31, 2015 *(millions of Canadian dollars)*	Carrying Value	Fair Value	Level 1	Level 2	Level 3
Assets:					
Cash and cash equivalents	94	94	94	–	–
Derivative instruments					
Fair value hedge – interest-rate swap	1	1	1	–	–
	95	95	95	–	–
Liabilities:					
Short-term notes payable	1,491	1,491	1,491	–	–
Long-term debt	8,724	9,993	–	9,993	–
	10,215	11,484	1,491	9,993	–

December 31, 2014 *(millions of Canadian dollars)*	Carrying Value	Fair Value	Level 1	Level 2	Level 3
Assets:					
Cash and cash equivalents	100	100	100	–	–
Derivative instruments					
Fair value hedges – interest-rate swaps	2	2	–	2	–
	102	102	100	2	–
Liabilities:					
Bank indebtedness	2	2	2	–	–
Derivative instruments					
Undesignated contracts – interest-rate swaps	3	3	–	3	–
Long-term debt	8,925	10,411	–	10,411	–
	8,930	10,416	2	10,414	–

Cash and cash equivalents include cash and short-term investments. The carrying values are representative of fair value because of the short-term nature of these instruments.

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, 2015 and 2014.

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 costs, foreign exchange rates and interest rates. The Company is exposed to fluctuations in interest rates as its regulated return on equity is derived using a formulaic approach that takes into account anticipated interest rates, but is not currently exposed to material commodity price risk or material foreign exchange risk.

The OEB-approved adjustment formula for calculating return on equity in a deemed regulatory capital structure of 60% debt and 40% equity provides for increases and decreases depending on changes in benchmark rates of return for Government of Canada debt. The Company estimates that a 1% decrease in the forecasted long-term Government of Canada bond yield used in determining its rate of return would reduce the Company's transmission business' 2015 net income by approximately $20 million (2014 – $20 million) and its distribution business' 2015 net income by approximately $13 million (2014 – $10 million). The Company's net income is adversely impacted by rising interest rates as the Company's maturing long-term debt is refinanced at market rates. The Company periodically utilizes interest rate swap agreements to mitigate elements of interest rate risk.

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.

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 net income for the years ended December 31, 2015 or 2014.

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, 2015 and 2014 are included in financing charges as follows:

Year ended December 31 *(millions of Canadian dollars)*	2015	2014
Unrealized loss (gain) on hedged debt	(1)	(3)
Unrealized loss (gain) on fair value interest-rate swaps	1	3
Net unrealized loss (gain)	–	–

At December 31, 2015, Hydro One had $50 million (2014 – $250 million) of notional amounts of fair value hedges outstanding related to interest-rate swaps, with assets at fair value of $1 million (2014 – $2 million). During the years ended December 31, 2015 and 2014, 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, 2015 and 2014, 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, 2015 and 2014, there was no significant accounts receivable balance due from any single customer.

At December 31, 2015, the Company's provision for bad debts was $61 million (2014 – $66 million). Adjustments and write-offs were determined on the basis of a review of overdue accounts, taking into consideration historical experience. At December 31, 2015, approximately 6% (2014 – 6%) of the Company's net accounts receivable were aged more than 60 days.

Hydro One manages its counterparty credit risk through various techniques including: entering into transactions with highly-rated counterparties; limiting total exposure levels with individual counterparties consistent with the Company's Board-approved Credit Risk Policy; entering into master agreements which enable net settlement and the contractual right of offset; and monitoring the financial condition of counterparties. In addition to payment netting language in master agreements, the Company establishes credit limits, margining thresholds and collateral requirements for each counterparty. Counterparty credit limits are based on an internal credit review that considers a variety of factors, including the results of a scoring model, leverage, liquidity, profitability, credit ratings and risk management capabilities. The determination of credit exposure for a particular counterparty is the sum of current exposure plus the potential future exposure with that counterparty. The current exposure is calculated as the sum of the principal value of money market exposures and the market value of all contracts that have a positive mark-to-market position on the measurement date. The Company would 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, 2015, the counterparty credit risk exposure on the fair value of these interest-rate swap contracts was $1 million (2014 – $3 million). At December 31, 2015, Hydro One's credit exposure for all derivative instruments, and applicable payables and receivables, had a credit rating of investment grade, with one financial institution as the counterparty.

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, and the revolving standby facilities totaling $2,550 million. The short-term liquidity under the Commercial Paper Program, and anticipated levels of funds from operations should be sufficient to fund normal operating requirements.

At December 31, 2015, accounts payable and accrued liabilities in the amount of $753 million (2014 – $784 million) were expected to be settled in cash at their carrying amounts within the next 12 months.

At December 31, 2015, Hydro One Inc. had long-term debt in the principal amount of $8,723 million (2014 – $8,923 million). Principal repayments and related weighted average interest rates are summarized by the number of years to maturity in the following table:

Years to Maturity	Long-term Debt Principal Repayments *(millions of Canadian dollars)*	Weighted Average Interest Rate *(%)*
1 year	500	4.3
2 years	600	5.2
3 years	750	2.8
4 years	228	1.2
5 years	650	2.9
	2,728	3.5
6 – 10 years	600	3.2
Over 10 years	5,395	5.4
	8,723	4.7

Interest payments on long-term debt are summarized by year in the following table:

Year	Interest Payments *(millions of Canadian dollars)*
2016	397
2017	386
2018	355
2019	332
2020	322
	1,792
2021-2025	1,496
2026 +	4,080
	7,368

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 access to capital, the Company targets to maintain strong credit quality. The Company considers its capital structure to consist of shareholders' equity, including preferred shares, long-term debt, short-term notes payable, and cash and cash equivalents. At December 31, 2015 and 2014, the Company's capital structure was as follows:

December 31 *(millions of Canadian dollars)*	2015	2014
Long-term debt payable within one year	500	552
Short-term notes payable	1,491	–
Less: cash and cash equivalents	94	100
	1,897	452
Long-term debt	8,224	8,373
Preferred shares	418	323
Common shares	5,623	3,314
Retained earnings	3,806	4,249
	9,429	7,563
Total capital	19,968	16,711

Hydro One Inc. has customary covenants typically associated with long-term debt. Among other things, Hydro One Inc.'s long-term debt and credit facility covenants limit the permissible debt to 75% of its total capitalization, limit the ability to sell assets and impose a negative pledge provision, subject to customary exceptions. At December 31, 2015 and 2014, Hydro One Inc. 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 employees of Haldimand Hydro and Woodstock Hydro. Employees of Haldimand Hydro and Woodstock Hydro participate in the OMERS Plan. 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 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, 2015 were $2 million (2014 – $2 million). At December 31, 2015, Company contributions payable included in accrued liabilities on the Consolidated Balance Sheets were less than $1 million (2014 – less than $1 million). Hydro One contributions do not represent more than 5% of total contributions to the OMERS Plan, as indicated in OMERS' most recently available annual report for the year ended December 31, 2014.

At December 31, 2014, the OMERS Plan was 90.8% funded, with an unfunded liability of $7.1 billion. This unfunded liability could 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 2015 of $177 million (2014 – $174 million) were based on an actuarial valuation effective December 31, 2013 and the expected level of pensionable earnings. Estimated annual Pension Plan contributions for 2016 are approximately $180 million, based on the actuarial valuation as at December 31, 2013 and projected levels of pensionable earnings. Future minimum contributions beyond 2016 will be based on an actuarial valuation effective no later than December 31, 2016. Contributions are payable one month in arrears. All of the contributions are expected to be in the form of cash.

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.

Year ended December 31	Pension Benefits		Post-Retirement and Post-Employment Benefits	
(millions of Canadian dollars)	**2015**	2014	**2015**	2014
Change in projected benefit obligation				
Projected benefit obligation, beginning of year	**7,535**	6,576	**1,582**	1,531
Current service cost	**186**	145	**43**	41
Interest cost	**302**	312	**64**	73
Benefits paid	**(334)**	(319)	**(47)**	(45)
Net actuarial loss (gain)	**(6)**	821	**(27)**	(18)
Change due to Hydro One Brampton spin-off	**–**	–	**(5)**	–
Projected benefit obligation, end of year	**7,683**	7,535	**1,610**	1,582
Change in plan assets				
Fair value of plan assets, beginning of year	**6,299**	5,731	**–**	–
Actual return on plan assets	**582**	703	**–**	–
Benefits paid	**(334)**	(319)	**–**	–
Employer contributions	**177**	174	**–**	–
Employee contributions	**40**	35	**–**	–
Administrative expenses	**(33)**	(25)	**–**	–
Fair value of plan assets, end of year	**6,731**	6,299	**–**	–
Unfunded status	**952**	1,236	**1,610**	1,582

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

December 31	Pension Benefits		Post-Retirement and Post-Employment Benefits	
(millions of Canadian dollars)	**2015**	2014	**2015**	2014
Accrued liabilities	**–**	–	**50**	49
Pension benefit liability	**952**	1,236	**–**	–
Post-retirement and post-employment benefit liability	**–**	–	**1,560**	1,533
Unfunded status	**952**	1,236	**1,610**	1,582

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)*	2015	2014
PBO	7,683	7,535
ABO	7,020	6,887
Fair value of plan assets	6,731	6,299

On an ABO basis, the Pension Plan was funded at 96% at December 31, 2015 (2014 – 91%). On a PBO basis, the Pension Plan was funded at 88% at December 31, 2015 (2014 – 84%). 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, 2015 and 2014 for the Pension Plan:

Year ended December 31 *(millions of Canadian dollars)*	2015	2014
Current service cost, net of employee contributions	146	110
Interest cost	302	312
Expected return on plan assets, net of expenses	(406)	(369)
Actuarial loss amortization	119	103
Prior service cost amortization	2	2
Net periodic benefit costs	163	158
Charged to results of operations[1]	81	81

[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, 2015, pension costs of $177 million (2014 – $174 million) were attributed to labour, of which $81 million (2014 – $81 million) was charged to operations, and $96 million (2014 – $93 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, 2015 and 2014 for the post-retirement and post-employment benefit plans:

Year ended December 31 *(millions of Canadian dollars)*	2015	2014
Current service cost, net of employee contributions	43	41
Interest cost	64	73
Actuarial loss amortization	14	18
Prior service cost amortization	–	2
Net periodic benefit costs	121	134
Charged to results of operations	55	62

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 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, 2015 and 2014:

	Pension Benefits		Post-Retirement and Post-Employment Benefits	
Year ended December 31	**2015**	2014	**2015**	2014
Significant assumptions:				
Weighted average discount rate	**4.00%**	4.00%	**4.10%**	4.00%
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]	**–**	–	**4.36%**	4.36%

[1] 6.38% per annum in 2016, grading down to 4.36% per annum in and after 2031 (2014 – 6.52% in 2015, grading down to 4.36% 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, 2015 and 2014. 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	**2015**	2014
Pension Benefits:		
Weighted average expected rate of return on plan assets	**6.50%**	6.50%
Weighted average discount rate	**4.00%**	4.75%
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)*	**13**	11
Post-Retirement and Post-Employment Benefits:		
Weighted average discount rate	**4.00%**	4.75%
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)*	**13.8**	12
Rate of increase in health care cost trends[1]	**4.36%**	4.39%

[1] 6.52% per annum in 2015, grading down to 4.36% per annum in and after 2031 (2014 – 6.81% in 2014, grading down to 4.39% 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 a 1% change in health care cost trends on the projected benefit obligation for the post-retirement and post-employment benefits at December 31, 2015 and 2014 is as follows:

December 31 *(millions of Canadian dollars)*	**2015**	2014
Projected benefit obligation:		
Effect of a 1% increase in health care cost trends	**252**	248
Effect of a 1% decrease in health care cost trends	**(196)**	(193)

The effect of a 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, 2015 and 2014 is as follows:

Year ended December 31 *(millions of Canadian dollars)*	**2015**	2014
Service cost and interest cost:		
Effect of a 1% increase in health care cost trends	**22**	23
Effect of a 1% decrease in health care cost trends	**(16)**	(17)

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, 2015 and 2014:

December 31, 2015				December 31, 2014			
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**	23	25	24	26

Estimated Future Benefit Payments

At December 31, 2015, estimated future benefit payments to the participants of the Plans were:

(millions of Canadian dollars)	**Pension Benefits**	Post-Retirement and Post-Employment Benefits
2016	316	53
2017	328	55
2018	339	57
2019	350	59
2020	360	61
2021 through to 2025	1,928	342
Total estimated future benefit payments through to 2025	3,621	627

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)*	2015	2014
Pension Benefits:		
Actuarial loss (gain) for the year	(181)	511
Actuarial loss amortization	(119)	(103)
Prior service cost amortization	(2)	(2)
	(302)	406
Post-Retirement and Post-Employment Benefits:		
Actuarial loss (gain) for the year	(27)	(18)
Actuarial loss amortization	(14)	(18)
Prior service cost amortization	–	(2)
	(41)	(38)

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, 2015 and 2014:

Year ended December 31 *(millions of Canadian dollars)*	2015	2014
Pension Benefits:		
Prior service cost	–	2
Actuarial loss	952	1,234
	952	1,236
Post-Retirement and Post-Employment Benefits:		
Actuarial loss	240	273
	240	273

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:

December 31	Pension Benefits		Post-Retirement and Post-Employment Benefits	
(millions of Canadian dollars)	2015	2014	2015	2014
Prior service cost	–	2	–	–
Actuarial loss	96	119	8	10
	96	121	8	10

Pension Plan Assets

Investment Strategy

On a regular basis, Hydro One evaluates its investment strategy to ensure that Pension 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 Human Resource 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, 2015, the Pension Plan target asset allocations and weighted average asset allocations were as follows:

	Target Allocation (%)	Pension Plan Assets (%)
Equity securities	55.0	58.2
Debt securities	35.0	36.4
Other[1]	10.0	5.4
	100.0	100.0

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

At December 31, 2015, the Pension Plan held $9 million Hydro One corporate bonds (2014 – $nil) and $420 million of debt securities of the Province (2014 – $340 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, 2015 and 2014. 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, 2015 and 2014, 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 & Poor's Rating Services, DBRS Limited, and Fitch Ratings Inc., and "A1" by Moody's Investors Service, 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, 2015 and 2014:

December 31, 2015 *(millions of Canadian dollars)*	Level 1	Level 2	Level 3	Total
Pooled funds	–	23	299	322
Cash and cash equivalents	191	–	–	191
Short-term securities	–	80	–	80
Real estate	–	–	2	2
Corporate shares – Canadian	923	–	–	923
Corporate shares – Foreign	2,931	–	–	2,931
Bonds and debentures – Canadian	–	2,074	–	2,074
Bonds and debentures – Foreign	–	199	–	199
Total fair value of plan assets[1]	4,045	2,376	301	6,722

[1] At December 31, 2015, the total fair value of Pension Plan assets excludes $27 million of interest and dividends receivable, and $18 million relating to accruals for pension administration expense and foreign exchange contracts payable.

December 31, 2014 *(millions of Canadian dollars)*	Level 1	Level 2	Level 3	Total
Pooled funds	–	18	142	160
Cash and cash equivalents	166	–	–	166
Short-term securities	–	176	–	176
Real estate	–	–	2	2
Corporate shares – Canadian	1,008	–	–	1,008
Corporate shares – Foreign	2,766	–	–	2,766
Bonds and debentures – Canadian	–	1,799	–	1,799
Bonds and debentures – Foreign	–	211	–	211
Total fair value of plan assets[1]	3,940	2,204	144	6,288

[1] At December 31, 2014, the total fair value of Pension Plan assets excludes $18 million of interest and dividends receivable, and $7 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, 2015 and 2014. 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)	2015	2014
Fair value, beginning of year	144	119
Realized and unrealized gains	51	30
Purchases	106	23
Sales and disbursements	–	(28)
Fair value, end of year	301	144

There were no significant transfers between any of the fair value levels during the years ended December 31, 2015 and 2014.

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, real estate and infrastructure 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. Real estate and infrastructure investments represent funds that invest in real assets which are not publicly traded on a stock exchange. Investment strategies in real estate include limited partnerships that seek to generate a total return through income and capital growth by investing primarily in global and Canadian limited partnerships. Investment strategies in infrastructure include limited partnerships in core infrastructure assets focusing on assets that generate stable, long-term cash flows and deliver incremental returns relative to conventional fixed-income investments. Private equity, real estate and infrastructure 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 and infrastructure 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 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, 2015 and 2014:

Year ended December 31, 2015 (millions of Canadian dollars)	PCB	Land Assessment and Remediation	Total
Environmental liabilities, January 1	172	67	239
Interest accretion	8	2	10
Expenditures	(8)	(11)	(19)
Revaluation adjustment	(24)	1	(23)
Environmental liabilities, December 31	148	59	207
Less: current portion	12	10	22
	136	49	185

Year ended December 31, 2014 *(millions of Canadian dollars)*	PCB	Land Assessment and Remediation	Total
Environmental liabilities, January 1	201	65	266
Interest accretion	9	2	11
Expenditures	(5)	(13)	(18)
Revaluation adjustment	(33)	13	(20)
Environmental liabilities, December 31	172	67	239
Less: current portion	8	10	18
	164	57	221

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, 2015 *(millions of Canadian dollars)*	**PCB**	**Land Assessment and Remediation**	**Total**
Undiscounted environmental liabilities	**168**	**61**	**229**
Less: discounting accumulated liabilities to present value	**20**	**2**	**22**
Discounted environmental liabilities	**148**	**59**	**207**

December 31, 2014 *(millions of Canadian dollars)*	PCB	Land Assessment and Remediation	Total
Undiscounted environmental liabilities	195	70	265
Less: discounting accumulated liabilities to present value	23	3	26
Discounted environmental liabilities	172	67	239

At December 31, 2015, the estimated future environmental expenditures were as follows:

(millions of Canadian dollars)	
2016	22
2017	25
2018	26
2019	28
2020	30
Thereafter	98
	229

Hydro One records a liability for the estimated future expenditures for land assessment and remediation and for the phase-out and destruction of PCB-contaminated mineral oil removed from electrical equipment 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.

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 2.0% 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.

PCBs

The Environment Canada regulations, enacted under the *Canadian Environmental Protection Act,* 1999, govern the management, storage and disposal of PCBs based on certain criteria, including type of equipment, in-use status, and PCB-contamination thresholds. Under current regulations, Hydro One's PCBs have to be disposed of by the end of 2025, with the exception of specifically exempted equipment. 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 $168 million (2014 – $195 million). These expenditures are expected to be incurred over the period from 2016 to 2025. As a result of its annual review of environmental liabilities, the Company recorded a revaluation adjustment in 2015 to reduce the PCB environmental liability by $24 million (2014 – $33 million).

Land Assessment and Remediation

The Company's best estimate of the total estimated future expenditures to complete its land assessment and remediation program is $61 million (2014 –$70 million). These expenditures are expected to be incurred over the period from 2016 to 2023. As a result of its annual review of environmental liabilities, the Company recorded a revaluation adjustment in 2015 to increase the land assessment and remediation environmental liability by $1 million (2014 – $13 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. Asset retirement obligations, 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 asset retirement obligation 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 asset retirement obligation, 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 asset retirement obligations, 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 asset retirement obligations 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. Asset retirement obligations 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, 2015, Hydro One had recorded asset retirement obligations of $9 million (2014 – $9 million), consisting of $8 million (2014 – $8 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 $1 million (2014 – $1 million) related to the future decommissioning and removal of two switching stations. The amount of interest recorded is nominal.

18. Share Capital

Common Shares

The Company is authorized to issue an unlimited number of common shares. At December 31, 2015, the Company had 595,000,000 common shares issued and outstanding.

The amount and timing of any dividends payable by Hydro One is at the discretion of the Hydro One Board of Directors and is established on the basis of Hydro One's results of operations, maintenance of its deemed regulatory capital structure, financial condition, cash requirements, the satisfaction of solvency tests imposed by corporate laws for the declaration and payment of dividends and other factors that the Board of Directors may consider relevant.

Preferred Shares

The Company is authorized to issue an unlimited number of preferred shares, issuable in series. At December 31, 2015, two series of preferred shares are authorized for issuance: the Series 1 preferred shares and the Series 2 preferred shares. At December 31, 2015, the Company had 16,720,000 Series 1 preferred shares and no Series 2 preferred shares issued and outstanding.

Hydro One may from time to time issue preferred shares in one or more series. Prior to issuing shares in a series, the Hydro One Board of Directors is required to fix the number of shares in the series and determine the designation, rights, privileges, restrictions and conditions attaching to that series of preferred shares. Holders of Hydro One's preferred shares are not entitled to receive notice of, to attend or to vote at any meeting of the shareholders of Hydro One except that votes may be granted to a series of preferred shares when dividends have not been paid on any one or more series as determined by the applicable series provisions. Each series of preferred shares ranks on parity with every other series of preferred shares, and are entitled to a preference over the common shares and any other shares ranking junior to the preferred shares, with respect to dividends and the distribution of assets and return of capital in the event of the liquidation, dissolution or winding up of Hydro One.

For the period commencing from the date of issue of the Series 1 preferred shares and ending on and including November 19, 2020, the holders of Series 1 preferred shares are entitled to receive fixed cumulative preferential dividends of $1.0625 per share per year, if and when declared by the Board of Directors, payable quarterly. The dividend rate will reset on November 20, 2020 and every five years thereafter at a rate equal to the sum of the then five-year Government of Canada bond yield and 3.53%. The Series 1 preferred shares will not be redeemable by Hydro One prior to November 20, 2020, but will be redeemable by Hydro One on November 20, 2020 and on November 20 of every fifth year thereafter at a redemption price equal to $25.00 for each Series 1 preferred share redeemed, plus any accrued or unpaid dividends. The holders of Series 1 preferred shares will have the right, at their option, on November 20, 2020 and on November 20 of every fifth year thereafter, to convert all or any of their Series 1 preferred shares into Series 2 preferred shares on a one-for-one basis, subject to certain restrictions on conversion. At December 31, 2015, Series 1 preferred dividends of $3 million or $0.18 per share were in arrears.

The holders of Series 2 preferred shares will be entitled to receive quarterly floating rate cumulative dividends, if and when declared by the Board of Directors, at a rate equal to the sum of the then three-month Government of Canada treasury bill rate and 3.53% as reset quarterly. The Series 2 preferred shares will not be redeemable by Hydro One prior to November 20, 2020, but will be redeemable by Hydro One at a redemption price equal to $25.00 for each Series 2 preferred share redeemed, if redeemed on November 20, 2025 or on November 20 of every fifth year thereafter, or $25.50 for each Series 2 preferred share redeemed, if redeemed on any other date after November 20, 2020, in each case plus any accrued or unpaid dividends. The holders of Series 2 preferred shares will have the right, at their option, on November 20, 2025 and on November 20 of every fifth year thereafter, to convert all or any of their Series 2 preferred shares into Series 1 preferred shares on a one-for-one basis, subject to certain restrictions on conversion.

Prior to October 31, 2015, the Company had 12,920,000 issued and outstanding 5.5% cumulative preferred shares held by the Province, with a redemption value of $25 per share or $323 million total value. These preferred shares were entitled to an annual cumulative dividend of $18 million, or $1.375 per share, which was payable on a quarterly basis. These preferred shares had conditions for their redemption that were outside the control of the Company because the Province could exercise its right to redeem in the event of change in ownership without approval of the Company's Board of Directors. At December 31, 2014, these preferred shares were classified on the Consolidated Balance Sheet as temporary equity because the redemption feature was outside the control of the Company. On October 31, 2015, these preferred shares were purchased and cancelled by Hydro One Inc. See "Reorganization" below for further details.

Reorganization

Prior to the completion of the IPO, Hydro One and Hydro One Inc. completed a series of transactions (Pre-IPO Transactions) that resulted in, among other things, on October 31, 2015, Hydro One acquiring all of the issued and outstanding shares of Hydro One Inc. from the Province and issuing new common shares and preferred shares to the Province.

The following tables present the changes to common and preferred shares as a result of Pre-IPO Transactions, as well as the movement in the number of common and preferred shares during the year ended December 31, 2015. There was no movement in common or preferred shares during the year ended December 31, 2014.

		Preferred Shares	
(millions of Canadian dollars)	Common Shares	Equity	Temporary Equity
Common shares issued – purchase and cancellation of preferred shares *(c)*	323	–	(323)
Acquisition of Hydro One Inc. *(d)*			
Common shares of Hydro One Inc. acquired by Hydro One	(3,441)	–	–
Common shares of Hydro One issued to Province	3,023	–	–
Preferred shares of Hydro One issued to Province	–	418	–
Common shares issued *(e)*	2,600	–	–
Total Pre-IPO Transactions adjustment	2,505	418	(323)

		Preferred Shares	
(number of shares)	Common Shares	Equity	Temporary Equity
Number of shares – January 1, 2015 *(a)*	100,000	–	12,920,000
Common shares issued *(b)*	100,000	–	–
Pre-IPO Transactions:			
Common shares issued – purchase and cancellation of preferred shares *(c)*	2,640	–	(12,920,000)
Acquisition of Hydro One Inc.*(d)*			
Common shares of Hydro One Inc. acquired by Hydro One	(102,640)	–	–
Common shares of Hydro One issued to Province	12,197,500,000	–	–
Preferred shares of Hydro One issued to Province	–	16,720,000	–
Common shares issued *(e)*	2,600,000,000	–	–
Common shares consolidation *(f)*	(14,202,600,000)	–	–
Number of shares – December 31, 2015	595,000,000	16,720,000	–

(a) At January 1, 2015, all common and preferred shares represent the shares of Hydro One Inc.

