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Frank D'Andrea
Vice President, Chief Regulatory Officer,
Chief Risk Officer

BY COURIER

May 4, 2018

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 Distribution 2018-2022 Rate Application – Interrogatory Response Update for 2017 Financial Information

On February 12, 2018 Hydro One filed responses to interrogatories from OEB Staff and intervernors. Where interrogatories requested information related to the 2017 year end results, Hydro One indicated the information was not available at that time, but would update the response when the information was finalized. Hydro One now submits the updated responses to include the requested 2017 year end results.

This filing has been submitted electronically using the Board's Regulatory Electronic Submission System and two (2) hard copies will be sent via courier.

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

Sincerely,

ORIGINAL SIGNED BY FRANK D'ANDREA

Frank D'Andrea

Encls.
cc. EB-2017-0049 parties (electronic)

The Society of Energy Professionals Interrogatory # 1

Issue:

Issue 1: Has Hydro One responded appropriately to all relevant OEB directions from previous proceedings?

Reference:

None

Interrogatory:

Please file Hydro One's relevant updated financial reports as they become publicly available including quarterly and annual MD&A and consolidated financial statements, Networks Distribution annual financial statements, credit rating reports etc.

Response:

Please refer to Exhibit I-32-BOMA-B153 Attachments 1 to 9 for Hydro One Limited and Hydro One Inc. MD&A and consolidated financial statements for Q1, Q2 and Q3 of 2017.

2017 HOI and HOL Financial Statements and MD&A are provided as attachments to this Exhibit:
Attachment 1 – 2017 HOI Financial Statements
Attachment 2 – 2017 HOI MD&A
Attachment 3 – 2017 HOL Financial Statements
Attachment 4 – 2017 HOL MD&A
Attachment 5 – 2017 Distribution Business Financial Statements

Please refer to Exhibit I-36-BOMA-B156 Attachments 1 to 7 for rating agency reports by DBRS, Moody's and S&P, released since those included in the prefiled evidence.

Witness: CHHELAVDA Samir

The Consolidated Financial Statements, Management's Discussion and Analysis (MD&A) and related financial information have been prepared by the management of Hydro One Inc. (Hydro One or the Company). Management is responsible for the integrity, consistency and reliability of all such information presented. The Consolidated Financial Statements have been prepared in accordance with United States Generally Accepted Accounting Principles and applicable securities legislation. The MD&A has been prepared in accordance with National Instrument 51-102.

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 12, 2018.

Management is responsible for establishing and maintaining adequate disclosure controls and procedures and internal control over financial reporting as described in the annual MD&A. Management evaluated the effectiveness of the design and operation of internal control over financial reporting based on the framework and criteria established in the Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on that evaluation, management concluded that the Company's internal control over financial reporting was effective at a reasonable level of assurance as of December 31, 2017. As required, the results of that evaluation were reported to the Audit Committee of the Hydro One Board of Directors and the external auditors.

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 control over reporting and disclosure. 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.

On behalf of Hydro One's management:

Mayo Schmidt
President and Chief Executive Officer

Christopher Lopez
Senior Vice President, Finance
acting in the capacity of chief financial officer

To the Shareholder of Hydro One Inc.

We have audited the accompanying consolidated financial statements of Hydro One Inc., which comprise the consolidated balance sheets as at December 31, 2017 and December 31, 2016, 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 Inc. as at December 31, 2017 and December 31, 2016, 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 12, 2018

HYDRO ONE INC.
CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME
For the years ended December 31, 2017 and 2016

Year ended December 31 *(millions of Canadian dollars, except per share amounts)*	2017	2016
Revenues		
Distribution (includes $279 related party revenues; 2016 – $160) *(Note 26)*	4,366	4,915
Transmission (includes $1,526 related party revenues; 2016 – $1,556) *(Note 26)*	1,581	1,587
	5,947	6,502
Costs		
Purchased power (includes $1,594 related party costs; 2016 – $2,103) *(Note 26)*	2,875	3,427
Operation, maintenance and administration *(Note 26)*	1,014	1,043
Depreciation and amortization *(Note 5)*	810	769
	4,699	5,239
Income before financing charges and income taxes	**1,248**	**1,263**
Financing charges *(Note 6)*	411	392
Income before income taxes	**837**	**871**
Income taxes *(Note 7)*	120	135
Net income	**717**	**736**
Other comprehensive income	—	—
Comprehensive income	**717**	**736**
Net income attributable to:		
Noncontrolling interest *(Note 25)*	6	6
Common shareholder	711	730
	717	**736**
Comprehensive income attributable to:		
Noncontrolling interest *(Note 25)*	6	6
Common shareholder	711	730
	717	**736**
Earnings per common share *(Note 23)*		
Basic	$4,999	$5,132
Diluted	$4,999	$5,132
Dividends per common share declared *(Note 22)*	$105	$14

See accompanying notes to Consolidated Financial Statements.

HYDRO ONE INC.
CONSOLIDATED BALANCE SHEETS
At December 31, 2017 and 2016

December 31 *(millions of Canadian dollars)*	2017	2016
Assets		
Current assets:		
Cash and cash equivalents	—	48
Accounts receivable *(Note 8)*	635	833
Due from related parties *(Note 26)*	439	224
Other current assets *(Note 9)*	104	97
	1,178	1,202
Property, plant and equipment *(Note 10)*	19,871	19,068
Other long-term assets:		
Regulatory assets *(Note 12)*	3,049	3,145
Deferred income tax assets *(Note 7)*	954	1,213
Intangible assets *(Note 11)*	369	349
Goodwill *(Note 4)*	325	327
Other assets	5	6
	4,702	5,040
Total assets	**25,751**	**25,310**
Liabilities		
Current liabilities:		
Bank indebtedness	3	—
Short-term notes payable *(Note 15)*	926	469
Long-term debt payable within one year *(Notes 15, 16)*	752	602
Accounts payable and other current liabilities *(Note 13)*	892	933
Due to related parties *(Note 26)*	343	253
	2,916	2,257
Long-term liabilities:		
Long-term debt (includes $541 measured at fair value; 2016 – $548) *(Notes 15, 16)*	9,315	10,078
Regulatory liabilities *(Note 12)*	128	209
Deferred income tax liabilities *(Note 7)*	70	60
Other long-term liabilities *(Note 14)*	2,734	2,765
	12,247	13,112
Total liabilities	**15,163**	**15,369**
Contingencies and Commitments *(Notes 28, 29)*		
Subsequent Events *(Note 31)*		
Preferred shares *(Note 21)*	486	—
Noncontrolling interest subject to redemption *(Note 25)*	22	22
Equity		
Common shares *(Note 21)*	4,856	5,391
Retained earnings	5,183	4,487
Accumulated other comprehensive loss	(9)	(9)
Hydro One shareholder's equity	10,030	9,869
Noncontrolling interest *(Note 25)*	50	50
Total equity	**10,080**	**9,919**
	25,751	**25,310**

See accompanying notes to Consolidated Financial Statements.

On behalf of the Board of Directors:

David Denison
Chair

Philip Orsino
Chair, Audit Committee

HYDRO ONE INC.
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
For the years ended December 31, 2017 and 2016

Year ended December 31, 2017 *(millions of Canadian dollars)*	Common Shares	Retained Earnings	Accumulated Other Comprehensive Loss	Hydro One Shareholder's Equity	Non-controlling Interest *(Note 25)*	Total Equity
January 1, 2017	5,391	4,487	(9)	9,869	50	9,919
Net income	—	711	—	711	4	715
Other comprehensive income	—	—	—	—	—	—
Distributions to noncontrolling interest	—	—	—	—	(4)	(4)
Dividends on common shares	—	(15)	—	(15)	—	(15)
Return of stated capital *(Note 21)*	(535)	—	—	(535)	—	(535)
December 31, 2017	**4,856**	**5,183**	**(9)**	**10,030**	**50**	**10,080**

Year ended December 31, 2016 *(millions of Canadian dollars)*	Common Shares	Retained Earnings	Accumulated Other Comprehensive Loss	Hydro One Shareholder's Equity	Non-controlling Interest *(Note 25)*	Total Equity
January 1, 2016	6,000	3,759	(9)	9,750	52	9,802
Net income	—	730	—	730	4	734
Other comprehensive income	—	—	—	—	—	—
Distributions to noncontrolling interest	—	—	—	—	(6)	(6)
Dividends on common shares	—	(2)	—	(2)	—	(2)
Return of stated capital *(Note 21)*	(609)	—	—	(609)	—	(609)
December 31, 2016	**5,391**	**4,487**	**(9)**	**9,869**	**50**	**9,919**

See accompanying notes to Consolidated Financial Statements.

HYDRO ONE INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the years ended December 31, 2017 and 2016

Year ended December 31 *(millions of Canadian dollars)*	2017	2016
Operating activities		
Net income	717	736
Environmental expenditures	(24)	(20)
Adjustments for non-cash items:		
Depreciation and amortization (excluding asset removal costs)	720	679
Regulatory assets and liabilities	112	(16)
Deferred income taxes	96	111
Other	10	10
Changes in non-cash balances related to operations *(Note 27)*	63	168
Net cash from operating activities	**1,694**	**1,668**
Financing activities		
Long-term debt issued	—	2,300
Long-term debt repaid	(602)	(502)
Short-term notes issued	3,795	3,031
Short-term notes repaid	(3,338)	(4,053)
Promissory note issued *(Note 26)*	486	—
Promissory note repaid *(Note 26)*	(486)	—
Return of stated capital	(535)	(609)
Preferred shares issued	486	—
Dividends paid	(15)	(2)
Distributions paid to noncontrolling interest	(6)	(9)
Change in bank indebtedness	3	—
Other	—	(10)
Net cash from (used in) financing activities	**(212)**	**146**
Investing activities		
Capital expenditures *(Note 27)*		
Property, plant and equipment	(1,456)	(1,594)
Intangible assets	(80)	(61)
Acquisitions *(Note 4)*	—	(224)
Capital contributions received *(Note 27)*	9	21
Other	(3)	3
Net cash used in investing activities	**(1,530)**	**(1,855)**
Net change in cash and cash equivalents	(48)	(41)
Cash and cash equivalents, beginning of year	48	89
Cash and cash equivalents, end of year	**—**	**48**

See accompanying notes to Consolidated Financial Statements.

1. DESCRIPTION OF THE BUSINESS

Hydro One Inc. (Hydro One or the Company) was incorporated on December 1, 1998, under the Business Corporations Act (Ontario) and is wholly-owned by Hydro One Limited. The principal businesses of Hydro One are the transmission and distribution of electricity to customers within Ontario.

2. SIGNIFICANT ACCOUNTING POLICIES

Basis of Consolidation

These Consolidated Financial Statements include the accounts of the Company and its subsidiaries. Intercompany transactions and balances have been eliminated.

Basis of Accounting

These Consolidated Financial Statements are prepared and presented in accordance with United States (US) Generally Accepted Accounting Principles (GAAP) and in Canadian dollars.

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, 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 Networks Inc. (Hydro One Networks), Hydro One Sault Ste. Marie LP (HOSSM) (formerly Great Lakes Power Transmission LP), and its 66% interest in B2M Limited Partnership (B2M LP). The Company's Distribution Business consists of the distribution businesses of Hydro One Networks, as well as Hydro One Remote Communities Inc. (Hydro One Remote Communities).

Transmission

In November 2017, the Ontario Energy Board (OEB) approved Hydro One Networks' 2017 transmission rates revenue requirement of $1,438 million. See Note 12 - Regulatory Assets and Liabilities for additional information.

In December 2015, the OEB approved B2M LP's 2015-2019 rates revenue requirements of $39 million, $36 million, $37 million, $38 million and $37 million for the respective years. 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. On June 8, 2017, the OEB approved the 2017 rates revenue requirement of $34 million, updated for the cost of capital parameters.

On September 28, 2017, the OEB issued its Decision and Order on HOSSM's 2017 transmission rates application, denying the requested revenue requirement for 2017. HOSSM's 2016 approved revenue requirement of $41 million will remain in effect for 2017.

Distribution

In March 2015, the OEB approved Hydro One Networks' distribution revenue requirements of $1,326 million for 2015, $1,430 million for 2016 and $1,486 million for 2017. The OEB has subsequently approved updated revenue requirements of $1,410 million for 2016 and $1,415 million for 2017.

On March 30, 2017, the OEB approved an increase of 1.9% to Hydro One Remote Communities' basic rates for the distribution and generation of electricity, with an effective date of May 1, 2017.

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 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 include its regulatory assets and liabilities in setting 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 would 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. At the end of each month, electricity delivered to customers since the date of the last billed meter reading is estimated, and the corresponding unbilled revenue is recorded. 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 billed accounts receivable by applying internally developed loss rates to the outstanding receivable balances by aging category. Loss rates applied to the billed 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 allowance for doubtful accounts is 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 the shareholder of Hydro One. Noncontrolling interest is initially recorded at fair value and subsequently the amount is adjusted for the proportionate share of net income and other comprehensive income (OCI) 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

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 using new information about recognition or measurement as it becomes available.

<u>Deferred Income Taxes</u>

Deferred income taxes are provided for using the liability method. Under this method, deferred income tax liabilities are recognized on all taxable temporary differences between the tax bases and carrying amounts of assets and liabilities. Deferred income tax assets are recognized for deductible temporary differences between tax bases and carrying amounts of assets and liabilities, the carry forward unused tax credits and tax losses to the extent that it is more-likely-than-not that these deductions, credits, and losses can be utilized. Deferred income tax assets and liabilities are measured 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.

Management reassesses the deferred income tax assets at each balance sheet date and reduces the amount to the extent that it is more-likely-than-not that the deferred income tax asset will not 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 tax assets and liabilities 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 most recent reviews resulted in changes to rates effective January 1, 2015 and January 1, 2017 for Hydro One Networks' distribution and transmission businesses, respectively. 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
Property, plant and equipment:			
Transmission	55 years	1% – 3%	2%
Distribution	46 years	1% – 7%	2%
Communication	16 years	1% – 15%	6%
Administration and service	20 years	1% – 20%	6%
Intangible assets	10 years	10%	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.

Acquisitions and Goodwill

The Company accounts for business acquisitions using the acquisition method of accounting and, accordingly, the assets and liabilities of the acquired entities are primarily measured at their estimated fair value at the date of acquisition. Costs associated with pending acquisitions are expensed as incurred. Goodwill represents the cost of acquired 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.

Based on assessment performed as at September 30, 2017, the Company has concluded that goodwill was not impaired at December 31, 2017.

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. As at December 31, 2017 and 2016, no asset impairment had been recorded.

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 net of related debt 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 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 16 – 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. The changes in fair value of the undesignated derivative instruments are reflected in results of operations.

Embedded derivative instruments are separated from their host contracts and are 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, 2017 or 2016.

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.

Hydro One recognizes its contributions to the defined contribution pension plan as pension expense, with a portion being capitalized as part of labour costs included in capital expenditures. The expensed amount is included in operation, maintenance and administration costs in the Consolidated Statements of Operations and Comprehensive Income.

<u>Defined Benefit Pension</u>

Defined benefit 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.

<u>Post-retirement and Post-employment Benefits</u>

Post-retirement and post-employment benefits are recorded and included in rates on an accrual basis. Costs are determined by independent actuaries using the projected benefit method prorated on service and based on assumptions that reflect management's best estimates. Past service costs from plan amendments are amortized to results of operations based on the expected average remaining service period.

For post-retirement benefits, all actuarial gains or losses are deferred using the "corridor" approach. The amount calculated above the "corridor" is amortized to results of operations on a straight-line basis over the expected average remaining service life of active employees in the plan and over the remaining life expectancy of inactive employees in the plan. The post-retirement benefit obligation is remeasured to its fair value at each year end based on an annual actuarial report, with an offset to the associated regulatory asset, to the extent of the remeasurement adjustment.

For post-employment obligations, the associated regulatory liabilities representing actuarial gains on transition to US GAAP are amortized to results of operations based on the "corridor" approach. 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.

Stock-Based Compensation

<u>Share Grant Plans</u>

Hydro One measures share grant plans based on fair value of share grants as estimated based on the grant date Hydro One Limited common 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. Costs are transfered from the regulatory asset to labour costs at the time the share grants vest and are issued, and are recovered in rates. Forfeitures are recognized as they occur.

Deferred Share Unit (DSU) Plans

The Company records the liabilities associated with its Directors' and Management DSU Plans 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 Hydro One Limited common share closing price at the end of each reporting period.

Long-term Incentive Plan (LTIP)

The Company measures the restricted share units (RSUs) and performance share units (PSUs), issued under Hydro One Limited's LTIP, at fair value based on the grant date Hydro One Limited common share price. The related compensation expense is recognized over the vesting period on a straight-line basis. Forfeitures are recognized as they occur.

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 have been recorded 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.

3. NEW ACCOUNTING PRONOUNCEMENTS

The following tables present Accounting Standards Updates (ASUs) issued by the Financial Accounting Standards Board that are applicable to Hydro One:

Recently Adopted Accounting Guidance

ASU	Date issued	Description	Effective date	Anticipated impact on Hydro One
2016-06	March 2016	Contingent call (put) options that are assessed to accelerate the payment of principal on debt instruments need to meet the criteria of being "clearly and closely related" to their debt hosts.	January 1, 2017	No impact upon adoption

Recently Issued Accounting Guidance Not Yet Adopted

ASU	Date issued	Description	Effective date	Anticipated impact on Hydro One
2014-09 2015-14 2016-08 2016-10 2016-12 2016-20 2017-05 2017-10 2017-13 2017-14	May 2014 – November 2017	ASU 2014-09 was issued in May 2014 and provides guidance on revenue recognition relating to 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. ASU 2015-14 deferred the effective date of ASU 2014-09 by one year. Additional ASUs were issued in 2016 and 2017 that simplify transition and provide clarity on certain aspects of the new standard.	January 1, 2018	Hydro One has completed the review of all its revenue streams and has concluded that there will be no material impact upon adoption.
2016-02 2018-01	February 2016 – January 2018	Lessees are required to recognize the rights and obligations resulting from operating leases as assets (right to use the underlying asset for the term of the lease) and liabilities (obligation to make future lease payments) on the balance sheet. ASU 2018-01 permits an entity to elect an optional practical expedient to not evaluate under Topic 842 land easements that exist or expired before the entity's adoption of Topic 842 and that were not previously accounted for as leases under Topic 840.	January 1, 2019	An initial assessment is currently underway encompassing a review of existing leases, which will be followed by a review of relevant contracts. No quantitative determination has been made at this time. The Company is on track for implementation of this standard by the effective date.
2016-15	August 2016	The amendments provide guidance for eight specific cash flow issues with the objective of reducing the existing diversity in practice.	January 1, 2018	No material impact
2017-01	January 2017	The amendment clarifies the definition of a business and provides additional guidance on evaluating whether transactions should be accounted for as acquisitions (or disposals) of assets or businesses.	January 1, 2018	No material impact
2017-04	January 2017	The amendment removes the second step of the current two-step goodwill impairment test to simplify the process of testing goodwill.	January 1, 2020	Under assessment
2017-07	March 2017	Service cost components of net benefit cost associated with defined benefit plans are required to be reported in the same line as other compensation costs arising from services rendered by the Company's employees. All other components of net benefit cost are to be presented in the income statement separately from the service cost component. Only the service cost component is eligible for capitalization where applicable.	January 1, 2018	Hydro One has applied for a regulatory deferral account to maintain the capitalization of OPEB related costs. As such, there will be no material impact.
2017-09	May 2017	Changes to the terms or conditions of a share-based payment award will require an entity to apply modified accounting unless the modified award meets all conditions stipulated in this ASU.	January 1, 2018	No impact
2017-11	July 2017	When determining whether certain financial instruments should be classified as liabilities or equity instruments, a down round feature no longer precludes equity classification when assessing whether the instrument is indexed to an entity's own stock.	January 1, 2019	Under assessment
2017-12	August 2017	Amendments will better align an entity's risk management activities and financial reporting for hedging relationships through changes to both the designation and measurement guidance for qualifying hedging relationships and the presentation of hedge results.	January 1, 2019	Under assessment

4. BUSINESS COMBINATIONS

Acquisition of HOSSM

On October 31, 2016, Hydro One acquired HOSSM, an Ontario regulated electricity transmission business operating along the eastern shore of Lake Superior, north and east of Sault Ste. Marie, Ontario from Brookfield Infrastructure Holdings Inc. The total purchase price for HOSSM was approximately $376 million, including the assumption of approximately $150 million in outstanding indebtedness. During 2017, the Company completed the final determination of the fair value of assets acquired and liabilities assumed with no significant changes, which resulted in a total goodwill of approximately $157 million arising from the HOSSM acquisition. The difference between the preliminary and final purchase price allocation to fair value of assets acquired and liabilities related to a $2 million decrease in deferred income tax liabilities which resulted in a corresponding decrease to goodwill. The following table summarizes the final fair value of the assets acquired and liabilities assumed:

(millions of dollars)	
Cash and cash equivalents	5
Property, plant and equipment	221
Intangible assets	1
Regulatory assets	50
Goodwill	157
Working capital	(2)
Long-term debt	(186)
Pension and post-employment benefit liabilities, net	(5)
Deferred income taxes	(15)
	226

Goodwill arising from the HOSSM acquisition consists largely of the synergies and economies of scale expected from combining the operations of Hydro One and HOSSM. HOSSM contributed revenues of $6 million and less than $1 million of net income to the Company's consolidated financial results for the year ended December 31, 2016. All costs related to the acquisition have been expensed through the Consolidated Statements of Operations and Comprehensive Income. HOSSM's financial information was not material to the Company's consolidated financial results for the year ended December 31, 2016 and therefore, has not been disclosed on a pro forma basis.