(b) On August 31, 2015, Hydro One was incorporated under the *Business Corporations Act* (Ontario) and issued 100,000 common shares to the Province for proceeds of $100,000.

(c) On October 31, 2015, Hydro One Inc. purchased and cancelled 12,920,000 preferred shares of Hydro One Inc. previously held by the Province for cancellation at a price equal to the redemption price of the preferred shares totaling $323 million, which was satisfied by the issuance to the Province of 2,640 common shares of Hydro One Inc.

(d) On October 31, 2015, all of the issued and outstanding common shares of Hydro One Inc. were acquired by Hydro One from the Province in return for 12,197,500,000 common shares of Hydro One and 16,720,000 Series 1 preferred shares of Hydro One.

(e) On November 4, 2015, Hydro One issued 2.6 billion common shares to the Province for proceeds of $2.6 billion.

(f) On November 4, 2015, the common shares of Hydro One were consolidated by way of articles of amendment approved by the Province as sole shareholder so that, after such consolidation, 595,000,000 common shares of Hydro One were issued and outstanding.

Share Ownership Restrictions

The *Electricity Act* imposes share ownership restrictions on securities of Hydro One carrying a voting right (Voting Securities). These restrictions provide that no person or company (or combination of persons or companies acting jointly or in concert) may beneficially own or exercise control or direction over more than 10% of any class or series of Voting Securities, including common shares of the Company (Share Ownership Restrictions). The Share Ownership Restrictions do not apply to Voting Securities held by the Province, nor to an underwriter who holds Voting Securities solely for the purpose of distributing those securities to purchasers who comply with the Share Ownership Restrictions.

19. Dividends

In 2015, preferred share dividends in the amount of $13 million (2014 – $18 million) and common share dividends in the amount of $875 million (2014 – $269 million) were declared.

In August 2015, Hydro One declared a dividend in-kind on its common shares payable in all of the issued and outstanding shares of Hydro One Brampton. See Note 4 – Business Combinations.

20. Earnings Per Share

Basic earnings per common share (EPS) is calculated by dividing net income attributable to common shareholders of Hydro One by the weighted average number of common shares outstanding.

Diluted EPS is calculated by dividing net income attributable to common shareholders of Hydro One by the weighted average number of common shares outstanding adjusted for the effects of potentially dilutive share grant plans, which is calculated using the treasury stock method.

Year ended December 31	2015	2014
Net income attributable to common shareholders *(millions of Canadian dollars)*	690	731
Weighted average number of shares		
Basic	496,272,733	477,837,100
Effect of dilutive share grant plans *(Note 21)*	94,691	–
Diluted	496,367,424	477,837,100
EPS		
Basic	$1.39	$1.53
Diluted	$1.39	$1.53

Pro forma Adjusted non-GAAP Basic and Diluted EPS

The following pro forma adjusted non-GAAP basic and diluted EPS has been prepared by management on a supplementary basis which assumes that the total number of common shares outstanding was 595,000,000 in each of the years ended December 31, 2015 and 2014. The supplementary pro forma disclosure is used internally by management subsequent to the IPO of Hydro One to assess the Company's performance and is considered useful because it eliminates the impact of the issuance of common shares to the Province prior to the IPO. Prior to the IPO, the Province was the sole shareholder of Hydro One and disclosure of EPS did not provide meaningful information. EPS is considered an important measure and management believes that presenting it for all periods based on the number of outstanding shares on, and subsequent to, the IPO provides users with a basis to evaluate the operations of the Company with comparable companies.

Year ended December 31 (unaudited)	2015	2014
Net income attributable to common shareholders *(millions of Canadian dollars)*	690	731
Pro forma weighted average number of common shares		
Basic	595,000,000	595,000,000
Effect of dilutive share grant plans *(Note 21)*	94,691	–
Diluted	595,094,691	595,000,000
Pro forma adjusted non-GAAP EPS		
Basic	$1.16	$1.23
Diluted	$1.16	$1.23

The above pro forma adjusted non-GAAP basic and diluted EPS does not have any standardized meaning in US GAAP.

21. Stock-based Compensation

Share Grant Plans

At December 31, 2015, Hydro One had two share grant plans, one for the benefit of certain members of the Power Workers' Union (the PWU Share Grant Plan) and one for the benefit of certain members of The Society of Energy Professionals (the Society Share Grant Plan).

The PWU Share Grant Plan provides for the issuance of common shares of Hydro One from treasury to certain eligible members of the Power Workers' Union annually, commencing on April 1, 2017 and continuing until the earlier of April 1, 2028 or the date an eligible employee no longer meets the eligibility criteria of the PWU Share Grant Plan. To be eligible, an employee must be a member of the Pension Plan on April 1, 2015, be employed on the date annual share issuance occurs and continue to have under 35 years of service. The requisite service period for the PWU share grant plan begins on July 3, 2015, which is the date the share grant plans were ratified by the PWU. The number of common shares issued annually to each eligible employee will be equal to 2.7% of such eligible employee's salary as at April 1, 2015, divided by $20.50, being the price of the common shares of Hydro One in the IPO. The aggregate number of common shares issuable under the PWU Share Grant Plan shall not exceed 3,981,763 common shares. In 2015, 3,979,062 common shares were granted under the PWU Share Grant Plan.

The Society Share Grant Plan provides for the issuance of common shares of Hydro One from treasury to certain eligible members of The Society of Energy Professionals annually, commencing on April 1, 2018 and continuing until the earlier of April 1, 2029 or the date an eligible employee no longer meets the eligibility criteria of the Society Share Grant Plan. To be eligible, an employee must be a member of the Pension Plan on September 1, 2015, be employed on the date annual share issuance occurs and continue to have under 35 years of service. Therefore the requisite service period for the Society Share Grant Plan begins on September 1, 2015. The number of common shares issued annually to each eligible employee will be equal to 2.0% of such eligible employee's salary as at September 1, 2015, divided by $20.50, being the price of the common shares of Hydro One in the IPO. The aggregate number of common shares issuable under the Society Share Grant Plan shall not exceed 1,434,686 common shares. In 2015, 1,433,292 common shares were granted under the Society Share Grant Plan.

The fair value of the share grants is estimated based on the grant date share price of $20.50 and is recognized using the graded-vesting attribution method as the share grant plans have both a performance condition and a service condition. Total fair value of shares granted in 2015 is $111 million (2014 – $nil). Total share based compensation recognized during 2015 was $10 million (2014 – $nil) and was recorded as a regulatory asset. The historical turnover rate relating to members of the Power Workers' Union and The Society of Energy Professionals is not believed to be reflective of a future turnover rate due to benefits conferred by the share grant plans. At December 31, 2015 the Company expects all eligible employees to receive the share grants until such time that they no longer meet the eligibility criteria and therefore, a forfeiture rate of 0% is assumed in amounts recognized during 2015. The Company will reevaluate this assumption in subsequent periods based on actual experience.

A summary of share grant activity under the Plan as of December 31, 2015 is presented below:

Years ended December 31, 2015	Share Grants *(Number)*	Weighted-Average Price
Outstanding – beginning of year	–	–
Granted (non-vested)	5,412,354	$20.50
Outstanding – end of year	5,412,354	–

Directors' DSU Plan

Under the Company's Directors' DSU Plan, directors can elect to receive credit for their annual cash retainer in a notional account of DSUs in lieu of cash. Hydro One's Board of Directors may also determine from time to time that special circumstances exist that would reasonably justify the grant of DSUs to a director as compensation in addition to any regular retainer or fee to which the director is entitled.

Each DSU represents a unit with an underlying value equivalent to the value of one common share of the Company and is entitled to accrue common share dividend equivalents in the form of additional DSUs at the time dividends are paid, subsequent to declaration by Hydro One's Board of Directors.

(number of DSUs)	**2015**	2014
DSUs outstanding – January 1	**–**	–
DSUs granted	**20,525**	–
DSUs outstanding – December 31	**20,525**	–

For the year ended December 31, 2015, an expense of less than $1 million (2014 – $nil) was recognized in earnings with respect to the DSU Plan. At December 31, 2015, a liability of less than $1 million (December 31, 2014 – $nil), related to outstanding DSUs has been recorded at the closing price of the Company's common shares of $22.29 and is included in accrued liabilities on the Balance Sheet.

Employee Share Ownership Plan

Effective December 15, 2015, Hydro One established an Employee Share Ownership Plan (ESOP). Under the ESOP, certain eligible management and non-represented employees may contribute between 1% and 6% of their base salary towards purchasing common shares of Hydro One. The Company will match 50% of the employee's contributions, up to a maximum Company contribution of $25,000 per calendar year. No contributions were made under the ESOP during 2015.

Long-term Incentive Plan

Effective August 31, 2015, the Board of Directors of Hydro One adopted a Long-term Incentive Plan (LTIP). Under the LTIP, long-term incentives will be granted to certain executive and management employees, and all equity-based awards will be settled in newly-issued shares of Hydro One from treasury, consistent with the provisions of the plan. The aggregate number of shares issuable under the LTIP shall not exceed 11,900,000 shares.

The LTIP provides flexibility to award a range of vehicles, including restricted share units, performance share units, stock options, share appreciation rights, restricted shares, deferred share units and other share-based awards. The mix of vehicles is intended to vary by role to recognize the level of executive accountability for overall business performance. No long-term incentives were awarded during 2015.

22. Noncontrolling Interest

On December 16, 2014, the relevant Bruce to Milton Line transmission assets totalling $526 million were transferred from Hydro One Networks to B2M LP. This was financed by 60% debt ($316 million) and 40% equity ($210 million). On December 17, 2014, the Saugeen Ojibway Nation (SON) acquired a 34.2% equity interest in B2M LP for consideration of $72 million, representing the fair value of the equity interest acquired. The SON's initial investment in B2M LP consists of $50 million of Class A units and $22 million of Class B units.

The Class B units have a mandatory put option which requires that upon the occurrence of an enforcement event (i.e. an event of default such as a debt default by the SON or insolvency event), Hydro One purchase the Class B units of B2M LP for net book value on the redemption date. The noncontrolling interest relating to the Class B units is classified on the Consolidated Balance Sheet as temporary equity because the redemption feature is outside the control of the Company. The balance of the noncontrolling interest is classified within equity.

The following tables show the movements in noncontrolling interest for the years ended December 31, 2015 and December 31, 2014:

Year ended December 31, 2015 *(millions of Canadian dollars)*	Temporary Equity	Equity	Total
Noncontrolling interest – January 1, 2015	21	49	70
Distributions to noncontrolling interest	(1)	(4)	(5)
Net income attributable to noncontrolling interest	3	7	10
Noncontrolling interest – December 31, 2015	23	52	75

Year ended December 31, 2014 *(millions of Canadian dollars)*	Temporary Equity	Equity	Total
Noncontrolling interest – January 1, 2014	–	–	–
Amount contributed by noncontrolling interest	22	50	72
Net income (loss) attributable to noncontrolling interest	(1)	(1)	(2)
Noncontrolling interest – December 31, 2014	21	49	70

23. Related Party Transactions

The Province is the majority shareholder of Hydro One. The OEFC, IESO, Ontario Power Generation Inc. (OPG), the OEB, and Hydro One Brampton are related parties to Hydro One because they are controlled or significantly influenced by the Province. Effective January 1, 2015, the OPA and IESO have merged and are now operating as IESO.

The Province

- During 2015, Hydro One paid dividends to the Province totalling $888 million (2014 – $287 million). In addition, on August 31, 2015, Hydro One declared a dividend in-kind on its common shares payable in all of the issued and outstanding shares of Hydro One Brampton. See Note 4 – Business Combinations.
- On November 4, 2015, Hydro One issued common shares to the Province for proceeds of $2.6 billion. See Note 18 – Share Capital.
- During 2015, Hydro One Inc. incurred certain IPO related expenses totaling $7 million, which will be reimbursed to the Company by the Province.

IESO

- In 2015, Hydro One purchased power in the amount of $2,318 million (2014 – $2,601 million) from the IESO-administered electricity market.
- Hydro One receives revenues for transmission services from the IESO, based on OEB-approved uniform transmission rates. Transmission revenues for 2015 include $1,548 million (2014 – $1,556 million) related to these services.
- Hydro One receives amounts for rural rate protection from the IESO. Distribution revenues for 2015 include $127 million (2014 – $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 for 2015 include $32 million (2014 – $32 million) related to these services.
- The IESO (OPA prior to January 1, 2015) funds substantially all of the Company's CDM programs. The funding includes program costs, incentives, and management fees. During 2015, Hydro One received $70 million (2014 – $33 million) related to these programs.

OPG

- In 2015, Hydro One purchased power in the amount of $11 million (2014 – $23 million) from OPG.
- Hydro One has service level agreements with OPG. These services include field, engineering, logistics and telecommunications services. In 2015, revenues related to the provision of construction and equipment maintenance services with respect to these service level agreements were $7 million (2014 – $12 million), primarily for the Transmission Business. Operation, maintenance and administration costs in 2015 and 2014 related to the purchase of services with respect to these service level agreements were not significant.

OEFC

- In 2015, Hydro One made PILs to the OEFC totalling $2.9 billion (2014 – $86 million), including Departure Tax of $2.6 billion (2014 – $nil).
- In 2015, Hydro One purchased power in the amount of $6 million (2014 – $9 million) from power contracts administered by the OEFC.
- During 2015, Hydro One paid a $8 million (2014 – $5 million) 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. Hydro One has not made any claims under the indemnity since it was put in place in 1999. Hydro One and the OEFC, with the consent of the Minister of Finance, terminated the indemnity fee effective October 31, 2015.
- PILs and payments in lieu of property taxes were paid to the OEFC.

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. In 2015, Hydro One incurred $12 million (2014 – $12 million) in OEB fees.

Hydro One Brampton

- Effective August 31, 2015, Hydro One Brampton is no longer a subsidiary of Hydro One, but is indirectly owned by the Province. For change in ownership of Hydro One Brampton, see Note 4 – Business Combinations.
- Subsequent to August 31, 2015, Hydro One continues to provide certain management, administrative and smart meter network services to Hydro One Brampton pursuant to certain service level agreements, which are provided at market rates. These agreements will continue until the end of 2016 (except in the case of smart meter network services, which will continue until the end of 2017). Hydro One Brampton has the right to renew these agreements (other than smart meter network services) for additional one-year terms to end no later than December 31, 2019. Additionally, on August 31, 2015, Hydro One Inc. and Hydro One Brampton entered into a license agreement which permits Hydro One Brampton to use the "Hydro One" name and related licensed marks. These agreements will terminate if the Province disposes of its interest in Hydro One Brampton, except in the case of the smart meter network services agreement, which is anticipated to continue for a transition period after the Province disposes of its interest in Hydro One Brampton. During 2015, revenues related to the provision of services with respect to these service level agreements were $1 million.

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.

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

(millions of Canadian dollars)	**December 31, 2015**	December 31, 2014
Due from related parties	**191**	224
Due to related parties[1]	**(138)**	(227)

[1] Included in due to related parties at December 31, 2015 are amounts owing to the IESO in respect of power purchases of $134 million (2014 – $214 million).

24. 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)*	**2015**	2014
Accounts receivable	**240**	(93)
Due from related parties	**33**	(27)
Materials and supplies	**2**	–
Prepaid expenses and other assets	**4**	(13)
Accounts payable	**(23)**	39
Accrued liabilities	**(15)**	(35)
Due to related parties	**(89)**	(3)
Accrued interest	**(4)**	–
Long-term accounts payable and other liabilities	**–**	(3)
Post-retirement and post-employment benefit liability	**60**	80
	208	(55)

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 accounting for capitalized depreciation and the net change in related accruals:

Year ended December 31 *(millions of Canadian dollars)*	2015	2014
Capital investments in property, plant and equipment	(1,623)	(1,511)
Capitalized depreciation and net change in accruals included in capital investments in property, plant and equipment	28	30
Capital expenditures – property, plant and equipment	(1,595)	(1,481)

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

Year ended December 31 *(millions of Canadian dollars)*	2015	2014
Capital investments in intangible assets	(40)	(19)
Net change in accruals included in capital investments in intangible assets	3	(4)
Capital expenditures – intangible assets	(37)	(23)

Capital Contributions

Hydro One enters into contracts governed by the OEB Transmission System Code when a transmission customer requests a new or upgraded transmission connection. The customer is required to make a capital contribution to Hydro One based on the shortfall between the present value of the costs of the connection facility and the present value of revenues. The present value of revenues is based on an estimate of load forecast for the period of the contract with Hydro One. Once the connection facility is commissioned, in accordance with the OEB Transmission System Code, Hydro One will periodically reassess the estimated of load forecast which will lead to a decrease, or an increase in the capital contributions from the customer. The increase or decrease in capital contributions is recorded directly to fixed assets in service. In 2015, capital contributions from these reassessments totalled $62 million, which represents the difference between the revised load forecast of electricity transmitted compared to the load forecast in the original contract, subject to certain adjustments. No reassessments occurred in 2014.

Supplementary Information

Year ended December 31 *(millions of Canadian dollars)*	2015	2014
Net interest paid	416	412
Income taxes / PILs paid	2,933	86

25. 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.

In September 2015, Hydro One and three of its subsidiaries were served with a class action suit in which the representative plaintiff is seeking up to $125 million in damages related to allegations of improper billing practices. Hydro One intends to defend the action. Due to the preliminary stage of legal proceedings, an estimate of a possible loss related to this claim cannot be made.

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 2015, the Company paid approximately $1 million (2014 – $1 million) in respect of consents obtained. 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.

26. Commitments

Outsourcing Agreements

Inergi LP (Inergi), an affiliate of Capgemini Canada Inc., provides services to Hydro One, including settlements, source to pay services, pay operations services, information technology, finance and accounting services. The agreement with Inergi for these services expires in December 2019. In addition, Inergi provides customer service operations outsourcing services to Hydro One. The agreement for these services expires in February 2018.

Brookfield Global Integrated Solutions (formerly Brookfield Johnson Controls Canada LP) (Brookfield) provides services to Hydro One, including facilities management and execution of certain capital projects as deemed required by the Company. The current agreement with Brookfield expires in December 2024.

At December 31, 2015, the annual commitments under the outsourcing agreements were as follows: 2016 – $167 million; 2017 – $138 million; 2018 – $106 million; 2019 – $99 million; 2020 – $2 million; and thereafter – $11 million.

Trilliant Agreement

In December 2015, Hydro One entered into an agreement with Trilliant Holdings Inc. and Trilliant Networks (Canada) Inc. (Trilliant) for the supply, maintenance and support services for smart meters and related hardware and software, including additional software licenses, as well as certain professional services. This agreement is for a term of ten years, from December 31, 2015 to December 31, 2025, with the option to renew for an additional term of five years at Hydro One's sole discretion. At December 31, 2015, the annual commitments under the agreement were as follows: 2016 – $17 million; 2017 – $17 million; 2018 – $17 million; 2019 – $17 million; 2020 – $16 million; and thereafter – $6 million.

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, 2015, Hydro One Inc. provided prudential support to the IESO on behalf of its subsidiaries using parental guarantees of $329 million (2014 – $330 million), and on behalf of a distributor using guarantees of $1 million (2014 – $1 million). In addition, as at December 31, 2015, Hydro One Inc. has provided letters of credit in the amount of $15 million (2014 – $8 million) to the IESO. The IESO could draw on these guarantees and/or letters of credit if these subsidiaries or distributor 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 Hydro One Inc.'s liability under the terms of a trust fund established pursuant to the supplementary pension plan for eligible employees of Hydro One Inc. The supplementary pension plan trustee is required to draw upon these letters of credit if Hydro One Inc. 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 Hydro One Inc.'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, 2015, Hydro One Inc. had letters of credit of $139 million (2014 – $126 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 typical terms of between three and five years, but several leases have lesser or greater terms to address special circumstances and/or opportunities. Renewal options, which are generally prevalent in most leases, have similar terms of three to five years. 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 or pre-established rents. There are no restrictions placed upon Hydro One by entering into these leases.

During the year ended December 31, 2015, the Company made lease payments totaling $7 million (2014 – $11 million). At December 31, 2015, the future minimum lease payments under non-cancellable operating leases were as follows; 2016 –$11 million; 2017 – $10 million; 2018 – $9 million; 2019 – $4 million; 2020 – $8 million; and thereafter – $3 million.

27. Segmented Reporting

Hydro One has three reportable segments:

- The Transmission Business, which comprises the core business of transmitting high voltage electricity across the province, interconnecting more than 70 local distribution companies and certain large directly connected industrial customers throughout the Ontario electricity grid;
- The Distribution Business, which comprises the core business of delivering electricity to end customers and certain other municipal electricity distributors; and
- Other Business, which includes certain corporate activities and the operations of the Company's 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 income taxes 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, 2015 *(millions of Canadian dollars)*	Transmission	Distribution	Other	Consolidated
Revenues	1,536	4,949	53	6,538
Purchased power	–	3,450	–	3,450
Operation, maintenance and administration	426	633	76	1,135
Depreciation and amortization	374	380	5	759
Income (loss) before financing charges and income taxes	736	486	(28)	1,194
Capital investments	943	711	9	1,663

Year ended December 31, 2014 *(millions of Canadian dollars)*	Transmission	Distribution	Other	Consolidated
Revenues	1,588	4,903	57	6,548
Purchased power	–	3,419	–	3,419
Operation, maintenance and administration	394	742	56	1,192
Depreciation and amortization	346	367	9	722
Income (loss) before financing charges and income taxes	848	375	(8)	1,215
Capital investments	845	680	5	1,530

Total Assets by Segment:

December 31 *(millions of Canadian dollars)*	2015	2014
Transmission	12,066	12,540
Distribution	9,213	9,805
Other	3,049	205
Total assets	24,328	22,550

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

28. Subsequent Events

Dividends

On February 11, 2016, preferred share dividends in the amount of $6 million and common share dividends in the amount of $202 million were declared.

Dividend Reinvestment Plan

On February 11, 2016, Hydro One's Board of Directors approved the creation of a Dividend Reinvestment Plan which the Company currently intends to put in place in March 2016. The Dividend Reinvestment Plan will enable eligible shareholders to have their regular quarterly cash dividends automatically reinvested in additional Hydro One common shares acquired on the open market.

Great Lakes Power Transmission Purchase Agreement

On January 28, 2016, Hydro One reached an agreement to acquire from Brookfield Infrastructure various entities that own and control Great Lakes Power Transmission LP, an Ontario regulated electricity transmission business operating along the eastern shore of Lake Superior, north and east of Sault Ste. Marie, Ontario, for $222 million in cash, subject to customary adjustments, plus the assumption of approximately $151 million in outstanding indebtedness. The acquisition is pending a *Competition Act* approval as well as regulatory approval from the OEB.

CORPORATE AND SHAREHOLDER INFORMATION

Corporate Address
483 Bay Street
Toronto, ON M5G 2P5
tel: 416-345-5000 or 1-877-955-1155
www.HydroOne.com

Customer Inquiries
Hydro One Networks Inc.
P.O. Box 5700
Markham, ON L3R 1C8

Billing and Service Inquiries:
tel: 1-888-664-9376
fax: 1-888-625-4401 or 905-944-3251
e-mail: CustomerCommunications@HydroOne.com

Report an Emergency (24 hours):
tel: 1-800-434-1235

General Shareholder Inquiries
Computershare Trust Company of Canada
100 University Avenue
Toronto, ON M5J 2Y1
tel: 514-982-7555 or 1-800-564-6253
fax: 1-888-453-0330 or 416-263-9394
e-mail: service@computershare.com

Dividend Reinvestment Plan (DRIP)
tel: 514-982-7555 or 1-800-564-6253
www.HydroOne.com/DRIP

Institutional Investors and Securities Analysts
tel: 416-345-6867
e-mail: investor.relations@HydroOne.com

Media Inquiries
tel: 416-345-6868 or 1-877-506-7584

Dividends
Unless indicated otherwise, all dividends paid by Hydro One Limited to common shareholders are designated as "eligible" dividends for the purpose of the Income Tax Act (Canada) and any similar provincial legislation.

H LISTED ON TMX Toronto Stock Exchange

hydroOne

Hydro One Limited is one of North America's largest electrical utilities, with a regulated transmission grid delivering 96% of Ontario's electricity by capacity, and a regulated distribution operation delivering electricity to more than 1.3 million end-use customers safely and reliably.

www.HydroOne.com

TSX: H

HYDRO ONE INC. - BRIDGE YEAR (2017) QUARTERLY REPORTS

Hydro One Inc.’s Bridge Year (2017) Quarterly Reports will be provided as they become available.

Hydro One Networks Inc.

Distribution

Reconciliation of Regulatory Financial Results with Audited Financial Statements
For year ending December 31, 2015 ($ Millions)

	Total per Exhibit A-6-2 Attachment 2	Adjustments	Utility Income
REVENUE			
Energy sales	4,305	-	4,305
Rural rate protection	125	-	125
Other	45	-	45
TOTAL REVENUE	**4,475**	**-**	**4,475**
COSTS			
Purchased power	3,087	-	3,087
Operation, maintenance & administration	574	-	574
Depreciation and amortization	360	-	360
TOTAL COSTS	**4,021**	**-**	**4,021**
Income before financing charges & income taxes	**454**	-	**454**
		-	
Financing charges	146	-	146
Income before income taxes	**308**	-	**308**
		-	
Income taxes	51	-	51
NET INCOME	**257**	**-**	**257**

RATING AGENCY REPORTS

This Exhibit includes copies of the most recent rating agency reports performed by Moody's Investor Service, Dominion Bond Rating Service ("DBRS"), and Standard & Poor's.

- Attachment 1: Moody's Investor Service, Credit Opinion, dated: November 10, 2015
- Attachment 2: DBRS Report, dated: April 12, 2016
- Attachment 3: Standard & Poor's Research, dated: September 14, 2016

MOODY'S
INVESTORS SERVICE

Credit Opinion: Hydro One Inc.

Global Credit Research - 10 Nov 2015

Toronto, Ontario, Canada

Ratings

Category	Moody's Rating
Outlook	Stable
Senior Unsecured -Dom Curr	A3
Commercial Paper	P-2

Contacts

Analyst	Phone
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William L. Hess/New York City	212.553.3837

Key Indicators

[1]**Hydro One Inc.**

	6/30/2015(L)	12/31/2014	12/31/2013	12/31/2012	12/31/2011
CFO pre-WC + Interest / Interest	4.3x	3.9x	4.0x	4.0x	4.0x
CFO pre-WC / Debt	14.8%	13.4%	14.1%	13.6%	14.1%
CFO pre-WC - Dividends / Debt	13.7%	10.7%	12.1%	10.1%	12.4%
Debt / Capitalization	53.3%	53.4%	54.9%	57.6%	56.4%

[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations. Source: Moody's Financial Metrics

Note: For definitions of Moody's most common ratio terms please see the accompanying User's Guide.

Opinion

Rating Drivers

- Supportive regulatory environment

- Predictable cash flow and stable financial metrics

- Relationship with the Province of Ontario

Corporate Profile

Hydro One Inc. (HOI) is an electricity transmission and distribution company. HOI is about 85% indirectly owned by the Province of Ontario; however, its ownership position in Hydro One will likely decline to about 40% over the next several years. Hydro One Limited (HOL) is the publicly traded vehicle that owns 100% of HOI. HOI is regulated by the Ontario Energy Board (OEB) under cost-of-service and incentive rate frameworks. The transmission business owns and operates virtually all of Ontario's electricity transmission system representing 56% of HOI's total assets of $23 billion as at 30 June 2015. The distribution business serves about 1.3 million customers and owns a substantial portion of the province's electricity distribution system representing 44% of

HOI's total assets. HOI began operations in 1999, pursuant to the Electricity Act 1998, when the former Ontario Hydro was restructured into five entities: Ontario Power Generation Inc. (OPG), the Independent Electricity System Operator (IESO), Ontario Electricity Financial Corporation (OEFC), the Electricity Safety Authority and HOI. The Province does not guarantee HOI's debt obligations.

SUMMARY RATING RATIONALE

As a government related issuer, HOI's A3 rating reflects its baseline credit assessment (BCA) of baa1 with a one notch uplift attributable to the moderate probability of extraordinary support from the Province of Ontario vs. our previous assumption of strong support prior to the development of a clear plan to partially privatize HOI. HOI's BCA of baa1 is derived from our Regulated Electric and Gas Utilities rating methodology, and reflects its low business risk profile driven by its supportive regulatory environment. We expect cash flow from operations to remain predictable and financial metrics to remain at the low end of the spectrum for the ratings as a result of the existing allowed return on equity and deemed capital structure established by the regulator. The one notch uplift attributed to HOI as a government related issuer incorporates our expectation of an enduring, albeit weaker link between HOI and the Province.

DETAILED RATING CONSIDERATIONS

SUPPORTIVE REGULATORY ENVIRONMENT

The supportive regulatory environment is a key driver of HOI's credit quality and baa1 BCA. Supporting our view, HOI's monopoly position as a Transmission and Distribution (T&D) company with no commodity price risk underpins its credit strength. We expect the regulatory environment to remain relatively transparent, predictable and broadly credit supportive. The legislative and judicial underpinnings are well developed and we expect them to remain unchanged. Rates for the transmission business are established using cost of service principles with frequent cost of service rate resets. Distribution rates are established through an incentive rate mechanism, with periodic cost of service rate resets. The company does not have any direct commodity risk exposure since commodity costs are a pass through for the distribution business. The company does have some exposure to volume risk that is typically driven by weather variability and the underlying performance of the economies in its service territories. The company has inherently lower business risk as a T&D business compared to the price, volume, operational or environmental risks typically associated with generation activities. The company does not have any supply obligations.

PREDICTABLE CASH FLOW AND STABLE FINANCIAL METRICS

We expect the company to continue to generate stable cash flow, a key credit strength. Underpinning this stability, cash flow from operations is generally a function of the company's rate base, its deemed capital structure (established by the regulator), the allowed return on equity (currently about 9%) and depreciation. We have assumed that the company continues to perform broadly in line with the levels established by the regulator. While the company continues to move forward with a large capital program that could exceed a total of $3 billion for 2015 and 2016 (around 45% of which is growth capex), we believe that a combination of frequent cost of service rate resets in the transmission business and an approved rate base for 2015-2017 for the distribution business, mitigates the downward pressure the large capital program would otherwise place on credit metrics. We expect that HOI's CFO Pre-W/C to Debt (3 year average) adjusted for the $2.6 billion initial public offering related one-off tax payment in 2015 will be maintained between 12-14% in 2015-2017.

RELATIONSHIP WITH THE PROVINCE OF ONTARIO

In accordance with Moody's Government Related Issuer (GRI) rating methodology, HOI's A3 rating reflects the following:

- Aa2/Negative local currency rating of the Province of Ontario.

- High default dependence as a result of HOI's exposure to virtually all facets of the provincial economy and its operational and financial proximity to the government.

- Moderate probability of extraordinary support from the Province reflecting the strategic importance of HOI to the provincial economy as an essential service provider, the partial planned privatization of Hydro One and the medium to long term decline in political willingness to provide support.

We believe the Province will continue to have effective control over Hydro One. Following the IPO, the government's nominations over the board of directors will decline to 40%, with an assumption that the province maintains a 40% equity interest in Hydro One as broadly required by legislation. In addition, limitations have been placed on other shareholders that restrict their equity interest in Hydro One to less than 10%. Further, the government may seek to remove the board of directors at its discretion. However, since the government has stated its intent is to engage Hydro One as an investor, this has, in our view reduced the long term probability of "strong" support. Mitigating its control somewhat the government has implemented a pre-defined set of criteria to promote an independent, professional board with relevant expertise and a commercial orientation. These changes have been made in a stated attempt to improve the efficiency of Hydro One and they also reduce the government ties to the company. We do not believe any public policy mandates in the past several years have had a material negative affect on credit quality and the probability of further public policy initiatives has declined with the initial equity offering.

Liquidity Profile

Hydro One has adequate liquidity.

Hydro One has demonstrated its ability to readily access capital markets. Up to $1.5 billion can be issued under its commercial paper (CP) program which is backstopped by a bank syndicated committed revolver of $1.5 billion maturing in June 2020. At 30 June 2015, HOI had no CP or revolver borrowings outstanding. In addition, prior to the IPO HOI added an $800 million committed credit facility expiring October 30, 2018. HOL has its own $250 million committed credit facility that expires in November of 2020.

Hydro One relies in part on debt to finance its ongoing capex. The company has issued long-term debt of $350 million in the first two quarters of 2015 and had cash and cash equivalents balance of $270 million as of June 30, 2015. Together with available credit facilities and estimated operating cash flows of around $1.5 billion in the next 12 months these funds will be sufficient to finance around $1 billion long-term debt maturities, capex of $1.5 billion and dividends of $1.5 billion.

Rating Outlook

The outlook on Hydro One is stable, reflecting the expectation of a stable, ongoing relationship with the Province and a BCA that remains unchanged based on our favorable regulatory assessment and predictable cash flow generation.

What Could Change the Rating - Up

Moody's could upgrade the ratings if we change the BCA of Hydro One to a3 from baa1. This could result from more favorable regulatory outcomes or a sustained improvement in financial metrics including CFO pre-W/C to debt in the high teens (14.8% at 6/30/2015). A one notch upgrade of the Province would not lead to an upgrade of Hydro One.

What Could Change the Rating - Down

A downgrade of Hydro One's BCA would lead to a downgrade of the senior unsecured rating, so long as Moody's opinion of likely support from the Province remains unchanged or reduces. This could result from a deterioration in the regulatory environment or a deterioration in financial metrics, including CFO pre-W/C to debt below 11% on a sustained basis (14.8% at 6/30/2015). A one notch downgrade of the Province would not lead to a downgrade of Hydro One. Further reductions in government ownership of Hydro One Limited down to 40% would not lead to further negative rating action all else being equal. A reduction in government ownership below 40% or a reduction in implied "moderate" support could also lead to a downgrade.

Rating Factors

Hydro One Inc.

Regulated Electric and Gas Utilities Industry Grid [1][2]	**Current LTM 6/30/2015**		[3]**Moody's 12-18 Month Forward ViewAs of 11/10/2015**	
Factor 1 : Regulatory Framework (25%)	**Measure**	**Score**	**Measure**	**Score**
a) Legislative and Judicial Underpinnings of the Regulatory Framework	A	A	A	A
b) Consistency and Predictability of	A	A	A	A

Regulation				
Factor 2 : Ability to Recover Costs and Earn Returns (25%)				
a) Timeliness of Recovery of Operating and Capital Costs	A	A	A	A
b) Sufficiency of Rates and Returns	Baa	Baa	Baa	Baa
Factor 3 : Diversification (10%)				
a) Market Position	A	A	A	A
b) Generation and Fuel Diversity	N/A	N/A	N/A	N/A
Factor 4 : Financial Strength (40%)				
a) CFO pre-WC + Interest / Interest (3 Year Avg)	4.1x	Baa	4.0x - 4.5x	Baa
b) CFO pre-WC / Debt (3 Year Avg)	13.9%	Baa	12% - 14%	Baa
c) CFO pre-WC - Dividends / Debt (3 Year Avg)	12.1%	Baa	8% - 10%	Baa
d) Debt / Capitalization (3 Year Avg)	54.9%	Baa	50% - 52%	Baa
Rating:				
Grid-Indicated Rating Before Notching Adjustment		Baa1		Baa1
HoldCo Structural Subordination Notching	0	0	0	0
a) Indicated Rating from Grid		Baa1		Baa1
b) Actual Rating Assigned				A3

Government-Related Issuer	**Factor**
a) Baseline Credit Assessment	baa1
b) Government Local Currency Rating	Aa2
c) Default Dependence	High
d) Support	Moderate
e) Final Rating Outcome	A3

[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations. [2] As of 6/30/2015(L); Source: Moody's Financial Metrics [3] This represents Moody's forward view; not the view of the issuer; and unless noted in the text, does not incorporate significant acquisitions and divestitures.

This publication does not announce a credit rating action. For any credit ratings referenced in this publication, please see the ratings tab on the issuer/entity page on http://www.moodys.com for the most updated credit rating action information and rating history.

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Rating Report

Hydro One Inc.

DBRS

Insight beyond the rating.

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Ratings

Debt	Rating	Rating Action	Trend
Issuer Rating	A (high)	Confirmed	Stable
Senior Unsecured Debentures	A (high)	Confirmed	Stable
Commercial Paper	R-1 (low)	Confirmed	Stable

Rating Update

On April 7, 2016, DBRS Limited (DBRS) confirmed the Issuer Rating and the Senior Unsecured Debentures rating of Hydro One Inc. (HOI or the Company,) at A (high), and the Commercial Paper (CP) rating at R-1 (low). All trends are Stable. The rating confirmations reflect the Company's low business risk profile resulting from the supportive regulatory framework in Ontario and a reasonable financial profile sustained by predictable earnings and cash flows. The Stable trends assume that the regulatory regime will continue to remain transparent and supportive, allowing the Company to earn adequate returns and recover prudently incurred costs on a timely basis.

DBRS rates HOI as a stand-alone entity and does not assume any credit support from its owner, Hydro One Limited (HOL, 84% owned by the Province of Ontario (the Province, rated AA (low), Stable trend by DBRS)) or from the Province. In November 2015, the Province transferred its ownership of HOI to its wholly owned newly established corporation, HOL, and partially monetized approximately 16% of its ownership of HOL through an initial public offering (IPO) (please refer to the DBRS press release "DBRS Confirms Issuer Rating and Debt Ratings of Hydro One Inc. Downgrades Commercial Paper Rating" dated November 5, 2015, for more details). On April 4, 2016, HOL announced a secondary offering of an additional 15% of its common shares by the Province. DBRS notes that there is no impact on the business risk profile of HOI's regulated utility business resulting from HOL's IPO and the secondary offering, as HOI's low-risk business profile continues to be supported by a reasonable regulatory framework and operations in an extensive franchise area. The Company's transmission business (approximately, 60% of 2015 EBIT) operates approximately 96% of the Province's electricity transmission network and distribution business (approximately 40% of 2015 EBIT) and services nearly 26% of the total customers in Ontario. HOI's transmission and distribution business operates under a cost-of-service model (COS) approved by the Ontario Energy Board (OEB), which permits the Company to charge rates for its services that allow it to recover the costs of providing its services and earn an allowed return on equity (ROE).

HOI's balance sheet and key credit metrics remained reasonable for the current rating category. However, credit metrics could be pressured, as DBRS expects HOI's dividend payout ratio to remain high in order to meet HOL's dividend objectives to pay approximately 70% to 80% of its consolidated net income as dividends. DBRS expects the Company to continue generating free cash flow deficits over the medium term, resulting from the high capex and dividends, requiring the Company to have a greater reliance on borrowings. DBRS expects HOI's internally generated cash flow to fund the majority of capex and dividends while maintaining DBRS-adjusted debt-to-capital below 60% and cash flow-to-total debt at or above 15%. HOI's ratings could be affected should its cash flow-to-debt ratio weaken further from the current level and its DBRS-adjusted debt-to-capital exceeds 60% on a sustained basis.

Financial Information

	For the year ended December 31				
(CA$ millions where applicable)	2015	2014	2013	2012	2011
Cash flow/Total debt	13.3%	15.5%	15.3%	15.4%	14.6%
Total debt in capital structure 1	51.1%	53.0%	55.2%	55.6%	55.6%
Total debt in capital structure 1, 2	55.8%	53.0%	55.2%	55.6%	55.6%
EBIT gross interest coverage (times)	2.75	2.84	2.95	2.91	2.75

1 Includes operating leases.
2 DBRS adjusted, excludes deferred tax assets related to departure tax.

Issuer Description

Hydro One Inc. (HOI) is the largest electricity transmission and distribution company in Ontario. HOI owns and operates substantially all of Ontario's electricity transmission network.

Rating Considerations

Strengths

1. Reasonable regulatory environment

HOI's earnings are contributed by its low-risk regulated transmission and distribution businesses, which operate under a reasonable regulatory framework. The OEB rate approval framework permits HOI a reasonable opportunity to recover operating and capital costs and earn the approved rates of return. The Company's deemed capital structure (debt-to-equity of 60%:40%) has remained unchanged for several years. DBRS views the utility regulatory framework in Ontario as transparent and supportive for regulated transmission and distribution operators.

2. Extensive franchise area

HOI owns the largest transmission and distribution businesses in Ontario. The Company operates approximately 96% of the Province's electricity transmission network, is connected to 47 local distribution companies and 90 transmission connected companies, and serves approximately five million customers. HOI's transmission system is also interconnected to systems in Manitoba, Michigan, Minnesota, New York and Québec through the use of interties. Load growth is expected to be modest and in line with economic growth in the Province. The distribution business spans approximately 75% of the Province, serving over 1.3 million customers, or approximately 26% of the total customers in Ontario.

3. Reasonable financial profile

The Company continues to maintain a reasonably healthy balance sheet. Although credit metrics have weakened relative to previous years, they have remained reasonable for the current rating category (adjusted debt-to-capital ratio at 55.8%, EBIT interest coverage at 2.75 times (x) and cash flow-to-debt at 13.3% for 2015).

Challenges

1. High level of planned capex

HOI is currently in the midst of an aggressive build-out program that will continue over the next several years. Capex was approximately $1.6 billion for 2015 (approximately $945 million for transmission and approximately $700 million for distribution) with a plan for $1.6 billion in each of 2016 and 2017. Therefore, DBRS expects the Company to continue generating free cash flow deficits over the medium term. The free cash flow deficits, combined with lengthy construction times, could potentially put temporary pressure on the balance sheet and coverage ratios during the build-out phase.

2. Earnings sensitive to volume and costs

Earnings and cash flows for electricity distribution companies are partially dependent on the volume of electricity sold. Weather patterns, seasonality and economic conditions directly affect the volume of electricity sold and, therefore, earnings. The OEB approves HOI's transmission and distribution rates based on projected electricity load and consumption levels. If actual load or consumption materially falls below projected levels, earnings of these businesses could be adversely affected. Furthermore, current revenue requirements are approved based on cost assumptions that could materially differ from actual costs. 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 costs. However, the earnings' sensitivity to volume for the distribution segment is expected to be largely mitigated when the fixed-rate framework is fully implemented by 2019.

3. High dividend payouts

Compared with historical levels, DBRS expects the Company to pay out a higher portion of its earnings as dividends to support HOL's dividend policy (payout approximately 70% to 80% of consolidated net income). The payout ratio at December 31, 2015, was 12.7% (excluding the $800 million special dividend to the Province in Q4 2015) and 36% in 2014. DBRS expects HOI's dividend payout ratio to remain high in order to meet HOL's dividend objectives to pay approximately 70% to 80% of its consolidated net income as dividends, and consequently, in addition to high capital expenditure commitments, the Company will need to access significant external funding to finance the potentially sizable free cash flow deficits expected over the medium term.

Earnings and Outlook

(CA$ millions where applicable)	For the year ended December 31 2015	2014	2013	2012	2011
Net Revenue	3,079	3,129	3,054	2,954	2,843
EBITDA	1,949	1,985	1,905	1,883	1,751
EBIT	1,192	1,263	1,229	1,224	1,135
Gross interest expense	433	444	416	421	412
Earning before taxes	814	874	858	854	779
Income taxes	(113)	(86)	(106)	(118)	(147)
Minority interest	(10)	2	0	0	0
Net income before non-recurring items	691	790	752	736	632
Non-recurring items [1]	1	(41)	51	9	9
Reported net income	692	749	803	745	641
Return on equity	9.0%	10.3%	10.6%	11.1%	10.2%

1 DBRS adjustment of $48 million for customer service recovery project costs in 2014 and $43 million property tax recovery in 2013.

	2015	2014	2013	2012	2011
Transmission rate base (CA$ billions)	10.17	9.93	9.35	8.80	7.90
Distribution rate base (CA$ billions)	6.59	5.03	5.03	5.03	5.03
Allowed ROE - Transmission	9.30%	9.36%	8.93%	9.42%	9.66%
Allowed ROE - Distribution	9.30%	9.66%	9.66%	9.66%	9.66%
Deemed Equity (Transmission & Distribution)	40%	40%	40%	40%	40%

2015 Summary

- HOI's earnings are supported by a reasonable regulatory environment, extensive franchise area and a diverse customer base that is growing at a steady rate.
- HOI's net earnings were lower in 2015 compared with 2014, resulting from lower average Ontario peak demand caused by milder weather in 2015, higher depreciation and amortization expense, higher income tax expense, the spin-off of Hydro One Brampton Networks Inc. (HOBNI), and transfer of Hydro One Telecom Inc. (HOTI) to HOL.

2016 Outlook

- Earnings for 2016 are expected to be in line with 2015, as the impact of the lower allowed ROE approved by the OEB (9.19% in 2016 versus 9.30% in 2015) for both the transmission and distribution segments is expected to be largely offset by the higher rate base for 2016.

Financial Profile

(CA$ millions where applicable)	For the year ended December 31 2015	2014	2013	2012	2011
Net income before non-recurring items	691	790	752	736	632
Depreciation & amortization	667	641	597	589	550
Deferred income taxes and other	(3)	(51)	41	(12)	(6)
Cash flow from operations	**1,355**	**1,380**	**1,390**	**1,313**	**1,176**
Dividends paid	(888)	(287)	(218)	(370)	(168)
Capital expenditures	(1,631)	(1,504)	(1,387)	(1,454)	(1,447)
Free cash flow (bef. working cap. changes)	(1,164)	(411)	(215)	(511)	(439)
Changes in non-cash work. cap. items	187	(55)	11	(40)	184
Changes in regulatory assets	(3)	(69)	3	12	47
Deferred income tax asset 1	(2,798)	0	0	0	0
Net Free Cash Flow	(3,778)	(535)	(201)	(539)	(208)
Acquisitions	(143)	(66)	0	0	0
Short-term investments	0	0	0	0	0
Long-term investments 2	0	250	0	0	0
Amount to be financed	(3,921)	(351)	(201)	(539)	(208)
Net equity change	2,600	72	0	0	0
Net debt change	1,254	(177)	574	488	239
Other	56	(9)	(3)	18	25
Change in cash	(11)	(465)	370	(33)	56
Total debt	10,215	8,927	9,088	8,521	8,047
Cash and equivalents	89	100	565	195	228
Cash flow-to-total debt	13.3%	15.5%	15.3%	15.4%	14.6%
Total debt in capital structure 3	51.1%	53.0%	55.2%	55.6%	55.6%
Total debt in capital structure 4	55.8%	53.0%	55.2%	55.6%	55.6%
EBIT gross interest coverage (times)	2.75	2.84	2.95	2.91	2.75
Debt-to-rate base	61%	60%	63%	62%	62%
Dividend payout ratio	128.6%	36.3%	29.0%	50.3%	26.6%

1 Impact of deferred income tax asset that resulted as a consequence of leaving the PILs Regime and entering the Federal Tax Regime.
2 Proceeds of $250 million Province of Ontario FRNs redeemed in 2014.
3 Includes operating leases.
4 Excludes deferred income taxes assets of $1.6 billion.

2015 Summary

- Overall, HOI's financial profile weakened in 2015, resulting from higher capital expenditures and a special dividend paid to the Province. However, key credit metrics—adjusted-total debt-to-capital (55.8%) and EBIT interest coverage (2.75x)—remained in the upper end of the "A" rating category, and cash flow-to-total debt (13.3%) was weaker in the lower end of the "A" rating range.
- As part of the pre-IPO transactions, HOI increased debt levels to recapitalize at its target regulatory capital structure of 60% debt to rate base, with the increased borrowings used to pay an $800 million special dividend to the Province.
- HOI made capital investments of approximately $1.6 billion and placed $1.5 billion of new assets in-service in 2015. Free cash flow deficits were largely financed with debt.
- HOI paid a departure tax of $2.8 billion, resulting from the transition from the Payment in Lieu of Taxes Regime to the Federal Tax Regime, which was funded by the $2.6 billion equity injection from the Province. HOI has not included the departure tax payment in the rate-setting process. The balance in the deferred tax asset is expected to act as a tax shield for HOI's future tax liabilities, reducing cash taxes payable by the Company. However, no advance income tax ruling has been obtained from the Canada Revenue Agency in respect of the

Financial Profile (CONTINUED)

tax treatment of these assets. DBRS has therefore removed the balance of this asset from the Company's equity in calculating the leverage ratio.

- In August 2015, as part of the pre-IPO transactions, HOI transferred 100% ownership of HOBNI to the Province by paying a dividend in-kind to the Province. On November 6, 2015, HOI transferred HOTI, its non-regulated business, to HOL, resulting in HOI becoming a pure regulated utility. The IPO, the divestiture of HOBNI and transfer of HOTI did not have any material impact on the credit profile of the Company.

2016 Outlook

- DBRS expects free cash flow deficits to continue, as the Company plans to incur capital expenditures of approximately $1.6 billion to $1.7 billion in each year from 2016 to 2020 (approximately $900 million for transmission and $700 million for distribution) to build critical infrastructure and to address the Company's aging power system needs.
- DBRS expects HOI to support HOL's dividend policy (annual dividends of approximately 70% to 80% of consolidated net income) to the extent that such dividend payouts maintain HOI's regulatory capital structure (debt at 60% of rate base). Consequently, DBRS expects HOI to pay a higher portion of its earnings as dividends going forward.
- DBRS expects that free cash flow deficits will be funded prudently in order to maintain leverage below 60%.
- Cash flow from operations is expected to grow over the medium to long term as capital projects are placed into service and included in the rate base. As a result, key credit metrics are expected to remain supportive for the current rating category despite high capex and dividends.

Long-Term Debt Maturities and Bank Lines

Credit Facilities and Long-Term Debt

(CAD millions - As at December 31, 2015)	Amount	Draw/LOCs	Available	Maturity
Cash & Cash Equivalents	89		89	
Revolving standby credit facility	1,500	1,491	9	Jun. 2020
Three-year senior, revolving term credit facility	800	-	800	Oct. 2018
Total	**2,389**	**1,491**	**898**	

Source: Pg. 27 2015 Q4 FS.

- The Company has adequate liquidity for its normal operating requirements.
- HOI has access to a $1.5 billion commercial paper program supported by two committed revolving credit facilities of $2.3 billion. As of December 31, 2015, approximately $1,491 million of commercial paper was outstanding.