Agreement to Purchase Orillia Power

On August 15, 2016, the Company reached an agreement to acquire Orillia Power Distribution Corporation (Orillia Power), an electricity distribution company located in Simcoe County, Ontario, from the City of Orillia for approximately $41 million, including the assumption of approximately $15 million in outstanding indebtedness and regulatory liabilities, subject to closing adjustments. The acquisition is subject to regulatory approval by the OEB.

5. DEPRECIATION AND AMORTIZATION

Year ended December 31 *(millions of dollars)*	2017	2016
Depreciation of property, plant and equipment	634	603
Asset removal costs	90	90
Amortization of intangible assets	62	56
Amortization of regulatory assets	24	20
	810	769

6. FINANCING CHARGES

Year ended December 31 *(millions of dollars)*	2017	2016
Interest on long-term debt	450	424
Interest on short-term notes	6	9
Other	12	15
Less: Interest capitalized on construction and development in progress	(56)	(54)
Interest earned on cash and cash equivalents	(1)	(2)
	411	392

7. INCOME TAXES

Income tax expense differs from the amount that would have been recorded using the combined Canadian federal and Ontario statutory income tax rate. The reconciliation between the statutory and the effective tax rates is provided as follows:

Year ended December 31 *(millions of dollars)*	2017	2016
Income before income taxes	837	871
Income taxes at statutory rate of 26.5% (2016 - 26.5%)	222	231
Increase (decrease) resulting from:		
Net temporary differences recoverable in future rates charged to customers:		
Capital cost allowance in excess of depreciation and amortization	(55)	(53)
Pension contributions in excess of pension expense	(13)	(16)
Overheads capitalized for accounting but deducted for tax purposes	(17)	(16)
Interest capitalized for accounting but deducted for tax purposes	(15)	(14)
Environmental expenditures	(6)	(5)
Other	1	5
Net temporary differences	(105)	(99)
Net permanent differences	3	3
Total income taxes	120	135

The major components of income tax expense are as follows:

Year ended December 31 *(millions of dollars)*	2017	2016
Current income taxes	24	24
Deferred income taxes	96	111
Total income taxes	120	135
Effective income tax rate	14.3%	15.5%

Deferred Income Tax Assets and Liabilities

Deferred income tax assets and liabilities 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 arise from differences between the tax basis and the carrying amounts of the assets and liabilities. At December 31, 2017 and 2016, deferred income tax assets and liabilities consisted of the following:

December 31 *(millions of dollars)*	2017	2016
Deferred income tax assets		
Depreciation and amortization in excess of capital cost allowance	109	477
Non-depreciable capital property	271	271
Post-retirement and post-employment benefits expense in excess of cash payments	558	603
Environmental expenditures	71	74
Non-capital losses	240	213
Tax credit carryforwards	49	27
Investment in subsidiaries	84	75
Other	13	3
	1,395	1,743
Less: valuation allowance	(364)	(352)
Total deferred income tax assets	1,031	1,391
Less: current portion	—	—
	1,031	1,391
Deferred income tax liabilities		
Regulatory amounts that are not recognized for tax purposes	(47)	(153)
Goodwill	(10)	(10)
Capital cost allowance in excess of depreciation and amortization	(74)	(64)
Other	(16)	(11)
Total deferred income tax liabilities	(147)	(238)
Less: current portion	—	—
	(147)	(238)
Net deferred income tax assets	884	1,153

The net deferred income tax assets are presented on the Consolidated Balance Sheets as follows:

December 31 *(millions of dollars)*	2017	2016
Long-term:		
Deferred income tax assets	954	1,213
Deferred income tax liabilities	(70)	(60)
Net deferred income tax assets	884	1,153

The valuation allowance for deferred tax assets as at December 31, 2017 was $364 million (2016 – $352 million). The valuation allowance primarily relates to temporary differences for non-depreciable assets and investments in subsidiaries. As of December 31, 2017 and 2016, the Company had non-capital losses carried forward available to reduce future years' taxable income, which expire as follows:

Year of expiry *(millions of dollars)*	2017	2016
2034	2	2
2035	221	221
2036	558	579
2037	123	—
Total losses	904	802

8. ACCOUNTS RECEIVABLE

December 31 *(millions of dollars)*	2017	2016
Accounts receivable – billed	297	427
Accounts receivable – unbilled	367	441
Accounts receivable, gross	664	868
Allowance for doubtful accounts	(29)	(35)
Accounts receivable, net	635	833

The following table shows the movements in the allowance for doubtful accounts for the years ended December 31, 2017 and 2016:

Year ended December 31 *(millions of dollars)*	2017	2016
Allowance for doubtful accounts – beginning	(35)	(61)
Write-offs	25	37
Additions to allowance for doubtful accounts	(19)	(11)
Allowance for doubtful accounts – ending	(29)	(35)

9. OTHER CURRENT ASSETS

December 31 *(millions of dollars)*	2017	2016
Regulatory assets *(Note 12)*	46	37
Materials and supplies	18	19
Prepaid expenses and other assets	40	41
	104	97

10. PROPERTY, PLANT AND EQUIPMENT

December 31, 2017 *(millions of dollars)*	Property, Plant and Equipment	Accumulated Depreciation	Construction in Progress	Total
Transmission	15,509	5,162	989	11,336
Distribution	10,213	3,513	149	6,849
Communication	1,088	742	22	368
Administration and service	1,561	857	46	750
Easements	638	70	—	568
	29,009	10,344	1,206	19,871

December 31, 2016 *(millions of dollars)*	Property, Plant and Equipment	Accumulated Depreciation	Construction in Progress	Total
Transmission	14,692	4,862	910	10,740
Distribution	9,656	3,305	243	6,594
Communication	1,069	674	9	404
Administration and service	1,632	924	61	769
Easements	628	67	—	561
	27,677	9,832	1,223	19,068

Financing charges capitalized on property, plant and equipment under construction were $54 million in 2017 (2016 – $52 million).

11. INTANGIBLE ASSETS

December 31, 2017 *(millions of dollars)*	Intangible Assets	Accumulated Amortization	Development in Progress	Total
Computer applications software	698	370	41	369
Other	5	5	—	—
	703	375	41	369

December 31, 2016 *(millions of dollars)*	Intangible Assets	Accumulated Amortization	Development in Progress	Total
Computer applications software	621	326	53	348
Other	5	4	—	1
	626	330	53	349

Financing charges capitalized to intangible assets under development were $2 million in 2017 (2016 – $2 million). The estimated annual amortization expense for intangible assets is as follows: 2018 – $67 million; 2019 – $57 million; 2020 – $40 million; 2021 – $39 million; and 2022 – $36 million.

12. REGULATORY ASSETS AND LIABILITIES

Regulatory assets and liabilities arise as a result of the rate-setting process. Hydro One has recorded the following regulatory assets and liabilities:

December 31 *(millions of dollars)*	2017	2016
Regulatory assets:		
Deferred income tax regulatory asset	1,762	1,587
Pension benefit regulatory asset	981	900
Post-retirement and post-employment benefits	36	243
Environmental	196	204
Share-based compensation	40	31
Debt premium	27	32
Foregone revenue deferral	23	—
Distribution system code exemption	10	10
B2M LP start-up costs	4	5
Retail settlement variance account	—	145
2015-2017 rate rider	—	7
Pension cost variance	—	4
Other	16	14
Total regulatory assets	3,095	3,182
Less: current portion	(46)	(37)
	3,049	3,145
Regulatory liabilities:		
Green Energy expenditure variance	60	69
External revenue variance	46	64
CDM deferral variance	28	54
Pension cost variance	23	—
2015-2017 rate rider	6	—
Deferred income tax regulatory liability	5	4
Other	17	18
Total regulatory liabilities	185	209
Less: current portion	(57)	—
	128	209

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 2017 income tax expense would have been higher by approximately $113 million (2016 – $104 million).

On September 28, 2017, the OEB issued its Decision and Order on Hydro One Networks' 2017 and 2018 transmission rates revenue requirements (Decision). In its Decision, the OEB concluded that the net deferred tax asset resulting from transition from the payments in lieu of tax regime under the *Electricity Act* (Ontario) to tax payments under the federal and provincial tax regime should not accrue entirely to Hydro One's shareholders and that a portion should be shared with ratepayers. On November 9, 2017, the OEB issued a Decision and Order that calculated the portion of the tax savings that should be shared with ratepayers. The OEB's calculation would result in an impairment of Hydro One Networks' transmission deferred income tax regulatory asset of up to approximately $515 million. If the OEB were to apply the same calculation for sharing in Hydro One Networks' 2018-2022 distribution rates, for which a decision is currently outstanding, it would result in an additional impairment of up to approximately $370 million related to Hydro One Networks' distribution deferred income tax regulatory asset. In October 2017, the Company filed a Motion to Review and Vary (Motion) the Decision and filed an appeal with the Divisional Court of Ontario (Appeal). On December 19, 2017, the OEB granted a hearing of the merits of the Motion which is scheduled for mid-February 2018. In both cases, the Company's position is that the OEB made errors of fact and law in its determination of allocation of the tax savings between the shareholders and ratepayers. The Appeal is being held in abeyance pending the outcome of the Motion. If the Decision is upheld, based on the facts known at this time, the exposure from the potential impairments would be a one-time decrease in net income of up to approximately $885 million. Based on the assumptions that the OEB applies established rate making principles in a manner consistent with its past practice and does not exercise its discretion to take other policy considerations into account, management is of the view that it is likely that the Company's Motion will be granted and the aforementioned tax savings will be allocated to the benefit of Hydro One shareholders.

Pension Benefit Regulatory Asset

In accordance with OEB rate orders, pension costs are recovered 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, OCI would have been lower by $80 million and operation, maintenance and administration expenses would have been higher by $1 million (2016 – OCI higher by $52 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, 2017 OCI would have been higher by $207 million (2016 – lower by $3 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 2017, the environmental regulatory asset increased by $1 million (2016 – decreased by $1 million) to reflect related changes in the Company's PCB liability, and increased by $7 million (2016 – $10 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, 2017 operation, maintenance and administration expenses would have been higher by $8 million (2016 – $9 million). In addition, 2017 amortization expense would have been lower by $24 million (2016 – $20 million), and 2017 financing charges would have been higher by $8 million (2016 – $8 million).

Share-based Compensation

The Company recognizes costs associated with share grant plans in a regulatory asset as management considers it probable that share grant plans' costs will be recovered in the future through the rate-setting process. In the absence of rate-regulated accounting, 2017 operation, maintenance and administration expenses would have been higher by $7 million (2016 – $9 million). Share grant costs are transferred to labour costs at the time the share grants vest and are issued, and are recovered in rates in accordance with recovery of said labour costs.

Debt Premium

The value of debt assumed in the acquisition of HOSSM has been recorded at fair value in accordance with US GAAP - Business Combinations. The OEB allows for recovery of interest at the coupon rate of the Senior Secured Bonds and a regulatory asset has been recorded for the difference between the fair value and face value of this debt. The debt premium is recovered over the remaining term of the debt.

Foregone Revenue Deferral

As part of its September 2017 decision on Hydro One Networks' transmission rate application for 2017 and 2018 rates, the OEB approved the foregone revenue account to record the difference between revenue earned under the rates approved as part of the decision, effective January 1, 2017, and revenue earned under the interim rates until the approved 2017 rates were implemented. The OEB approved a similar account for B2M LP in June 2017 to record the difference between revenue earned under the newly approved rates, effective January 1, 2017, and the revenue recorded under the interim 2017 rates. The balances of these accounts will be returned to or recovered from ratepayers, respectively, over a one-year period ending December 31, 2018. The draft rate order submitted by Hydro One Networks was approved by the OEB in November, 2017. This draft rate order reflects the September 2017 decision, including a reduction of the amount of cash taxes approved for recovery in transmission rates due to the OEB's basis to share the savings resulting from a deferred tax asset with ratepayers. The Company's position in the aforementioned Motion is that the OEB made errors of fact and law in its determination of allocation of the tax savings between the shareholders and ratepayers. Therefore, the Company has also reflected the impact of the Company's position with respect to the Motion in the Foregone Revenue Deferral account. The timing for recovery of this impact will be determined as part of the outcome of the Motion.

Distribution System Code (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 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 Networks distribution applications. In March 2015, the OEB approved the disposition of the DSC exemption deferral account balance at December 31, 2013, including accrued interest, which was recovered through the 2015-2017 Rate Rider. In addition, the OEB also approved Hydro One's request to discontinue this deferral account. There were no additions to this regulatory account in 2017 or 2016. The remaining balance in this account at December 31, 2016, including accrued interest, was requested for recovery through the 2018-2022 distribution rate application.

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 are being recovered over a four-year period which began in 2016, in accordance with the OEB decision.

Retail Settlement Variance Account (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.

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 included the balances approved for disposition by the OEB and was disposed of in accordance with the OEB decision over a 32-month period ended on December 31, 2017. The balance remaining in the account represents an over-collection to be returned to ratepayers in a future rate application. We have not requested recovery of the remaining balance of this account in the current distribution rate application.

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 deficit 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 was recovered through the 2015-2017 Rate Rider. In September 2017, the OEB approved the disposition of the transmission business portion of the total pension cost variance account as at December 31, 2015, including accrued interest, which is being recovered over a two-year period ending December 31, 2018. In the absence of rate-regulated accounting, 2017 revenue would have been higher by $24 million (2016 – $25 million).

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.

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. In September 2017, the OEB approved the disposition of the external revenue variance account as at December 31, 2015, including accrued interest, which is being returned to customers over a two-year period ending December 31, 2018.

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. The balance in the CDM deferral variance account relates to the actual 2013 and 2014 CDM compared to the amounts included in 2013 and 2014 revenue requirements, respectively. There were no additions to this regulatory account in 2017 or 2016. The balance of the account at December 31, 2015, including interest, was approved for disposition in the 2017-2018 transmission rate decision and is currently being drawn down over a 2-year period ending December 31, 2018.

13. ACCOUNTS PAYABLE AND OTHER CURRENT LIABILITIES

December 31 *(millions of dollars)*	2017	2016
Accounts payable	173	177
Accrued liabilities	563	651
Accrued interest	99	105
Regulatory liabilities *(Note 12)*	57	—
	892	933

14. OTHER LONG-TERM LIABILITIES

December 31 *(millions of dollars)*	2017	2016
Post-retirement and post-employment benefit liability *(Note 18)*	1,507	1,628
Pension benefit liability *(Note 18)*	981	900
Environmental liabilities *(Note 19)*	168	177
Due to related parties *(Note 26)*	39	26
Asset retirement obligations *(Note 20)*	9	9
Long-term accounts payable and other liabilities	30	25
	2,734	2,765

15. 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 its 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 up to 365 days. The Commercial Paper Program is supported by the Company's committed revolving credit facilities totalling $2.3 billion. In June 2017, the maturity date of Hydro One's $2.3 billion credit facilities was extended from June 2021 to June 2022.

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 that no event of default has occurred or would result from such credit extension.

Long-Term Debt

The following table presents long-term debt outstanding at December 31, 2017 and 2016:

December 31 *(millions of dollars)*	2017	2016
5.18% Series 13 notes due 2017	—	600
2.78% Series 28 notes due 2018	750	750
Floating-rate Series 31 notes due 2019[1]	228	228
1.48% Series 37 notes due 20192	500	500
4.40% Series 20 notes due 2020	300	300
1.62% Series 33 notes due 20202	350	350
1.84% Series 34 notes due 2021	500	500
3.20% Series 25 notes due 2022	600	600
2.77% Series 35 notes due 2026	500	500
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
3.91% Series 36 notes due 2046	350	350
3.72% Series 38 notes due 2047	450	450
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
Hydro One long-term debt (a)	9,923	10,523
6.6% Senior Secured Bonds due 2023 (Face value - $110 million)	136	144
4.6% Note Payable due 2023 (Face value - $36 million)	40	40
HOSSM long-term debt (b)	176	184
	10,099	10,707
Add: Net unamortized debt premiums	14	15
Add: Unrealized mark-to-market gain[2]	(9)	(2)
Less: Deferred debt issuance costs	(37)	(40)
Total long-term debt	10,067	10,680

[1] The interest rates of the floating-rate notes are referenced to the three-month Canadian dollar bankers' acceptance rate, plus a margin.

[2] The unrealized mark-to-market net gain relates to $50 million of the Series 33 notes due 2020 and $500 million Series 37 notes due 2019. The unrealized mark-to-market net gain is offset by a $9 million (2016 – $2 million) unrealized mark-to-market net loss on the related fixed-to-floating interest-rate swap agreements, which are accounted for as fair value hedges.

(a) Hydro One long-term debt

At December 31, 2017, long-term debt of $9,923 million (2016 - $10,523 million) was outstanding, the majority of which was issued under Hydro One's Medium Term Note (MTN) Program. The maximum authorized principal amount of notes issuable under the current MTN Program prospectus filed in December 2015 is $3.5 billion. At December 31 2017, $1.2 billion remained available for issuance until January 2018. In 2017, no long-term debt was issued and $600 million of long-term debt was repaid under the MTN Program (2016 - $2,300 million issued and $500 million repaid).

(b) HOSSM long-term debt

At December 31, 2017, long-term debt of $176 million (2016 - $184 million), with a face value of $146 million (2016 - $148 million) was held by HOSSM. In 2017, $2 million of HOSSM long-term debt was repaid (2016 - $2 million).

The total long-term debt is presented on the consolidated balance sheets as follows:

December 31 *(millions of dollars)*	2017	2016
Current liabilities:		
Long-term debt payable within one year	752	602
Long-term liabilities:		
Long-term debt	9,315	10,078
Total long-term debt	10,067	10,680

Principal and Interest Payments

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 dollars)*	Weighted Average Interest Rate *(%)*
1 year	752	2.8
2 years	731	1.6
3 years	653	2.9
4 years	503	1.9
5 years	604	3.2
	3,243	2.5
6 – 10 years	631	3.5
Over 10 years	6,195	5.2
	10,069	4.2

Interest payment obligations related to long-term debt are summarized by year in the following table:

Year	Interest Payments *(millions of dollars)*
2018	426
2019	402
2020	384
2021	370
2022	355
	1,937
2023-2027	1,672
2028+	4,081
	7,690

16. 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, 2017 and 2016, the Company's carrying amounts of cash and cash equivalents, accounts receivable, due from related parties, bank indebtedness, short-term notes payable, accounts payable, and due to related parties are representative of fair value due to 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, 2017 and 2016 are as follows:

December 31 *(millions of dollars)*	2017 Carrying Value	2017 Fair Value	2016 Carrying Value	2016 Fair Value
$50 million of MTN Series 33 notes	49	49	50	50
$500 million MTN Series 37 notes	492	492	498	498
Other notes and debentures	9,526	11,027	10,132	11,462
Long-term debt, including current portion	10,067	11,568	10,680	12,010

Fair Value Measurements of Derivative Instruments

At December 31, 2017, Hydro One had interest-rate swaps in the amount of $550 million (2016 – $550 million) that were used to convert fixed-rate debt to floating-rate debt. These swaps are classified as fair value hedges. Hydro One's fair value hedge exposure was approximately 6% (2016 – 5%) of its total long-term debt. At December 31, 2017, Hydro One had the following interest-rate swaps designated as fair value hedges:

- 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; and
- two $125 million and one $250 million fixed-to-floating interest-rate swap agreements to convert the $500 million MTN Series 37 notes maturing November 18, 2019 into three-month variable rate debt.

At December 31, 2017 and 2016, the Company had no interest-rate swaps classified as undesignated contracts.

Fair Value Hierarchy

The fair value hierarchy of financial assets and liabilities at December 31, 2017 and 2016 is as follows:

December 31, 2017 *(millions of dollars)*	Carrying Value	Fair Value	Level 1	Level 2	Level 3
Liabilities:					
Bank indebtedness	3	3	3	—	—
Short-term notes payable	926	926	926	—	—
Long-term debt, including current portion	10,067	11,568	—	11,568	—
Derivative instruments					
Fair value hedges – interest-rate swaps	9	9	9	—	—
	11,005	12,506	938	11,568	—

December 31, 2016 *(millions of dollars)*	Carrying Value	Fair Value	Level 1	Level 2	Level 3
Assets:					
Cash and cash equivalents	48	48	48	—	—
	48	48	48	—	—
Liabilities:					
Short-term notes payable	469	469	469	—	—
Long-term debt, including current portion	10,680	12,010	—	12,010	—
Derivative instruments					
Fair value hedges – interest-rate swaps	2	2	2	—	—
	11,151	12,481	471	12,010	—

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 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 transfers between any of the fair value levels during the years ended December 31, 2017 or 2016.