Long-term debt maturity profile

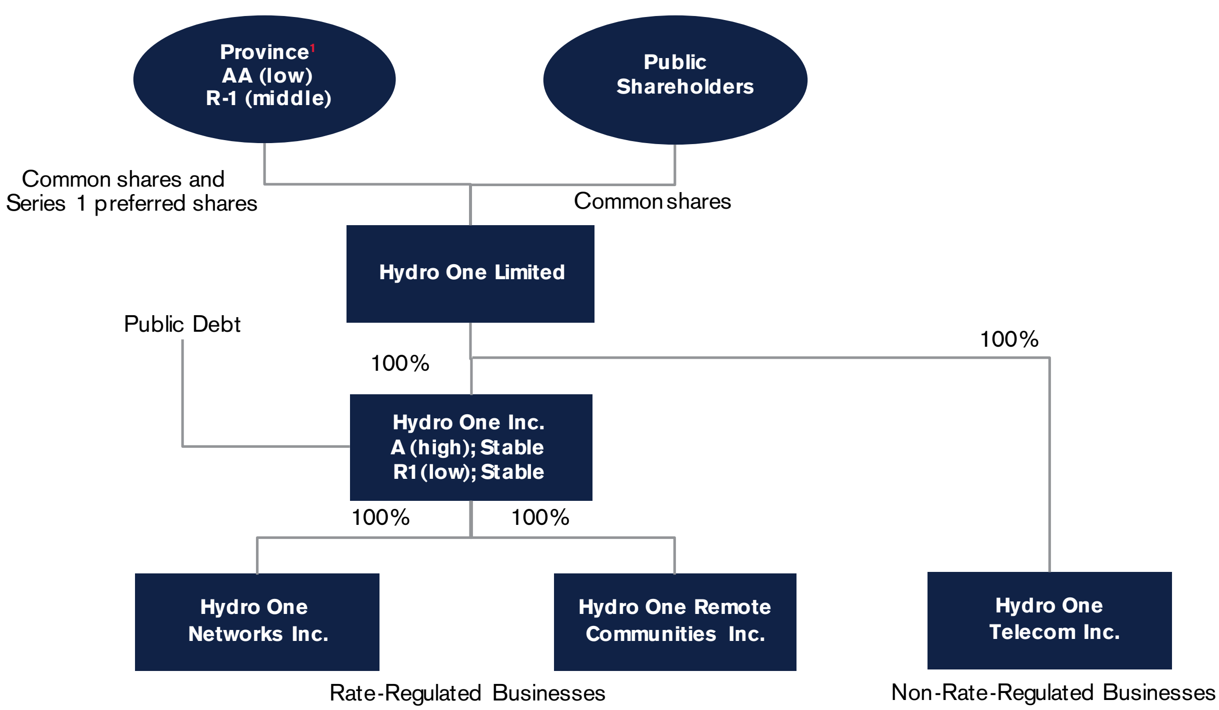
(CAD millions - As at December 31, 2015)	2016	2017	2018	2019	2020	Thereafter	Total
Principal Repayments	500	600	750	228	650	5,995	8,723
% of Total	6%	7%	9%	3%	7%	69%	100%

- HOI has adequate access to capital markets.
- In December 2015, HOI filed a $3.5 billion Medium-Term Notes (MTN) shelf prospectus, which is available for issuance until January 2018.
- In February 2016, the Company issued three tranches with an aggregate amount of $1.35 billion under the MTN program to repay its maturing long-term and short-term debt, as well as for other general corporate purposes.
- HOI's long-term debt and credit facilities covenants limit the permissible debt to 75% of its total capitalization and limit the ability to sell assets and impose negative pledge provisions, subject to customary exceptions. At December 31, 2015, HOI was in compliance with all of these covenants and limitations.
- The Company's refinancing risk remains manageable because of its well-spread-out, long-term debt maturities, with less than 10% of the total long-term debt due in the near term.

Major Projects and Acquisitions

- Major transmission projects include (1) the Toronto Midtown Transmission Reinforcement project, a new transmission line in midtown Toronto and the refurbishment of an underground cable, with an approved budget of $115 million. The estimated cost is $123 million, and it is expected to be in service in 2016; (2) the Guelph Area Transmission Refurbishment Project, an upgrade of a transmission line and transmission stations in south-central Guelph, with an approved budget of $103 million, expected to be in service in 2016; (3) the Clarington Transmission Station Project to install additional autotransformer capacity in the east Greater Toronto Area, with an approved budget of $297 million, expected to be in service in 2018/2019; (4) the Supply to Essex County Transmission Reinforcement Project, a new transmission line in the Windsor-Essex region, expected to be in service by 2018; and (5) the Northwest Bulk Transmission Line Project, a new transmission line in the west Thunder Bay area, expected to be in service as early as 2020.
- In January 2016, HOI entered into a purchase agreement to acquire Great Lakes Power Transmission LP for $222 million in cash and the assumption of approximately $150 million in debt. The asset has a rate base of approximately $219 million, with 15 transmission stations and 560 kilometres of high- and medium-voltage 44-230 kV transmission lines covering a service area of approximately 12,000 square kilometres. Upon the completion of the transaction, HOI will operate approximately 98% of Ontario's transmission capacity.
- In October 2015, HOI acquired Woodstock Hydro, an electricity distribution company located in southwestern Ontario, for approximately $32 million, including working capital and other closing adjustments.
- As part of the local distribution company consolidation in Ontario, in March 2015, the Company received OEB approval for the acquisition of Haldimand Hydro, an electricity distribution and telecom company located in southwestern Ontario. The acquisition was completed in June 2015 for approximately $73 million, including working capital and other closing adjustments.

Simplified Ownership Structure (as at December 31, 2015)



Notes:
1 As of December 31, 2015, the Province owned approximately 84% of Hydro One Limited's common shares and 100% of the outstanding Series 1 preferred shares. with 14% of common shares held by the public.

- HOI is 100% owned by HOL, which is in turn owned 84% by the Province and 16% by public shareholders.
- HOL announced in April 2016 that the Province will monetize another approximately 15% of HOL, with the transaction expected to close on April 14, 2016.
- HOI is a regulated utility that owns Hydro One Networks Inc. and Hydro One Remote Communities Inc.
- Hydro One Networks Inc. carries on rate-regulated transmission and distribution businesses.
- Hydro One Remote Communities, Inc. generates and supplies electricity to remote communities in northern Ontario.

Regulation

Regulatory Overview

- HOI has a good track record of prudently managing its regulatory risk. HOI's transmission and distribution businesses are licensed and regulated by the OEB. DBRS has assessed the regulatory environment to be reasonable. (Refer to Assessment of HOI's Regulatory Environment on Page 8.)
- The OEB uses a deemed debt-to-common equity structure of 60% to 40% for both the transmission and distribution business.

Transmission

- HOI's transmission business continues to operate under a COS framework. In January 2015, the OEB approved HOI's transmission rates revenue requirement for 2015 of $1,477 million and the 2016 revenue requirement of $1,516 million, subject to adjustments for the cost of capital parameters. In January 2016, the OEB revised the revenue requirement for 2016 to $1,480 million excluding the Bruce to Milton LP transmission network on an allowed ROE of 9.19%.
- In December 2015, the OEB approved the revenue requirement of the Bruce to Milton LP transmission network for five years from 2015 to 2019, with a revenue requirement range of $36 million to $39 million annually.
- HONI plans to submit its 2017–2018 transmission rate application in Q2 2016 based on the COS model.
- In 2015, the OEB initiated a discussion to develop a framework for the application of the Renewed Regulatory Framework for Electricity Distributions (RRFE) principles to transmitters. In February 2016, the OEB issued a new set of filing requirements with performance-based principles for transmission applications, which will likely apply to HOI's transmission revenue application for 2019–2023.

Distribution

- OEB's RRFE established a rate-setting policy that contains three performance-based rate-setting methods (PBR): 4th Generation Incentive Rate-setting (suitable for most distributors), Custom Incentive Rate-setting (CIR), suitable for those distributors with large or highly variable capital requirements) and the Annual Incentive Rate-setting Index (suitable for distributors with limited incremental capital requirements). Electricity distributors may select the rate-setting method that best meets their needs and circumstances, and apply to the OEB accordingly.
- HOI's distribution business opted to use the CIR method under the RRFE. In December 2013, HOI filed a five-year distribution custom rate application (2015–2019) with the OEB customized to fit HOI's specific business circumstances, primarily servicing rural and remote areas of the province and significant multi-year capital programs. The OEB did not consider HOI's custom COS application as sufficiently aligned with its performance-based framework for setting rates, and approved rates for a shorter three-year period (2015–2017) based on the COS methodology with the allowed ROE to be updated annually. However, the OEB approved the rate base and capital expenditures for 2015–2017, as applied for by HOI.
- HOI will likely file a distribution application for 2018–2022 rates in 2017.
- Under both COS and PBR, HOI can charge rates for its services that allow it to recover the costs of providing its services and earn an allowed ROE. PBR encourages the Company to improve efficiency over time, resulting in lower costs to provide the same service. Although the transition to CIR option for distribution rates entails some regulatory lag and forecasting risk, it is not expected to materially affect HOI's business risk profile.
- In March 2015, the OEB approved HOI's distribution rates revenue requirement for 2015 of $1,326 million; $1,430 million for 2016; and $1,486 million for 2017. In January 2016, the OEB revised the revenue requirement for 2016 to $1,410 million based on an updated 2016 allowed ROE of 9.19%.
- Hydro One Remote Communities Inc. operates under the 4th Generation Incentive Rate-setting.

DBRS Assessment of Regulatory Environment

Criteria	Score	Analysis
1. Deemed Equity	Excellent Good **Satisfactory** Below Average Poor	The OEB allows HOI's transmission and distribution business to have a deemed equity of 40%, which has been consistent historically.
2. Allowed ROE	Excellent **Good** Satisfactory Below Average Poor	The cost of capital parameters are updated annually by the OEB. The OEB has set ROE for the transmission and distribution business at 9.19% for 2016.
3. Energy Cost Recovery	**Excellent** Good Satisfactory Below Average Poor	There is no power price risk, as HOI is not responsible for purchasing power from generation facilities or the wholesale market. Power costs are passed on to ratepayers, and HOI collects the payments from its customers either on a monthly or bi-monthly basis (on a monthly basis effective January 1, 2017).
4. Capital and Operating Cost Recovery	Excellent **Good** Satisfactory Below Average Poor	Major capital costs are pre-approved by the OEB and added to the rate base after project completion. In addition, the OEB can approve rate riders to allow for the recovery or disposition of specific regulatory accounts over specified time frames.
5. COS versus IRM	Excellent **Good** Satisfactory Below Average Poor	Hydro One's distribution business has opted to use the five-year CIR option under the RRFE. However, the distribution business has been allowed to operate under a COS rate-setting methodology by the OEB until 2017. Transmission rates are based on COS application rate orders approved by the OEB every two years.
6. Political Interference	Excellent Good Satisfactory **Below Average** Poor	After years of a relatively stable political and regulatory environment, the utility sector in Ontario could face growing challenges. As generation costs potentially rise above and ultimately test the political ceiling (10% increase in the total bill annually), it may be difficult for the utilities to pass costs onto ratepayers.
7. Retail Rate	Excellent Good **Satisfactory** Below Average Poor	Retail rates in Ontario are higher than many of the other Canadian provinces. The retail rate is set by the OEB. Average prices for residential customers in major cities in Ontario were around 14 cents to 15 cents per kilowatt hour in 2015.
8. Stranded Cost Recovery	Excellent **Good** Satisfactory Below Average Poor	HOI has a limited history of stranded costs. Most prudently incurred or budgeted capital expenditures are approved by the OEB. DBRS notes that there can be some regulatory lag in the approval of capital expenditures.
9. Rate Freeze	Excellent Good **Satisfactory** Below Average Poor	From 2002 to 2005, because of rising rates during Ontario's experimental utility deregulation phase, a distribution rate freeze was imposed. There have been no subsequent province-wide rate freezes.
10. Market Structure (Deregulation)	Excellent **Satisfactory** Poor	Distribution and transmission remains fully regulated under the OEB.

Hydro One Inc.

Balance Sheet

(CAD millions)

	As at December 31				As at December 31		
	2015	2014	2013		2015	2014	2013
Assets				**Liabilities & Equity**			
Cash & equivalents	89	100	565	S.T. borrowings	1,491	2	31
Accounts receivable	772	1,016	923	Accounts payable	743	784	789
Inventories	21	23	23	Current portion L.T.D.	500	552	756
Prepaid expenses & other	263	311	547	Other current liab.	247	377	415
Total Current Assets	**1,145**	**1,450**	**2,058**	**Total Current Liab.**	**2,981**	**1,715**	**1,991**
Net fixed assets	17,893	17,401	16,431	Long-term debt	8,224	8,373	8,301
Future income tax assets	1,610	7	11	Deferred income taxes	206	1,313	1,129
Goodwill & intangibles	499	449	446	Pension and other liabilities	2,687	2,999	2,586
Regulatory assets	3,015	3,200	2,636	Regulatory liabilities	236	168	163
Investments & others	41	43	43	L.T. Payables & Other L.T. liab.	44	35	40
				Preferred shares	0	323	323
				Minority interest	75	70	0
				Common equity	6,000	3,314	3,314
				Retained earnings	3,759	4,249	3,787
				Accumulated OCI	(9)	(9)	(9)
Total Assets	**24,203**	**22,550**	**21,625**	**Total Liab & SE**	**24,203**	**22,550**	**21,625**

Balance Sheet & Liquidity & Capital Ratios

	For the year ended December 31				
	2015	2014	2013	2012	2011
Current ratio	0.38	0.85	1.03	0.73	0.70
Cash flow/Total debt	13.3%	15.5%	15.3%	15.4%	14.6%
Total debt in capital structure 1	51.1%	53.0%	55.2%	55.6%	55.6%
(Cash flow-dividends)/Capex (times)	0.29	0.73	0.84	0.65	0.70
Dividend payout ratio	128.6%	36.3%	29.0%	50.3%	26.6%
Coverage Ratios (times)					
EBIT gross interest coverage	2.75	2.84	2.95	2.91	2.75
EBITDA gross interest coverage	4.50	4.47	4.58	4.47	4.25
Fixed-charges coverage	2.76	2.86	2.94	2.89	2.75
Profitability Ratios					
EBITDA margin	63.3%	63.4%	62.4%	63.7%	61.6%
EBIT margin	38.7%	40.4%	40.2%	41.4%	39.9%
Profit margin	22.4%	25.2%	24.6%	24.9%	22.2%
Return on equity	9.0%	10.3%	10.6%	11.1%	10.2%
Return on capital	5.6%	6.4%	6.4%	6.7%	6.3%

1 Including operating leases.

Rating History

	Current	2015	2014	2013	2012	2011
Issuer Rating	A (high)	A (high)	A (high)	A (high)	A (high)	A (high)
Senior Unsecured Debentures	A (high)	A (high)	A (high)	A (high)	A (high)	A (high)
Commercial Paper	R-1 (low)	R-1 (low)	R-1 (middle)	R-1 (middle)	R-1 (middle)	R-1 (middle)

Previous Action

- DBRS Confirms Issuer Rating and Debt Ratings of Hydro One Inc. Downgrades Commercial Paper Rating, Nov 5, 2015.

Previous Report

- *Hydro One Inc.*: Rating Report, April 10, 2015.

Notes:
All figures are in Canadian dollars unless otherwise noted.

For the definition of Issuer Rating, please refer to Rating Definitions under Rating Policy on **www.dbrs.com**.

Generally, Issuer Ratings apply to all senior unsecured obligations of an applicable issuer, except when an issuer has a significant or unique level of secured debt.

S&P Global
Ratings

Research

Summary:

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Hydro One Inc.

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Summary:

Hydro One Ltd.
Hydro One Inc.

Credit Rating: A/Stable/--

Rationale

Business Risk	Financial Risk
• Relatively stable regulatory regime • Natural monopoly service provider • Limited commodity-price risk and low volume-risk exposure	• Stable regulated cash flow • Large capital program

Outlook

The stable outlook on Hydro One Ltd. (HOL) and Hydro One Inc. (HOI) reflects our view of the stable regulatory regime, which we believe contributes to predictable and stable cash flows at HOI. The outlook also reflects our view that HOL's growth strategy will continue to focus on the low-risk regulated transmission and distribution business. Although the level of capital expenditure will be slightly elevated for the next couple of years, with slightly weaker credit metrics, we expect credit metrics will improve through our outlook horizon, with adjusted funds from operations (AFFO)-to-debt of 10%-11%.

Downside scenario

We could lower the ratings on HOL and HOI if we expect AFFO-to-debt to be below 10% consistently. A change in growth strategy toward unregulated operations could also lead to a negative rating action. Although we don't expect it in our outlook period, a less supportive regulatory regime or market restructuring would also likely negatively affect the rating.

Upside scenario

We could take a positive rating action on HOL and HOI if we expected HOL's consolidated AFFO-to-debt to rise and stay above 16%. However given the company's stable regulatory regime, current capital programs, and expected dividend policy, we don't forecast this to happen within our outlook horizon.

Our Base-Case Scenario

The key driver in our analysis continues to be the regulatory framework and the utility's performance within it.

Assumptions

- HOI and HOL will continue to focus on regulated electricity transmission and distribution business
- HOI will not experience any adverse regulatory decisions from the Ontario Energy Board (OEB), the regulator for the Province of Ontario, and that OEB continues to operate in a transparent and stable manner
- HOL and HOI operating performance and margins will remain stable
- HOI will continue to earn return on equity (ROE) of approximately 9.19% along with a deemed capital structure of 60% debt

Key Metrics

	2015A	2016E	2017E
AFFO/debt	9.1%	10%-11%	10%-11%
Debt/debt and equity	55.6%	57%-60%	57%-60%

Note: S&P Global Ratings-adjusted ratios. AFFO--Adjusted funds from operations. A--Actual. E--Estimated.

Business Risk

In our opinion, the OEB's regulatory framework continues to support stable cash flow, which we believe is a key credit strength. The framework allows for the recovery of prudent costs and the opportunity to earn a modest return. We believe that rates for the transmission business will continue to be set based on regular cost of service applications until 2018. Distribution rates for 2016 were established under the custom incentive rate-setting (IR) mechanism and the OEB had approved Hydro One's rate base in 2015. The custom IR is suitable for distributors with large or highly variable capital requirements that exceed historical levels. The regulatory framework limits Hydro One's exposure to commodity risk and associated cash flow volatility. Although the distribution business must bill customers for the commodity delivered, the cost is a flow-through. The company has no obligation to ensure an adequate supply of electricity and is not burdened with the procurement process or power purchase agreements, which reduces operating risk.

Further supporting the excellent business risk profile is the asset-intensive nature of electricity distribution that limits competitive risk. We believe that HOI's customer base supports the overall stability of its revenues and severely limits exposure to any particular customer or customer class. In the transmission business, municipally owned investment-grade electricity distribution companies collect transmission revenues and forward them to Hydro One through the Independent Electricity System Operator. The company's distribution business collects revenues from a relatively stable customer base that residential and commercial customers dominate. We view the economy of Ontario, which the transmission business services, as large, wealthy, and well-diversified. Given HOI's regulated nature, we believe that the company is less exposed to short-term economic cycles. We characterize both the industry and the country of operation as stable, with generally low-risk factors that do not limit the rating.

Financial Risk

We expect Hydro One will continue generating stable cash flow, a key credit strength. Underpinning this stability, FFO consists primarily of regulated net income that is the product of the rate base, deemed capital structure and the allowed ROE, and depreciation. We believe the company has stable financial policies that support ongoing stable credit metrics consistent with its significant financial risk profile. A cornerstone of Hydro One's financial policies is a target capital structure broadly in line with the deemed capital structure the OEB established, which includes about 60% debt. Although the company has a large capital program of about C$1.7 billion in 2016, we believe that it will maintain its target capital structure, curtailing spending or dividends as required.

Liquidity

The short-term rating on Hydro One Inc. is 'A-1' and the company continues to have adequate liquidity. We expect liquidity sources to exceed uses by more than 1.1x over the next twelve months. In the event of a 10% drop in the company's EBITDA we also expect there are sufficient liquidity sources to cover uses. In our view, the company has sound relationships with banks and generally satisfactory standing in the credit markets. In the unlikely event of a liquidity distress, we expect the company to scale back on its capital spending and dividends to preserve credit metrics.

Principal Liquidity Sources	Principal Liquidity Uses
• Cash availability of about C$6 million as of second-quarter 2016 • Committed undrawn credit facilities of about C$2.55 billion as of second-quarter 2016, expiring from 2018-2020 • Cash FFO of about C$1.5 billion over the next 12 months	• Debt maturities of about C$998 million over the next 12 months • Working capital cash outflow of about C$12 million in that time • Capital expenditure of C$1.70 billion-C$1.75 billion over the next 12 months • Dividends of C$550 million-C$600 million in that period

Other Modifiers

Based on the application of our positive comparable rating analysis modifier, we raised the anchor one notch to arrive at the 'a' stand-alone credit profile. We believe that Hydro One occupies a unique position in Ontario's electricity market as it owns virtually all of Ontario's transmission lines, creating a barrier to entry that a very favorable transmission regulation further supports. In addition, we believe Hydro One is a strong operator in the face of a large and diverse geographic service area. Finally, the company's cash flows come from the transmission and distribution business, which we consider to be at the lower end of risk spectrum for utilities.

Group Support

We also apply the group rating methodology in rating HOI. Pursuant to our criteria, we view HOI as a core entity to the HOL group because HOI generates virtually all of the group's cash flows; is unlikely to be sold in the near future; and shares the same name, reputation, operations and management team as the HOL group. We have equalized our ratings on HOI with the 'a' group credit profile, leading to the final 'A' rating on the subsidiary.

Government Influence

Our view of extraordinary government support is low. This is based on what we consider the utility's limited importance role, reflecting that HOI's credit standing is less important to Ontario than it previously was following the privatization and our view that another private sector entity can easily undertake the company's activities if necessary. The limited link reflects our expectation that the province's involvement with Hydro One to be as an investor rather than manager.

Ratings Score Snapshot

Hydro One Ltd.
Corporate Credit Rating: A/Stable/--

Business risk: Excellent

- Country risk: Very low
- Industry risk: Very low
- Competitive position: Excellent

Financial risk: Significant

- Cash flow/Leverage: Significant

Anchor: 'a-'

Modifiers

- Diversification/Portfolio effect: Neutral (no impact)
- Capital structure: Neutral (no impact)
- Liquidity: Adequate (no impact)
- Financial policy: Neutral (no impact)
- Management and governance: Satisfactory (no impact)
- Comparable rating analysis: Positive (+1 notch)

Stand-alone credit profile: 'a'

Group credit profile: 'a'

- Status within group: Parent (no impact)
- Likelihood of extraordinary Government support: Low (no impact)

Hydro One Inc.

Corporate Credit Rating: A/Stable/A-1

Business risk: Excellent

- Country risk: Very low
- Industry risk: Very low
- Competitive position: Excellent

Financial risk: Significant

- Cash flow/Leverage: Significant

Anchor: 'a-'

Modifiers

- Diversification/Portfolio effect: Neutral (no impact)
- Capital structure: Neutral (no impact)
- Liquidity: Adequate (no impact)
- Financial policy: Neutral (no impact)
- Management and governance: Satisfactory (no impact)
- Comparable rating analysis: Positive (+1 notch)

Stand-alone credit profile: 'a'

Group credit profile: 'a'

- Status within group: Core (no impact)
- Likelihood of extraordinary government support: Low (no impact)

Related Criteria And Research

Related Criteria

- Rating Government-Related Entities: Methodology And Assumptions, March 25, 2015
- Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Dec. 16, 2014
- Corporate Methodology, Nov. 19, 2013
- Corporate Methodology: Ratios And Adjustments, Nov. 19, 2013
- Group Rating Methodology, Nov. 19, 2013
- Country Risk Assessment Methodology And Assumptions, Nov. 19, 2013
- Methodology: Industry Risk, Nov. 19, 2013
- Key Credit Factors For The Regulated Utilities Industry, Nov. 19, 2013
- Methodology For Linking Short-Term And Long-Term Ratings For Corporate, Insurance, And Sovereign Issuers, May 7, 2013
- Management And Governance Credit Factors For Corporate Entities And Insurers, Nov. 13, 2012

- General Criteria: Use Of CreditWatch And Outlooks, Sept. 14, 2009
- 2008 Corporate Criteria: Rating Each Issue, April 15, 2008

PROSPECTUS FOR MOST RECENT FINANCING

This Exhibit includes copies of the prospectus for recent public debt offerings.

- Attachment 1: Short Form Base Shelf Prospectus, December 14, 2015

No securities regulatory authority has expressed an opinion about these securities and it is an offence to claim otherwise.

This short form prospectus has been filed under legislation in each of the provinces of Canada that permits certain information about these securities to be determined after this prospectus has become final and that permits the omission from this prospectus of that information. The legislation requires the delivery to purchasers of a prospectus supplement containing the omitted information within a specified period of time after agreeing to purchase any of these securities. All shelf information omitted from this shelf prospectus will be contained in one or more prospectus supplements that will be delivered to purchasers together with the base shelf prospectus.

This short form prospectus constitutes a public offering of these securities only in those jurisdictions where they may be lawfully offered for sale and therein only by persons permitted to sell such securities. The securities to be issued hereunder have not been and will not be registered under the United States Securities Act of 1933, as amended, or any state securities laws and may not be offered, sold or delivered within the United States of America and its territories and possessions except in certain transactions exempt from the registration requirements of such Act. See "Plan of Distribution".

Information has been incorporated by reference in this short form prospectus from documents filed with securities commissions or similar authorities in Canada*. Each shelf prospectus supplement will be incorporated by reference into this shelf prospectus for the purposes of securities legislation as of the date of the shelf prospectus supplement and only for the purposes of the distribution of the securities to which the shelf prospectus supplement pertains. Copies of the documents incorporated herein by reference may be obtained on request without charge from the Secretary of Hydro One Inc., 483 Bay Street, South Tower, 8th Floor, Toronto, Ontario, M5G 2P5, (416) 345-6044 and are also available electronically at www.sedar.com.*

SHORT FORM BASE SHELF PROSPECTUS

New Issue — December 14, 2015

hydroOne

HYDRO ONE INC.
$3,500,000,000
Medium Term Notes
(unsecured)

Hydro One Inc. (the "company") may offer and issue from time to time medium term notes (the "Notes") in an aggregate principal amount of up to $3.5 billion in Canadian currency (or the equivalent thereof in other currencies or currency units at the time of issue) during the twenty-five months from the date of issuance of the receipt for this short form prospectus.