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 which 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 anticipated interest rates into account. The Company is not currently exposed to material commodity price risk or material foreign exchange 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. The Company may also utilize interest-rate derivative instruments to lock in interest-rate levels in anticipation of future financing.

A hypothetical 100 basis points increase in 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, 2017 and 2016.

For derivative instruments that are designated and qualify as fair value hedges, the gain or loss on the derivative instrument 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, 2017 and 2016 was not material.

Credit Risk

Financial assets create a risk that a counterparty will fail to discharge an obligation, causing a financial loss. At December 31, 2017 and 2016, 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 material amount of revenue from any single customer. At December 31, 2017 and 2016, there was no material accounts receivable balance due from any single customer.

At December 31, 2017, the Company's provision for bad debts was $29 million (2016 – $35 million). Adjustments and write-offs are determined on the basis of a review of overdue accounts, taking into consideration historical experience. At December 31, 2017, approximately 5% (2016 – 6%) of the Company's net accounts receivable were outstanding for 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; entering into master agreements which enable net settlement and the contractual right of offset; and monitoring the financial condition of counterparties. The Company monitors current 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, 2017 and 2016, the counterparty credit risk exposure on the fair value of these interest-rate swap contracts was not material. At December 31, 2017, Hydro One's credit exposure for all derivative instruments, and applicable payables and receivables, had a credit rating of investment grade, with four financial institutions as the counterparties.

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 credit facilities. The short-term liquidity under the Commercial Paper Program, revolving standby credit facilities, and anticipated levels of funds from operations are expected to be sufficient to fund normal operating requirements.

17. 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. At December 31, 2017 and 2016, the Company's capital structure was as follows:

December 31 *(millions of dollars)*	2017	2016
Long-term debt payable within one year	752	602
Short-term notes payable	926	469
Bank indebtedness	3	—
Less: cash and cash equivalents	—	(48)
	1,681	1,023
Long-term debt	9,315	10,078
Preferred shares	486	—
Common shares	4,856	5,391
Retained earnings	5,183	4,487
Total capital	21,521	20,979

Hydro One and HOSSM have customary covenants typically associated with long-term debt. Hydro One's long-term debt and credit facility covenants limit 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, 2017, the Company was in compliance with all financial covenants and limitations associated with the outstanding borrowings and credit facilities.

18. PENSION AND POST-RETIREMENT AND POST-EMPLOYMENT BENEFITS

Hydro One has a defined benefit pension plan (Pension Plan), a defined contribution pension plan (DC Plan), a supplemental pension plan (Supplemental Plan), and post-retirement and post-employment benefit plans.

DC Plan

Hydro One established a DC Plan effective January 1, 2016. The DC Plan covers eligible management employees hired on or after January 1, 2016, as well as management employees hired before January 1, 2016 who were not eligible or had not irrevocably elected to join the Pension Plan as of September 30, 2015. Members of the DC Plan have an option to contribute 4%, 5% or 6% of their pensionable earnings, with matching contributions by Hydro One.

Hydro One contributions to the DC Plan for the year ended December 31, 2017 were $1 million (2016 – less than $1 million). At December 31, 2017, Company contributions payable included in accrued liabilities on the Consolidated Balance Sheets were less than $1 million (2016 – less than $1 million).

Pension Plan, Supplemental Plan, and Post-Retirement and Post-Employment Plans

The Pension Plan is a defined benefit contributory plan which covers eligible regular employees of Hydro One and its subsidiaries. The Pension Plan provides benefits based on highest three-year average pensionable earnings. For management employees who commenced employment on or after January 1, 2004, and for The Society of Energy Professionals (The Society)-represented staff hired after November 17, 2005, benefits are based on highest five-year average pensionable earnings. After retirement, pensions are indexed to inflation. Membership in the Pension Plan was closed to management employees who were not eligible or had not irrevocably elected to join the Pension Plan as of September 30, 2015. These employees are eligible to join the DC Plan.

Company and employee contributions to the Pension Plan are based on actuarial valuations performed at least every three years. Annual Pension Plan contributions for 2017 of $87 million (2016 – $108 million) were based on an actuarial valuation effective December 31, 2016 (2016 - based on an actuarial valuation effective December 31, 2015) and the level of pensionable earnings. Estimated annual Pension Plan contributions for 2018 and 2019 are approximately $71 million for each year based on the actuarial valuation as at December 31, 2016 and projected levels of pensionable earnings. Future minimum contributions beyond 2019 will be based on an actuarial valuation effective no later than December 31, 2019. Contributions are payable one month in arrears. All of the contributions are expected to be in the form of cash.

The Supplemental 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 Supplemental Plan obligation is included with other post-retirement and post-employment benefit obligations on the Consolidated Balance Sheets.

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 *(millions of dollars)*	Pension Benefits 2017	Pension Benefits 2016	Post-Retirement and Post-Employment Benefits 2017	Post-Retirement and Post-Employment Benefits 2016
Change in projected benefit obligation				
Projected benefit obligation, beginning of year	7,774	7,683	1,676	1,591
Current service cost	147	144	48	41
Employee contributions	49	45	—	—
Interest cost	304	308	67	66
Benefits paid	(368)	(354)	(44)	(43)
Net actuarial loss (gain)	352	(52)	(195)	14
Change due to employees transfer	—	—	—	7
Projected benefit obligation, end of year	8,258	7,774	1,552	1,676
Change in plan assets				
Fair value of plan assets, beginning of year	6,874	6,731	—	—
Actual return on plan assets	662	370	—	—
Benefits paid	(368)	(354)	(34)	(43)
Employer contributions	87	108	34	43
Employee contributions	49	45	—	—
Administrative expenses	(27)	(26)	—	—
Fair value of plan assets, end of year	7,277	6,874	—	—
Unfunded status	981	900	1,552	1,676

Hydro One presents its benefit obligations and plan assets net on its Consolidated Balance Sheets as follows:

December 31 *(millions of dollars)*	Pension Benefits 2017	Pension Benefits 2016	Post-Retirement and Post-Employment Benefits 2017	Post-Retirement and Post-Employment Benefits 2016
Other assets[1]	1	1	—	—
Accrued liabilities	—	—	52	55
Pension benefit liability	981	900	—	—
Post-retirement and post-employment benefit liability[2]	—	—	1,507	1,628
Net unfunded status	980	899	1,559	1,683

[1] Represents the funded status of HOSSM defined benefit pension plan.
[2] Includes $7 million (2016 – $7 million) relating to HOSSM post-employment benefit plans.

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 dollars)*	2017	2016
PBO	8,258	7,774
ABO	7,614	7,094
Fair value of plan assets	7,277	6,874

On an ABO basis, the Pension Plan was funded at 96% at December 31, 2017 (2016 – 97%). On a PBO basis, the Pension Plan was funded at 88% at December 31, 2017 (2016 – 88%). 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, 2017 and 2016 for the Pension Plan:

Year ended December 31 *(millions of dollars)*	2017	2016
Current service cost	147	144
Interest cost	304	308
Expected return on plan assets, net of expenses	(442)	(432)
Amortization of actuarial losses	79	96
Net periodic benefit costs	88	116
Charged to results of operations[1]	37	45

[1] The Company accounts for pension costs consistent with their inclusion in OEB-approved rates. During the year ended December 31, 2017, pension costs of $85 million (2016 – $105 million) were attributed to labour, of which $37 million (2016 – $45 million) was charged to operations, and $48 million (2016 – $60 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, 2017 and 2016 for the post-retirement and post-employment benefit plans:

Year ended December 31 *(millions of dollars)*	2017	2016
Current service cost	48	41
Interest cost	67	66
Amortization of actuarial losses	16	15
Net periodic benefit costs	131	122
Charged to results of operations	58	53

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, 2017 and 2016:

	Pension Benefits		Post-Retirement and Post-Employment Benefits	
Year ended December 31	2017	2016	2017	2016
Significant assumptions:				
Weighted average discount rate	3.40%	3.90%	3.40%	3.90%
Rate of compensation scale escalation (long-term)	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]	—	—	4.04%	4.36%

[1] 5.26% per annum in 2018, grading down to 4.04% per annum in and after 2031 (2016 – 6.25% in 2017, 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, 2017 and 2016. 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	2017	2016
Pension Benefits:		
Weighted average expected rate of return on plan assets	6.50%	6.50%
Weighted average discount rate	3.90%	4.00%
Rate of compensation scale escalation (long-term)	2.50%	2.50%
Rate of cost of living increase	2.00%	2.00%
Average remaining service life of employees *(years)*	15	15
Post-Retirement and Post-Employment Benefits:		
Weighted average discount rate	3.90%	4.10%
Rate of compensation scale escalation (long-term)	2.50%	2.50%
Rate of cost of living increase	2.00%	2.00%
Average remaining service life of employees *(years)*	15.2	15.3
Rate of increase in health care cost trends[1]	4.36%	4.36%

[1] 6.25% per annum in 2017, grading down to 4.36% per annum in and after 2031 (2016 – 6.38% in 2016, grading down to 4.36% 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, 2017 and 2016 is as follows:

December 31 *(millions of dollars)*	2017	2016
Projected benefit obligation:		
Effect of a 1% increase in health care cost trends	247	286
Effect of a 1% decrease in health care cost trends	(188)	(219)

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, 2017 and 2016 is as follows:

Year ended December 31 *(millions of dollars)*	2017	2016
Service cost and interest cost:		
Effect of a 1% increase in health care cost trends	28	22
Effect of a 1% decrease in health care cost trends	(20)	(16)

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, 2017 and 2016:

December 31, 2017				December 31, 2016			
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
22	24	23	24	22	24	23	24

Estimated Future Benefit Payments

At December 31, 2017, estimated future benefit payments to the participants of the Plans were:

(millions of dollars)	Pension Benefits	Post-Retirement and Post-Employment Benefits
2018	326	53
2019	335	54
2020	342	56
2021	350	57
2022	358	58
2023 through to 2027	1,886	311
Total estimated future benefit payments through to 2027	3,597	589

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 dollars)*	2017	2016
Pension Benefits:		
Actuarial loss (gain) for the year	159	35
Amortization of actuarial losses	(79)	(96)
	80	(61)
Post-Retirement and Post-Employment Benefits:		
Actuarial loss (gain) for the year	(195)	14
Amortization of actuarial losses	(16)	(15)
Amounts not subject to regulatory treatment	4	4
	(207)	3

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, 2017 and 2016:

Year ended December 31 *(millions of dollars)*	2017	2016
Pension Benefits:		
Actuarial loss	981	900
Post-Retirement and Post-Employment Benefits:		
Actuarial loss	36	243

The following table provides the components of regulatory assets at December 31 that are expected to be amortized as components of net periodic benefit costs in the following year:

	Pension Benefits		Post-Retirement and Post-Employment Benefits	
December 31 *(millions of dollars)*	2017	2016	2017	2016
Actuarial loss	84	79	2	6

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, 2017, the Pension Plan target asset allocations and weighted average asset allocations were as follows:

	Target Allocation (%)	Pension Plan Assets (%)
Equity securities	55	60
Debt securities	35	31
Other[1]	10	9
	100	100

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

At December 31, 2017, the Pension Plan held $11 million (2016 – $11 million) Hydro One corporate bonds and $415 million (2016 – $450 million) of debt securities of the Province.

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, 2017 and 2016. 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, 2017 and 2016, there were no significant concentrations (defined as greater than 10% of plan assets) of risk in the Pension Plan's assets.

The Pension Plan's Statement of Investment Beliefs and Guidelines provides guidelines and restrictions for eligible investments taking into account credit ratings, maximum investment exposure and other controls in order to limit the impact of this risk. 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 highly rated financial institutions, and also by 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, 2017 and 2016:

December 31, 2017 *(millions of dollars)*	Level 1	Level 2	Level 3	Total
Pooled funds	—	16	549	565
Cash and cash equivalents	153	—	—	153
Short-term securities	—	109	—	109
Derivative instruments	—	5	—	5
Corporate shares – Canadian	921	—	—	921
Corporate shares – Foreign	3,307	125	—	3,432
Bonds and debentures – Canadian	—	1,879	—	1,879
Bonds and debentures – Foreign	—	194	—	194
Total fair value of plan assets[1]	4,381	2,328	549	7,258

[1] At December 31, 2017, the total fair value of Pension Plan assets and liabilities excludes $28 million of interest and dividends receivable, $10 million of pension administration expenses payable, $1 million of sold investments receivable and $1 million of purchased investments payable.

December 31, 2016 *(millions of dollars)*	Level 1	Level 2	Level 3	Total
Pooled funds	—	20	425	445
Cash and cash equivalents	146	—	—	146
Short-term securities	—	127	—	127
Corporate shares – Canadian	911	—	—	911
Corporate shares – Foreign	2,985	113	—	3,098
Bonds and debentures – Canadian	—	1,943	—	1,943
Bonds and debentures – Foreign	—	193	—	193
Total fair value of plan assets[1]	4,042	2,396	425	6,863

[1] At December 31, 2016, the total fair value of Pension Plan assets excludes $27 million of interest and dividends receivable, $15 million of purchased investments payable, $9 million of pension administration expenses payable, and $7 million of sold investments receivable.

See note 16 - 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, 2017 and 2016. The Pension Plan classifies financial instruments as Level 3 when the fair value is measured based on at least one significant input that is not observable in the markets or due to lack of liquidity in certain markets. The gains and losses presented in the table below may include changes in fair value based on both observable and unobservable inputs.

Year ended December 31 *(millions of dollars)*	2017	2016
Fair value, beginning of year	425	301
Realized and unrealized gains	(31)	23
Purchases	171	151
Sales and disbursements	(16)	(50)
Fair value, end of year	549	425

There were no significant transfers between any of the fair value levels during the years ended December 31, 2017 and 2016.

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. This sensitivity analysis resulted in negligible changes in the fair value of financial instruments classified in this level.

Valuation Techniques Used to Determine Fair Value

Pooled funds mainly consist 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 consist of demand cash deposits held with banks and cash held by the investment managers. Cash equivalents are categorized as Level 1.

Short-term securities are valued at cost plus accrued interest, which approximates fair value due to their short-term nature. Short-term securities are categorized as Level 2.

Derivative instruments are used to hedge the Pension Plan's foreign currency exposure back to Canadian dollars. The most significant currencies being hedged against the Canadian dollar are the United States dollar, Euro, and Japanese Yen. The terms to maturity of the forward exchange contracts at December 31, 2017 are within three months. 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 determined using standard interpolation methodology primarily based on the World Markets exchange rates. Derivative instruments are categorized as Level 2.

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 are presented at published closing trade quotations, and are categorized as Level 2.

19. ENVIRONMENTAL LIABILITIES

The following tables show the movements in environmental liabilities for the years ended December 31, 2017 and 2016:

Year ended December 31, 2017 *(millions of dollars)*	PCB	Land Assessment and Remediation	Total
Environmental liabilities - beginning	143	61	204
Interest accretion	6	2	8
Expenditures	(16)	(8)	(24)
Revaluation adjustment	1	7	8
Environmental liabilities - ending	134	62	196
Less: current portion	(20)	(8)	(28)
	114	54	168

Year ended December 31, 2016 *(millions of dollars)*	PCB	Land Assessment and Remediation	Total
Environmental liabilities - beginning	148	59	207
Interest accretion	7	1	8
Expenditures	(11)	(9)	(20)
Revaluation adjustment	(1)	10	9
Environmental liabilities - ending	143	61	204
Less: current portion	(18)	(9)	(27)
	125	52	177

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, 2017 *(millions of dollars)*	PCB	Land Assessment and Remediation	Total
Undiscounted environmental liabilities	142	64	206
Less: discounting environmental liabilities to present value	(8)	(2)	(10)
Discounted environmental liabilities	134	62	196

December 31, 2016 *(millions of dollars)*	PCB	Land Assessment and Remediation	Total
Undiscounted environmental liabilities	158	66	224
Less: discounting environmental liabilities to present value	(15)	(5)	(20)
Discounted environmental liabilities	143	61	204

At December 31, 2017, the estimated future environmental expenditures were as follows:

(millions of dollars)	
2018	28
2019	27
2020	32
2021	34
2022	31
Thereafter	54
	206

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 $142 million (2016 – $158 million). These expenditures are expected to be incurred over the period from 2018 to 2025. As a result of its annual review of environmental liabilities, the Company recorded a revaluation adjustment in 2017 to increase the PCB environmental liability by $1 million (2016 – reduce by $1 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 $64 million (2016 – $66 million). These expenditures are expected to be incurred over the period from 2018 to 2044. As a result of its annual review of environmental liabilities, the Company recorded a revaluation adjustment in 2017 to increase the land assessment and remediation environmental liability by $7 million (2016 – $10 million).

20. 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. 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 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, 2017, Hydro One had recorded asset retirement obligations of $9 million (2016 – $9 million), primarily 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.

21. SHARE CAPITAL

Common Shares

The Company is authorized to issue an unlimited number of common shares. At December 31, 2017, the Company had 142,239 common shares issued and outstanding (2016 – 142,239).

In 2017, a return of stated capital in the amount of $535 million (2016 – $609 million) was paid.

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, 2017, two series of preferred shares are authorized for issuance: the Class A preferred shares and Class B preferred shares. At December 31, 2017, the Company had 485,870 Class B preferred shares and no Class A preferred shares issued and outstanding (2016 - no Class A or Class B preferred shares issued and outstanding).

<u>Class A Preferred Shares</u>

On November 2, 2015, a special resolution of Hydro One Limited (as sole shareholder of Hydro One) was made to amend the articles of Hydro One to delete the share ownership restrictions and to amend the Hydro One preferred share terms to provide for basic redeemable preferred shares. When issued, the Class A preferred shares will be redeemable at the option of the Company. The holders of the Class A preferred shares will be entitled to receive, if and when declared by the Hydro One Board of Directors, non-cumulative preferred share dividends at a rate per year to be determined by the Hydro One Board of Directors. The holders of the Class A preferred shares will not be entitled to receive notice of, or to attend or to vote at, any meeting of the shareholders of Hydro One. The holders of the Class A preferred shares will be entitled to receive, before any distributions to the holders of common shares and any other shares ranking junior to the Class A preferred shares, an amount equal to the amount paid for the Class A preferred shares together with all dividends declared and unpaid up to the date of liquidation, dissolution or winding up of Hydro One, or the date of redemption.

Class B Preferred Shares

On November 10, 2017, a special resolution of Hydro One Limited was made to amend the articles of Hydro One to create an unlimited number of Class B preferred shares. The holders of the Class B preferred shares are 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 average 3-month Canadian dollar bankers' acceptance rate and 0.25% as reset quarterly. The holders of the Class B preferred shares will not be entitled to receive notice of, or to attend or to vote at, any meeting of the shareholders of Hydro One. The holders of the Class B preferred shares will be entitled to receive, before any distributions to the holders of the Class A preferred shares, the common shares and any other shares ranking junior to the Class B preferred shares, an amount equal to the amount paid for the Class B preferred shares together with all dividends unpaid up to the date of liquidation, dissolution or winding up of Hydro One, or the date of redemption.

The Class B preferred shares have a redemption feature that is outside the control of the Company because the holders can exercise their right to redeem the Class B preferred shares at any time without approval of the Company's Board of Directors. The Class B preferred shares are classified on the Consolidated Balance Sheet as temporary equity because this redemption feature is outside the control of the Company.

On November 20, 2017, Hydro One issued 485,870 Class B preferred shares to 2587264 Ontario Inc., a subsidiary of Hydro One Limited, for proceeds of $486 million.

22. DIVIDENDS

In 2017, common share dividends in the amount of $15 million (2016 – $2 million) were declared and paid.

23. EARNINGS PER COMMON SHARE

Basic and diluted earnings per common share (EPS) is calculated by dividing net income attributable to common shareholder of Hydro One by the weighted average number of common shares outstanding. The weighted average number of shares outstanding at December 31, 2017 was 142,239 (2016 – 142,239). There were no dilutive securities during 2017 or 2016.

24. STOCK-BASED COMPENSATION

The following compensation plans were established by Hydro One Limited, however they represent components of compensation costs of Hydro One in current and future periods.

Share Grant Plans

Hydro One Limited has two share grant plans (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). 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 PWU Share Grant Plan provides for the issuance of common shares of Hydro One Limited 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. 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 began on July 3, 2015, which is the date the share grant plan was 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, 3,952,212 Hydro One Limited common shares were granted under the PWU Share Grant Plan relevant to the total share based compensation recognized by Hydro One.

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 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 began 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, 1,367,158 Hydro One Limited common shares were granted under the Society Share Grant Plan relevant to the total share based compensation recognized by Hydro One.

The fair value of the Hydro One Limited 2015 share grants of $111 million was 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. In 2017, 369,266 common shares of Hydro One Limited were granted under the Share Grant Plans (2016 - nil) to eligible employees of Hydro One. Total share based compensation recognized during 2017 was $17 million (2016 – $21 million) and was recorded as a regulatory asset.