The Notes will have a term to maturity of not less than one year and will be issuable in Canadian currency (or in other currencies or currency units) in fully registered definitive or global form, in which case the Notes will be exchangeable only under certain conditions for definitive Notes.

Notes issued hereunder will be direct unsecured obligations of the company, will be issued under a trust indenture in any number of series or separate issues thereof, and will at their respective dates of issue rank *pari passu* with all other unsecured and unsubordinated Indebtedness (as defined below) of the company then outstanding, except as to any sinking fund which pertains exclusively to any particular Indebtedness of the company.

The specific variable terms of an offering of Notes (including the aggregate principal amount of the Notes being offered, the currency or currencies, the issue and delivery date, the form, the maturity date, the interest rate (either fixed or floating and, if floating, the manner of calculation thereof), the issue price, the interest payment date(s), any redemption or repayment provisions, any provisions entitling the company to extend the maturity date of the Notes, the name(s) of the dealer(s) offering the Notes, the commission payable to such dealer(s), the method of distribution and the net proceeds to the company) will be set forth in a prospectus supplement or pricing supplement which will accompany this short form prospectus. Unless otherwise indicated in a prospectus supplement or pricing supplement, the Notes will not be listed on any securities exchange.

This short form prospectus does not qualify the issuance of Notes: (i) entitling the holder to exchange or convert the Notes into securities issued by the company or into securities issued by another entity; or (ii) in respect of which the payment of principal and/or interest may be determined, in whole or in part, by reference to one or more underlying interests including, for example, an equity or debt security, a statistical measure of economic or financial performance including, but not limited to, any currency, consumer price or mortgage index, or the price or value of one or more commodities, indices or other items, or any other item or formula, or any combination or basket of the foregoing items. For greater certainty, however, this short form prospectus does qualify for issuance Notes in respect of which the payment of principal and/or interest may be determined, in whole or in part, by reference to published rates of a central banking authority or one or more financial institutions, such as a prime rate or a bankers' acceptance rate, or to recognized market benchmark interest rates, such as CDOR, LIBOR or EURIBOR, or to interest rates on Government of Canada bonds.

Investing in the Notes involves risks. See "Risk Factors" in this short form prospectus, which may be amended or supplemented in any prospectus supplement or pricing supplement.

Unless otherwise indicated in a prospectus supplement or pricing supplement, there is no market through which these securities may be sold and purchasers may not be able to resell securities purchased under this short form prospectus. This may affect the pricing of the securities in the secondary market, the transparency and availability of trading prices, the liquidity of the securities, and the extent of issuer regulation. See "Risk Factors".

Purchasers are advised that it may not be possible for investors to enforce judgments obtained in Canada against any person or company that is incorporated, continued or otherwise organized under the laws of a foreign jurisdiction or resides outside of Canada, even if the party has appointed an agent for service of process. See "Agent for Service of Process in Canada."

RATES ON APPLICATION

The Notes may be offered severally by one or more of BMO Nesbitt Burns Inc., Casgrain & Company Limited, CIBC World Markets Inc., Desjardins Securities Inc., Laurentian Bank Securities Inc., National Bank Financial Inc., RBC Dominion Securities Inc., Scotia Capital Inc. and TD Securities Inc. pursuant to the dealer agreement referred to under the heading "Plan of Distribution" or such other dealers as may be selected from time to time by the company (the "Dealers"), in each case acting as agent of the company or as principal. Where the Notes are offered by the Dealer(s) as agent, the commissions payable in connection with sales of such Notes shall be agreed from time to time between the company and any such Dealers. Where the Notes are purchased by the Dealer(s) as principal, the Notes shall be purchased at such prices and with such commissions as may be agreed from time to time between the company and any such Dealer(s) for resale to the public at prices to be negotiated with each purchaser. Such resale prices may vary during the distribution period and as between purchasers. In each case, the commissions payable, if any, will be set forth in a prospectus supplement or pricing supplement that will accompany and be incorporated by reference in this short form prospectus. Each Dealer's compensation will increase or decrease by the amount by which the aggregate price paid for Notes by purchasers exceeds or is less than the price paid by the Dealer, acting as principal, to the company. The company may also offer the Notes directly to potential purchasers pursuant to applicable statutory exemptions at prices and upon terms negotiated between the purchaser and the company.

BMO Nesbitt Burns Inc., CIBC World Markets Inc., Desjardins Securities Inc., Laurentian Bank Securities Inc., National Bank Financial Inc., RBC Dominion Securities Inc., Scotia Capital Inc. and TD Securities Inc. are subsidiaries or affiliates of lenders (the "HOI Lenders") that have made (i) a $1.5 billion unsecured revolving credit facility (the "2013 Credit Facility") and (ii) a $800 million unsecured revolving credit facility (the "2015 Credit Facility", and together with the 2013 Credit Facility, the "Credit Facilities") available to the company. In addition, BMO Nesbitt Burns Inc., CIBC World Markets Inc., National Bank Financial Inc.,

RBC Dominion Securities Inc., Scotia Capital Inc. and TD Securities Inc. are subsidiaries or affiliates of lenders (the "HOL Lenders", and together with the HOI Lenders, the "Lenders") that have made a $250 million operating credit facility (the "HOL Credit Facility") available to the company's sole shareholder, Hydro One Limited ("HOL"). As of December 14, 2015, there is no outstanding indebtedness under the 2013 Credit Facility, the 2015 Credit Facility or the HOL Credit Facility. However, if and when there is outstanding indebtedness to any of the HOI Lenders under the Credit Facilities, to any of the HOL Lenders under the HOL Credit Facility, or under any future credit facility with one or more of the Lenders, the company may be considered a connected issuer of those Dealers who are affiliates of such Lenders for purposes of securities laws in Canada. See "Plan of Distribution".

The offering of Notes is subject to the approval of certain legal matters on behalf of the company by Osler, Hoskin & Harcourt LLP and on behalf of the Dealers by Blake, Cassels & Graydon LLP.

The company's head and registered office is located at 483 Bay Street, South Tower, 8th Floor, Toronto, Ontario, M5G 2P5.

The company's consolidated financial statements incorporated by reference in this short form prospectus have been prepared in accordance with U.S. generally accepted accounting principles. Unless otherwise specified or the context otherwise requires, all references herein to currency are references to Canadian dollars.

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DOCUMENTS INCORPORATED BY REFERENCE

The following documents, which have been filed with the securities commission or similar regulatory authority in each of the provinces of Canada, are specifically incorporated by reference in this short form prospectus:

(a) the annual information form of the company dated February 27, 2015 (the "AIF");

(b) the comparative audited consolidated financial statements of the company, and the notes thereto, as at and for the fiscal years ended December 31, 2014 and 2013, together with the report of the auditors thereon dated February 11, 2015;

(c) management's discussion and analysis of financial results ("MD&A") for the year ended December 31, 2014;

(d) the unaudited consolidated financial statements of the company, and the notes thereto, as at September 30, 2015 and for the three and nine month periods ended September 30, 2015 and September 30, 2014 together with MD&A for those periods;

(e) the material change report of the company dated September 18, 2015 regarding the secondary offering of common shares by HOL and certain transactions in connection with such offering involving the capital structure of the company; and

(f) the disclosure in the following sections of the supplemented PREP prospectus of HOL dated October 29, 2015 (the "HOL Prospectus") in respect of the secondary offering of common shares of HOL (the "IPO") by the Province of Ontario (the "Province"):

(i) "Meaning of Certain References" at page 1 of the HOL Prospectus;

(ii) "Market and Industry Data" at pages 4 to 5 of the HOL Prospectus;

(iii) the disclosure under the subheadings "Overview", "Ontario's Electricity Industry – Regulation of Transmission and Distribution", "Ontario's Electricity Industry – Transmission" and "Ontario's Electricity Industry – Distribution" in "Electricity Industry" at pages 21 to 22, pages 24 to 25, pages 25 to 26 and pages 26 to 27, respectively, of the HOL Prospectus;

(iv) "Rate-Regulated Utilities" at pages 30 to 34 of the HOL Prospectus;

(v) "Business of Hydro One" at pages 35 to 52 of the HOL Prospectus;

(vi) "Pre-Closing Transactions" at pages 100 to 102 of the HOL Prospectus;

(vii) "Corporate Structure – Corporate Structure and Subsidiaries" at pages 103 to 104 of the HOL Prospectus;

(viii) "Departure Tax" at page 108 of the HOL Prospectus;

(ix) the disclosure under the subheadings "Overview", "Governance Agreement – Subsidiary Governance", "Termination of Existing Shareholder Declarations and Resolutions" and "Ontario Electricity Financial Corporation Indemnity" in "Governance and Relationship with Principal Shareholder" at pages 110 to 111, page 119, pages 121 to 122 and page 122, respectively, of the HOL Prospectus;

(x) "Directors and Management of the Company" at pages 123 to 136 of the HOL Prospectus;

(xi) "Executive Compensation" at pages 136 to 153 of the HOL Prospectus;

(xii) "Directors' Compensation" at pages 153 to 154 of the HOL Prospectus;

(xiii) "Risk Factors" at pages 160 to 173 of the HOL Prospectus, excluding the disclosure under the subheading "Risks Relating to this Offering";

(xiv) "Interests of Management and Others in Material Transactions" at pages 174 to 175 of the HOL Prospectus; and

(xv) "Glossary" at pages 178 to 182 of the HOL Prospectus.

(collectively, the "Included Sections").

The Included Sections have been incorporated by reference into, and form a part of, this short form prospectus because they supplement certain of the company's historical disclosure and they also contain a description of the impacts to the company and its subsidiaries as a result of the IPO and related transactions. As the Included Sections were prepared in advance of the completion of the IPO on November 5, 2015 (the "IPO Closing"), certain portions of the Included Sections contain future-looking statements, such as "prior to the closing of this offering", "on closing", "on or prior to closing of this offering", "concurrently with the closing of this offering", "upon completion of this offering" and phrases of similar effect. Accordingly, and for greater certainty, all transactions, agreements and other matters contemplated in the Included Sections to be completed, entered into or to take effect on or prior to the IPO Closing were completed, entered into or made effective, as the case may be, in the manner contemplated by the Included Sections. As such, unless otherwise indicated in this short form prospectus, this short form prospectus should be read with the understanding that such transactions, agreements and other matters contemplated in the Included Sections have been completed, entered into or made effective, as the case may be, in the manner contemplated by the Included Sections. The company has determined there is no material information in the HOL Prospectus relating to the company or the Notes that has not been incorporated by reference into this short form prospectus.

Updated earnings coverage ratios, as required, will be filed quarterly with the appropriate securities regulatory authorities either as prospectus supplements or as part of the company's unaudited interim and audited annual consolidated financial statements and will be deemed to be incorporated by reference into this short form prospectus for the purposes of the offering of Notes hereunder.

Any documents of the type required by National Instrument 44-101 – *Short Form Prospectus Distributions* to be incorporated by reference in a short form prospectus, including documents of the types referred to in paragraphs (a) through (e) above (except confidential material change reports), and any business acquisition reports filed by the company with the securities regulatory authorities in Canada since the end of the financial year in respect of which its then current annual information form is filed, shall be deemed to be incorporated by reference into this short form prospectus. Upon a new annual information form and new annual financial statements and related MD&A being filed by the company with, and where required, accepted by, the applicable securities regulatory authorities during the currency of this short form prospectus, the Included Sections, the previous annual information form, previous annual financial statements and related MD&A, and all previous interim financial statements and related MD&A filed prior to the commencement of the company's financial year in which the new annual information form, new annual financial statements and related MD&A are filed shall be deemed no longer to be incorporated into this short form prospectus for purposes of future offers and sales of Notes hereunder.

A pricing supplement or prospectus supplement containing the specific variable terms for an issue of Notes will be delivered to purchasers of such Notes together with this short form prospectus and will be deemed to be incorporated by reference into this short form prospectus as of the date of the pricing supplement or prospectus supplement, solely for the purposes of the Notes issued under that pricing supplement or prospectus supplement. Any template version of marketing materials for an issue of Notes filed by the company with the securities regulatory authorities in Canada after the date of the pricing supplement or prospectus supplement in respect of such issue of Notes and before the termination of the distribution of such Notes will be deemed to be incorporated by reference into that pricing supplement or prospectus supplement.

Any statement contained in this short form prospectus or in a document incorporated or deemed to be incorporated by reference herein shall be deemed to be modified or superseded and not incorporated by reference, for purposes of this short form prospectus, to the extent that a statement contained herein or in any other subsequently filed document which also is or is deemed to be incorporated by reference herein modifies or supersedes such prior statement. The modifying or superseding statement need not state that it has modified or superseded a prior statement or include any other information set forth in the document that it modifies or supersedes. The making of a modifying or superseding statement shall not be deemed an admission for any purposes that the modified or superseded statement, when made, constituted a misrepresentation, an untrue statement of a material fact or an omission to state a material fact that is required to be stated or that is necessary to make a statement not misleading in light of the circumstances in which it was made. Any statement so modified or superseded shall not constitute a part of this short form prospectus, except as so modified or superseded.

CAUTIONARY NOTE REGARDING FORWARD-LOOKING INFORMATION

This short form prospectus, including the documents incorporated by reference herein, contains "forward-looking information" within the meaning of applicable Canadian securities laws that is based on current expectations, estimates, forecasts and projections about the business of the company and the industry in which the company operates and includes beliefs and assumptions made by the management of the company. Such information includes, but is not limited to, statements about the general development of the company's business, the company's strategy, future capital expenditures, and expectations regarding developments in the statutory and operating framework for electricity distribution and transmission in Ontario. Additional forward-looking information is identified in the various documents incorporated by reference in this short form prospectus, including the section entitled "Forward-Looking Information" in the company's annual information form and the section entitled "Forward-Looking Statements and Information" in the company's MD&A. Words such as "expect", "anticipate", "intend", "attempt", "may", "plan", "will", "believe", "seek", "estimate", and variations of such words and similar expressions are intended to identify such forward-looking information. The forward-looking information contained in this short form prospectus, including the documents incorporated by reference herein, are not guarantees of future performance and involve assumptions and risks and uncertainties that are difficult to predict. In particular, this forward-looking information is based on a variety of factors and assumptions including, but not limited to: no unforeseen changes in the legislative and operating framework for Ontario's electricity market; favourable decisions from the Ontario Energy Board and other regulatory bodies concerning outstanding and future rate and other applications; no unexpected delays in obtaining required approvals; no unforeseen changes in rate orders or rate setting methodologies for the company's distribution and transmission businesses; no unfavourable changes in environmental regulation; the continued use and availability of U.S. GAAP; a stable regulatory environment; and no significant event occurring outside the ordinary course of business. These assumptions are based on information currently available to the company including information obtained by the company from third-party sources. Actual outcomes and results may differ materially from what is expressed, implied or forecasted in this forward-looking information. While the company does not know what impact any of these differences may have, the company's business, results of operations, financial condition and 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 information are discussed in more detail under "Risk Factors" in this short form prospectus and in any prospectus supplement or pricing supplement and in the sections entitled "Forward-Looking Information" and "Risk Factors" in the company's annual information form and the sections entitled "Risk Management and Risk Factors" and "Forward-Looking Statements and Information" in the company's MD&A. You should carefully consider these and other factors and not place undue reliance on forward-looking information.

The company does not intend, and the company disclaims any obligation, to update any forward-looking information, except as required by law.

THE COMPANY

The company is the largest electricity transmission and distribution company in Ontario. The company owns and operates substantially all of Ontario's electricity transmission network, and the company is the largest electricity distributor in Ontario by number of customers.

The company has three business segments: (i) transmission; (ii) distribution; and (iii) other business.

The company's transmission business consists of owning, operating and maintaining its transmission system, which accounts for 96% of Ontario's transmission network. This includes the company's 66% interest in B2M Limited Partnership, a limited partnership between the company and the Saugeen Ojibway Nation in respect of the Bruce-to-Milton transmission line. The company's transmission business is a rate-regulated business that earns revenues mainly from charging transmission rates that must be approved by the Ontario Energy Board. The company's transmission business accounted for approximately 72% of its total net income in 2014. All of the company's transmission business is carried out by its wholly-owned subsidiary, Hydro One Networks Inc., except for the portion of its business held through B2M Limited Partnership, which the company controls.

The company's distribution business consists of owning, operating and maintaining its distribution system, which the company owns primarily through its wholly-owned subsidiary, Hydro One Networks Inc., the largest local distribution company in Ontario. The company's distribution system is also the largest in Ontario, and principally serves rural communities. The company's distribution business is a rate-regulated business that earns revenues mainly by charging distribution rates that must be approved by the Ontario Energy Board. The company's distribution business accounted for approximately 28% of its total net income in 2014 (which included the net income of Hydro One Brampton Networks Inc., which was a subsidiary of the company until August 31, 2015). The company's distribution business also includes the business of its wholly-owned subsidiary, Hydro One Remote Communities Inc., which operates on a cost-recovery basis and supplies electricity to customers in remote communities in northern Ontario.

The company's transmission and distribution businesses are both operated through Hydro One Networks Inc. This allows both businesses to utilize common operating platforms, technology, work processes, equipment and field staff and thereby take advantage of operating efficiencies and synergies. For regulatory purposes, Hydro One Networks Inc. files separate rate applications with the Ontario Energy Board for each of its licensed transmission and distribution businesses.

The Ontario Energy Board regulates the company's transmission and distribution businesses and issues rate orders to establish the revenue requirements required to cover the approved cost of these businesses plus a specified rate of return.

The company's other business segment includes certain corporate activities and is not rate-regulated.

The company is a wholly-owned subsidiary of HOL. The address of the head and registered office and principal place of business of the company is 483 Bay Street, South Tower, 8th Floor, Toronto, Ontario, M5G 2P5.

CREDIT RATINGS

As of the date of this short form prospectus, the Notes have been rated A by Standard & Poor's Ratings Services ("S&P") and A (high) by DBRS Limited ("DBRS") and have been provisionally rated A3 by Moody's Investors Services, Inc. ("Moody's"). The following information relating to credit ratings is based on information made available to the public by the rating agencies.

Credit ratings are intended to provide investors with an independent measure of the credit quality of an issue of securities. The rating agencies rate long-term debt instruments by rating categories ranging from a high of AAA to a low of D (C in the case of Moody's). Long-term debt instruments which are rated in the A category by S&P are in the third highest category and mean the obligor's capacity to meet its financial commitments and obligations is strong but is considered somewhat more susceptible to the adverse effects of changes in circumstances and adverse economic conditions than obligations in higher rated categories. S&P may modify the ratings from AA to CCC using a plus (+) or minus (-) sign to show relative standing within the major rating categories. Long-term debt instruments which are rated in the A category by DBRS are in the third highest category and are considered to be of a good credit quality, with substantial capacity for the payment of financial obligations. Entities in the A category are considered to be vulnerable to future events, but qualifying negative factors are considered manageable. The "high" modifier indicates relative standing within this rating category by DBRS. Long-term debt instruments which are rated in the A category by Moody's are in the third highest category and are considered upper-medium grade and are subject to low credit risk. Moody's applies numerical modifiers 1, 2 and 3 to each generic rating classification from Aa through Caa. The modifier 3 indicates a ranking in the lower end of that generic rating category. The A3 rating assigned to the Notes by Moody's is a provisional rating and a definitive rating will be assigned to each offering of Notes under this short form prospectus only after Moody's reviews the terms and conditions of the drawdown. In some circumstances, no rating may be assigned to a drawdown, and if a definitive rating is issued, it may differ from the provisional rating.

The ratings mentioned above are not a recommendation to purchase, sell or hold the company's debt securities including the Notes and do not comment as to market price or suitability for a particular investor. There can be no assurance that the ratings will remain in effect for any given period of time or that the ratings will not be revised or withdrawn entirely by any or all of S&P, DBRS and Moody's at any time in the future if in their judgment circumstances so warrant.

The company has made, and anticipates making, payments to each of S&P, DBRS and Moody's pursuant to the ratings agency services agreements entered into with such credit rating organizations with respect to the ratings assigned to the long-term debt of the company. In addition, as Notes are issued, the company expects to make payments to such credit rating organizations pursuant to the ratings agency services agreements entered into with such credit rating organizations for the ratings they assign to the Notes of a particular series. The company has also made payments to S&P for ratings evaluation services in connection with the IPO and to DBRS for ratings evaluation services in connection with the disposition of Hydro One Brampton Networks Inc. There have been no other services provided by any of such credit rating organizations to the company within the last two years.

ELIGIBILITY FOR INVESTMENT

In the opinion of Osler, Hoskin & Harcourt LLP, counsel to the company, and Blake, Cassels & Graydon LLP, counsel to the Dealers, unless otherwise specified in the applicable prospectus supplement or pricing supplement, the Notes, if issued on the date hereof, would be qualified investments under the *Income Tax Act* (Canada) and the regulations thereunder (collectively, the "Tax Act") for a trust governed by a registered retirement savings plan ("RRSP"), registered retirement income fund ("RRIF"), registered education savings plan, registered disability savings plan, deferred profit sharing plan (other than a trust governed by a deferred profit sharing plan for which any employer is the company or an employer who does not deal with the company at arm's length, within the meaning of the Tax Act) or a tax-free savings account ("TFSA").

The Notes will not be a "prohibited investment" for a TFSA, RRSP or RRIF, provided that the holder of the TFSA or the annuitant under a RRSP or RRIF, (i) deals at arm's length with the company for purposes of the Tax Act, and (ii) does not have a "significant interest", within the meaning of the Tax Act, in the company. Holders of a TFSA and annuitants under a RRSP or RRIF should consult their own tax advisors as to whether the Notes will be a "prohibited investment" for such TFSA, RRSP or RRIF in their particular circumstances.

EARNINGS COVERAGE RATIOS

For the twelve months ended December 31, 2014 and the twelve months ended September 30, 2015, the company's consolidated income before provision for payment in lieu of corporate income taxes and interest expense (net of capitalized interest) was $1,218 million and $1,281 million, respectively. Interest expense (net of capitalized interest) for these periods was $379 million and $380 million, respectively, and including capitalized interest, was $426 million and $429 million, respectively. Preferred share dividends declared for each of these periods were $18 million.

The following table sets forth the earnings coverage ratio for the company for the twelve month period ended December 31, 2014, based on audited information, and for the twelve month period ended September 30, 2015, based on unaudited information, in each case without giving effect to any Notes to be issued under this short form prospectus:

	December 31, 2014	**September 30, 2015**
Earnings coverage on long-term debt obligations(1)(2)	2.77	2.89

(1) The earnings coverage ratio has been calculated as the sum of net income attributable to the shareholder of the company, provision for payments in lieu of corporate income taxes and financing charges divided by the sum of financing charges, capitalized interest and cumulative preferred dividends.

(2) The earnings coverage ratio has been adjusted to give effect to the issuance on April 30, 2015 of $350 million of 1.62% medium term notes due April 30, 2020, as if such notes had been issued at the beginning of each respective twelve month period noted above. For the purpose of calculating the earnings coverage ratio for the periods noted above, it has also been assumed that the proceeds of such notes were used to repay the floating rate and fixed rate medium term notes maturing in July and September 2015, respectively.

DESCRIPTION OF THE NOTES

General

The following is a summary of the material attributes and characteristics of the Notes, and does not purport to be complete and is qualified in its entirety by reference to the Notes and the Trust Indenture (as defined below).

The terms and conditions set forth in this section "Description of the Notes" will apply to each Note unless otherwise specified in the applicable prospectus supplement or pricing supplement. The company reserves the right to set forth in a prospectus supplement or pricing supplement specific variable terms of or amendments to the Notes which are not within the options and parameters set forth in this short form prospectus. References in this section "Description of the Notes" refer to all medium term notes of the company which have previously been or are to be issued under the Trust Indenture.

This short form prospectus qualifies under applicable Canadian securities laws the distribution of $3.5 billion aggregate principal amount of Notes in Canadian currency (or the equivalent thereof in other currencies or currency units at the time of issue) which have been authorized for issue under the Trust Indenture. This amount is subject to amendment from time to time as determined by the company. The company has previously issued $2.163 billion aggregate principal amount of medium term notes under its short form prospectus dated September 4, 2013.

Notes issued hereunder will have a term to maturity of not less than one year and will be issuable in Canadian currency (or in other currencies or currency units at the time of issue) in fully registered definitive or global form, in which case the Notes will be exchangeable only under certain conditions for definitive Notes (as described under the heading "Global Notes" below). Each interest-bearing Note will bear interest at either a fixed rate (a "Fixed Rate Note") or a floating rate (a "Floating Rate Note"). Notes will be issued from time to time at such rates of interest and at par, at a premium or at a discount, may be subject to redemption or repayment prior to maturity, or may include terms entitling the company to extend the maturity dates of the Notes, which terms shall be determined by the company based on a number of factors, including advice from the Dealers. The Notes will be unsecured and will, at their respective dates of issue, rank *pari passu* with all other unsecured and unsubordinated Indebtedness and obligations of the company then outstanding, except as to any sinking fund which pertains exclusively to any particular Indebtedness of the company. The company may also, from time to time, issue debt securities and incur additional debt otherwise than through the issuance of Notes pursuant to this short form prospectus.