A summary of share grant activity under the Share Grant Plans during years ended December 31, 2017 and 2016 is presented below:

Year ended December 31, 2017	Share Grants (number of common shares)	Weighted-Average Price
Share grants outstanding - beginning	5,239,678	$20.50
Vested and issued[1]	(369,266)	—
Forfeited	(132,629)	$20.50
Share grants outstanding - ending	4,737,783	$20.50

[1] On April 1, 2017, Hydro One LImited issued from treasury 369,266 common shares to eligible Hydro One employees in accordance with provisions of the PWU Share Grant Plan.

Year ended December 31, 2016	Share Grants (number of common shares)	Weighted-Average Price
Share grants outstanding – beginning	5,319,370	$20.50
Forfeited[1]	(79,692)	$20.50
Share grants outstanding – ending	5,239,678	$20.50

[1] Includes shares forfeited as well as shares transferred corresponding to transfer of employees from an affiliate company.

Directors' DSU Plan

Under the 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 Limited'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 Hydro One Limited and is entitled to accrue Hydro One Limited common share dividend equivalents in the form of additional DSUs at the time dividends are paid, subsequent to declaration by Hydro One Limited's Board of Directors.

During the years ended December 31, 2017 and 2016, the Company granted awards under the Directors' DSU Plan, as follows:

Year ended December 31 *(number of DSUs)*	2017	2016
DSUs outstanding – beginning	99,083	20,525
DSUs granted	88,007	78,558
DSUs outstanding – ending	187,090	99,083

For the year ended December 31, 2017, an expense of $2 million (2016 – $2 million) was recognized in earnings with respect to the Directors' DSU Plan. At December 31, 2017, a liability of $4 million (2016 – $2 million), related to outstanding DSUs has been recorded at the closing price of Hydro One Limited's common shares of $22.40 and is included in long-term accounts payable and other liabilities on the Consolidated Balance Sheets.

Management DSU Plan

Under the Management DSU Plan, eligible executive employees can elect to receive a specified proportion of their annual short-term incentive in a notional account of DSUs in lieu of cash. Each DSU represents a unit with an underlying value equivalent to the value of one common share of Hydro One Limited 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.

During the years ended December 31, 2017 and 2016, the Company granted awards under the Management DSU Plan, as follows:

Year ended December 31 *(number of DSUs)*	2017	2016
DSUs outstanding - beginning	—	—
Granted	64,828	—
Paid	(1,068)	—
DSUs outstanding - ending	63,760	—

For the year ended December 31, 2017, an expense of $2 million (2016 - $nil) was recognized in earnings with respect to the Management DSU Plan. At December 31, 2017, a liability of $2 million (2016 – $nil) related to outstanding DSUs has been recorded at the closing price of Hydro One Limited common shares of $22.40 and is included in long-term accounts payable and other liabilities on the Consolidated Balance Sheets.

Employee Share Ownership Plan

In 2015, Hydro One Limited established Employee Share Ownership Plans (ESOP) for certain eligible management and non-represented employees (Management ESOP) and for certain eligible Society-represented staff (Society ESOP). Under the Management ESOP, the eligible management and non-represented employees may contribute between 1% and 6% of their base salary towards purchasing common shares of Hydro One Limited. The Company matches 50% of their contributions, up to a maximum Company contribution of $25,000 per calendar year. Under the Society ESOP, the eligible Society-represented staff may contribute between 1% and 4% of their base salary towards purchasing common shares of Hydro One Limited. The Company matches 25% of their contributions, with no maximum Company contribution per calendar year. In 2017, Company contributions made under the ESOP were $2 million (2016 - $2 million).

LTIP

Effective August 31, 2015, the Board of Directors of Hydro One Limited adopted an LTIP. Under the LTIP, long-term incentives are 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 RSUs, PSUs, 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.

During 2017 and 2016, Hydro One Limited granted awards under its LTIP as follows:

	PSUs		RSUs	
Year ended December 31 *(number of units)*	2017	2016	2017	2016
Units outstanding – beginning	228,890	—	252,440	—
Units granted	300,090	233,710	239,280	257,260
Units vested	(609)	—	(14,079)	—
Units forfeited	(103,251)	(4,820)	(89,501)	(4,820)
Units outstanding – ending	425,120	228,890	388,140	252,440

The grant date total fair value of the awards granted in 2017 was $13 million (2016 – $12 million). The compensation expense related to these awards recognized by the Company during 2017 was $6 million (2016 – $3 million).

25. NONCONTROLLING INTEREST

On December 16, 2014, 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 during the years ended December 31, 2017 and 2016:

Year ended December 31, 2017 *(millions of dollars)*	Temporary Equity	Equity	Total
Noncontrolling interest – beginning	22	50	72
Distributions to noncontrolling interest	(2)	(4)	(6)
Net income attributable to noncontrolling interest	2	4	6
Noncontrolling interest – ending	22	50	72

Year ended December 31, 2016 *(millions of dollars)*	Temporary Equity	Equity	Total
Noncontrolling interest – beginning	23	52	75
Distributions to noncontrolling interest	(3)	(6)	(9)
Net income attributable to noncontrolling interest	2	4	6
Noncontrolling interest – ending	22	50	72

26. RELATED PARTY TRANSACTIONS

Hydro One is owned by Hydro One Limited. The Province is a shareholder of Hydro One Limited with approximately 47.4% ownership at December 31, 2017. The IESO, Ontario Power Generation Inc. (OPG), Ontario Electricity Financial Corporation (OEFC), the OEB, and Hydro One Telecom, are related parties to Hydro One because they are controlled or significantly influenced by the Province or by Hydro One Limited. Hydro One Brampton was a related party until February 28, 2017, when it was acquired from the Province by Alectra Inc., and subsequent to the acquisition by Alectra Inc., is no longer a related party to Hydro One.

Year ended December 31 *(millions of dollars)*

Related Party	Transaction	2017	2016
IESO	Power purchased	1,583	2,096
	Revenues for transmission services	1,521	1,549
	Amounts related to electricity rebates	357	—
	Distribution revenues related to rural rate protection	247	125
	Distribution revenues related to the supply of electricity to remote northern communities	32	32
	Funding received related to CDM programs	59	63
OPG	Power purchased	9	6
	Revenues related to provision of construction and equipment maintenance services	2	4
	Costs related to the purchase of services	1	1
OEFC	Power purchased from power contracts administered by the OEFC	2	1
OEB	OEB fees	8	11
Hydro One Brampton	Cost recovery from management, administrative and smart meter network services	—	3
Hydro One Limited	Return of stated capital	535	609
	Dividends paid	15	2
	Stock-based compensation costs	23	24
	Cost recovery for services provided	6	—
Hydro One Telecom	Services received – costs expensed	24	24
	Services received – costs capitalized	—	12
	Revenues for services provided	3	3
2587264 Ontario Inc.	Promissory note issued and repaid[1]	486	—
	Preferred shares issued[2]	486	—

[1] On October 17, 2017, Hydro One issued a promissory note to 2587264 Ontario Inc., a subsidiary of Hydro One Limited, totalling $486 million. On November 20, 2017, Hydro One repaid the $486 million promissory note to 2587264 Ontario Inc., as well as interest totalling $1 million.

[2] On November 20, 2017, Hydro One issued 485,870 Class B preferred shares to 2587264 Ontario Inc. for proceeds of $486 million. See Note 21 for details of the Class B preferred shares.

Sales to and purchases from related parties are based on the requirements of the OEB's Affiliate Relationships Code. Outstanding balances at period end are interest-free and settled in cash.

27. CONSOLIDATED STATEMENTS OF CASH FLOWS

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

Year ended December 31 *(millions of dollars)*	2017	2016
Accounts receivable	191	(59)
Due from related parties	(215)	(40)
Materials and supplies	1	2
Prepaid expenses and other assets	2	(17)
Accounts payable	7	18
Accrued liabilities	(89)	52
Due to related parties	88	113
Accrued interest	(6)	9
Long-term accounts payable and other liabilities	(2)	6
Post-retirement and post-employment benefit liability	86	84
	63	168

Capital Expenditures

The following table reconciles investments in property, plant and equipment and the amounts 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 dollars)*	2017	2016
Capital investments in property, plant and equipment	(1,482)	(1,624)
Capitalized depreciation and net change in accruals included in capital investments in property, plant and equipment	26	30
Cash outflow for capital expenditures – property, plant and equipment	(1,456)	(1,594)

The following table reconciles investments in intangible assets and the amounts presented in the Consolidated Statements of Cash Flows after accounting for the net change in related accruals:

Year ended December 31 *(millions of dollars)*	2017	2016
Capital investments in intangible assets	(74)	(67)
Net change in accruals included in capital investments in intangible assets	(6)	6
Cash outflow for capital expenditures – intangible assets	(80)	(61)

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 2017, capital contributions from these reassessments totalled $9 million (2016 – $21 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.

Supplementary Information

Year ended December 31 *(millions of dollars)*	2017	2016
Net interest paid	452	418
Income taxes paid	11	30

28. CONTINGENCIES

Legal Proceedings

Hydro One is involved in various lawsuits and claims 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.

Hydro One, Hydro One Networks, Hydro One Remote Communities, and Norfolk Power Distribution Inc. are defendants in a class action suit in which the representative plaintiff is seeking up to $125 million in damages related to allegations of improper billing practices. The plaintiff's motion for certification was dismissed by the court on November 28, 2017, but the plaintiff has appealed the court's decision, and it is likely that no decision will be rendered by the appeal court until the second half of 2018. At this time, 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 2017, the Company paid approximately $2 million (2016 – $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.

29. COMMITMENTS

The following table presents a summary of Hydro One's commitments under leases, outsourcing and other agreements due in the next 5 years and thereafter.

December 31, 2017 *(millions of dollars)*	Year 1	Year 2	Year 3	Year 4	Year 5	Thereafter
Outsourcing agreements	139	95	2	2	2	7
Long-term software/meter agreement	17	17	16	2	1	3
Operating lease commitments	10	5	9	4	1	4

Outsourcing Agreements

Hydro One has agreements with Inergi LP (Inergi) for the provision of back office and IT outsourcing services, including settlements, source to pay services, pay operations services, information technology and finance and accounting services, expiring on December 31, 2019, and for the provision of customer service operations outsourcing services expiring on February 28, 2018. Hydro One is currently in the process of insourcing the customer service operations services and will not be renewing the existing agreement for these services with Inergi. Agreements have been reached with The Society and the PWU to facilitate the insourcing of these services effective March 1, 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 agreement with Brookfield for these services expires in December 2024.

Long-term Software/Meter Agreement

Trilliant Holdings Inc. and Trilliant Networks (Canada) Inc. (collectively Trilliant) provide services to Hydro One for the supply, maintenance and support services for smart meters and related hardware and software, including additional software licences, as well as certain professional services. The agreement with Trilliant for these services expires in December 2025, but Hydro One has the option to renew for an additional term of five years at its sole discretion.

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, 2017, the Company made lease payments totalling $10 million (2016 – $10 million).

Other Commitments

The following table presents a summary of Hydro One's other commercial commitments by year of expiry in the next 5 years and thereafter.

December 31, 2017 *(millions of dollars)*	Year 1	Year 2	Year 3	Year 4	Year 5	Thereafter
Credit facilities	—	—	—	—	2,300	—
Letters of credit[1]	177	—	—	—	—	—
Guarantees[2]	325	—	—	—	—	—

[1] Letters of credit consist of a $154 million letter of credit related to retirement compensation arrangements, a $16 million letter of credit provided to the IESO for prudential support, $6 million in letters of credit to satisfy debt service reserve requirements, and $1 million in letters of credit for various operating purposes.

[2] Guarantees consist of prudential support provided to the IESO by Hydro One on behalf of its subsidiaries.

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. The IESO could draw on these guarantees and/or letters of credit if these purchasers 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's liability under the terms of a trust fund established pursuant to the supplementary pension plan for eligible employees of Hydro One. The supplementary pension plan trustee is required to draw upon these letters of credit if Hydro One is in default of its obligations under the terms of this plan. Such obligations include the requirement to provide the trustee with an annual actuarial report as well as letters of credit sufficient to secure Hydro One'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.

30. SEGMENTED REPORTING

Hydro One has three reportable segments:

- The Transmission Segment, which comprises the transmission of 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 Segment, which comprises the delivery of electricity to end customers and certain other municipal electricity distributors; and
- Other Segment, which includes certain corporate activities.

The designation of segments has been based on a combination of regulatory status and the nature of the 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).

Year ended December 31, 2017 *(millions of dollars)*	Transmission	Distribution	Other	Consolidated
Revenues	1,581	4,366	—	5,947
Purchased power	—	2,875	—	2,875
Operation, maintenance and administration	391	599	24	1,014
Depreciation and amortization	420	390	—	810
Income (loss) before financing charges and income taxes	770	502	(24)	1,248
Capital investments	968	588	—	1,556

Year ended December 31, 2016 *(millions of dollars)*	Transmission	Distribution	Other	Consolidated
Revenues	1,587	4,915	—	6,502
Purchased power	—	3,427	—	3,427
Operation, maintenance and administration	410	613	20	1,043
Depreciation and amortization	390	379	—	769
Income (loss) before financing charges and income taxes	787	496	(20)	1,263
Capital investments	988	703	—	1,691

Total Assets by Segment:

December 31 *(millions of dollars)*	2017	2016
Transmission	13,612	13,083
Distribution	9,279	9,393
Other	2,860	2,834
Total assets	25,751	25,310

Total Goodwill by Segment:

December 31 *(millions of dollars)*	2017	2016
Transmission *(Note 4)*	157	159
Distribution	168	168
Total goodwill	325	327

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

31. SUBSEQUENT EVENTS

Dividends and Return of Stated Capital

On February 12, 2018, preferred share dividends in the amount of $2 million and common share dividends in the amount of $5 million were declared. On the same date, a return of stated capital in the amount of $128 million was approved.

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 thereto (Consolidated Financial Statements) of Hydro One Inc. (Hydro One or the Company) for the year ended December 31, 2017. 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. Under the US/Canada Multijurisdictional Disclosure System, the Company is permitted to prepare this MD&A in accordance with the disclosure requirements of Canada, which can vary from those of the US. This MD&A provides information for the year ended December 31, 2017, based on information available to management as of February 12, 2018.

CONSOLIDATED FINANCIAL HIGHLIGHTS AND STATISTICS

Year ended December 31 *(millions of dollars, except as otherwise noted)*	2017	2016	Change
Revenues	5,947	6,502	(8.5%)
Purchased power	2,875	3,427	(16.1%)
Revenues, net of purchased power[1]	3,072	3,075	(0.1%)
Operation, maintenance and administration costs	1,014	1,043	(2.8%)
Depreciation and amortization	810	769	5.3%
Financing charges	411	392	4.8%
Income tax expense	120	135	(11.1%)
Net income attributable to common shareholder of Hydro One	**711**	**730**	**(2.6%)**
Basic earnings per common share (EPS)	$4,999	$5,132	(2.6%)
Diluted EPS	$4,999	$5,132	(2.6%)
Net cash from operating activities	1,694	1,668	1.6%
Funds from operations (FFO)[1]	1,625	1,491	9.0%
Capital investments	1,556	1,691	(8.0%)
Assets placed in-service	1,578	1,599	(1.3%)
Transmission: Average monthly Ontario 60-minute peak demand *(MW)*	19,587	20,690	(5.3%)
Distribution: Electricity distributed to Hydro One customers *(GWh)*	25,876	26,289	(1.6%)

	2017	2016
Debt to capitalization ratio[2]	51.1%	52.9%

[1] See section "Non-GAAP Measures" for description and reconciliation of FFO and Revenues, net of purchased power.
[2] Debt to capitalization ratio has been presented at December 31, 2017 and 2016, and has been calculated as total debt (includes total long-term debt and short-term borrowings, net of cash and cash equivalents) divided by total debt plus total shareholder's equity, including preferred shares but excluding any amounts related to noncontrolling interest.

OVERVIEW

Hydro One is the largest electricity transmission and distribution company in Ontario. Hydro One owns and operates substantially all of Ontario's electricity transmission network, and approximately 123,000 circuit kilometres of primary low-voltage distribution network. Hydro One has three business segments: (i) transmission; (ii) distribution; and (iii) other business.

For the year ended December 31, 2017, Hydro One's business segments accounted for the Company's total revenues, net of purchased power, as follows:

	Transmission	Distribution	Other
Percentage of Company's total revenues, net of purchased power	51%	49%	0%

At December 31, 2017, Hydro One's business segments accounted for the Company's total assets as follows:

	Transmission	Distribution	Other
Percentage of Company's total assets	53%	36%	11%

Transmission Segment

Hydro One's transmission business owns, operates and maintains Hydro One's transmission system, which accounts for approximately 98% of Ontario's transmission capacity based on revenue approved by the Ontario Energy Board (OEB). The transmission business consists of the transmission system operated by the Company's subsidiaries, Hydro One Networks Inc. (Hydro One Networks) and Hydro One Sault Ste. Marie LP (HOSSM) (formerly Great Lakes Power Transmission LP), as well as 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 OEB.

	2017	2016
Electricity transmitted[1] *(MWh)*	132,090,992	136,989,747
Transmission lines spanning the province *(circuit-kilometres)*	30,290	30,259
Rate base *(millions of dollars)*	11,251	10,775
Capital investments *(millions of dollars)*	968	988
Assets placed in-service *(millions of dollars)*	889	937

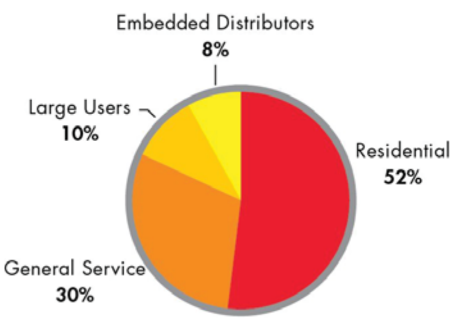
[1] Electricity transmitted represents total electricity transmission in Ontario by all transmitters.

Distribution Segment

Hydro One's distribution business is the largest in Ontario and consists of the distribution system operated by the Company'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 are approved by the OEB.

	2017	2016
Electricity distributed to Hydro One customers *(GWh)*	25,876	26,289
Electricity distributed through Hydro One lines *(GWh)*[1]	36,525	37,394
Distribution lines spanning the province *(circuit-kilometres)*	123,361	122,599
Distribution customers *(number of customers)*	1,372,362	1,355,302
Rate base *(millions of dollars)*	7,389	7,056
Capital investments *(millions of dollars)*	588	703
Assets placed in-service *(millions of dollars)*	689	662

[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).



2017 Distribution Revenues

Other Business Segment

Hydro One's other business segment consists of certain corporate activities.

PRIMARY FACTORS AFFECTING RESULTS OF OPERATIONS

Transmission Revenues

Transmission revenues primarily consist of regulated 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 power generators and from third-party land use.

Distribution Revenues

Distribution revenues include regulated 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 the 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 revenues such as charges for late payments.

Purchased Power Costs

Purchased power costs are incurred by the distribution business and represent the cost of the electricity purchased by the Company for delivery to customers within Hydro One's distribution service territory. These costs are comprised of the following: the wholesale commodity cost of energy; the Global Adjustment, which is the difference between amounts the IESO pays energy producers for the electricity they produce and the actual fair market value of this electricity; and the wholesale market service and transmission charges levied by the 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 to provide safe and reliable electricity to the Company's residential, small business, commercial, and industrial customers across the province. These include costs related to distribution line clearing and forestry control to reduce power outages caused by trees, line maintenance and repair, land assessment and remediation, as well as issuing timely and accurate bills and responding to customer inquiries. 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 and amortization 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 and short-term borrowings, and gains and losses on interest rate swap agreements, net of interest earned on short-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.

RESULTS OF OPERATIONS

Net Income

Net income attributable to common shareholder for the year ended December 31, 2017 of $711 million is a decrease of $19 million or 2.6% from the prior year. Significant influences on net income included:

- decrease in transmission and distribution revenues due to lower energy consumption during 2017 resulting from milder weather;
- higher transmission revenues driven by OEB's decision on the 2017-2018 transmission rates filing;
- transmission and distribution revenues were also impacted by a reduction in the 2017 allowed regulated return on equity (ROE) from 9.19% to 8.78%;
- higher OM&A costs primarily resulting from lower bad debt expense in 2016 due to revised estimates of uncollectible accounts resulting from the stabilization of the customer information system, partially offset by a reduction of provision for payments in lieu of property taxes following a favourable reassessment of the regulations, insurance proceeds received due to failed equipment at two transformer stations, a tax recovery of previous year's expenses, reduced vegetation management costs, and lower support services costs;

- higher depreciation expense due to an increase in property, plant and equipment; and
- increased financing charges primarily due to a higher weighted average long-term debt portfolio during 2017 compared to 2016, including long-term debt assumed as part of the HOSSM acquisition in the fourth quarter of 2016.

Revenues

Year ended December 31 *(millions of dollars, except as otherwise noted)*	2017	2016	Change
Transmission	1,581	1,587	(0.4%)
Distribution	4,366	4,915	(11.2%)
Total revenues	5,947	6,502	(8.5%)
Transmission	1,581	1,587	(0.4%)
Distribution, net of purchased power	1,491	1,488	0.2%
Total revenues, net of purchased power	3,072	3,075	(0.1%)
Transmission: Average monthly Ontario 60-minute peak demand *(MW)*	19,587	20,690	(5.3%)
Distribution: Electricity distributed to Hydro One customers *(GWh)*	25,876	26,289	(1.6%)

Transmission Revenues

Transmission revenues decreased by 0.4% in 2017 primarily due to the following:

- lower average monthly Ontario 60-minute peak demand mainly due to milder weather in the first three quarters of 2017;
- decreased OEB-approved transmission rates primarily reflecting a reduction in 2017 allowed ROE for the transmission business from 9.19% to 8.78%; offset by
- higher revenues driven by the OEB's decision on the 2017-2018 transmission rates filing; and
- additional revenues resulting from the acquisition of HOSSM in the fourth quarter of 2016.

Distribution Revenues, Net of Purchased Power

Distribution revenues, net of purchased power, increased by 0.2% in 2017 primarily due to the following:

- lower energy consumption mainly resulting from milder weather in the first three quarters of 2017; offset by
- higher external revenues related to Conservation and Demand Management (CDM) incentive bonus; and
- higher OEB-approved distribution rates for 2017, net of a reduction in 2017 allowed ROE for the distribution business from 9.19% to 8.78%.

OM&A Costs

Year ended December 31 *(millions of dollars)*	2017	2016	Change
Transmission	391	410	(4.6%)
Distribution	599	613	(2.3%)
Other	24	20	20.0%
	1,014	1,043	(2.8%)

Transmission OM&A Costs

The decrease of 4.6% in transmission OM&A costs for the year ended December 31, 2017 was primarily due to:

- a reduction of provision for payments in lieu of property taxes following a favourable reassessment of the regulation;
- lower support services costs; and
- insurance proceeds received due to equipment failures at the Fairchild and Campbell transmission stations; partially offset by
- higher volume of environmental management program work.

Distribution OM&A Costs

The decrease of 2.3% in distribution OM&A costs for the year ended December 31, 2017 was primarily due to:

- continued lower expenditures for vegetation management due to strategic changes to the forestry program scope that resulted in cost efficiency and improved management of the Company's rights of ways;
- lower volume of line maintenance work;
- lower spend on development and research programs; and
- a tax recovery of previous year's expenses; partially offset by

- lower bad debt expense in 2016 due to revised estimates of uncollectible accounts as a result of stabilization of the customer information system, partially offset by lower bad debt expense in 2017 attributable to lower write-offs and improved accounts receivable aging; and
- increased storm restoration costs as a result of Hurricane Irma restoration efforts in Florida. These restoration efforts had no impact on the Company's net income, as related revenues were recorded in distribution revenues during the year.

Other OM&A Costs

The increase in other OM&A costs for the year ended December 31, 2017 was driven by higher consulting costs primarily related to strategy development and higher corporate management costs in the first quarter of 2017.

Depreciation and Amortization

The increase of $41 million or 5.3% in depreciation and amortization costs for 2017 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.

Financing Charges

The increase of $19 million or 4.8% in financing charges for the year ended December 31, 2017 was primarily due to an increase in interest expense on long-term debt driven by a higher weighted average long-term debt portfolio during 2017 including the long-term debt assumed as part of the HOSSM acquisition in the fourth quarter of 2016; partially offset by a decrease in the weighted average interest rate for long-term debt.

Income Tax Expense

Income tax expense for the year ended December 31, 2017 decreased by $15 million compared to 2016, and the Company realized an effective tax rate of approximately 14.3% in 2017, compared to approximately 15.5% realized in 2016. The decreases in the tax expense and the effective tax rate are primarily due to lower income before taxes in 2017.

SELECTED ANNUAL FINANCIAL STATISTICS

Year ended December 31 *(millions of dollars, except per share amounts)*	2017	2016	2015
Revenues	5,947	6,502	6,529
Net income attributable to common shareholder	711	730	679
Basic EPS	$4,999	$5,132	$6,340
Diluted EPS	$4,999	$5,132	$6,340
Dividends per common share declared	$105	$14	$8,750
Dividends per preferred share declared	—	—	$1.03

December 31 *(millions of dollars)*	2017	2016	2015
Total assets	25,751	25,310	24,169
Total non-current financial liabilities	9,315	10,078	8,207

QUARTERLY RESULTS OF OPERATIONS

Quarter ended *(millions of dollars, except EPS and ratio)*	Dec 31, 2017	Sep 30, 2017	Jun 30, 2017	Mar 31, 2017	Dec 31, 2016	Sep 30, 2016	Jun 30, 2016	Mar 31, 2016
Revenues	1,429	1,511	1,361	1,646	1,604	1,693	1,533	1,672
Purchased power	662	675	649	889	858	870	803	896
Revenues, net of purchased power	767	836	712	757	746	823	730	776
Net income to common shareholder	180	241	120	170	131	233	155	211
Basic and diluted EPS	$1,265	$1,694	$844	$1,195	$921	$1,638	$1,086	$1,485
Earnings coverage ratio[1]	2.7	2.5	2.6	2.7	2.8	2.8	2.7	2.6

[1] Earnings coverage ratio has been presented for the twelve months ended as of each date indicated above and has been calculated as net income before financing charges and income taxes attributable to shareholder of Hydro One, divided by the sum of financing charges, capitalized interest, and preferred dividends.

Variations in revenues and net income over the quarters are primarily due to the impact of seasonal weather conditions on customer demand and market pricing.

CAPITAL INVESTMENTS

The Company makes capital investments to maintain the safety, reliability and integrity of its transmission and distribution system 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.

Assets Placed In-Service

The following table presents Hydro One's assets placed in-service during the year ended December 31, 2017 and 2016:

Year ended December 31 *(millions of dollars)*	2017	2016	Change
Transmission	889	937	(5.1%)
Distribution	689	662	4.1%
Total assets placed in-service	1,578	1,599	(1.3%)

Transmission Assets Placed In-Service

Transmission assets placed in-service decreased by $48 million or 5.1% during the year ended December 31, 2017 primarily due to the following:

- substantial investments of two major local area supply projects, Guelph Area Transmission Refurbishment and Toronto Midtown Transmission Reinforcement, were placed in-service in 2016;
- completion of the Advanced Distribution System project at Owen Sound transmission station in 2016;
- timing of assets placed in-service for the sustainment investments at Burlington and Bruce A transmission stations; partially offset by investments at Aylmer and Overbrook transmission stations; and
- lower volume of end-of-life transformer replacements work; partially offset by
- substantial investments of major development projects at Leamington and Holland transmission stations were placed in-service in the fourth quarter of 2017;
- higher volume of overhead lines and component refurbishments and replacements; and
- the completion of the Field Workforce Optimization (Move-to-Mobile) project in June 2017.

Distribution Assets Placed In-Service

Distribution assets placed in-service increased by $27 million or 4.1% during the year ended December 31, 2017 primarily due to the following:

- higher volume of subdivision connections due to increased demand;
- the completion of the Move-to-Mobile project in June 2017;
- the completion of an operation center in Bolton in February 2017;
- the completion of the Outage Response Management System (ORMS) project in the third quarter of 2017; and
- substantial investments that were placed in-service for the Leamington transmission station feeder development project; partially offset by
- the Advanced Metering Infrastructure Wireless Telecom project was placed in-service during 2016;
- lower volume of generation connection projects; and
- lower volume of distribution station refurbishments and spare transformer purchases.

Capital Investments

The following table presents Hydro One's capital investments during the years ended December 31, 2017 and 2016:

Year ended December 31 *(millions of dollars)*	2017	2016	Change
Transmission			
Sustaining	764	750	1.9%
Development	137	156	(12.2%)
Other	67	82	(18.3%)
	968	988	(2.0%)
Distribution			
Sustaining	280	384	(27.1%)
Development	227	217	4.6%
Other	81	102	(20.6%)
	588	703	(16.4%)
Total capital investments	1,556	1,691	(8.0%)

Transmission Capital Investments

Transmission capital investments decreased by $20 million or 2.0% during the year ended December 31, 2017. Principal impacts on the levels of capital investments included:

- construction work on Clarington Transmission Station project is substantially complete and therefore, lower investments in 2017;
- decreased investments in information technology projects, primarily due to completion of certain projects and timing of work on other projects;
- lower volume of transmission station refurbishments and component replacements work; and
- substantial completion of the Guelph Area Transmission Refurbishment project in 2016; partially offset by
- higher volume of overhead lines and component refurbishments and replacements; and
- substantial completion of the Leamington transmission station project to address the electricity needs in Windsor and Essex County.

Distribution Capital Investments

Distribution capital investments decreased by $115 million or 16.4% during the year ended December 31, 2017. Principal impacts on the levels of capital investments included:

- lower volume of work within station refurbishment programs;
- lower volume of line refurbishments and replacements work;
- lower volume of wood pole replacements;
- lower volume of fleet and work equipment purchases;
- decreased investments in information technology projects, primarily due to completion of certain projects and timing of work on other projects;
- completion of the Bolton Operation Centre; partially offset by
- higher volume of work on new connections and upgrades due to increased demand.

Major Transmission Capital Investment Projects

The following table summarizes the status of significant transmission projects as at December 31, 2017:

Project Name	Location	Type	Anticipated In-Service Date	Estimated Cost	Capital Cost To Date
Development Projects:					
Supply to Essex County Transmission Reinforcement	Windsor-Essex area Southwestern Ontario	New transmission line and station	2018	$57 million[1]	$52 million
Clarington Transmission Station	Oshawa area Southwestern Ontario	New transmission station	2018	$267 million	$223 million
East-West Tie Station Expansion	Northern Ontario	New transmission connection and station expansion	2021	$157 million	$7 million
Northwest Bulk Transmission Line	Thunder Bay Northwestern Ontario	New transmission line	2024	$350 million	$1 million
Sustainment Projects:					
Bruce A Transmission Station	Tiverton Southwestern Ontario	Station sustainment	2020	$109 million[2]	$105 million
Richview Transmission Station Circuit Breaker Replacement	Toronto Southwestern Ontario	Station sustainment	2019	$103 million	$85 million
Beck #2 Transmission Station Circuit Breaker Replacement	Niagara area Southwestern Ontario	Station sustainment	2022	$93 million	$51 million
Lennox Transmission Station Circuit Breaker Replacement	Napanee Southeastern Ontario	Station sustainment	2023	$95 million	$44 million

[1] In February 2018, the estimated cost to complete the Supply to Essex County Transmission Reinforcement project was reduced from $73 million to $57 million.
[2] The estimated cost to complete the Bruce A Transmission Station project is currently under review.

Future Capital Investments

Following is a summary of estimated capital investments by Hydro One over the years 2018 to 2022. The Company's estimates are based on management's expectations of the amount of capital expenditures that will be required to provide transmission and distribution services that are efficient, reliable, and provide value for customers, consistent with the OEB's Renewed Regulatory Framework. The 2018 transmission capital investments estimates differ from the prior year disclosures, representing an annual decrease of $122 million to reflect the OEB's focus on planning practices and the pacing of sustainment capital investments, specifically, tower coating, stations, and insulator investments, as indicated in the OEB's 2017-2018 transmission rates decision issued in September 2017. The projections and the timing of 2019-2022 expenditures are subject to approval by the OEB.

The following table summarizes Hydro One's annual projected capital investments for 2018 to 2022, by business segment:

(millions of dollars)	2018	2019	2020	2021	2022
Transmission	1,010	1,217	1,278	1,486	1,404
Distribution	641	751	715	719	805
Total capital investments	**1,651**	**1,968**	**1,993**	**2,205**	**2,209**

The following table summarizes Hydro One's annual projected capital investments for 2018 to 2022, by category:

(millions of dollars)	2018	2019	2020	2021	2022
Sustainment	1,103	1,220	1,328	1,547	1,608
Development	340	484	487	490	430
Other[1]	208	264	178	168	171
Total capital investments	**1,651**	**1,968**	**1,993**	**2,205**	**2,209**

[1] "Other" capital expenditures consist of special projects, such as those relating to information technology.

SUMMARY OF SOURCES AND USES OF CASH

Hydro One's primary sources of cash flows are funds generated from operations, capital market debt issuances and bank credit facilities that are used to satisfy Hydro One's capital resource requirements, including the Company's capital expenditures, servicing and repayment of debt, and dividend payments.

Year ended December 31 *(millions of dollars)*	2017	2016
Cash provided by operating activities	1,694	1,668
Cash provided by (used in) financing activities	(212)	146
Cash used in investing activities	(1,530)	(1,855)
Decrease in cash and cash equivalents	(48)	(41)

Cash provided by operating activities

Cash from Operating Activities increased by $26 million during 2017 primarily due to changes in regulatory variance and deferral accounts, as well as lower energy-related receivables which decreased as a result of improved collections in 2017. These factors were partially offset by changes in accrual balances.

Cash provided by financing activities

Sources of cash

- The Company did not issue long-term debt in 2017, compared to proceeds from the issuance of $2.3 billion in 2016.
- The Company received proceeds of $3,795 million from the issuance of short-term notes in 2017, compared to $3,031 million received in 2016.
- The company received $486 million from issuance of preferred shares in 2017, compared to no preferred shares issued in 2016.

Uses of cash

- In 2017, the Company made returns of stated capital totalling $535 million, compared to returns of stated capital totalling $609 million made in 2016.
- The Company repaid $3,338 million of short-term notes in 2017, compared to $4,053 million repaid in 2016.
- The Company repaid $602 million of long-term debt in 2017, compared to long-term debt of $502 million repaid in 2016.

Cash used in investing activities

Uses of cash

- Capital expenditures were $119 million lower in 2017, primarily due to lower volume and timing of capital investment work.
- In 2016, the Company paid $224 million to acquire HOSSM, compared to no acquisition payments made in 2017.

LIQUIDITY AND FINANCING STRATEGY

Short-term liquidity is provided through funds from operations, Hydro One's commercial paper program, and the Company's consolidated bank credit facilities. Under the commercial paper program, Hydro One is authorized to issue up to $1.5 billion in short-term notes with a term to maturity of up to 365 days. At December 31, 2017, Hydro One had $926 million in commercial paper borrowings outstanding, compared to $469 million outstanding at December 31, 2016. In addition, the Company has revolving bank credit facilities totalling $2.3 billion maturing in 2022. 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, 2017, the Company's long-term debt in the principal amount of $10,069 million included $9,923 million of long-term debt, the majority of which was issued under Hydro One's Medium Term Note (MTN) Program, and long-term debt in the principal amount of $146 million held by HOSSM. At December 31, 2017, the maximum authorized principal amount of notes issuable under the current MTN Program prospectus filed in December 2015 was $3.5 billion, with $1.2 billion remaining available for issuance until January 2018. The long-term debt consists of notes and debentures that mature between 2018 and 2064, and at December 31, 2017, had an average term to maturity of approximately 15.8 years and a weighted average coupon rate of 4.2%.

At December 31, 2017, the Company was in compliance with all financial covenants and limitations associated with the outstanding borrowings and credit facilities.

Credit Ratings

At December 31, 2017, Hydro One's long-term and short-term debt ratings were as follows:

Rating Agency	Short-term Debt Rating	Long-term Debt Rating
DBRS Limited	R-1 (low)	A (high)
Moody's Investors Service (Moody's)[1]	Prime-2	A3
Standard & Poor's Rating Services (S&P)[1]	A-1	A

[1] On July 19, 2017, S&P and Moody's revised their outlooks on Hydro One to negative from stable, while affirming the existing debt ratings.

Effect of Interest Rates

The Company is exposed to fluctuations of interest rates as its regulated return on equity (ROE) is derived using a formulaic approach that takes into account changes in benchmark interest rates for Government of Canada debt and the A-rated utility corporate bond yield spread. 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 2017, Hydro One contributed approximately $87 million to its pension plan, compared to contributions of approximately $108 million in 2016, and incurred $88 million in net periodic pension benefit costs, compared to $116 million incurred in 2016.

In May 2017, Hydro One filed an actuarial valuation of its Pension Plan as at December 31, 2016. Based on this valuation and 2017 levels of pensionable earnings, the 2017 annual Company pension contributions have decreased by approximately $17 million from $105 million as estimated at December 31, 2016, primarily due to improvements in the funded status of the plan and future actuarial assumptions, and also reflect the impact of changes implemented by management to improve the balance between employee and Company contributions to the Pension Plan. Hydro One estimates that total Company pension contributions for 2018 and 2019 will be approximately $71 million for each year.

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".

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 and commercial commitments:

December 31, 2017 *(millions of 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	10,069	752	1,384	1,107	6,826
Long-term debt – interest payments	7,690	426	786	725	5,753
Short-term notes payable	926	926	—	—	—
Pension contributions[1]	151	71	80	—	—
Environmental and asset retirement obligations	215	28	59	65	63
Outsourcing agreements	247	139	97	4	7
Operating lease commitments	33	10	14	5	4
Long-term software/meter agreement	56	17	33	3	3
Total contractual obligations	19,387	2,369	2,453	1,909	12,656
Other commercial commitments *(by year of expiry)*					
Credit facilities[2]	2,300	—	—	2,300	—
Letters of credit[3]	177	177	—	—	—
Guarantees[4]	325	325	—	—	—
Total other commercial commitments	2,802	502	—	2,300	—

[1] Contributions to the Hydro One Pension Fund are generally made one month in arrears. The 2018 and 2019 minimum pension contributions are based on an actuarial valuation as at December 31, 2016 and projected levels of pensionable earnings.

[2] In June 2017, the maturity date of Hydro One's $2.3 billion credit facilities was extended from June 2021 to June 2022.

[3] Letters of credit consist of a $154 million letter of credit related to retirement compensation arrangements, a $16 million letter of credit provided to the IESO for prudential support, $6 million in letters of credit to satisfy debt service reserve requirements, and $1 million in letters of credit for various operating purposes.

[4] Guarantees consist of prudential support provided to the IESO by Hydro One on behalf of its subsidiaries.

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 deemed 40% equity level 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 and variance accounts over specified time frames.

The following table summarizes the status of Hydro One's major regulatory proceedings:

Application	Years	Type	Status
Electricity Rates			
Hydro One Networks	2017-2018	Transmission – Cost-of-service	OEB decision received[1]
Hydro One Networks	2015-2017	Distribution – Custom	OEB decision received
Hydro One Networks	2018-2022	Distribution – Custom	OEB decision pending
B2M LP	2015-2019	Transmission – Cost-of-service	OEB decision received
HOSSM	2017-2018	Transmission – Revenue Cap	OEB decision received
Mergers Acquisitions Amalgamations and Divestitures (MAAD)			
Orillia Power Distribution Corporation	n/a	Acquisition	OEB decision pending
Leave to Construct			
East-West Tie Station Expansion	n/a	Section 92	OEB decision pending

[1] In October 2017, the Company filed a Motion to Review and Vary the OEB's decision and filed an appeal with the Divisional Court of Ontario.

The following table summarizes the key elements and status of Hydro One's electricity rate applications:

Application	Year	ROE Allowed (A) or Forecast (F)	Rate Base	Rate Application Status	Rate Order Status
Transmission					
Hydro One Networks	2017	8.78% (A)	$10,523 million	Approved in September 2017	Approved in November 2017
	2018	9.00% (A)	$11,148 million	Approved in September 2017	Approved in December 2017
B2M LP	2017	8.78% (A)	$509 million	Approved in December 2015	Approved in June 2017
	2018	9.00% (A)	$502 million	Approved in December 2015	Filed in December 2017
	2019	9.00% (F)	$496 million	Approved in December 2015	To be filed in 2018 Q4
HOSSM	2017	9.19% (A)	$218 million	Approved in September 2017	n/a
	2018	9.19% (A)	$218 million	Approved in September 2017	n/a
Distribution					
Hydro One Networks	2017	8.78% (A)	$7,190 million	Approved in March 2015	Approved in December 2016
	2018	9.00% (A)	$7,666 million	Filed in March 2017[1]	To be filed in 2018 Q4
	2019	9.00% (F)	$8,027 million	Filed in March 2017[1]	To be filed in 2018 Q4
	2020	9.00% (F)	$8,430 million	Filed in March 2017[1]	To be filed in 2019 Q4
	2021	9.00% (F)	$8,960 million	Filed in March 2017[1]	To be filed in 2020 Q4
	2022	9.00% (F)	$9,327 million	Filed in March 2017[1]	To be filed in 2021 Q4

[1] On June 7 and December 21, 2017, Hydro One Networks filed updates to the application reflecting recent financial results and other adjustments.

Electricity Rates Applications

Hydro One Networks - Transmission

On September 28, 2017, the OEB issued its Decision and Order on Hydro One Networks' 2017 and 2018 transmission rates revenue requirements (Decision), with 2017 rates effective January 1, 2017. Key changes to the application as filed included reductions in planned capital expenditures of $126 million and $122 million for 2017 and 2018, respectively, in OM&A expenses related to compensation by $15 million for each year, and in estimated tax savings from the IPO by $24 million and $26 million for 2017 and 2018, respectively. On October 10, 2017, Hydro One Networks filed a Draft Rate Order reflecting the changes outlined in the Decision.