Neither the aggregate principal amount of Notes which will be issued and sold nor the issue price to the public of the Notes has been established as the Notes will be issued at such times, in such amounts and at such prices as the company determines from time to time. Notes issued hereunder will be offered and sold during the twenty-five months from the date of issuance of the receipt for this short form prospectus at prices negotiated with the purchasers, and the prices at which the Notes will be offered and sold may vary as between purchasers and during the distribution period. The Notes will be issued from time to time at the discretion of the company in an aggregate principal amount not to exceed $3.5 billion in Canadian currency, or the equivalent thereof calculated at the applicable rates of exchange prevailing at the time of issue of Notes issued in currencies other than Canadian currency.

The specific variable terms of any offering of Notes, including, in the case of Floating Rate Notes, the information necessary for the calculation of interest thereon, will be set forth in a prospectus supplement or pricing supplement to this short form prospectus. Where Notes are offered and sold in currencies other than Canadian dollars, the Canadian dollar equivalent of the offering price and the rate of exchange at the last feasible date will be included in the applicable prospectus supplement or pricing supplement.

Trust Indenture

The Notes will be issued under a trust indenture dated as of June 4, 2001, as supplemented or modified from time to time (collectively, the "Trust Indenture") between the company and Computershare Trust Company of Canada, as trustee (the "Trustee", which term shall include, unless the context otherwise requires, its successors and assigns). The following is a brief summary of the material attributes and characteristics of the Trust Indenture. This summary does not purport to be complete and reference should be made to the Trust Indenture for more detailed information.

The Trust Indenture permits the issuance from time to time of additional unsecured medium term notes without limitation as to aggregate principal amount, subject to compliance with the covenants contained therein.

The Notes will be direct obligations of the company and will rank *pari passu* with all other medium term notes from time to time issued and outstanding under the Trust Indenture and with other present and future unsubordinated and unsecured Indebtedness of the company, except as to any sinking fund which pertains exclusively to any particular Indebtedness of the company. The Notes will not be secured by any mortgage, pledge or charge, except in the circumstances referred to under the subheading "Negative Pledge".

<u>Negative Pledge</u>

The Trust Indenture contains provisions to the effect that the company will not, nor will it permit any Designated Subsidiary (as defined below) to, create, assume or suffer to exist any Security Interest (as defined below) on any of the company's or the Designated Subsidiary's assets to secure any Obligation (as defined below) unless at the same time it shall secure all the Notes then outstanding on an equal basis. This covenant is, however, subject to the following exceptions:

- any Security Interest that secures the Obligations of a Designated Subsidiary which exists prior to the date on which it becomes a Designated Subsidiary and which (a) was not incurred in contemplation of that person becoming a Designated Subsidiary and (b) was not applicable to the company or any other Designated Subsidiary or the properties or assets of the company or any other Designated Subsidiary;
- any Security Interest granted by the company or a Designated Subsidiary to secure the Notes;
- any Purchase Money Mortgage (as defined below) or Capital Lease Obligation (as defined below) of the company or any Designated Subsidiary;

- any Security Interest on a property or asset acquired by the company or a Designated Subsidiary that secures the Obligations of a person, whether or not that Obligation is assumed by the acquiring person, which Security Interest exists at the time that property or asset is acquired and which (a) was not incurred in contemplation of that property or asset being acquired and (b) was not applicable to the company or any other Designated Subsidiary or the properties or assets of the company or any other Designated Subsidiary;

- any Security Interest given in the ordinary course of business by the company or a Designated Subsidiary to any bank or banks or other lenders to secure any Indebtedness payable on demand or maturing within 18 months of the date that Indebtedness is incurred or of the date of any renewal or extension of that Indebtedness;

- any Security Interest granted by any Designated Subsidiary in favour of the company or any Wholly-Owned Designated Subsidiary (as defined below);

- any Security Interest on or against cash or marketable debt securities pledged to secure any non-speculative Financial Instrument Obligation (as defined below) which hedges Indebtedness of the company or of a Designated Subsidiary;

- any Security Interest for taxes, assessments, government charges or claims that are being contested in good faith and in respect of which appropriate provision is made in the company's consolidated financial statements in accordance with GAAP;

- Security Interests securing appeal bonds or other similar Security Interests arising in connection with contracts, bids, tenders or court proceedings, including, without limitation, surety bonds, security for costs of litigation where required by law and letters of credit, or any other instruments serving a similar purpose;

- a Security Interest in cash or marketable debt securities in a sinking fund account established by the company in support of a series of Notes;

- a lien or deposit under workers' compensation, social security or similar legislation or good faith deposits in connection with bids, tenders, leases, contracts or expropriation proceedings, or deposits to secure public or statutory obligations or deposits of cash or obligations to secure surety and appeal bonds;

- any lien or privilege imposed by law, such as builders', carriers', warehousemen's, landlords', mechanics' and material men's liens and privileges, and any lien or privilege arising out of judgments or awards with respect to which the company or a Designated Subsidiary at the time is prosecuting an appeal or proceedings for review and with respect to which it has secured a stay of execution pending that appeal or proceedings for review; or any liens for taxes, assessments or governmental charges or levies not at the time due and delinquent or the validity of which is being contested at the time by the company or a Designated Subsidiary in good faith; or undetermined or inchoate lien privileges and charges incidental to current operations which have not at such time been filed pursuant to law against the company or a Designated Subsidiary or which relate to obligations not due or delinquent; or the deposit of cash or securities in connection with any lien or privilege referred to in this clause;

- any minor encumbrance, such as easements, rights-of-way, servitudes or other similar rights in land granted to or reserved by other persons, rights-of-way for sewers, electric lines, telegraph and telephone lines, oil and natural gas pipelines and other similar purposes, or zoning or other restrictions as to the company's use of real property, which do not in the aggregate materially detract from the value of that property or materially impair its use in the operation of the business of the company or a Designated Subsidiary;

- any right reserved to or vested in, whether by statutory provision or otherwise, any municipality or governmental or other public authority to terminate, purchase assets used in connection with or require annual or other periodic payments as a condition to the continuance of, any lease, license, franchise, grant or permit acquired by the company or a Designated Subsidiary;

- any lien or right of distress reserved in or exercisable under any lease for rent and for compliance with the terms of that lease;

- any Security Interest granted by the company or a Designated Subsidiary to a public utility or any municipality or governmental or other public authority when required by that utility, municipality or other authority in connection with the operations of the company or a Designated Subsidiary;

- any reservation, limitation, proviso or condition, if any, expressed in any original grants to the company or a Designated Subsidiary from the Crown; and

- any extension, renewal, alteration, substitution or replacement, in whole or in part, of any Security Interest referred to in the foregoing clauses, provided that the Security Interest is limited to all or part of the same property that secured the Security Interest, the principal amount of the secured Obligations is not increased by that action, the term of the secured Indebtedness is not shortened and the terms and conditions are no more restrictive in any material respect than the Security Interest so extended.

In addition to the Security Interests permitted above, the company or any Designated Subsidiary may create, assume or suffer to exist any Security Interest on any of its assets if, after giving effect to that Security Interest, the aggregate amount of Indebtedness secured by the Security Interests permitted only by this paragraph does not at that time exceed 5% of the Consolidated Net Worth (as defined below) of the company.

<u>Limitation on Funded Obligations</u>

So long as any of the Notes issued under the Trust Indenture remain outstanding, neither the company nor any of its Designated Subsidiaries will, directly or indirectly, guarantee, incur, issue or become liable for or in respect of any Funded Obligations (as defined below) unless after giving pro forma effect to that guarantee, incurrence, issuance or liability, including the application or use of the resulting net proceeds, the aggregate principal amount of Consolidated Funded Obligations (as defined below) does not exceed 75% of the Total Consolidated Capitalization (as defined below). This covenant, however, will not prevent the incurrence of Capital Lease Obligations, Purchase Money Obligations and non-speculative Financial Instrument Obligations.

<u>Ceasing to be a Designated Subsidiary</u>

The Board of Directors of the company may elect that any Designated Subsidiary cease to be a Designated Subsidiary, except that an election may not be made in respect of any Designated Subsidiary:

- if the Designated Subsidiary owns any Funded Obligations of the company or any shares, voting interests or Funded Obligations of any other Designated Subsidiary;

- if the Designated Subsidiary owns or has any ownership interest in any Principal Property (as defined below); or

- if, after giving effect to the election, the company would not be entitled to issue Funded Obligations in the principal amount of at least $1.00.

<u>Mergers, Consolidations and Sales of Assets</u>

The company will not enter into any transaction in which all or substantially all of its property and assets would become the property of any other person, whether by way of reorganization, consolidation, amalgamation, arrangement, merger, transfer, sale or otherwise, unless:

- the company shall be the surviving person, or the person, if other than the company, formed by the amalgamation, consolidation or into which the company is merged or that acquires by disposition all or substantially all of the property or assets of the company, shall be a company organized and validly existing under the federal laws of Canada or any of its provinces or territories and shall expressly assume, by a supplemental indenture executed and delivered to the Trustee in form satisfactory to the Trustee, all of the company's obligations under the Trust Indenture;

- immediately before and after giving effect to the transaction, no Event of Default (as defined below) or event that with the passing of time or the giving of notice, or both, would constitute an Event of Default shall have occurred and be continuing; and

- neither the company nor any successor, either at the time of or immediately after the consummation of any such transaction, will be insolvent or generally fail to meet, or admit in writing its inability or unwillingness to meet, its obligations as they generally become due.

Events of Default

Each of the following is an Event of Default under the Trust Indenture with respect to Notes of any series:

(1) failure to pay any principal or premium, if any, on any Notes when due, at maturity, upon redemption or otherwise and the continuance of such default for a period of five days;

(2) failure to pay any interest on any Notes when due and the continuance of that default for a period of 45 days;

(3) the sale, transfer or other disposition of all or substantially all of the company's undertaking or assets other than in accordance with the covenant described above under the subheading "Mergers, Consolidations and Sales of Assets";

(4) default in the performance or breach of any other covenant or agreement of the company under the Trust Indenture, any supplemental indenture or the Notes and the continuance of that default for a period of 60 days after written notice to the company by the Trustee or by holders of at least 25% of all Notes issued under the Trust Indenture;

(5) default by the company or any Material Subsidiary (as defined below), whether as primary obligor, guarantor or surety, on any payment of principal, premium, if any, or interest on any Indebtedness, the outstanding principal amount of which Indebtedness exceeds $100 million in the aggregate, beyond any applicable grace period or failure to perform or observe any other agreement, term or condition contained in any agreement under which that Indebtedness is created, or if any default, failure or other event under that agreement shall occur and be continuing, and the effect of that default, failure or other event is to cause $100 million or more of that Indebtedness to become due or to be required to be repurchased prior to any stated maturity;

(6) the rendering of a judgment or judgments, not subject to appeal, against the company or any Material Subsidiary in an aggregate amount in excess of $100 million by a court or courts of competent jurisdiction, which judgment or judgments remain undischarged and unstayed for a period of 60 days; and

(7) specified events of bankruptcy, insolvency or reorganization affecting the company or any Material Subsidiary.

If an Event of Default applicable only to the issued and outstanding Notes of a series occurs and is continuing, either the Trustee or the holders of not less than 25% in principal amount of Notes of that series then outstanding may declare the principal of, and interest and premium, if any, on all Notes of that series to be due and payable immediately.

If, however, an Event of Default applicable to all Notes issued and outstanding under the Trust Indenture, or an Event of Default described in clause (5), (6), or (7) above occurs and is continuing, either the Trustee or the holders of not less than 25% in principal amount of all issued and outstanding Notes, treated as one class, may declare the principal amount of all the Notes then outstanding to be due and payable immediately.

Subject to the provisions of the Trust Indenture relating to the duties of the Trustee, in case an Event of Default applicable to any Notes shall occur and be continuing, the Trustee will be under no obligation to exercise any of its rights or powers under the Trust Indenture at the request or direction of any of the holders of those Notes, unless those holders shall have offered to the Trustee reasonable indemnity. Subject to such provisions for the indemnification of the Trustee, the holders of a majority in principal amount of Notes of all series affected by an Event of Default will have the right to direct the time, method and place of conducting any proceedings for any remedy available to the Trustee or exercising any trust or power conferred on the Trustee in respect of the Notes of all series affected by that Event of Default.

Defeasance

The Trust Indenture requires the Trustee to release the company from its obligations under the Trust Indenture relating to a particular series of Notes if specified conditions are satisfied. Among other things, the company must deposit money or securities for the payment of all principal of and interest and any other amounts on that series of Notes as well as for the payment of the expenses of the Trustee. The deposited money or securities must be denominated in the currency in which principal of these Notes is payable and, in the case of deposited securities, must constitute direct obligations of Canada or specified provinces of Canada or an agency or instrumentality of Canada.

Amendments and Waivers

The Trust Indenture provides that the company and the Trustee may enter into supplemental indentures ("Supplemental Indentures") without the consent of the holders of the Notes of any or all series to:

- add limitations or restrictions to be observed upon the amount or issue of Notes, provided that such limitations or restrictions shall not be materially adverse to the interests of the holders of the Notes;
- add covenants for the protection of the holders of the Notes of any series;
- provide for any additional Event of Default;
- make such provisions not inconsistent with the Trust Indenture as may be necessary or desirable with respect to matters or questions arising thereunder, including the making of any modifications in the form of the Notes which do not affect the substance thereof and which it may be expedient to make, provided that such provisions and modifications will not adversely affect the holders of Notes;
- provide for the issue of Notes of any one or more series and establish the form and terms of any series of Notes;
- evidence the succession, or successive successions, of successors to the company and the covenants and obligations assumed by any such successor, in accordance with the provisions of the Trust Indenture; and
- giving effect to any extraordinary resolution or ordinary resolution of the holders of Notes in accordance with the Trust Indenture.

Other amendments and modifications of the Trust Indenture, Supplemental Indentures and Notes may be made by the company and the Trustee with the consent of the holders of not less than 66⅔% (and in certain circumstances, a majority) in principal amount of Notes of all series voting on such amendment or modification and, if the rights of holders of Notes of a particular series of Notes would be affected differently than rights of holders of Notes of other series, not less than 66⅔% (and, in certain circumstances, a majority) in principal amount of Notes of the series so affected by that modification or amendment voting on such amendment or modification, in each case, voting as one class. However, no modification or amendment may, without the consent of the holder of each outstanding Note of the affected series,

- reduce the principal amount at maturity of, extend the fixed maturity of, or alter the redemption provisions of, those Notes;
- change the currency in which those Notes or any premium or accrued interest is payable;
- reduce the percentage in principal amount at maturity outstanding of those Notes that must consent to an amendment, supplement or waiver or consent to take any action under the Trust Indenture, Supplemental Indenture or those Notes;
- impair the right to institute suit for the enforcement of any payment on or with respect to those Notes;
- waive a default in payment with respect to those Notes;
- reduce the rate or extend the time for payment of interest on those Notes;
- affect the ranking of those Notes in a manner adverse to the holders; or
- make any changes to the Trust Indenture, Supplemental Indentures or those Notes that would result in the company being required to make any withholding or deduction from payments made under or with respect to those Notes.

The holders of 66⅔% in principal amount of the Notes of all series with respect to which an Event of Default shall have occurred and be continuing, voting as one class, may waive any Event of Default, except in the case of a default in payment of principal with respect to the Notes or except, further, in respect of a covenant or provision which cannot be modified or amended without the consent of the holder of each outstanding Note affected.

<u>Definitions</u>

In addition to the definitions set out above, the Trust Indenture contains definitions substantially to the following effect:

"Capital Lease Obligation" means any monetary obligation of the company or a Designated Subsidiary under any leasing or similar arrangement which, in accordance with GAAP, would be classified as a capital lease and for the purposes of the Trust Indenture, the amount of Capital Lease Obligations will be the capitalized amount thereof, determined in accordance with GAAP;

"Consolidated Funded Obligations" means the aggregate amount of all Funded Obligations of the company and its Designated Subsidiaries determined on a consolidated basis in accordance with GAAP;

"Consolidated Net Worth" means, as at any date, the consolidated shareholders' equity of the company and its Designated Subsidiaries as at that date determined in accordance with GAAP;

"Contingent Liability" means any agreement, undertaking or arrangement by which any person guarantees, endorses or otherwise becomes or is contingently liable upon (by direct or indirect agreement, contingent or otherwise, to provide funds for payment, to supply funds to, or otherwise to invest in, a debtor, or otherwise to assure a creditor against loss) the Obligation of any other person (other than by endorsements of instruments in the course of collection), or guarantees the payment of dividends or other distributions upon the shares of any other person. The amount of any person's obligation under any Contingent Liability will, subject to any limitation contained in that Contingent Liability, be deemed to be the outstanding principal amount (or maximum principal amount, if larger) of the debt, obligation or other liability guaranteed thereby;

"Designated Subsidiary" means any subsidiary which is designated as such by the directors of the company, provided that any such subsidiary may only be so designated if, after giving effect thereto, the company would be entitled under the Trust Indenture to issue Funded Obligations in the principal amount of at least $1.00 and further provided that a subsidiary cannot be so designated if any of its shares are owned by a subsidiary which is not itself a Designated Subsidiary;

"Financial Instrument Obligations" means, with respect to any person at any time, the obligations of that person under any transaction that is a rate swap, basis swap, forward rate transaction, commodity swap, commodity option, commodity future, equity or equity index swap or option, bond, note or bill option, interest rate option, forward foreign exchange transaction, cap, collar or floor transaction, currency swap, cross-currency rate swap, swaption, currency option or any other similar transaction, including any option to enter into any of the foregoing, or any combination of the foregoing to the extent of the net amount due to or accruing due by the person under that obligation, determined by marking that obligation to market at that time in accordance with its terms;

"Funded Obligations" means all Indebtedness created, assumed or guaranteed, which matures by its terms on, or is renewable at the option of the obligor to, a date more than 18 months after the date of the original creation, assumption or guarantee thereof;

"GAAP" means as at any date of determination:

(1) accounting principles which are recognized as being generally accepted in Canada, if the company is then preparing its financial statements in accordance with such principles; or

(2) accounting principles which are recognized as being generally accepted in the United States, if the company is then preparing its financial statements in accordance with such principles;

"Indebtedness" means, without duplication, with respect to any person,

(1) all obligations of that person for borrowed money, including obligations with respect to bankers' acceptances and contingent reimbursement obligations, excluding Preferred Securities issued by that person;

(2) all obligations issued or assumed by that person in connection with its acquisition of property in respect of the deferred purchase price of that property;

(3) all Capital Lease Obligations and Purchase Money Obligations of that person; and

(4) all Contingent Liabilities of that person in respect of any of the foregoing;

"Material Subsidiary" means, as at any date, a Designated Subsidiary,

(1) the total assets of which represent more than 10% of the total assets of the company determined on a consolidated basis as shown in the most recently publicly released consolidated financial statements of the company; or

(2) the total revenues of which represent more than 10% of the total revenues of the company determined on a consolidated basis as shown in the most recently publicly released consolidated financial statements of the company;

"Obligations" means, without duplication, with respect to any person, all items which, in accordance with GAAP, would be included as liabilities on the liability side of the balance sheet of that person as of the date at which Obligations are to be determined, other than Preferred Securities issued by that person; and all Contingent Liabilities of that person in respect of any of the foregoing;

"Preferred Securities" means:

(1) securities which on the date of issue by a person (a) have a term to maturity of more than 30 years, (b) are unsecured and rank subordinate to the unsecured and unsubordinated Indebtedness of that person outstanding on that date, (c) entitle that person to satisfy the obligation to pay the principal or face amount by issuing common shares, (d) entitle that person to defer the payment of interest for more than four years without causing an event of default to occur, and (e) entitle that person to satisfy the obligation to make payments of interest by issuing common shares; and

(2) shares of any class in the capital of a corporation or securities representing ownership interests in any person other than a corporation which, in either case, are not common shares;

"Principal Property" means any of the company's and its subsidiaries' fixed assets used for the transmission, transformation and distribution of electricity in Ontario as of June 4, 2001 (the date of the Trust Indenture);

"Purchase Money Mortgage" means any security interest, mortgage, pledge, charge or other encumbrance created, issued or assumed by the company or a Designated Subsidiary to secure a Purchase Money Obligation; provided that the security interest, mortgage, pledge, charge or other encumbrance is limited to the property (including associated rights) acquired, constructed, installed or improved using the funds advanced to the company or a Designated Subsidiary in connection with that Purchase Money Obligation;

"Purchase Money Obligation" means Indebtedness of the company or a Designated Subsidiary incurred or assumed to finance the purchase price, in whole or in part, of any property (except any Indebtedness which constitutes a Funded Obligation and which was incurred or assumed to finance the purchase price, in whole or in part, of any shares, bonds or other securities) or incurred to finance the cost, in whole or in part, of construction or installation of or improvements to any real property or fixtures provided that such Indebtedness is incurred or assumed within 24 months after the purchase of such real property or fixtures or the completion of such construction, installation or improvements, as the case may be, and includes any extension, renewal or refunding of any such Indebtedness, so long as the principal amount thereof outstanding on the date of such extension, renewal or refunding is not increased;

"Security Interest" means any assignment, mortgage, charge (whether fixed or floating), hypothec, pledge, lien, or other encumbrance on or interest in property or assets that secures payment of Indebtedness or Obligation;

"Total Consolidated Capitalization" means, at any time and from time to time, without duplication, the sum of (1) the principal amount of all Consolidated Funded Obligations at the time outstanding, and (2) the total share capital of the company at the time outstanding, based upon the stated capital on the books of the company, and (3) the principal amount of all outstanding Preferred Securities referred to in clause (1) of the definition of "Preferred Securities" plus the total amount of (or less the amount of any net deficits in) the contributed or capital surplus of the company and the retained earnings of the company and all Designated Subsidiaries in accordance with GAAP after adding back the amount shown on the consolidated balance sheet of the company and its Designated Subsidiaries for minority interests applicable to Designated Subsidiaries and eliminating all intercorporate items, plus the amount of any premium on capital of the company not included in its surplus, and less the amount, if any, by which the capital account of the company or the consolidated capital surplus account of the company and all Designated Subsidiaries (determined in the manner described above) has at any time been increased as a result of any write-up in the value of the shares of a subsidiary which is not a Designated Subsidiary to reflect the equity of the company in its retained earnings or otherwise, or as a result of a restatement of the amount at which any other assets of the company or any Designated Subsidiary are recorded on its books. The amount of Total Consolidated Capitalization of the company and all Designated Subsidiaries at any time shall be ascertained in Canadian dollars; and

"Wholly-Owned Designated Subsidiary" means a Designated Subsidiary, all of the outstanding shares in the capital of which are owned, directly or indirectly, by or for the company and/or by or for one or more other Wholly-Owned Designated Subsidiaries.

Global Notes

Notes may be issued in the form of fully registered global notes ("Global Notes") held by, or on behalf of, CDS Clearing and Depository Services Inc. ("CDS") or another corporation performing similar services that is acceptable to the Trustee (the "Depository") as custodian of the Global Notes and, in such event, Notes will be registered in the name of the Depository or its nominee (a "Nominee"). Where CDS acts as Depository for a series of Notes, The Depositary Trust Company ("DTC"), Euroclear Bank S.A./N.V., as operator of the Euroclear System ("Euroclear") and Clearstream Banking, société anonyme ("Clearstream, Luxembourg"), in each case as direct or indirect participants in CDS, will record beneficial ownership of such series of Notes on behalf of their respective accountholders or participants, to the extent the company makes such series of Notes eligible with DTC, Euroclear or Clearstream, Luxembourg, as applicable (and the company specifies as such in the prospectus supplement or pricing supplement with respect to the particular series of Notes).

Purchasers of Notes represented by Global Notes will not receive Notes in definitive form ("Definitive Notes"). Instead, ownership of such Notes will be constituted through beneficial interests in the Global Notes, and will be represented through book-entry accounts of institutions (including the Dealers), as direct and indirect participants of the Depository ("participants") which, to the extent the Depository is CDS, may include DTC, Euroclear and Clearstream, Luxembourg to the extent applicable as noted above, acting on behalf of the beneficial owners of such Notes. Each purchaser of a Note represented by a Global Note will receive a customer confirmation of purchase from the Dealer or other person from or through whom the Note is purchased in accordance with the practices and procedures of such Dealer or other person. The Depository will be responsible for establishing and maintaining book-entry accounts for its participants having interests in Global Notes.

If Global Note(s) are issued and the Depository notifies the company that it is unwilling or unable to continue as depository in connection with the Global Notes, or if at any time the Depository ceases to be a clearing agency or otherwise ceases to be depository and the company and the Trustee are unable to locate a qualified replacement, or if the company elects to terminate the book-entry system, beneficial owners of Notes represented by Global Notes will receive Definitive Notes.

DTC, Euroclear and Clearstream, Luxembourg

Where CDS acts as Depository for a series of Notes, to the extent the company makes such series of Notes eligible with DTC, Euroclear or Clearstream, Luxembourg (and the company specifies as such in the prospectus supplement or pricing supplement with respect to such series of Notes), holders may hold such series of Notes through the accounts maintained by DTC, Euroclear or Clearstream, Luxembourg, as applicable, as participants in CDS only if they are participants of those systems, or indirectly through organizations which are participants of those systems.

In such case, DTC, Euroclear and Clearstream, Luxembourg will hold omnibus book-entry positions on behalf of their participants through customers' securities accounts in their respective depositaries which in turn will hold such positions in customers' securities accounts in the names of the nominees of the depositaries on the books of CDS. All securities in DTC, Euroclear and Clearstream, Luxembourg are held on a fungible basis without attribution of specific certificates to specific securities clearance accounts.