In its Decision, the OEB concluded that the net deferred tax asset resulting from transition from the payments in lieu of tax regime under the *Electricity Act* (Ontario) to tax payments under the federal and provincial tax regime should not accrue entirely to Hydro One's shareholders and that a portion should be shared with ratepayers. On November 9, 2017, the OEB issued a Decision and Order that calculated the portion of the tax savings that should be shared with ratepayers. The OEB's calculation would result in an impairment of Hydro One Networks' transmission deferred income tax regulatory asset of up to approximately $515 million. If the OEB were to apply the same calculation for sharing in Hydro One Networks' 2018-2022 distribution rates, for which a decision is currently outstanding, it would result in an additional impairment of up to approximately $370 million related to Hydro One Networks' distribution deferred income tax regulatory asset.

In October 2017, the Company filed a Motion to Review and Vary (Motion) the Decision and filed an appeal with the Divisional Court of Ontario (Appeal). On December 19, 2017, the OEB granted a hearing of the merits of the Motion which is scheduled for mid-February 2018. In both cases, the Company's position is that the OEB made errors of fact and law in its determination of allocation of the tax savings between the shareholders and ratepayers. The Appeal is being held in abeyance pending the outcome of the Motion. If the Decision is upheld, based on the facts known at this time, the exposure from the potential impairments would be a one-time decrease in net income of up to approximately $885 million, resulting in an annual decrease to FFO in the range of $50 million to $60 million. Based on the assumptions that the OEB applies established rate making principles in a manner consistent with its past practice and does not exercise its discretion to take other policy considerations into account, management is of the view that it is likely that the Company's Motion will be granted and the aforementioned tax savings will be allocated to the benefit of Hydro One shareholders.

In October 2017, the intervenor Anwaatin Inc. also filed a Motion to Review and Vary the OEB Decision (Anwaatin Motion) alleging that the OEB breached its duty of procedural fairness, failed to respond to certain evidence, and failed to provide reasons on the capital budget as it related to reliability issues impacting Anwaatin Inc.'s constituents. The Anwaatin Motion will be heard by the OEB on February 13, 2018.

On November 23, 2017, the OEB approved the 2017 rates revenue requirement of $1,438 million. On December 20, 2017, the OEB approved the 2018 rates revenue requirement of $1,511 million, which included a $25 million increase from the approved amount, as a result of the OEB-updated cost of capital parameters. Uniform Transmission Rates (UTRs), reflecting these approved amounts, were approved by the OEB on February 1, 2018 to be effective as of January 1, 2018.

Hydro One Networks - Distribution

On March 31, 2017, Hydro One Networks filed a custom application with the OEB for 2018-2022 distribution rates under the OEB's incentive-based regulatory framework (2018-2022 Distribution Application), which was subsequently updated on June 7 and December 21, 2017. The application reflects the level of capital investments required to minimize degradation in overall system asset condition, to meet regulatory requirements, and to maintain current reliability levels. Management expects that a decision will be received in 2018.

On November 17, 2017, Hydro One filed with the OEB a request for interim rates based on current OEB-approved rates, adjusted for an updated load forecast. On December 1, 2017, the OEB denied this request and set interim rates based on current OEB-approved rates with no adjustments.

In Hydro One's December 21, 2017 update to the 2018-2022 Distribution Application, Hydro One described the impact to the proposed revenue requirement of various developments since initially filing the application. These included, without limitation, the updated cost of capital parameters and inflation factor for 2018 issued by the OEB, and reductions in the 2018 OM&A forecast and 2018-2022 capital forecasts.

B2M LP

In December 2015, the OEB approved B2M LP's revenue requirement for years 2015 to 2019, subject to annual updates in each of 2016, 2017 and 2018 to adjust its revenue requirement for the following year consistent with the OEB's updated cost of capital parameters. On June 8, 2017, the OEB approved B2M LP's Rate Order reflecting 2017 transmission revenue requirement of $34 million, effective January 1, 2017.

On February 1, 2018, the OEB issued its Decision and Rate Order for 2018 UTRs declaring the 2018 UTRs as interim, as the B2M LP application for an update to its 2018 transmission revenue requirement is still under consideration by the OEB.

HOSSM

On September 28, 2017, the OEB issued its Decision and Order on HOSSM's 2017 transmission rates application, denying the requested revenue requirement for 2017. HOSSM's 2016 approved revenue requirement of $41 million will remain in effect for 2017 and 2018.

Hydro One Remote Communities Inc.

On August 28, 2017, Hydro One Remote Communities Inc. filed an application with the OEB seeking approval of its 2018 revenue requirement of $57 million and electricity rates effective May 1, 2018. On December 14, 2017, the OEB issued a Procedural Order with key dates for filing additional materials and reply submissions. On February 7, 2018, Hydro One Remote Communities Inc. and the intervenors in the rate proceeding reached a full settlement agreement on all issues. The agreement is expected to be reviewed by the OEB for approval in March 2018. Upon the OEB's approval, new rates are expected to be implemented by May 1, 2018.

Hydro One Remote Communities Inc. is fully financed by debt and is operated as a break-even entity with no ROE.

MAAD Applications

Orillia Power MAAD Application

In August 2016, the Company reached an agreement to acquire Orillia Power Distribution Corporation (Orillia Power). The acquisition is subject to regulatory approval by the OEB. On July 27, 2017, the OEB issued a Procedural Order No.6 (Procedural Order) in the matter of Hydro One's MAAD application to acquire Orillia Power. The Procedural Order stated that the OEB has decided to delay a decision on the Orillia Power MAAD application until Hydro One defends its cost allocation proposal in the 2018-2022 Distribution Application hearing to determine if the Orillia Power acquisition is likely to cause harm to any of its current customers. Because of the timetable of the 2018-2022 Distribution Application hearing, and the time it will take to receive a decision in that hearing, the effect of the Procedural Order will be to delay the Orillia Power MAAD application decision by as much as 18 months or more. On August 14, 2017, Hydro One filed a Motion to Review and Vary the Procedural Order requesting the OEB to allow the Orillia Power MAAD application to proceed immediately in the ordinary course. On October 24, 2017, the OEB issued a Procedural Order in response to Hydro One's Motion to Review and Vary, with key dates for filing additional materials on the Motion, hearing date, and filing of reply submissions. Final argument on the Motion to Review and Vary was filed on December 13, 2017.

On January 4, 2018, the OEB issued its Decision on Hydro One's Motion to Review and Vary, granting the motion and referring the MAAD file back to the original OEB panel for reconsideration. The OEB's findings were based on both procedural unfairness and the impact that a lengthy delay will have on the operations of Orillia Power. On February 5, 2018, the OEB issued Procedural Order No. 7 directing Hydro One to file evidence or submissions on its expectations of the overall cost structures following the deferred rebasing period and the effect on Orillia Power customers by February 15, 2018.

Other Applications

East-West Tie

In 2013, NextBridge Infrastructure (NextBridge), a partnership between NextEra Energy Canada, Enbridge Inc., and Borealis Infrastructure was designated by the OEB to complete the development work for the East-West Tie Line Project, a 230 kV, 400 km transmission line connecting Hydro One's Wawa and Lakehead transmission stations. This project is necessary to ensure the reliability of electricity supply in Northwestern Ontario, and was included as a priority project in the Province's 2010 Long-Term Energy Plan. On July 31, 2017, Hydro One filed a Leave to Construct application with the OEB to perform station upgrades to its Wawa and Lakehead transmission stations (East-West Tie Station Expansion), necessary to support the East-West Tie Line Project. Hydro One is acting as an intervenor in NextBridge's East-West Tie Line Project application.

On September 22, 2017, Hydro One filed with the OEB a Letter of Intent indicating that the Company plans to file a Leave to Construct application to construct the East-West Tie Line Project. On December 21, 2017, Hydro One re-confirmed with the OEB that it still intends to file this application in early 2018.

On November 13, 2017, NextBridge filed a letter with the OEB asserting that the OEB should strictly limit Hydro One's intervenor status to matters related to interconnection of the NextBridge East-West Tie Line Project to Hydro One transmission facilities and to ensure that Hydro One does not use its status as the Province's incumbent transmitter to compete unfairly against NextBridge's Leave to Construct application.

On December 1, 2017, the IESO released its needs assessment for the East-West Tie Line Project, as requested by the Minister of Energy. The IESO has reconfirmed that the project is still the recommended solution to supply electricity in Northwestern Ontario and continues to recommend an in-service date of 2020.

On December 5, 2017, Hydro One filed a letter with the OEB in response to NextBridge's request to impose limitations on Hydro One's participation as an intervenor. In the letter, Hydro One asked that the OEB allow Hydro One's status as an intervenor in the proceeding with full intervenor rights, and that the OEB reject NextBridge's requests relating to (i) documentation provided to Hydro One, (ii) creation of a confidentiality screen, and (iii) creation of novel filing requirements for a Leave to Construct application by Hydro One.

On December 21, 2017, both NextBridge and Hydro One received interrogatories from the OEB and Intervenors related to their respective Leave to Construct applications. Hydro One submitted its responses by the January 25, 2017 due date.

Other Regulatory Developments

Fair Hydro Plan and First Nations Rate Assistance Program

In March 2017, Ontario's Minister of Energy announced the Fair Hydro Plan, which included changes to the Global Adjustment, the Rural or Remote Electricity Rate Protection (RRRP) Program, the introduction of the First Nations rate assistance program, and improving the allocation of delivery charges across the rural and urban geographies of the province. Hydro One worked collaboratively with the OEB on the First Nations rate assistance program, and was a key stakeholder in providing solutions that address both the Global Adjustment and RRRP elements. The Fair Hydro Plan came into effect on July 1, 2017 and resulted in a reduction of approximately 25% on electricity bills for typical Ontario residential customers. The Province also launched a new Affordability Fund aimed at assisting electricity customers who cannot qualify for low-income conservation programs. Additional enhancements were also made to the existing Ontario Electricity Support Program (OESP).

Hydro One customers saw the full benefits of the Fair Hydro Plan for all electricity consumed after July 1, 2017. A typical rural residential customer using 750 kWh per month will see savings on their monthly bills of 31% on average, or approximately $600 annually. These changes did not have an impact on the net income of the Company.

Hydro One continues to work with First Nations customers living on reserves to help ensure the required applications are submitted to receive the benefits associated with the First Nations rate assistance program which provides a credit on the delivery charge.

OEB Pension and Other Post-Employment Benefits Costs

On September 14, 2017, the OEB issued its final report, Regulatory Treatment of Pension and Other Post-employment Benefits (OPEBs) Costs (Report), that establishes the use of the accrual accounting method as the default method on which to set rates for pension and OPEB amounts in cost-based applications, unless that method does not result in just and reasonable rates. The Report also provides for the establishment of a variance account, effective January 1, 2018, to track the difference between the forecasted accrual amount in rates and actual cash payments made, with asymmetric carrying charges in favour of ratepayers applied to the differential.

Hydro One currently reports and recovers its pension expense on a cash basis, and maintains the accrual method with respect to OPEBs. Transitioning from the cash basis to an accrual method for pension may have material negative rate impacts for customers, including a higher cost recovered through rates, more volatility relating to the ability to predict the effect on rates, and the pension offset (cumulative difference between the cash and accrual basis which is $981 million as at December 31, 2017) having to be recovered in rates on an accelerated basis. As the Report establishes that a basis other than the accrual accounting method may be acceptable if resulting in just and reasonable rates, Hydro One believes that the cash basis treatment of pension costs would continue to be supportable.

OTHER DEVELOPMENTS

Strategy

In 2017, the Company's Board of Directors approved Hydro One's strategy which details the Company's goal to become North America's leading utility, centered around three key pillars: (i) optimization and innovation, (ii) diversification, and (iii) growth.

Collective Agreements

On April 7, 2017, Hydro One reached an agreement with the Canadian Union of Skilled Workers (CUSW) for a renewal of the collective agreement. The agreement is for a five-year term, covering May 1, 2017 to April 30, 2022. The agreement was ratified by the CUSW and the Hydro One Board of Directors in May 2017.

Hydro One has agreements with Inergi LP (Inergi) for the provision of back office and IT outsourcing services, including settlements, source to pay services, pay operations services, information technology and finance and accounting services, expiring on December 31, 2019, and for the provision of customer service operations outsourcing services expiring on February 28, 2018. Hydro One is currently in the process of insourcing the customer service operations services and will not be renewing the existing agreement for these services with Inergi. Agreements have been reached with The Society of Energy Professionals (the Society) and the Power Workers' Union (PWU) to facilitate the insourcing of these services effective March 1, 2018.

The current collective agreement with the PWU expires on March 31, 2018. In January 2018, Hydro One and the PWU commenced collective bargaining with the official exchange of bargaining agendas. Both sides acknowledged their commitment to working towards the timely completion of collective bargaining.

Litigation

Hydro One, Hydro One Networks, Hydro One Remote Communities Inc., and Norfolk Power Distribution Inc. are defendants in a class action suit in which the representative plaintiff is seeking up to $125 million in damages related to allegations of improper billing practices. The plaintiff's motion for certification was dismissed by the court on November 28, 2017, but the plaintiff has appealed the court's decision, and it is likely that no decision will be rendered by the appeal court until the second half of 2018. At this time, an estimate of a possible loss related to this claim cannot be made.

Appointment of Chief Financial Officer

On January 28, 2018, Mr. Paul Dobson was appointed to the position of Chief Financial Officer of Hydro One, effective March 1, 2018. Mr. Dobson was most recently the Chief Financial Officer at Direct Energy Ltd. in Houston, Texas.

HYDRO ONE WORK FORCE

Hydro One has a skilled and flexible work force of approximately 5,300 regular employees and 2,000 non-regular employees province-wide, comprising of a mix of skilled trades, 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 flexibly utilize 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, 2017:

	Regular Employees	Non-Regular Employees	Total
PWU[1]	3,344	694	4,038
The Society	1,314	32	1,346
Canadian Union of Skilled Workers (CUSW) and construction building trade unions[2]	—	1,254	1,254
Total employees represented by unions	4,658	1,980	6,638
Management and non-represented employees	665	22	687
Total employees	5,323	2,002	7,325

[1] Includes 575 non-regular "hiring hall" employees covered by the PWU agreement.

[2] The construction building trade unions have collective agreements with the Electrical Power Systems Construction Association (EPSCA).

Share-based Compensation

During 2017 and 2016, the Company granted awards under its Long-term Incentive Plan, consisting of Performance Stock Units (PSUs) and Restricted Stock Units (RSUs), all of which are equity settled. At December 31, 2017 and 2016, 425,120 and 228,890 PSUs, respectively, and 388,140 and 252,440 RSUs, respectively, were outstanding.

NON-GAAP MEASURES

FFO

FFO is defined as net cash from operating activities, adjusted for (i) changes in non-cash balances related to operations, (ii) dividends paid on preferred shares, and (iii) distributions to noncontrolling interest. Management believes that FFO is helpful as a supplemental measure of the Company's operating cash flows as it excludes timing-related fluctuations in non-cash operating working capital and cash flows not attributable to the common shareholder. As such, FFO provides a consistent measure of the cash generating performance of the Company's assets.

Year ended December 31 *(millions of dollars)*	2017	2016
Net cash from operating activities	1,694	1,668
Changes in non-cash balances related to operations	(63)	(168)
Distributions to noncontrolling interest	(6)	(9)
FFO	1,625	1,491

Revenues, net of purchased power

Revenues, net of purchased power is defined as revenues less purchased power. Management believes that revenue, net of purchased power is helpful as a measure of net revenues for the Distribution segment, as purchased power is fully recovered through revenues.

Year ended December 31 *(millions of dollars)*	2017	2016
Revenues	5,947	6,502
Less: Purchased power	2,875	3,427
Revenues, net of purchased power	3,072	3,075

Year ended December 31 *(millions of dollars)*	2017	2016
Distribution revenues	4,366	4,915
Less: Purchased power	2,875	3,427
Distribution revenues, net of purchased power	1,491	1,488

FFO and Revenues, net of purchased power 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.

RELATED PARTY TRANSACTIONS

Hydro One is owned by Hydro One Limited. The Province is a shareholder of Hydro One with approximately 47.4% ownership at December 31, 2017. The IESO, Ontario Power Generation Inc. (OPG), Ontario Electricity Financial Corporation (OEFC), the OEB, and Hydro One Telecom, are related parties to Hydro One because they are controlled or significantly influenced by the Province or by Hydro One Limited. Hydro One Brampton was a related party until February 28, 2017, when it was acquired from the Province by Alectra Inc., and subsequent to the acquisition by Alectra Inc., is no longer a related party to Hydro One. The following is a summary of the Company's related party transactions during the years ended December 31, 2017 and 2016:

Year ended December 31 *(millions of dollars)*

Related Party	Transaction	2017	2016
IESO	Power purchased	1,583	2,096
	Revenues for transmission services	1,521	1,549
	Amounts related to electricity rebates	357	—
	Distribution revenues related to rural rate protection	247	125
	Distribution revenues related to the supply of electricity to remote northern communities	32	32
	Funding received related to CDM programs	59	63
OPG	Power purchased	9	6
	Revenues related to provision of construction and equipment maintenance services	2	4
	Costs related to the purchase of services	1	1
OEFC	Power purchased from power contracts administered by the OEFC	2	1
OEB	OEB fees	8	11
Hydro One Brampton	Cost recovery from management, administrative and smart meter network services	—	3
Hydro One Limited	Return of stated capital	535	609
	Dividends paid	15	2
	Stock-based compensation costs	23	24
	Cost recovery for services provided	6	—
Hydro One Telecom	Services received - costs expensed	24	24
	Services received - costs capitalized	—	12
	Revenues for services provided	3	3
2587264 Ontario Inc.	Promissory note issued and repaid[1]	486	—
	Preferred shares issued[2]	486	—

[1] On October 17, 2017, Hydro One issued a promissory note to 2587264 Ontario Inc., a subsidiary of Hydro One Limited, totalling $486 million. On November 20, 2017, Hydro One repaid the $486 million promissory note to 2587264 Ontario Inc., as well as interest totalling $1 million.

[2] On November 20, 2017, Hydro One issued 485,870 Class B preferred shares to 2587264 Ontario Inc. for proceeds of $486 million.

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 outstanding or 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, costs of debt and income taxes, or to earn a particular ROE. A failure to obtain acceptable rate orders, or approvals of appropriate returns on equity and costs actually incurred, such as occurred in the September 28, 2017 and November 9, 2017 OEB decisions (details above in "Electricity Rates Applications - Hydro One Networks - Transmission"), 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 and cash flows could be impacted.

Risks Relating to Actual Performance Against Forecasts

The Company's ability to recover the actual costs of providing service and earn the allowed ROE 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, administration, capital and financing costs above those included in the Company's approved revenue requirement. The inability to obtain acceptable rate decisions or to 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 can be expected to 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 Conservation and Demand Management programs whose results exceed forecasted expectations.

Risks Relating to Rate-Setting Models for Transmission and Distribution

The OEB approves and periodically changes the ROE for transmission and distribution businesses. The OEB may in the future decide to reduce the allowed ROE for either of these businesses, modify the formula or methodology it uses to determine the ROE, or reduce the weighting of the equity component of the deemed capital structure. Any such reduction could reduce the net income of the Company.

The OEB's recent Custom Incentive Rate-setting model requires that the term of a custom rate application be a minimum five-year period. There are risks associated with forecasting key inputs such as revenues, operating expenses and capital, 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.

After rates are set as part of a Custom Incentive Rate application, the OEB expects there to be no further rate applications for annual updates within the five-year term, unless there are exceptional circumstances, with the exception of the clearance of established deferral and variance accounts. For example, the OEB does not expect to address annual rate applications for updates for cost of capital (including ROE), working capital allowance or sales volumes. If there were an increase in interest rates over the period of a rate decision and no corresponding changes were permitted to the Company's allowed cost of capital (including ROE), then the result could be a decrease in the Company's financial performance.

To the extent that the OEB approves an In-Service Variance Account for the transmission and/or distribution businesses, and should the Company fail to meet the threshold levels of in-service capital, the OEB may reclaim a corresponding portion of the Company's revenues.

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 may be 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.

Any regulatory decision by the OEB to disallow or limit the recovery of any capital expenditures 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 Regulatory Treatment of Deferred Tax Asset

As a result of leaving the PILs Regime and entering the Federal Tax Regime in connection with the IPO of the Company, 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. The OEB's September 28, 2017 and November 9, 2017 decisions (see details above in "Electricity Rates Applications - Hydro One Networks - Transmission") alter Hydro One's allocation of the tax savings resulting from the deferred tax asset. If this approach is followed (pending the outcome of the Motion and Appeal), the exposure from the potential impairment from the regulatory treatment of the deferred tax asset could be a one-time decrease in net income, resulting in annual decreases to FFO.

Risks Relating to Other Applications to the OEB

The Company is also subject to the risk that it will not obtain, or will not obtain in a timely manner, 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.

Indigenous 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)) (Reserve) lands, and lands over which Indigenous people have Aboriginal, treaty, or other legal claims. Some Indigenous 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 and/or settlement of 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 give rise to the Crown's duty to consult and potentially accommodate Indigenous 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 an Indigenous 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 citizens. 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 OEFC 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. For each permit, the Company must negotiate an agreement (in the form of a memorandum of understanding) with the First Nation, the OEFC and any members of the First Nation who have occupancy rights. The agreement includes provisions whereby the First Nation consents to the issuance of 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 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 and restore the lands 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 example, Hydro One's licensed transmission and distribution businesses are required to comply with the terms of their licences, 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 North American Electric Reliability Corporation (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, requirements 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. 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. Where insurance is available for other assets, such insurance coverage may have deductibles, limits and/or exclusions. 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 or costs related to ensuring its continued ability to transmit or distribute electricity.

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. The Company must also comply with legislative and licence requirements relating to the collection, use and disclosure of personal information and information regarding consumers, wholesalers, generators and retailers.

Cyber-attacks or unauthorized access to corporate and information technology systems 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. Due to operating critical infrastructure, Hydro One may be at greater risk of cyber-attacks from third parties (including state run or controlled parties) that could impair or incapacitate its assets. In addition, in the course of its operations, the Company collects, uses, processes and stores information which could be exposed in the event of a cyber-security incident or other unauthorized access or disclosure, such as information about customers, suppliers, counterparties, employees and other third parties.

Security and system disaster recovery controls are in place; however, 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.

Labour Relations Risk

The substantial majority of the Company's employees are represented by either the PWU or the Society. 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 reached an agreement with the PWU 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 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 five-year term, covering the period from May 1, 2017 to April 30, 2022. Additionally, the EPSCA and a number of construction unions have reached renewal agreements, to which Hydro One is bound, for a five-year term, covering the period from May 1, 2015 to April 30, 2020. Agreements have also been reached with the Society and the PWU to facilitate the insourcing of customer service operations services effective March 1, 2018. Future negotiations with unions present the risk of a labour disruption and the ability to sustain the continued supply of energy to customers. The Company also 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 requirements of providing service to customers. Any of these could have a material adverse effect on the Company.

Work Force Demographic Risk

By the end of 2017, approximately 22% of the Company's employees who are members of the Company's defined benefit and defined contribution pension plans were eligible for retirement, and by the end of 2018, approximately 20% could be eligible. These percentages are not evenly spread across the Company's work force, but tend to be most significant in the most senior levels of the Company's staff and especially among management staff. During 2017, approximately 5% of the Company's work force (up from 3% in 2016) elected to retire. Accordingly, the Company's continued success will be tied to its ability to continue to attract and retain sufficient qualified staff to replace the capability lost through retirements and meet the demands of the Company's work programs.

In addition, the Company expects the skilled labour market for its industry will remain highly competitive. Many of the Company's current and potential employees being sought after possess skills and experience that are also highly coveted 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.

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 has substantial debt principal repayments, including $752 million in 2018, $731 million in 2019, and $653 million in 2020. In addition, from time to time, the Company may draw on its syndicated bank lines and/or issue short-term debt under Hydro One's $1.5 billion commercial paper program which would mature within approximately one year of issuance. The Company also plans to incur continued material capital expenditures for each of 2018 and 2019. 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, an inability of the Corporation to comply with its debt covenants, 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 ROE 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 ROE in a deemed regulatory capital structure of 60% debt and 40% equity provides for increases and decreases depending on changes in benchmark interest rates for Government of Canada debt and the A-rated utility corporate bond yield spread. The Company estimates that a decrease of 100 basis points in the combination of the forecasted long-term Government of Canada bond yield and the A-rated utility corporate bond yield spread used in determining its rate of return would reduce the Company's transmission business' 2019 net income by approximately $24 million. For the distribution business, after distribution rates are set as part of a Custom Incentive Rate application, the OEB does not expect to address annual rate applications for updates to allowed ROE, so fluctuations will have no impact to net income. 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 agreements which enable net settlement, and by monitoring the financial condition of counterparties. The Company does not trade in any energy derivatives. 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 numbers of generation facilities to the distribution network has resulted in greater than expected usage of some of the Company's equipment. 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 Indigenous 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. Failure to receive approvals for projects when spending has already occurred would result in the inability of the Company to recover the investment in the project as well as forfeit the anticipated return on investment. The assets involved may be considered impaired and result in the write off of the value of the asset, negatively impacting net income. External factors are considered in the Company's planning process. If the Company is unable to carry out capital expenditure plans in a timely manner, equipment performance may degrade, which may reduce network capacity, result in customer interruptions, compromise the reliability of the Company's networks 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

The Company is subject to provincial health and safety legislation. Findings of a failure to comply with this legislation could result in penalties and reputational risk, which could negatively impact the Company.

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. 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. Failure to obtain necessary approvals or permits could result in an inability to complete projects.

Hydro One emits certain greenhouse gases, including sulphur hexafluoride or "SF_6". There are increasing regulatory requirements and costs, along with attendant risks, associated with the release of such greenhouse gases, all of which could impose additional material costs on Hydro One.

Any 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 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, 2016, and was filed in May 2017, covering a three-year period from 2017 to 2019. Hydro One's contributions to its pension plan satisfy, and are expected to satisfy, minimum funding requirements. Contributions beyond 2019 will depend on the funded position of the plan, which is determined by investment returns, interest rates and changes in benefits and actuarial assumptions at that 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.

In 2017, the OEB released a report establishing the use of the accrual accounting method as the default method on which to set rates for pension and OPEB amounts in cost-based applications, unless that method does not result in just and reasonable rates. Hydro One currently reports and recovers its pension expense on a cash basis, and maintains the accrual method with respect to OPEBs. Transitioning from the cash basis to an accrual method for pension may have material negative rate impacts for customers or material negative impacts on the company should recovery of costs be disallowed by the OEB. See "- Other Post-Employment and Post-Retirement Benefits Risks".

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. Any element of total compensation costs which is disallowed in whole or part by the OEB and not recoverable from customers in rates could result in costs which could be material and could 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. In 2017, the OEB released a report establishing the use of the accrual accounting method as the default method on which to set rates for pension and OPEB amounts in cost-based applications, unless that method does not result in just and reasonable rates. Hydro One currently maintains the accrual accounting method with respect to OPEBs. If the OEB directed Hydro One to transition to a different accounting method for OPEBs, this could result in income volatility, due to an inability of the company to book the difference between the accrual and cash as a regulatory asset. 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

Hydro One has entered into an outsourcing arrangement with a third party for the provision of back office and IT 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 and fully transitioned, the Company could be required 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 becomes involved in, is named as a party to and is 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. See also "Other Developments - Litigation".

Transmission Assets on Third-Party Lands Risk

Some of the lands on which the Company's transmission assets are located are owned by third parties, including the Province and federal Crown, and are or may become subject to land claims by First Nations. The Company requires valid occupation rights to occupy such lands (which may take the form of land use permits, easements or otherwise). If the Company does not have valid occupational rights on third-party owned lands or has occupational rights that are subject to expiry, it may incur material costs to obtain or renew such occupational rights, or if such occupational rights cannot be renewed or obtained it may incur material costs to remove and relocate its assets and restore the subject land. If the Company does not have valid occupational rights and must incur costs as a result, this could have a material adverse effect on the Company or otherwise materially adversely impact the Company's operations.

Reputational, Public Opinion and Political Risk

Reputation risk is the risk of a negative impact to Hydro One's business, operations or financial condition that could result from a deterioration of Hydro One's reputation. Hydro One's reputation could be negatively impacted by changes in public opinion, attitudes towards the Company's privatization, failure to deliver on its customer promises and other external forces. Adverse reputational events or political actions could have negative impacts on Hydro One's business and prospects including, but not limited to, delays or denials of requisite approvals, such as denial of requested rates, and accommodations for Hydro One's planned projects, escalated costs, legal or regulatory action, and damage to stakeholder relationships.

Risk associated with change in Hydro One Limited capital structure

A change in the capital structure of Hydro One Limited could cause credit rating agencies which rate the outstanding debt obligations of Hydro One to re-evaluate and potentially downgrade their current credit ratings, which could increase the Company's borrowing costs.

Risks Relating to the Company's Relationship with Hydro One Limited and the Province

Indirect Ownership and Continued Influence by the Province and Voting Power

The Province currently owns approximately 47.4% of the outstanding common shares of Hydro One Limited and it is expected to continue to maintain a significant ownership interest in voting securities of Hydro One Limited for an indefinite period.

As a result of its significant ownership of the common shares of Hydro One Limited, the Province has, and is expected indefinitely to have, the ability to determine or significantly influence the outcome of shareholder votes at Hydro One Limited, subject to the restrictions in the governance agreement entered into between Hydro One Limited and the Province dated November 5, 2015 (Governance Agreement; available on SEDAR at www.sedar.com). Despite the terms of the Governance Agreement in which the Province has agreed to engage in the business and affairs of Hydro One Limited as an investor and not as a manager, there is a risk that the Province's engagement in the business and affairs of Hydro One Limited as an investor will be informed by its policy objectives and may influence the conduct of the business and affairs of Hydro One Limited in ways that may not be aligned with the interests of other shareholders of Hydro One Limited. This influence may also extend to Hydro One. As a result, the Province may influence the conduct of the business and affairs of Hydro One, and decisions may be made by the Province as a shareholder of Hydro One Limited which may not be aligned with the interests of the other security holders of Hydro One.

Composition of the Board of Directors of Hydro One

Under the Governance Agreement, Hydro One Limited has agreed that the board of directors of Hydro One and Hydro One Networks will be constituted to have the same members as the board of directors of Hydro One Limited, unless the board of directors of Hydro One Limited determines otherwise. The Governance Agreement contains provisions governing the independence of the members of the board of Hydro One Limited and the ability of the Province to nominate and, in certain circumstances, remove directors, which could indirectly impact the composition of the board of directors of Hydro One in a manner which may not be aligned with the interests of the other security holders of Hydro One. 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 Limited. Those same individuals, to the extent they are also on the board of directors of Hydro One, could similarly give disproportionate weight to the Province's indirect interest in Hydro One in exercising their business judgment and balancing the interests of the stakeholders of Hydro One.

More Extensive Regulation

Although under the Governance Agreement, the Province has agreed to engage in the business and affairs of Hydro One Limited 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 Hydro One Limited, which in turn could have a material adverse effect on Hydro One.

Prohibitions on Selling the Company's Transmission or Distribution Business

The *Electricity Act* prohibits Hydro One Limited 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 Hydro One Limited, and in turn, Hydro One, 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 Hydro One Limited, Hydro One or their security holders.

CRITICAL ACCOUNTING ESTIMATES AND JUDGMENTS

The preparation of Hydro One Consolidated Financial Statements requires the Company to make key estimates and critical 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 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. At the end of each month, electricity delivered to customers since the date of the last billed meter reading is estimated, and the corresponding unbilled revenue is recorded. The unbilled revenue estimate is affected by energy consumption, weather, and changes in the composition of customer classes.

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, 2017 decreased to 3.40% (from 3.90% at December 31, 2016) for pension benefits and decreased to 3.40% (from 3.90% at December 31, 2016) for the post-retirement and post-employment plans. The decrease in the discount rate has resulted in a corresponding increase in employee future benefits liabilities for the pension, 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. The Company believes 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 1.80% per annum as at December 31, 2016 to approximately 1.60% per annum as at December 31, 2017. 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, 2017.

Salary Increase Assumptions

Salary increases should reflect general wage increases plus an allowance for merit and promotional increases for current members of the plan, and should be consistent with the assumptions for consumer price inflation and real wage growth in the economy. The merit and promotion scale was developed based on the salary increase assumption review performed in 2017. The review considers actual salary experience from 2002 to 2016 using valuation data for all active members as at December 31, 2016, based on age and service and Hydro One's expectation of future salary increases. Additionally, the salary scale reflect negotiated salary rate increases over the contract period.

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 used at December 31, 2017 is 95% of 2014 Canadian Pensioners Mortality Private Sector table projected generationally using improvement Scale B.

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. For the post-retirement benefit plans, a trend study of historical Hydro One experience was conducted in 2017, which resulted in a change in the prescription drug, dental and hospital trends to be used for 2017 year-end reporting purposes. A 1% increase in the health care cost trends would result in a $29 million increase in 2017 interest cost plus service cost, and a $250 million increase in the benefit liability at December 31, 2017.

Valuation of Deferred Tax Assets

Hydro One assesses the likelihood of realizing deferred tax assets by reviewing all readily available current and historical information, including a forecast of future taxable income. To the extent management considers it is more likely than not that some portion or all of the deferred tax assets will not be realized, a valuation allowance is recognized.

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. As at December 31, 2017, no asset impairment had been recorded for assets within Hydro One's 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, 2017. Goodwill represents the cost of acquired distribution and transmission companies that is in excess of the fair value of the net identifiable assets acquired at the acquisition date.

DISCLOSURE CONTROLS AND PROCEDURES AND INTERNAL CONTROL OVER FINANCIAL REPORTING

Disclosure controls and procedures are part of a broad internal control framework integral to ensuring that the Company fairly presents in all material respects the financial condition, results of operations and cash flows of the Company for the periods presented in this MD&A and the Company's Annual Report. Disclosure controls and procedures include processes designed to ensure that information is recorded, processed, summarized and reported on a timely basis to the Company's management, including its Chief Executive and Chief Financial Officers, as appropriate, to make timely decisions regarding required disclosure. At the direction of the Company's Chief Executive Officer and the Senior Vice President, Finance, acting in the capacity of Chief Financial Officer, management evaluated disclosure controls and procedures as of the end of the period covered by this report. Based on that evaluation, management concluded that the Company's disclosure controls and procedures were effective at a reasonable level of assurance as at December 31, 2017.

Internal control over financial reporting is a subset of the internal control framework designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with US GAAP. The Company's internal control over financial reporting framework includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and disposition of the assets of the Company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with US GAAP, and that receipts and expenditures of the Company are being made only in accordance with authorization of management and directors of the Company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the Company's assets that could have a material effect on the Company's consolidated financial statements.

The Company's management, at the direction of the Chief Executive Officer and with the participation of the Senior Vice President, Finance, acting in the capacity of Chief Financial Officer, evaluated the effectiveness of the design and operation of internal control over financial reporting based on the framework and criteria established in the Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on that evaluation, management concluded that the Company's internal control over financial reporting was effective at a reasonable level of assurance as at December 31, 2017.

Together, disclosure controls and procedures and internal control over financial reporting provide internal control over reporting and disclosure. Internal control, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives and due to its inherent limitations, may not prevent or detect all misrepresentations. Furthermore, the effectiveness of internal control is affected by change and subject to the risk that internal control effectiveness may change over time.

The role of Chief Financial Officer was vacated effective May 19, 2017. Responsibilities of the Chief Financial Officer have been temporarily assigned to other senior executives with full oversight provided by the Chief Executive Officer. This model is expected to remain in place until Paul Dobson assumes the role of the new Chief Financial Officer on March 1, 2018. There were no significant changes in the design of the Company's internal control over financial reporting during the three months ended December 31, 2017 that have materially affected, or are reasonably likely to materially affect, the operation of the Company's internal control over financial reporting.

Management will continue to monitor its systems of internal control over reporting and disclosure and may make modifications from time to time as considered necessary.

NEW ACCOUNTING PRONOUNCEMENTS

The following tables present Accounting Standards Updates (ASUs) issued by the Financial Accounting Standards Board that are applicable to Hydro One:

Recently Adopted Accounting Guidance

ASU	Date issued	Description	Effective date	Anticipated impact on Hydro One
2016-06	March 2016	Contingent call (put) options that are assessed to accelerate the payment of principal on debt instruments need to meet the criteria of being "clearly and closely related" to their debt hosts.	January 1, 2017	No impact upon adoption

Recently Issued Accounting Guidance Not Yet Adopted

ASU	Date issued	Description	Effective date	Anticipated impact on Hydro One
2014-09 2015-14 2016-08 2016-10 2016-12 2016-20 2017-05 2017-10 2017-13 2017-14	May 2014 – November 2017	ASU 2014-09 was issued in May 2014 and provides guidance on revenue recognition relating to 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. ASU 2015-14 deferred the effective date of ASU 2014-09 by one year. Additional ASUs were issued in 2016 and 2017 that simplify transition and provide clarity on certain aspects of the new standard.	January 1, 2018	Hydro One has completed the review of all its revenue streams and has concluded that there will be no material impact upon adoption.
2016-02 2018-01	February 2016 – January 2018	Lessees are required to recognize the rights and obligations resulting from operating leases as assets (right to use the underlying asset for the term of the lease) and liabilities (obligation to make future lease payments) on the balance sheet. ASU 2018-01 permits an entity to elect an optional practical expedient to not evaluate under Topic 842 land easements that exist or expired before the entity's adoption of Topic 842 and that were not previously accounted for as leases under Topic 840.	January 1, 2019	An initial assessment is currently underway encompassing a review of existing leases, which will be followed by a review of relevant contracts. No quantitative determination has been made at this time. The Company is on track for implementation of this standard by the effective date.
2016-15	August 2016	The amendments provide guidance for eight specific cash flow issues with the objective of reducing the existing diversity in practice.	January 1, 2018	No material impact
2017-01	January 2017	The amendment clarifies the definition of a business and provides additional guidance on evaluating whether transactions should be accounted for as acquisitions (or disposals) of assets or businesses.	January 1, 2018	No material impact
2017-04	January 2017	The amendment removes the second step of the current two-step goodwill impairment test to simplify the process of testing goodwill.	January 1, 2020	Under assessment
2017-07	March 2017	Service cost components of net benefit cost associated with defined benefit plans are required to be reported in the same line as other compensation costs arising from services rendered by the Company's employees. All other components of net benefit cost are to be presented in the income statement separately from the service cost component. Only the service cost component is eligible for capitalization where applicable.	January 1, 2018	Hydro One has applied for a regulatory deferral account to maintain the capitalization of OPEB related costs. As such, there will be no material impact.
2017-09	May 2017	Changes to the terms or conditions of a share-based payment award will require an entity to apply modified accounting unless the modified award meets all conditions stipulated in this ASU.	January 1, 2018	No impact
2017-11	July 2017	When determining whether certain financial instruments should be classified as liabilities or equity instruments, a down round feature no longer precludes equity classification when assessing whether the instrument is indexed to an entity's own stock.	January 1, 2019	Under assessment
2017-12	August 2017	Amendments will better align an entity's risk management activities and financial reporting for hedging relationships through changes to both the designation and measurement guidance for qualifying hedging relationships and the presentation of hedge results.	January 1, 2019	Under assessment

SUMMARY OF FOURTH QUARTER RESULTS OF OPERATIONS

Three months ended December 31 *(millions of dollars, except EPS)*	2017	2016	Change
Revenues			
Distribution	1,049	1,228	(14.6%)
Transmission	380	376	1.1%
	1,429	1,604	(10.9%)
Costs			
Purchased power	662	858	(22.8%)
OM&A			
Distribution	147	162	(9.3%)
Transmission	84	115	(27.0%)
Other	(1)	6	(116.7%)
	230	283	(18.7%)
Depreciation and amortization	213	201	6.0%
	1,105	1,342	(17.7%)
Income before financing charges and income taxes	**324**	**262**	**23.7%**
Financing charges	101	101	0.0%
Income before income taxes	**223**	**161**	**38.5%**
Income taxes	41	28	46.4%
Net income	**182**	**133**	**36.8%**
Net income attributable to common shareholder of Hydro One	**180**	**131**	**37.4%**
Basic and Diluted EPS	$1,265	$921	37.4%
Capital Investments			
Distribution	161	201	(19.9%)
Transmission	267	274	(2.6%)
	428	**475**	**(9.9%)**
Assets Placed In-Service			
Distribution	207	211	(1.9%)
Transmission	522	488	7.0%
	729	**699**	**4.3%**

Net Income

Net income attributable to common shareholder for the quarter ended December 31, 2017 of $180 million is an increase of $49 million or 37.4% from the prior year. Significant influences on net income included:

- increase in distribution revenues due to higher energy consumption;
- higher transmission revenues driven by OEB's decision on the 2017-2018 transmission rates filing;
- transmission and distribution revenues were also impacted by a reduction in the 2017 allowed regulated return on equity (ROE) from 9.19% to 8.78%;
- lower OM&A costs primarily resulting from a reduction of provision for payments in lieu of property taxes following a favourable reassessment of the regulations, insurance proceeds received on failed equipment at two transformer stations, a tax recovery of previous year's expenses, lower support services costs, and reduced vegetation management costs; and
- higher depreciation expense due to an increase in rate base.

Revenues

The quarterly increase of $4 million or 1.1% in transmission revenues was primarily due to higher revenues driven by the OEB's decision on the 2017-2018 transmission rates filing, partially offset by lower OEB-approved transmission rates.

The quarterly increase of $17 million or 4.6% in distribution revenues, net of purchased power, was primarily due to higher energy consumption mainly resulting from colder weather in the fourth quarter of 2017; and higher external revenues related to CDM incentive bonus; partially offset by reduction in 2017 allowed ROE for the distribution business.

OM&A Costs

The quarterly decrease of $31 million or 27.0% in transmission OM&A costs was primarily due to a reduction of provision for payments in lieu of property taxes following a favourable reassessment of the regulations, lower support services costs, and insurance proceeds received due to equipment failures at the Fairchild and Campbell transmission stations.

The quarterly decrease of $15 million or 9.3% in distribution OM&A costs was primarily due to lower expenditures for vegetation management programs due to strategic changes to the forestry program scope that resulted in cost efficiency and improved management of the Company's rights of ways; lower bad debt expense attributable to lower write-offs and improved accounts receivable aging; and a tax recovery of previous year's expenses.