Transfers of such Notes by persons holding through Euroclear or Clearstream, Luxembourg participants, as applicable, will be effected through CDS, in accordance with CDS rules, on behalf of the relevant European international clearing system by its depositaries; however, such transactions will require delivery of transfer instructions to the relevant European international clearing system by the participant in such system in accordance with its rules and procedures and within its established deadlines (European time). The relevant European international clearing system will, if the transfer meets its requirements, deliver instructions to its depositaries to take action to effect the transfer of the Notes on its behalf by delivering Notes through CDS and receiving payment in accordance with its normal procedures for next-day funds settlement. Payments with respect to the Notes held through Euroclear or Clearstream, Luxembourg will be credited to the cash accounts of Euroclear participants or Clearstream, Luxembourg participants in accordance with the relevant system's rules and procedures, to the extent received by its depositaries.

All information in this short form prospectus concerning CDS, DTC, Euroclear and Clearstream, Luxembourg, reflects the company's understanding of the policies of such organizations which may change at any time without notice.

Fixed Rate Notes

Each Fixed Rate Note will bear interest from its original issue date at the rate per annum on the face thereof until the principal amount thereof is paid or made available for payment. Interest on a Fixed Rate Note will be calculated and payable monthly, quarterly, semi-annually or annually in arrears on the dates specified in such Fixed Rate Note, or other such dates as may be agreed to between the purchaser of the Note and the company (each, an "Interest Payment Date") and at maturity or upon earlier redemption or repayment. Interest Payment Dates will be set forth in the applicable prospectus supplement or pricing supplement for the Fixed Rate Note. Each payment of interest in respect of an Interest Payment Date will include interest accrued to but excluding such Interest Payment Date.

Floating Rate Notes

Each Floating Rate Note will bear interest from its original issue date at rates described in the Floating Rate Note and specified in the applicable prospectus supplement or pricing supplement.

The rate of interest on each Floating Rate Note will be reset monthly, quarterly, or as otherwise specified in the Floating Rate Note and applicable prospectus supplement or pricing supplement. Interest on each Floating Rate Note will be payable monthly, quarterly or as otherwise specified in the Floating Rate Note and applicable prospectus supplement or pricing supplement. Unless otherwise specified in the Floating Rate Note and applicable prospectus supplement or pricing supplement, the company will be the calculation agent with respect to the Floating Rate Notes. Upon request of the holder of any Floating Rate Note, the company will provide the interest rate then in effect.

Payment of Interest and Principal

Interest on each interest bearing Note will be payable on such periodic basis or at maturity and on such date or dates as may be agreed upon by the company and the purchaser of the Note. Payments of interest on each interest bearing Definitive Note will be made by cheque payable on the interest payment date and mailed to the address of, or if so directed by the holder, funds representing the interest payable will be forwarded by electronic funds transfer on the interest payment date to the account of, the holder appearing on the registers maintained by Computershare Trust Company of Canada, as registrar and transfer agent (the "Transfer Agent", which term shall include such other registrar or transfer agent as may from time to time be appointed by the company) at the close of business in the City of Toronto on the tenth business day (with "business day" being a day other than Saturday, Sunday, or a day on which financial institutions in Toronto, Ontario are authorized or obligated by law or regulation to close) prior to the interest payment date or such other day specified to the Trustee by the company and reflected in a Supplemental Indenture for a particular series of Notes. Payment of principal will be made at any branch in Canada of the bank designated in a Definitive Note against surrender of the Note.

Payment of interest and principal on each Global Note will be made to the Depository or the Nominee, as the case may be, as the registered holder of the Global Note. Interest payments on Global Notes will be made by wire transfer no later than the date interest is payable. Principal payments on Global Notes will be made by wire transfer on the maturity date delivered to the Depository or the Nominee, as the case may be, at maturity against receipt of the Global Note. As long as the Depository or the Nominee is the registered owner of a Global Note, the Depository or the Nominee, as the case may be, will be considered the sole owner of the Global Note for the purposes of receiving payment on the Note and for all other purposes under the Trust Indenture and the Note.

The company expects that the Depository or Nominee, upon receipt of any payment of principal or interest in respect of a Global Note, will credit participants' accounts, on the date principal or interest is payable, with payments in amounts proportionate to their respective beneficial interests in the principal amount of such Global Note as shown on the records of the Depository or the Nominee. The company also expects that such payments of principal and interest by participants to the owners of beneficial interests in such Global Note held through such participants will be governed by standing instructions and customary practices, as is the case with securities held for the accounts of customers in bearer form or registered in "street name" and will be the responsibility of such participants. The responsibility and liability of the company and the Trustee in respect of Notes represented by Global Notes is limited to making payment of any principal and interest due on such Global Notes to the Depository or the Nominee.

Payments of interest and principal will be made in the currency in which the Note is denominated unless otherwise specified in the applicable prospectus supplement or pricing supplement.

If the payment date for any amount of principal or interest on any Note is not, at the place of payment, a business day such payment will be made on the next business day and the holder of such Note shall not be entitled to any further interest or other payment in respect of such delay.

Transfers

The registered holder of a Definitive Note may transfer such Note upon payment of taxes incidental thereto, if any, by executing the form of transfer provided on the reverse side of the Note and surrendering the Note to the Transfer Agent at its principal office in the City of Toronto, upon which one or more new Definitive Notes will be issued in authorized denominations in the same aggregate principal amount as the Note so transferred, registered in the name or names of the transferee or transferees.

Transfers of beneficial ownership in Notes represented by Global Notes will be effected through records maintained by the Depository for such Global Notes or the Nominee (with respect to the interest of participants) and on the records of participants (with respect to the interest of beneficial owners other than participants). Beneficial owners of an interest in a Note represented by a Global Note who are not participants in the Depository's book-entry system, but who desire to purchase, sell or otherwise transfer ownership of or other interests in Global Notes, may do so only through participants in the Depository's book-entry system. A purchaser's interest in a Note represented by a Global Note will only be exchangeable for Definitive Notes in the limited circumstances set forth under the heading "Global Notes" above and in accordance with the procedures established by the Depository or the Nominee.

The ability of a beneficial owner of an interest in a Note represented by a Global Note to pledge the Note or otherwise take action with respect to such owner's interest therein other than through a participant may be limited due to the lack of a physical certificate.

No transfer of a Note will be registered during the 10 business days immediately preceding any date fixed for payment of interest on such Note or payment of the principal amount thereof.

PLAN OF DISTRIBUTION

The Notes may be offered for sale severally and on a continuous basis by one or more of BMO Nesbitt Burns Inc., Casgrain & Company Limited, CIBC World Markets Inc., Desjardins Securities Inc., Laurentian Bank Securities Inc., National Bank Financial Inc., RBC Dominion Securities Inc., Scotia Capital Inc. and TD Securities Inc. pursuant to an agreement dated December 14, 2015, among such Dealers and the company (the "Dealer Agreement") or such other Dealers as may be selected from time to time by the company, in each case acting as agent of the company or as principal. Where the Notes are offered by the Dealer(s) as agent(s), the commission payable by the company shall be agreed from time to time between the company and any such Dealer(s). Where the Notes are purchased by the Dealer(s) as principal, the Notes shall be purchased at such prices and with such commissions as may be agreed from time to time between the company and any such Dealer(s) for resale to the public at prices to be negotiated with each purchaser. Such resale prices may vary during the distribution period and as between purchasers. Each Dealer's compensation will increase or decrease by the amount by which the aggregate price paid for Notes by purchasers exceeds or is less than the price paid by the Dealer, acting as principal, to the company. The commission payable in connection with sales of Notes shall be no higher than 1.5% and shall be set forth in a prospectus supplement or pricing supplement that shall accompany this short form prospectus. The company has agreed to reimburse the Dealers for certain expenses and to indemnify each Dealer against certain liabilities including liabilities under applicable Canadian securities laws.

The company may also offer the Notes directly to potential purchasers pursuant to applicable statutory exemptions at prices and upon terms negotiated between the purchaser and the company.

The company and, if applicable, the Dealers, reserve the right to reject any offer to purchase the Notes in whole or in part. The company also reserves the right to withdraw, cancel or modify the offering of the Notes under this short form prospectus without notice. In addition, the obligations of the Dealers to purchase any particular issue of Notes as principal may be terminated at the discretion of the Dealers upon the occurrence of certain stated events as set out in detail in the Dealer Agreement. However, the Dealers are obligated to take up and pay for all Notes of a particular issue if any of the Notes of that issue are purchased under the Dealer Agreement by the Dealers as principal.

In connection with any offering of Notes, the Dealers may, when acting as an agent or purchasing as principal, over-allot or effect transactions which stabilize or maintain the market price of the Notes offered at a level above that which might otherwise prevail in the open market. Such transactions, if commenced, may be discontinued at any time.

The Dealers may from time to time purchase and sell the Notes in the secondary market but are not obliged to do so. Unless otherwise indicated in a prospectus supplement or pricing supplement, there is no market through which Notes may be resold and purchasers may not be able to resell Notes purchased under this short form prospectus. The offering price and other selling terms for any sales in the secondary market may, from time to time, be varied by the Dealers.

The offering of Notes hereunder is directed only to residents of the provinces of Canada and in the United States in certain transactions exempt from the provisions of the United States Securities Act of 1933, as amended (the "**Securities Act**"). The Notes have not been and will not be registered under the Securities Act or any state securities laws and may not be offered or sold within the United States except to "qualified institutional buyers" in reliance upon Rule 144A under the Securities Act. In addition, until 40 days after the commencement of the offering of an issue of Notes, an offer or sale of that issue within the United States by any Dealer (whether or not participating in the offering) may violate the registration requirements of the Securities Act if such offer or sale is made otherwise than in accordance with an exemption under the Securities Act.

BMO Nesbitt Burns Inc., CIBC World Markets Inc., Desjardins Securities Inc., Laurentian Bank Securities Inc., National Bank Financial Inc., RBC Dominion Securities Inc., Scotia Capital Inc. and TD Securities Inc. are subsidiaries or affiliates of the HOI Lenders which are lenders to the company under the 2013 Credit Facility and the 2015 Credit Facility, and BMO Nesbitt Burns Inc., CIBC World Markets Inc., National Bank Financial Inc., RBC Dominion Securities Inc., Scotia Capital Inc. and TD Securities Inc. are subsidiaries or affiliates of the HOL Lenders which are lenders to HOL under the HOL Credit Facility. As of December 14, 2015, there is no outstanding indebtedness under the 2013 Credit Facility, the 2015 Credit Facility or the HOL Credit Facility. Proceeds from the sale of particular series or issues of Notes in which such Dealers are acting as principals or agents may be used to repay indebtedness under the Credit Facilities or any future credit facility to which the company may be a party with one or more of the Lenders and may be indirectly used to repay indebtedness under the HOL Credit Facility. Consequently, if and when there is outstanding indebtedness to any of the Lenders under such facilities, the company may be considered a connected issuer of those Dealers who are affiliates of such Lenders for purposes of the securities laws of certain Canadian provinces. The decision to distribute the Notes will be made by the company and the terms and conditions of distribution will be determined through negotiations between the company and the Dealers. The Lenders will not have any involvement in such decision or determination. As of the date hereof, the company is in compliance with the terms of each of the Credit Facilities. Other than payment of their portion of the commissions, if applicable, or as set forth above in respect of the Credit Facilities and/or the HOL Credit Facility, none of the proceeds of such offerings of Notes will be applied, directly or indirectly, for the benefit of BMO Nesbitt Burns Inc., CIBC World Markets Inc., Desjardins Securities Inc., Laurentian Bank Securities Inc., National Bank Financial Inc., RBC Dominion Securities Inc., Scotia Capital Inc. and TD Securities Inc. or their affiliates. See "Use of Proceeds".

USE OF PROCEEDS

The net proceeds from the sale of Notes will be added to the general funds of the company and, together with funding from other sources, including internally generated funds and other external financings, will be used to finance the company's working capital requirements, to repay outstanding bank loans (which may include indebtedness under the Credit Facilities), debentures, notes or other Indebtedness, to make advances to subsidiaries of the company, to finance the company's capital expenditure program, to make acquisitions and for other general corporate purposes. Where appropriate, a prospectus supplement or pricing supplement will contain more specific information about the use of proceeds from each sale of Notes. All expenses relating to an offering of Notes, including any compensation paid to the Dealers, will be paid out of the company's general funds or netted out of the proceeds of the particular offering of Notes. The company may from time to time issue debt instruments and incur additional Indebtedness otherwise than through the issue of Notes pursuant to this short form prospectus.

PRIOR SALES

In the 12-month period prior to the date hereof, the company issued the following tranche of medium term notes under its short form prospectus dated September 4, 2013:

Note	Date of Issuance	Principal Amount	Sale Price (per $100 principal amount)	Gross Proceeds
Series 33 (1.62%) due 2020	April 30, 2015	$350,000,000	$99.990	$349,965,000

CERTAIN CANADIAN FEDERAL INCOME TAX CONSIDERATIONS

General

The following summary describes the principal Canadian federal income tax considerations generally applicable to a purchaser who acquires Notes, including entitlement to all payments thereunder, as a beneficial owner pursuant to this short form prospectus and who, at all relevant times, for purposes of the application of the Tax Act, deals at arm's length with the company and holds Notes as capital property (a "Holder"). Generally, Notes will be capital property to a purchaser provided the purchaser does not acquire or hold those Notes in the course of carrying on a business or as part of an adventure or concern in the nature of trade. Certain purchasers resident in Canada may be entitled to make or may have already made the irrevocable election permitted by subsection 39(4) of the Tax Act the effect of which may be to deem to be capital property any Notes (and all other "Canadian securities", as defined in the Tax Act) owned by such purchasers in the taxation year in which the election is made and in all subsequent taxation years. Purchasers whose Notes might not otherwise be considered to be capital property should consult their own tax advisors concerning this election.

This summary is based on the current provisions of the Tax Act and on counsel's understanding of the current administrative policies and assessing practices of the Canada Revenue Agency published in writing prior to the date hereof. This summary takes into account all specific proposals to amend the Tax Act publicly announced by or on behalf of the Minister of Finance (Canada) prior to the date hereof (the "Proposed Amendments") and assumes that all Proposed Amendments will be enacted in the form proposed. However, no assurances can be given that the Proposed Amendments will be enacted as proposed, or at all. This summary does not otherwise take into account or anticipate any changes in law or administrative policy or assessing practice whether by legislative, administrative or judicial action nor does it take into account tax legislation or considerations of any province, territory or foreign jurisdiction, which may differ from those discussed herein.

Depending upon the terms of any offering of the Notes as set forth in an applicable prospectus supplement or pricing supplement, the Canadian federal income tax considerations applicable to a Holder of the Notes at the time of such offering may be different from those described below. Such considerations may be described more particularly when such Notes are offered (and then only to the extent material) in the prospectus supplement or pricing supplement related thereto. In the event the Canadian federal income tax considerations are described in such prospectus supplement or pricing supplement, the description below will be superseded by the description in the prospectus supplement or pricing supplement to the extent indicated therein.

This summary is of a general nature only and is not, and is not intended to be, legal or tax advice to any particular purchaser. This summary is not exhaustive of all Canadian federal income tax considerations. Accordingly, prospective purchasers of Notes should consult their own tax advisors having regard to their own particular circumstances.

Currency Conversion

For purposes of the Tax Act, all amounts relating to the acquisition, holding or disposition of the Notes issued in a non-Canadian currency must be converted into Canadian dollars based on exchange rates as determined in accordance with the Tax Act. The amount of interest required to be included in the income of, and capital gains or capital losses realized by, a Holder may be affected by fluctuations in the applicable exchange rate.

Holders Resident in Canada

This portion of the summary is generally applicable to a Holder who, at all relevant times, for purposes of the application of the Tax Act, is, or is deemed to be, resident in Canada, is not affiliated with the company and has not entered into and will not enter into, with respect to the Notes acquired by such Holder, a "derivative forward agreement" as defined in the Tax Act (a "Resident Holder").

This portion of the summary is not applicable to (i) a purchaser an interest in which is a "tax shelter investment", (ii) a purchaser that is, for purposes of certain rules (referred to as the mark-to-market rules) applicable to securities held by financial institutions, a "financial institution", or (iii) a purchaser that reports its "Canadian tax results" in a currency other than Canadian currency, each as defined in the Tax Act. Such purchasers should consult their own tax advisors.

Taxation of Interest and other Amounts

A Resident Holder that is a corporation, partnership, unit trust or any trust of which a corporation or partnership is a beneficiary will be required to include in computing its income for a taxation year any interest on a Note that accrues or is deemed to accrue to such Resident Holder to the end of that taxation year, or becomes receivable or is received by the Resident Holder before the end of such year, to the extent that such interest was not included in computing the Resident Holder's income for a preceding taxation year.

Any other Resident Holder, including an individual and a trust of which neither a partnership nor a corporation is a beneficiary, will be required to include in computing its income for a taxation year any interest on a Note that is received or receivable by such Resident Holder in that taxation year (depending on the method regularly followed by the Resident Holder in computing its income) to the extent that such interest was not included in computing the Resident Holder's income for a preceding taxation year. Such a Resident Holder may also be required to include in the Resident Holder's income, for any taxation year that includes an "anniversary day" (as defined in the Tax Act) of the Note, any interest, or amount that is considered for the purposes of the Tax Act to be interest, on the Note which accrues to the Resident Holder to the end of such day, to the extent that such interest was not otherwise included in computing the Resident Holder's income for the year or a preceding taxation year. For this purpose, an "anniversary day" means the day that is one year after the day immediately preceding the date of issue of a Note, the day that occurs at every successive one year interval from that day and the day on which a Note is disposed of.

Where a Resident Holder is required to include an amount on account of interest on a Note that accrued in respect of the period prior to its date of acquisition, the Resident Holder will be entitled to a deduction in computing income of an equivalent amount. The adjusted cost base to the Resident Holder of the Note will be reduced by the amount which is so deducted.

Any amount paid by the company to a Resident Holder as a premium, penalty or bonus because of early repayment of all or part of the principal amount of a Note before its maturity will be deemed to be received by the Resident Holder as interest on the Note at that time and will be required to be included in computing the Resident Holder's income as described above, to the extent such amount can reasonably be considered to relate to, and does not exceed the value at the time of payment of, interest that, but for the repayment, would have been paid or payable by the company on the Note for a taxation year of the company ending after that time.

Disposition of Notes

On a disposition or deemed disposition of a Note, including a redemption, repayment prior to or on maturity or repurchase, a Resident Holder will generally be required to include in computing its income for the taxation year in which the disposition occurs the amount of interest that has accrued, or that has been deemed to have accrued, on the Note to that time except to the extent that such amount has otherwise been included in the Resident Holder's income for the year or a preceding taxation year.

Generally, on a disposition or deemed disposition of a Note, including a redemption, payment on maturity or purchase for cancellation, a Resident Holder will realize a capital gain (or capital loss) equal to the amount, if any, by which the proceeds of disposition, net of any amount included in the Resident Holder's income as interest (as described above) and any reasonable costs of disposition, exceed (or are less than) the adjusted cost base to the Resident Holder of the Note immediately before the disposition or deemed disposition. Generally, a Resident Holder is required to include in computing its income for a taxation year one-half of the amount of any capital gain (a "taxable capital gain") realized in the year. Subject to and in accordance with the provisions of the Tax Act, a Resident Holder is required to deduct one-half of the amount of any capital loss (an "allowable capital loss") realized in a taxation year from taxable capital gains realized by the Resident Holder in the year and allowable capital losses in excess of taxable capital gains for the year may be carried back and deducted in any of the three preceding taxation years or carried forward and deducted in any subsequent taxation year against net taxable capital gains realized in such years.

Holders Not Resident in Canada

This portion of the summary is generally applicable to a Holder who, at all relevant times, for purposes of the application of the Tax Act (1) is not, and is not deemed to be, resident in Canada, (2) deals at arm's length with any transferee resident (or deemed to be resident) in Canada to whom the Holder disposes of the Notes, and (3) does not use or hold the Notes in a business carried on or deemed to be carried on in Canada (a "Non-Resident Holder"). Special rules, which are not discussed in this summary, may apply to a Non-Resident Holder that is an insurer that carries on an insurance business in Canada and elsewhere.

This summary assumes that no interest paid on the Notes will be in respect of a debt or other obligation to pay an amount to a person with whom the company does not deal at arm's length, within the meaning of the Tax Act.

This portion of the summary is not applicable to a Non-Resident Holder that is a "specified shareholder" (as defined in subsection 18(5) the Tax Act) of the company or that does not deal at arm's length for purposes of the Tax Act with a "specified shareholder" of the company. Generally, for this purpose, a "specified shareholder" is a shareholder that owns or is deemed to own, either alone or together with persons with which the shareholder does not deal at arm's length for purposes of the Tax Act, shares of the company's capital stock that either (i) give such shareholders 25% or more of the votes that could be cast at an annual meeting of the shareholders or (ii) have a fair market value of 25% or more of the fair market value of all of the issued and outstanding shares of the company's capital stock. Such Non-Resident Holders should consult their own tax advisors.

No Canadian withholding tax will apply to interest, principal or premium paid or credited to a Non-Resident Holder by the company on a Note or to the proceeds received by a Non-Resident Holder on the disposition of a Note including a redemption, repayment prior to or on maturity or repurchase, unless all or any portion of such interest is contingent or dependent on the use of or production from property in Canada or is computed by reference to revenue, profit, cash flow, commodity price or any other similar criterion or by reference to dividends paid or payable to shareholders of any class of shares of the capital stock of a corporation (the "Participating Debt Interest"). The interest on Fixed Rate Notes, and on Floating Rate Notes in respect of which the payment of interest is determined by reference to published rates of a central banking authority or one or more financial institutions, or to recognized market benchmark interest rates or to interest rates on Government of Canada bonds is not Participating Debt Interest and, as such, no Canadian withholding tax will apply to interest paid or credited or deemed to be paid or credited on such Notes.

Generally, no other Canadian federal taxes on income or gains will be payable by a Non-Resident Holder on interest, principal or premium paid or credited to a Non-Resident Holder by the company on a Note or on the proceeds received by a Non-Resident Holder on the disposition of a Note including a redemption, repayment prior to or on maturity or repurchase.

RISK FACTORS

In addition to the other information contained and incorporated by reference in this short form prospectus, a purchaser should consult its own financial and legal advisors and should carefully consider the following risk factors before investing in the Notes. Notes will not be an appropriate investment for a purchaser if the purchaser does not understand the terms of the Notes or financial matters in general. A purchaser should not purchase Notes unless the purchaser understands, and can bear, all of the investment risks involving the Notes. For a discussion of the risks to which the company's business and industry are subject, please see the section entitled "Risk Factors" in the company's annual information form, the section entitled "Risk Management and Risk Factors" in the company's annual MD&A and the section entitled "Risk Factors" in the HOL Prospectus (excluding the disclosure under the subheading "Risks Relating to this Offering") and, for financial years ending on or after December 31, 2015, please see the section entitled "Risk Factors" in the company's annual information form and the section entitled "Risk Management and Risk Factors" in the company's annual MD&A. In addition to those risks, an investment in the Notes is subject to the following additional risks:

The Company Must Receive Dividends and Other Payments from Its Subsidiaries in Order to Make Payments to Holders of Notes

The company is a holding company that has no significant assets or operations other than the debt and equity of its subsidiaries. The company's most significant subsidiary is Hydro One Networks Inc., a regulated wholly-owned subsidiary which owns and operates the company's transmission and distribution assets. The company is dependent on dividends, interest, loans and other payments from this and other subsidiaries to meet its debt service and other obligations.

The company's subsidiaries are separate legal entities and have no obligation to pay any amounts due under the Notes and, except for their respective obligations under existing intercompany debt obligations owing to the company, have no obligation to make funds available to the company, whether by dividends, interest, loans or other payments. In addition, these subsidiaries have not guaranteed the Notes. In the event of bankruptcy, liquidation or reorganization of any of the company's subsidiaries, the creditors of these subsidiaries will generally be entitled to the payment of their claims before any assets are made available for distribution to the company, except to the extent that the company is recognized as a creditor of those subsidiaries.

The company's subsidiaries currently are not restricted in terms of their ability to pay dividends or make other payments to the company, other than by solvency provisions under generally applicable Ontario corporate law or partnership law, as applicable. However, they could become so restricted in the future by, among other things, other laws as well as agreements to which they may become parties in the future.

There May Be No Trading Market for the Notes and if One Develops, the Notes May Be Subject to Trading Price Fluctuations

The Notes are new issues of securities for which, unless otherwise indicated in a prospectus supplement or pricing supplement, there is no existing trading market. The company cannot predict whether any active trading market will develop for the Notes, even if the Notes are listed on a stock exchange.

Even if an active trading market develops for the Notes, the Notes could trade at prices that may be higher or lower than their initial offering prices, depending on many factors, including prevailing interest rates, the company's results of operations and financial position, the ratings assigned to the Notes and the company's other debt securities, and the markets for similar debt securities.

If a holder of Notes sells any Notes before their maturity, such holder may have to do so at a substantial discount from the issue price, and as a result such holder may suffer substantial losses.

Investors May Be Subject to the Risk of Exchange Rate Fluctuations

An investment in Notes that are denominated or payable in a currency other than the functional currency of the investor entails significant risks that are not associated with a similar investment in a security denominated in the functional currency of the investor. Such risks include, without limitation, the possibility of significant changes in rates of exchange between the two currencies, the possibility of the imposition or modification of foreign exchange controls in respect of one or both of the currencies, and potential illiquidity in the secondary market. These risks generally depend on circumstances over which the company has no control including political events, government policy and macroeconomic conditions. These risks will vary depending upon the currency or currencies involved and, where appropriate, will be more fully described in a prospectus supplement or pricing supplement.

In certain circumstances, investors may receive payments in currencies other than the currency in which the Notes are denominated. This may subject investors to exchange rate risk in respect of the conversion of principal and interest payments on the Notes from the currency in which the Notes are denominated to the currency of the payment which they receive, and they may also bear any costs of conversion incurred in connection therewith. For example, to the extent the company makes a series of Notes eligible with DTC, investors who hold such Notes through DTC where CDS acts as Depository and who do not elect to receive principal and interest payments in Canadian dollars will be subject to exchange rate risk in respect of the conversion of Canadian dollar principal and interest payments to U.S. dollars, and will also bear any costs of conversion incurred in connection therewith.

The Notes will be governed by and construed in accordance with the laws of the Province of Ontario and the laws of Canada applicable therein. A judgment by a Canadian court relating to any Note may be awarded only in Canadian currency and such judgment may be based on a rate of exchange in existence on a day other than the day of payment.

This short form prospectus does not describe all the risks of an investment in the Notes denominated or payable in a currency other than an investor’s functional currency, and prospective investors should consult their own financial and legal advisor as to the risks entailed with respect thereto. Notes denominated in currencies other than an investor’s functional currency are not appropriate investments for investors who are unfamiliar with foreign currency transactions.

Changes in Interest Rates Will Affect the Market Price or Value of the Notes

Generally, the market price or value of the Notes will decline as prevailing interest rates for comparable debt instruments rise, and increase as prevailing interest rates for comparable debt instruments decline. Fluctuations in interest rates may also impact borrowing costs of the company which may adversely affect its creditworthiness. It is impossible to predict whether interest rates will rise or fall.

Changes in Creditworthiness or Credit Ratings May Affect the Market Price or Value of the Notes

The perceived creditworthiness of the company and changes in credit ratings of the Notes may affect the market price or value and the liquidity of the Notes. In addition, negative changes in the company’s credit rating may affect the credit ratings of the Notes.

Floating Rate Notes Are, By Their Nature, Uncertain

Investments in Floating Rate Notes entail risks not associated with investments in Fixed Rate Notes. The resetting of the applicable rate on a Floating Rate Note may result in a lower interest rate as compared to a Fixed Rate Note issued at the same time. The applicable rate on a Floating Rate Note will fluctuate in accordance with fluctuations in the instrument or obligation or other measure on which the applicable rate is based, which in turn may fluctuate and be affected by a number of interrelated factors, including economic, financial and political events over which the company has no control.

The Notes May Be Subject to Early Redemption

Depending on the terms of the Notes, the company may have the right to redeem them, or the Notes may be automatically redeemable under some circumstances. If the Notes are redeemed, depending on the market conditions at the time of redemption, a holder of Notes may not be able to reinvest the redemption proceeds in a security with a comparable return.

LEGAL MATTERS

Certain legal matters in connection with any offering hereunder will be passed upon by Osler, Hoskin & Harcourt LLP for the company and by Blake, Cassels & Graydon LLP for the Dealers. The partners and associates of Osler, Hoskin & Harcourt LLP and Blake, Cassels & Graydon LLP beneficially own, directly or indirectly, less than one percent of the securities of the company or any associate or affiliate of the company.

AUDITORS, REGISTRAR AND TRANSFER AGENT

KPMG LLP, Chartered Professional Accountants, Licensed Public Accountants, located at 333 Bay Street, Suite 4600, Bay Adelaide Centre, Toronto, Ontario M5H 2S5, is the auditor of the company and has confirmed that it is independent of the company within the meaning of the relevant rules and related interpretations prescribed by the relevant professional bodies in Canada and any applicable legislation or regulation.

Registers for the registration and transfer of the Notes issued in registered form are kept at the principal offices of the Transfer Agent in the City of Toronto.

PURCHASERS' STATUTORY AND CONTRACTUAL RIGHTS

Securities legislation in certain of the provinces of Canada provides purchasers with the right to withdraw from an agreement to purchase securities. This right may be exercised within two business days after receipt or deemed receipt of a prospectus and any amendment. In several of the provinces, the securities legislation further provides a purchaser with remedies for rescission or, in some jurisdictions, revision of the price or damages if the prospectus and any amendment contains a misrepresentation or is not delivered to the purchaser, provided that the remedies for rescission, revision of the price or damages are exercised by the purchaser within the time limit prescribed by the securities legislation of the purchaser's province. The purchaser should refer to any applicable provisions of the securities legislation of the purchaser's province for the particulars of these rights or consult with a legal adviser.

AGENT FOR SERVICE OF PROCESS IN CANADA

Kathryn Jackson, a director of the company, resides outside of Canada. Ms. Jackson has appointed Hydro One Inc., 483 Bay Street, 8th Floor, South Tower, Toronto, Ontario, M5G 2P5, Canada, as agent for service of process in Canada. Purchasers are advised that it may not be possible for investors to enforce judgments obtained in Canada against any person or company that is incorporated, continued or otherwise organized under the laws of a foreign jurisdiction or resides outside of Canada, even if the party has appointed an agent for service of process.

CERTIFICATE OF HYDRO ONE INC.

Dated: December 14, 2015

This short form prospectus, together with the documents incorporated in this short form prospectus by reference, will, as of the date of the last supplement to this short form prospectus relating to the securities offered by this short form prospectus and the supplement(s), constitute full, true and plain disclosure of all material facts relating to the securities offered by this short form prospectus and the supplement(s) as required by the securities legislation of all of the provinces of Canada.

(Signed) Mayo Schmidt President and Chief Executive Officer	(Signed) Michael Vels Chief Financial Officer

On behalf of the Board of Directors:

(Signed) David Denison Director	(Signed) Christie J.B. Clark Director

CERTIFICATE OF DEALERS

Dated: December 14, 2015

To the best of our knowledge, information and belief, this short form prospectus, together with the documents incorporated in this short form prospectus by reference will, as of the date of the last supplement to this short form prospectus relating to the securities offered by this short form prospectus and the supplement(s), constitute full, true and plain disclosure of all material facts relating to the securities offered by this short form prospectus and the supplement(s) as required by the securities legislation of all the provinces of Canada.

BMO NESBITT BURNS INC.	CASGRAIN & COMPANY LIMITED	CIBC WORLD MARKETS INC.
By: (Signed) Grant Williams	By: (Signed) Stephen McHarg	By: (Signed) David Williams
DESJARDINS SECURITIES INC.	LAURENTIAN BANK SECURITIES INC.	NATIONAL BANK FINANCIAL INC.
By: (Signed) Ryan Godfrey	By: (Signed) Michel Richard	By: (Signed) John B. Carrique
RBC DOMINION SECURITIES INC.	SCOTIA CAPITAL INC.	TD SECURITIES INC.
By: (Signed) Robert M. Brown	By: (Signed) Murray Neal	By: (Signed) Greg McDonald

DISTRIBUTOR CONSOLIDATION

Since the last rebasing of its rates for 2015-2017, Hydro One Distribution has acquired three distribution companies – Norfolk Power Distribution Inc., Haldimand County Hydro Inc., and Woodstock Hydro Services Inc. (together the "Acquired Utilities"). The Acquired Utilities are now fully integrated into the operations of Hydro One Distribution.

1. TREATMENT OF PREMIUM PAID

Hydro One Inc. was the entity that acquired each of the three distribution companies. The premium on these acquisitions was paid by Hydro One's shareholder, and has not and will not be recovered from customers. Further discussion regarding the goodwill associated with the Norfolk transaction is available in Note 4 to Hydro One Networks Inc. Distribution Business' 2015 Financial Statements, which is filed as Exhibit A, Tab 6, Schedule 2, Attachment 2. The Haldimand and Woodstock transactions will be accounted for in the same manner, which will be identified in the 2016 Financial Statements, when available.

2. MAAD CONDITIONS OF APPROVAL

2.1 NORFOLK POWER DISTRIBUTION INC.

On July 3, 2014, the OEB approved the acquisition by Hydro One Inc. of Norfolk Power Inc., the owner of Norfolk Power Distribution Inc. ("NPDI"), and the subsequent transfer of NPDI's electricity distribution system to Hydro One Networks Inc. (EB-2013-0196/0187/0198) ("NPDI MAAD Decision"). The acquisition closed on August 29, 2014, and the NPDI distribution system was transferred to Hydro One on September 1, 2015, with Hydro One assuming all operations and asset management activities.

The NPDI MAAD Decision approved a five-year deferred rebasing period and "the Applicant's proposal that rate rebasing of the consolidated entity be deferred until approval of 2020 rates."[1] Hydro One submitted in its MAAD application that compared to NPDI's status quo operations, the aggregate expected savings resulting from the transaction for 10 years was between $38-$58 million[2] with ongoing net annual cost savings of approximately $3 million in OM&A, and approximately $2 million in capital expenditures.[3]

The following Condition of Approval was included in the NPDI MAAD Decision:

> *That with the first rates application that includes costs associated with NPDI's service area, HONI file a report with the Board delineating:*
> *a) The costs for NPDI's service area, tracked separately;*
> *b) The savings achieved as a result of the acquisition; and*
> *c) The portion of NPDI's and HONI's costs that are incremental costs incurred in connection with the acquisition.*[4]

2.1.1 NPDI REPORTING

Table 1 below provides the information requested in Conditions (a) and (b) above illustrating the incremental costs attributed to serving NPDI since the time of acquisition as compared to the status quo forecast provided in the MAAD Application.[5]

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[1] EB-2013-0196/0187/0198 Decision and Order, July 3, 2014, page 14
[2] IBID, page 19
[3] EB-2013-0196/0187/0198, Exhibit I, Tab 2, Schedule 2
[4] NPDI MAAD Decision, page 25
[5] EB-2013-0198/0187/0198, Exhibit I, Tab 2, Schedule 2, page 7

TABLE 1: NPDI SERVICE AREA SAVINGS

$/Million	2014	2015	2016
OM&A			
Status Quo Forecast	5.7	5.8	5.9
Hydro One MAAD Application Forecast	5.8	2.6	2.7
Hydro One Actual (2016 Forecast)	7.2	5.9	2.8
Projected Savings	(0.1)	3.2	3.2
Actual Savings	(1.5)	(0.1)	3.1
Capital			
Status Quo Forecast	5.0	4.7	4.6
Hydro One Forecast	3.1	2.9	2.9
Hydro One Actual (2016 Forecast)	3.5	2.1	2.4
Projected Savings	1.9	1.8	1.7
Actual Savings	1.5	2.6	2.0

OM&A cost savings in 2014 did not materialize as anticipated, due to a later than scheduled transaction closing date. This delay also impacted realized savings in 2015 as NPDI's full integration into Hydro One's distribution business was not completed until August 2015. The 2015 financial results are based on eight months of NPDI operating as a separate entity and four months operating as fully integrated into Hydro One's distribution business, thereby achieving only partial savings for the year. The first full year period of tracked costs for NPDI once fully integrated into Hydro One was 2016.

The third reporting requirement was in reference to incremental transaction costs. These "costs are to be borne by the purchaser and are to be covered by the savings that will accrue during the five-year rate setting deferral period[6]". Hydro One confirms that these costs have not and will not be included in any revenue requirement of Hydro One. The total incremental transaction costs relating to acquisition costs (excluding premium) and integration of NPDI into Hydro One are $6.4 million. This includes third-party advisory costs, information system costs (customers, finance and outage management systems), data integration and costs associated with bringing NPDI asset data into Hydro One's systems to operate the assets and serve customers.

2.2 HALDIMAND COUNTY HYDRO INC.

On March 12, 2015, the OEB approved the acquisition by Hydro One Inc. of all of the issued and outstanding shares of Haldimand County Utilities Inc., the owner of Haldimand County Hydro Inc. ("HCHI"), and the subsequent transfer of HCHI's electricity distribution system to Hydro One Networks Inc. (EB-2014-0244) ("HCHI MAAD Decision"). The acquisition closed on June 30, 2015, and the HCHI distribution system was transferred to Hydro One on September 1, 2016, with Hydro One assuming all operations and asset management activities.

The HCHI MAAD Decision approved a five-year deferred rebasing period from the closing of the proposed transaction. Hydro One, in the MAAD application, forecast ongoing net annual cost savings of over $4.0 million in OM&A and over $1.5 million in capital expenditure costs[7].

[6] EB-2013-0196/0187/0198 Decision and Order, July 3, 2014, page 22
[7] EB-2014-0244 Decision and Order, March 12, 2015, section 3.1.1., page 1

The following Condition of Approval was included in the HCHI MAAD Decision:

> *That, with its first rate application that includes costs associated with Haldimand's service area, HONI file a report with the OEB delineating:*
> *a) The costs for Haldimand's service area, tracked separately; and*
> *b) The savings achieved as a result of the acquisition.*

2.2.1 HCHI REPORTING

Table 2 provides the information requested in Conditions (a) and (b) above illustrating the incremental costs attributed to serving HCHI since the time of acquisition compared to the status quo forecast provided in the MAAD Application.

TABLE 2: HCHI SERVICE AREA SAVINGS

$/Million	2015	2016
OM&A		
Status Quo Forecast	8.2	8.3
Hydro One MAAD Application Forecast	6.4	4.4
Hydro One Actual (2016 Forecast)	7.7	6.0
Projected Savings	1.8	4.0
Actual Savings	0.5	2.3
Capital		
Status Quo Forecast	6.4	6.1
Hydro One Forecast	4.2	3.2
Hydro One Actual (2016 Forecast)[8]	6.9	3.1
Projected Savings	2.2	2.9
Actual Savings	(0.5)	3.2

[8] 2016 forecast numbers will be updated with 2016 actuals when Hydro One files its Blue Page update, currently planned for early June.

The 2015 actual results reflect six months of HCHI operating under the ownership of Haldimand County Utilities Inc., and the remaining half of the year operating under the ownership of Hydro One, but not fully integrated into its distribution business, thereby reducing achieved savings. The 2016 forecast includes eight months of costs for the former HCHI service area operating as a separate entity and four months of costs operating fully integrated into Hydro One.

2.3 WOODSTOCK HYDRO SERVICES INC.

On September 11, 2015, the OEB approved the acquisition by Hydro One Inc. of all of the issued and outstanding shares of Woodstock Hydro Holdings Inc., the owner of Woodstock Hydro Services Inc. ("WHSI"), and the subsequent transfer of WHSI's electricity distribution system to Hydro One Networks Inc. (EB-2014-0213) ("WHSI MAAD Decision"). The acquisition closed on October 31, 2015, and the distribution system of WHSI was transferred to Hydro One on September 1, 2016, with Hydro One assuming all operations and asset management activities.

The WHSI MAAD Decision approved a five-year deferred rebasing period from the closing of the proposed transaction. Hydro One, in the MAAD application, forecast ongoing net annual cost savings of approximately $3.0 million in OM&A and approximately $1.0 million in capital expenditure costs[9].

[9] EB-2014-0213, Decision and Order, Page 8

The following Condition of Approval was included in the WHSI MAAD Decision:

> *That Hydro One reports on the following, until Hydro One applies for new rates for existing Woodstock customers:*
>
> *a) All costs (including overhead corporate costs) associated with serving the Woodstock service area, recorded and reported both on an annual and cumulative basis from the time of the closing of the share purchase transaction;*
>
> *b) Actual savings achieved (being the difference between the total costs in a) and the costs of Woodstock as a stand-alone utility); and*
>
> *c) Indication of how those savings have or will be allocated.*

TABLE 3: WHSI SERVICE AREA SAVINGS

$/Million	2015	2016
OM&A Status Quo Forecast	3.9	4.6
Hydro One MAAD Application Forecast (excluding overhead corporate costs)	1.7	2.2
Hydro One Actual (excluding overhead corporate costs) (2016 Forecast)	4.2	3.8
Hydro One Actual (including overhead corporate costs) (2016 Forecast)	N/A[10]	3.9
Projected Savings	2.3	2.3
Actual Savings (excluding overheads)	(0.3)	1.1
Actual Savings (including overheads)	N/A	
Capital Status Quo Forecast	2.4	2.5

[10] As WHSI was not fully integrated into Hydro One's operations in 2015 it was essentially operating as "status quo". As a result, no corporate overhead costs were applied.

$/Million	2015	2016
Hydro One MAAD Application Forecast (excluding overhead corporate costs)	2.2	2.9
Hydro One Actual (excluding overhead corporate costs) (2016 Forecast)	2.2	2.5
Hydro One Actual (including overhead corporate costs) (2016 Forecast)	N/A[10]	2.6
Projected Savings	0.2	(0.5)
Actual Savings (excluding overhead corporate costs)	0.2	-
Actual Savings (including overhead corporate costs)	N/A	

The 2015 actual results reflect ten months of WHSI operating under the ownership of Woodstock Hydro Holdings Inc., and two months operating under the ownership of Hydro One, but not fully integrated into its distribution business. The 2016 forecast includes eight months of costs for the former WHSI service area operating as a separate entity and four months of costs operating fully integrated into Hydro One.

Hydro One has provided the savings both with and without overhead corporate costs. The "without" costs show results consistent with the costs presented in the MAAD Application.

3. INDUCEMENTS

There were no inducements or incentives beyond the purchase price to encourage a shareholder to agree to the consolidation.

4. RATE HARMONIZATION

Hydro One is now requesting approval, to create new customer rate classes for the former customers of NPDI, HCHI and WHSI. These rate classes will reflect the cost to serve the acquired customers, including anticipated productivity gains resulting from consolidation. Information on the new proposed customer rate classes is available in Exhibit G1, Tab 2, Schedule 1 "Customer Classification".

Each of the acquired customer groups had their previous OEB-approved base distribution rates frozen for a period of five years with a 1% decrease in that rate applied through a rate rider. The rate riders are reflected in their current-approved rate schedules with the following expiration dates:

- NPDI: September 7, 2019;
- HCHI: June 30, 2020; and
- WHSI: October 30, 2020.

Hydro One proposes to move the acquired customers to their new rate classes January 1, 2021. As discussed in Exhibit G1, Tab 2, Schedule 1, the former customers of NPDI and HCHI will be moved to the new "Acquired Mixed Density" rate classes and the former WHSI customers will be moved to the new "Acquired Urban" rate classes. In order to promote rate stability and predictability, Hydro One has not created a utility-specific rate class reflecting costs only for former NPDI customers in 2020. Instead, the proposed 2021 rates will reflect the combined costs to serve both NPDI and HCHI former customers. If new classes were established first for NPDI, and then adjusted one year later to include the costs to serve HCHI, former NPDI customers would experience an unnessary and undesirable instability in their rates over that two-year period.

All of the Acquired Utilities' rate freeze periods end prior to the new rate classes taking effect on January 1, 2021. As a result, Hydro One proposes to extend each of their Rate Riders, which reflect a 1% reduction in their base distribution rates, until December 31, 2020.

5. REVENUE REQUIREMENT ADJUSTMENT FOR ACQUIRED UTILITIES IN YEAR 2021

Hydro One's Custom IR application is determined using a cost of service revenue requirement in 2018 followed by a Revenue Cap Index (RCI) in Years 2 through 5. This approach (as described in Exhibit A, Tab 3, Schedule 2) will be utilized to establish rates for the acquired customer new rate classes commencing in Year 4.

5.1 OM&A ADJUSTMENT

Table 4 provides the last approved OM&A for each of the Acquired Utilities, actual OM&A for 2014 to 2016, and forecast OM&A for 2017 and 2018. Both of the actual and forecast amounts provided depict incremental costs only. For rate making purposes in 2021, overhead allocations will be applied to determine cost-based rates. The 2018 OM&A forecast will then be increased by 1.3% per annum, the proposed Inflation less Productivity Factor[11], resulting in a $10.7M increase in the OM&A revenue requirement components in 2021, as shown in Table 1 of Exhibit A, Tab 3, Schedule 2.

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[11] See Exhibit A, Tab 3, Schedule 2

TABLE 4: OM&A CALCULATION ($M)

	OEB Approved		2014	2015	2016	2017F	2018F
NPDI	2012	5.7	7.2	5.9	2.8	3.1	3.1
HCHI	2014	8.2	7.5	7.7	6.0	5.0	5.1
WHSI	2011	4.0	4.1	4.2	3.8	2.1	2.1
Total							$10.3

5.2 CAPITAL FACTOR ADJUSTMENT

The gross fixed assets and accumulated depreciation of the Acquired Utilities has been added to the opening balance of Hydro One's gross fixed assets and accumulated depreciation effective January 1, 2021. This results in an increase in the opening balance of net fixed assets of $151.1 million, on January 1, 2021. In addition, $14.9 million of working capital is reflected in the 2021 rate base. These changes are included in Exhibit D1, Tab 1, Schedule 1 and Exhibit D2, Tab 1 Schedule 1. This increase in Hydro One Distribution rate base is captured in the Revenue Requirement through the Capital Factor as described in Exhibit A, Tab 3, Schedule 2. Details on the capital expenditures for each utility are found in Appendix A of the Distribution System Plan (Exhibit B1, Tab 1, Schedule 1).

DRAFT ISSUES LIST

1.0		**CUSTOM APPLICATION**
1.1		Has Hydro One responded appropriately to all relevant OEB directions from previous proceedings, including commitments from prior settlement agreements?
1.2		Do any of Hydro One's proposed rates require rate smoothing or mitigation?
1.3		Is Hydro One's proposed Custom IR methodology consistent with the OEB's *Renewed Regulatory Framework* ("RRF Report")?
1.4		Are the values for its Custom Capital Factor appropriate?
1.5		Is Hydro One's proposed integration of Acquired Utilities for regulatory purposes adequate?
2.0		**OUTCOMES AND INCENTIVES**
2.1		Does Hydro One's Application promote and incent acceptable outcomes for existing and future customers (including, for example, cost control, system reliability, service quality, and bill impacts)?
2.2		Does the Application adequately incorporate and reflect the four outcomes identified in the RRF Report: (1) customer focus; (2) operational effectiveness; (3) public policy responsiveness; and (4) financial performance?
2.3		Does the Application adequately account for productivity gains in its forecasts? Does the Application adequately include expectations for gains relative to benchmarks that are external to the Company?
2.4		Does the Application adequately plan and pace capital expenditures?
2.5		Is the Applicant's proposal for performance monitoring and reporting adequate to demonstrate whether its planned outcomes are achieved?
2.6		Are the Applicant's proposed off-ramps and mid-term adjustments appropriate?
2.7		Has the Applicant adequately demonstrated its ability and commitment to

		manage within the revenue requirement set by this proceeding, given that actual costs and revenues will vary from those forecast?
3.0		**REVENUE REQUIREMENT**
3.1		Are the rate base values for 2018 – 2022, including the working capital allowances, as set out in the Application appropriate?
3.2		Is the Distribution System Plan for 2018 – 2022, as set out in the Application, appropriate considering the factors listed below? • Customer feedback and preferences • Productivity and benefit sharing • Cost benchmarking • Asset condition • Reliability and service quality • Impact on distribution rates • Trade-offs with OM&A spending • Government-mandated obligations • The Applicant's objectives
3.3		Is the capital structure and cost of capital component of the revenue requirement for 2018 – 2022 as set out in the Application appropriate?
3.4		Is the depreciation component of the revenue requirement for 2018 – 2022 as set out in the Application appropriate?
3.5		Is the taxes / PILs component of the revenue requirement for 2018 – 2022 as set out in the Application appropriate?
3.6		Are the OM&A programs and related components of the revenue requirement for 2018 – 2022 as set out in the Application appropriate? Is the rationale for planning choices appropriate and adequately explained and supported considering: • Customer feedback and preferences • Productivity and benefit sharing • Cost benchmarking • Asset condition

		• Reliability and service quality • Impact on distribution rates • Trade-offs with capital spending • Government-mandated obligations • The Applicant's objectives
3.7		Is the compensation strategy for 2018 – 2022 appropriate?
3.8		Are the proposed other revenues for 2018 – 2022 appropriate?
4.0		**LOAD FORECAST, COST ALLOCATION AND RATE DESIGN**
4.1		Is the load forecast, including the application of CDM savings and setting of the savings references for the LRAMVA appropriate?
4.2		Have customers of the Acquired Utilities been appropriately integrated into the Applicant's customer classes? Are the proposed new customer classes appropriate?
4.3		Are the proposed billing determinants appropriate?
4.4		Are the inputs to the cost allocation model appropriate?
4.5		Are the costs appropriately allocated?
4.6		Are the revenue-to-cost ratios for all rate classes over the 2018 – 2022 period appropriate?
4.7		Are the proposed fixed and variable charges for all rate classes over the 2018 – 2022 period appropriate?
4.8		Are the proposed Retail Transmission Service Rates appropriate?
4.9		Are the proposed specific service charges for miscellaneous services over the 2018 – 2022 period reasonable?
4.10		Are the proposed line losses over the 2018 – 2022 period appropriate?
4.11		Are the customers and load forecasts a reasonable reflection of the energy and demand requirements for 2018 – 2022?

5.0		**DEFERRAL AND VARIANCE ACCOUNTS**
5.1		Should the existing deferral and variance accounts proposed for continuation be continued?
5.2		Are the proposed new deferral and variance accounts reasonable?
5.3		Are the balances and the proposed methods for disposing of the balances in the existing deferral and variance accounts, appropriate?
5.4		Are the Applicant’s proposed rate riders appropriate?

LIST OF WITNESSES

The list of witnesses will be provided in advance of the oral hearing in this proceeding.

CURRICULA VITAE

Curricula Vitae information will be filed prior to the oral hearing.

NOTICES, PROCEDURAL ORDERS, CORRESPONDENCE

Notices, Procedural Orders, and Correspondence will be filed after this Application is submitted.

Witness: Oded Hubert