A further decrease of $7 million in other OM&A is primarily due to lower corporate organizational costs in the other segment.

Depreciation and Amortization

The increase of $12 million or 6.0% in depreciation and amortization costs for the fourth quarter of 2017 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.

Financing Charges

The financing charges for the fourth quarter of 2017 were comparable to prior year.

Income Taxes

Income tax expense for the fourth quarter of 2017 increased by $13 million compared to 2016, and the Company realized an effective tax rate of approximately 18.4% in the fourth quarter of 2017, compared to approximately 17.4% realized in 2016. The increase in the tax expense is primarily due to higher income before taxes in the fourth quarter of 2017.

Capital Investments

The decrease in transmission capital investments during the fourth quarter was primarily due to the following:

- lower volume and timing of spare transformer equipment purchases;
- timing and substantial completion of major development projects, including Guelph Area Transmission Refurbishment, Midtown Transmission Reinforcement, and Holland and Hawthorne transmission stations; and
- timing of work related to the Clarington Transmission Station project; partially offset by
- timing on work on station refurbishments and equipment replacement projects; and
- timing of work at Leamington transmission station.

The decrease in distribution capital investments during the fourth quarter was primarily due to the following:

- timing of capital contributions for jointly used facilities and lower volume of line relocation work;
- substantial completion of work on the Bolton Operation Centre in the fourth quarter of 2016;
- lower volume of work within distribution station refurbishment programs;
- timing of information technology projects including e-Billing and website redesign;
- lower volume of line refurbishments and replacements work; and
- lower volume of fleet and work equipment purchases; partially offset by
- high volume of work on new connections and upgrades due to increased demand.

Assets Placed In-Service

The increase in transmission assets placed in-service during the fourth quarter was primarily due to the following:

- substantial investments of major development projects at Leamington and Holland transmission stations were placed in-service in the fourth quarter of 2017;
- higher volume of investments for overhead lines and component refurbishments and replacement programs;
- timing of assets placed in-service for sustainment investment projects including the transformer asset replacement project at Overbrook transmission station and the breaker replacement project at Richview transmission station; partially offset by
- a large number of cumulative sustainment investments that were placed in-service in the fourth quarter of 2016 at the Bruce A and Burlington transmission stations;
- timing of investments that were placed in-service for the Advanced Distribution System project; and
- timing of assets that were placed in-service in the fourth quarter of 2016 for certain information technology development projects.

The decrease in distribution assets placed in-service during the fourth quarter was primarily due to the following:

- timing of distribution station refurbishments and spare transformer purchases; and
- lower volume of work on distribution generation connection projects; partially offset by
- higher volume of subdivision connections due to increased demand; and
- substantial investments that were placed in-service in the fourth quarter of 2017 for the Leamington transmission station feeder development project.

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, regulatory and economic environments in which it operates, and include beliefs and assumptions made by the management of the Company. Such statements include, but are not limited to, statements regarding: the Company's transmission and distribution rate applications, including resulting decisions, rates and expected impacts and timing; the Company's liquidity and capital resources and operational requirements; the standby credit facilities; expectations regarding the Company's financing activities; the Company's maturing debt; ongoing and planned projects and initiatives, including expected results and completion dates; expected future capital investments, including expected timing and investment plans; contractual obligations and other commercial commitments; the OEB; the Motion and the Appeal; the Anwaatin Motion; the East-West Tie Line Project and related regulatory application; collective agreements; Inergi outsourcing and customer service operations arrangements; the pension plan, future pension contributions, valuations and expected impacts; impacts of OEB treatment of pension and OPEBs costs; dividends; credit ratings; class action litigation; Hydro One's strategy and goals; effect of interest rates; non-GAAP measures; critical accounting estimates, including environmental liabilities, regulatory assets and liabilities, and employee future benefits; occupational rights; internal control over financial reporting and disclosure; the Fair Hydro Plan and First Nations Rate Assistance Program, including expected outcomes and impacts; recent accounting-related guidance; the Company's acquisitions and mergers, including Orillia Power; the appointment of Hydro One's new Chief Financial Officer; cyber and data security; expectations related to work force demographics; and reputational, public opinion and political risk. 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 share ownership of Hydro One's parent corporation 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 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 maintaining a complex information technology system infrastructure;
- the risks related to the Company's work force 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;
- 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 functions currently outsourced if agreements 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 investments, 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, including the Company's Annual Information Form, is available on SEDAR at www.sedar.com, the US Securities and Exchange Commission's EDGAR website at www.sec.gov/edgar.shtml, and the Company's website at www.HydroOne.com/Investors.

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 12, 2018.

Management is responsible for establishing and maintaining adequate disclosure controls and procedures and internal control over financial reporting as described in the annual MD&A. Management evaluated the effectiveness of the design and operation of internal control over financial reporting based on the framework and criteria established in the Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on that evaluation, management concluded that the Company's internal control over financial reporting was effective at a reasonable level of assurance as of December 31, 2017. As required, the results of that evaluation were reported to the Audit Committee of the Hydro One Board of Directors and the external auditors.

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 control over reporting and disclosure. 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.

On behalf of Hydro One's management:

Mayo Schmidt
President and Chief Executive Officer

Christopher Lopez
Senior Vice President, Finance
acting in the capacity of chief financial officer

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, 2017 and December 31, 2016, 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, 2017 and December 31, 2016, 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 12, 2018

HYDRO ONE LIMITED
CONSOLIDATED STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME
For the years ended December 31, 2017 and 2016

Year ended December 31 *(millions of Canadian dollars, except per share amounts)*	2017	2016
Revenues		
Distribution (includes $279 related party revenues; 2016 – $160) *(Note 27)*	4,366	4,915
Transmission (includes $1,523 related party revenues; 2016 – $1,553) *(Note 27)*	1,578	1,584
Other	46	53
	5,990	6,552
Costs		
Purchased power (includes $1,594 related party costs; 2016 – $2,103) *(Note 27)*	2,875	3,427
Operation, maintenance and administration *(Note 27)*	1,066	1,069
Depreciation and amortization *(Note 5)*	817	778
	4,758	5,274
Income before financing charges and income taxes	**1,232**	**1,278**
Financing charges *(Note 6)*	439	393
Income before income taxes	**793**	**885**
Income taxes *(Note 7)*	111	139
Net income	**682**	**746**
Other comprehensive income	1	—
Comprehensive income	**683**	**746**
Net income attributable to:		
Noncontrolling interest *(Note 26)*	6	6
Preferred shareholders	18	19
Common shareholders	658	721
	682	**746**
Comprehensive income attributable to:		
Noncontrolling interest *(Note 26)*	6	6
Preferred shareholders	18	19
Common shareholders	659	721
	683	**746**
Earnings per common share *(Note 24)*		
Basic	$1.11	$1.21
Diluted	$1.10	$1.21
Dividends per common share declared *(Note 23)*	$0.87	$0.97

See accompanying notes to Consolidated Financial Statements.

HYDRO ONE LIMITED
CONSOLIDATED BALANCE SHEETS
At December 31, 2017 and 2016

December 31 *(millions of Canadian dollars)*	2017	2016
Assets		
Current assets:		
Cash and cash equivalents	25	50
Accounts receivable *(Note 8)*	636	838
Due from related parties *(Note 27)*	253	158
Other current assets *(Note 9)*	105	102
	1,019	1,148
Property, plant and equipment *(Note 10)*	19,947	19,140
Other long-term assets:		
Regulatory assets *(Note 12)*	3,049	3,145
Deferred income tax assets *(Note 7)*	987	1,235
Intangible assets *(Note 11)*	369	349
Goodwill *(Note 4)*	325	327
Other assets	5	7
	4,735	5,063
Total assets	**25,701**	**25,351**
Liabilities		
Current liabilities:		
Short-term notes payable *(Note 15)*	926	469
Long-term debt payable within one year *(Notes 15, 17)*	752	602
Accounts payable and other current liabilities *(Note 13)*	905	945
Due to related parties *(Note 27)*	157	147
	2,740	2,163
Long-term liabilities:		
Long-term debt (includes $541 measured at fair value; 2016 – $548) *(Notes 15, 17)*	9,315	10,078
Convertible debentures *(Notes 16, 17)*	487	—
Regulatory liabilities *(Note 12)*	128	209
Deferred income tax liabilities *(Note 7)*	71	60
Other long-term liabilities *(Note 14)*	2,707	2,752
	12,708	13,099
Total liabilities	**15,448**	**15,262**
Contingencies and Commitments (Notes 29, 30)		
Subsequent Events (Note 32)		
Noncontrolling interest subject to redemption *(Note 26)*	22	22
Equity		
Common shares *(Note 22)*	5,631	5,623
Preferred shares *(Note 22)*	418	418
Additional paid-in capital *(Note 25)*	49	34
Retained earnings	4,090	3,950
Accumulated other comprehensive loss	(7)	(8)
Hydro One shareholders' equity	10,181	10,017
Noncontrolling interest *(Note 26)*	50	50
Total equity	**10,231**	**10,067**
	25,701	**25,351**

See accompanying notes to Consolidated Financial Statements.

On behalf of the Board of Directors:

David Denison
Chair

Philip Orsino
Chair, Audit Committee

HYDRO ONE LIMITED
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
For the years ended December 31, 2017 and 2016

Year ended December 31, 2017 *(millions of Canadian dollars)*	Common Shares	Preferred Shares	Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Hydro One Shareholders' Equity	Non-controlling Interest *(Note 26)*	Total Equity
January 1, 2017	5,623	418	34	3,950	(8)	10,017	50	10,067
Net income	—	—	—	676	—	676	4	680
Other comprehensive income	—	—	—	—	1	1	—	1
Distributions to noncontrolling interest	—	—	—	—	—	—	(4)	(4)
Dividends on preferred shares	—	—	—	(18)	—	(18)	—	(18)
Dividends on common shares	—	—	—	(518)	—	(518)	—	(518)
Common shares issued	8	—	(8)	—	—	—	—	—
Stock-based compensation *(Note 25)*	—	—	23	—	—	23	—	23
December 31, 2017	**5,631**	**418**	**49**	**4,090**	**(7)**	**10,181**	**50**	**10,231**

Year ended December 31, 2016 *(millions of Canadian dollars)*	Common Shares	Preferred Shares	Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Hydro One Shareholders' Equity	Non-controlling Interest *(Note 26)*	Total Equity
January 1, 2016	5,623	418	10	3,806	(8)	9,849	52	9,901
Net income	—	—	—	740	—	740	4	744
Other comprehensive income	—	—	—	—	—	—	—	—
Distributions to noncontrolling interest	—	—	—	—	—	—	(6)	(6)
Dividends on preferred shares	—	—	—	(19)	—	(19)	—	(19)
Dividends on common shares	—	—	—	(577)	—	(577)	—	(577)
Stock-based compensation *(Note 25)*	—	—	24	—	—	24	—	24
December 31, 2016	**5,623**	**418**	**34**	**3,950**	**(8)**	**10,017**	**50**	**10,067**

See accompanying notes to Consolidated Financial Statements.

HYDRO ONE LIMITED
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the years ended December 31, 2017 and 2016

Year ended December 31 *(millions of Canadian dollars)*	2017	2016
Operating activities		
Net income	682	746
Environmental expenditures	(24)	(20)
Adjustments for non-cash items:		
Depreciation and amortization (excluding asset removal costs)	727	688
Regulatory assets and liabilities	112	(16)
Deferred income taxes	85	114
Other	21	10
Changes in non-cash balances related to operations *(Note 28)*	113	134
Net cash from operating activities	**1,716**	**1,656**
Financing activities		
Long-term debt issued	—	2,300
Long-term debt repaid	(602)	(502)
Short-term notes issued	3,795	3,031
Short-term notes repaid	(3,338)	(4,053)
Convertible debentures issued *(Note 16)*	513	—
Dividends paid	(536)	(596)
Distributions paid to noncontrolling interest	(6)	(9)
Other *(Note 16)*	(27)	(10)
Net cash from (used in) financing activities	**(201)**	**161**
Investing activities		
Capital expenditures *(Note 28)*		
Property, plant and equipment	(1,467)	(1,600)
Intangible assets	(80)	(61)
Acquisitions *(Note 4)*	—	(224)
Capital contributions received *(Note 28)*	9	21
Other	(2)	3
Net cash used in investing activities	**(1,540)**	**(1,861)**
Net change in cash and cash equivalents	(25)	(44)
Cash and cash equivalents, beginning of year	50	94
Cash and cash equivalents, end of year	**25**	**50**

See accompanying notes to Consolidated Financial Statements.

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. At December 31, 2017, the Province held approximately 47.4% (2016 - 70.1%) of the common shares of Hydro One.

The principal businesses of Hydro One are the transmission and distribution of electricity to customers within Ontario.

2. SIGNIFICANT ACCOUNTING POLICIES

Basis of Consolidation

These Consolidated Financial Statements include the accounts of the Company and its subsidiaries. Intercompany transactions and balances have been eliminated.

Basis of Accounting

These Consolidated Financial Statements are prepared and presented in accordance with United States (US) Generally Accepted Accounting Principles (GAAP) and in Canadian dollars.

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, 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 Hydro One Networks Inc. (Hydro One Networks), Hydro One Sault Ste. Marie LP (HOSSM) (formerly Great Lakes Power Transmission LP), and 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, as well as Hydro One Remote Communities Inc. (Hydro One Remote Communities).

<u>Transmission</u>

In November 2017, the Ontario Energy Board (OEB) approved Hydro One Networks' 2017 transmission rates revenue requirement of $1,438 million. See Note 12 - Regulatory Assets and Liabilities for additional information.

In December 2015, the OEB approved B2M LP's 2015-2019 rates revenue requirements of $39 million, $36 million, $37 million, $38 million and $37 million for the respective years. 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. On June 8, 2017, the OEB approved the 2017 rates revenue requirement of $34 million, updated for the cost of capital parameters.

On September 28, 2017, the OEB issued its Decision and Order on HOSSM's 2017 transmission rates application, denying the requested revenue requirement for 2017. HOSSM's 2016 approved revenue requirement of $41 million will remain in effect for 2017.

<u>Distribution</u>

In March 2015, the OEB approved Hydro One Networks' distribution revenue requirements of $1,326 million for 2015, $1,430 million for 2016 and $1,486 million for 2017. The OEB has subsequently approved updated revenue requirements of $1,410 million for 2016 and $1,415 million for 2017.

On March 30, 2017, the OEB approved an increase of 1.9% to Hydro One Remote Communities' basic rates for the distribution and generation of electricity, with an effective date of May 1, 2017.

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 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 include its regulatory assets and liabilities in setting 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 would 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. At the end of each month, electricity delivered to customers since the date of the last billed meter reading is estimated, and the corresponding unbilled revenue is recorded. 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 billed accounts receivable by applying internally developed loss rates to the outstanding receivable balances by aging category. Loss rates applied to the billed 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 allowance for doubtful accounts is 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 and other comprehensive income (OCI) 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

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 using new information about recognition or measurement as it becomes available.

Deferred Income Taxes

Deferred income taxes are provided for using the liability method. Under this method, deferred income tax liabilities are recognized on all taxable temporary differences between the tax bases and carrying amounts of assets and liabilities. Deferred income tax assets are recognized for deductible temporary differences between tax bases and carrying amounts of assets and liabilities, the carry forward unused tax credits and tax losses to the extent that it is more-likely-than-not that these deductions, credits, and losses can be utilized. Deferred income tax assets and liabilities are measured 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.

Management reassesses the deferred income tax assets at each balance sheet date and reduces the amount to the extent that it is more-likely-than-not that the deferred income tax asset will not 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 tax assets and liabilities 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 most recent reviews resulted in changes to rates effective January 1, 2015 and January 1, 2017 for Hydro One Networks' distribution and transmission businesses, respectively. 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
Property, plant and equipment:			
Transmission	55 years	1% - 3%	2%
Distribution	46 years	1% - 7%	2%
Communication	16 years	1% - 15%	6%
Administration and service	20 years	1% - 20%	6%
Intangible assets	10 years	10%	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.

Acquisitions and Goodwill

The Company accounts for business acquisitions using the acquisition method of accounting and, accordingly, the assets and liabilities of the acquired entities are primarily measured at their estimated fair value at the date of acquisition. Costs associated with pending acquisitions are expensed as incurred. Goodwill represents the cost of acquired 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.

Based on assessment performed as at September 30, 2017, the Company has concluded that goodwill was not impaired at December 31, 2017.

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. 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, 2017 and 2016, 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 and for convertible debentures, the Company defers the external transaction costs related to obtaining financing and presents such amounts net of related debt or convertible debentures on the Consolidated Balance Sheets. Deferred issuance costs are amortized over the contractual life of the related debt or convertible debentures 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 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 17 - 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. The changes in fair value of the undesignated derivative instruments are reflected in results of operations.

Embedded derivative instruments are separated from their host contracts and are 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 that required bifurcation at December 31, 2017 or 2016.

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.

Hydro One recognizes its contributions to the defined contribution pension plan as pension expense, with a portion being capitalized as part of labour costs included in capital expenditures. The expensed amount is included in operation, maintenance and administration costs in the Consolidated Statements of Operations and Comprehensive Income.

<u>Defined Benefit Pension</u>

Defined benefit 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.

<u>Post-retirement and Post-employment Benefits</u>

Post-retirement and post-employment benefits are recorded and included in rates on an accrual basis. Costs are determined by independent actuaries using the projected benefit method prorated on service and based on assumptions that reflect management's best estimates. Past service costs from plan amendments are amortized to results of operations based on the expected average remaining service period.

For post-retirement benefits, all actuarial gains or losses are deferred using the "corridor" approach. The amount calculated above the "corridor" is amortized to results of operations on a straight-line basis over the expected average remaining service life of active employees in the plan and over the remaining life expectancy of inactive employees in the plan. The post-retirement benefit obligation is remeasured to its fair value at each year end based on an annual actuarial report, with an offset to the associated regulatory asset, to the extent of the remeasurement adjustment.

For post-employment obligations, the associated regulatory liabilities representing actuarial gains on transition to US GAAP are amortized to results of operations based on the "corridor" approach. 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.

Stock-Based Compensation

Share Grant Plans

Hydro One measures share grant plans based on fair value of share grants as estimated based on the grant date common 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. Costs are transfered from the regulatory asset to labour costs at the time the share grants vest and are issued, and are recovered in rates. Forfeitures are recognized as they occur.

Deferred Share Unit (DSU) Plans

The Company records the liabilities associated with its Directors' and Management DSU Plans 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.

Long-term Incentive Plan (LTIP)

The Company measures the restricted share units (RSUs) and performance share units (PSUs), issued under its LTIP, at fair value based on the grant date common share price. The related compensation expense is recognized over the vesting period on a straight-line basis. Forfeitures are recognized as they occur.

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 have been recorded 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.

3. NEW ACCOUNTING PRONOUNCEMENTS

The following tables present Accounting Standards Updates (ASUs) issued by the Financial Accounting Standards Board that are applicable to Hydro One:

Recently Adopted Accounting Guidance

ASU	Date issued	Description	Effective date	Anticipated impact on Hydro One
2016-06	March 2016	Contingent call (put) options that are assessed to accelerate the payment of principal on debt instruments need to meet the criteria of being "clearly and closely related" to their debt hosts.	January 1, 2017	No impact upon adoption

Recently Issued Accounting Guidance Not Yet Adopted

ASU	Date issued	Description	Effective date	Anticipated impact on Hydro One
2014-09 2015-14 2016-08 2016-10 2016-12 2016-20 2017-05 2017-10 2017-13 2017-14	May 2014 – November 2017	ASU 2014-09 was issued in May 2014 and provides guidance on revenue recognition relating to 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. ASU 2015-14 deferred the effective date of ASU 2014-09 by one year. Additional ASUs were issued in 2016 and 2017 that simplify transition and provide clarity on certain aspects of the new standard.	January 1, 2018	Hydro One has completed the review of all its revenue streams and has concluded that there will be no material impact upon adoption.
2016-02 2018-01	February 2016 – January 2018	Lessees are required to recognize the rights and obligations resulting from operating leases as assets (right to use the underlying asset for the term of the lease) and liabilities (obligation to make future lease payments) on the balance sheet. ASU 2018-01 permits an entity to elect an optional practical expedient to not evaluate under Topic 842 land easements that exist or expired before the entity's adoption of Topic 842 and that were not previously accounted for as leases under Topic 840.	January 1, 2019	An initial assessment is currently underway encompassing a review of existing leases, which will be followed by a review of relevant contracts. No quantitative determination has been made at this time. The Company is on track for implementation of this standard by the effective date.
2016-15	August 2016	The amendments provide guidance for eight specific cash flow issues with the objective of reducing the existing diversity in practice.	January 1, 2018	No material impact
2017-01	January 2017	The amendment clarifies the definition of a business and provides additional guidance on evaluating whether transactions should be accounted for as acquisitions (or disposals) of assets or businesses.	January 1, 2018	No material impact
2017-04	January 2017	The amendment removes the second step of the current two-step goodwill impairment test to simplify the process of testing goodwill.	January 1, 2020	Under assessment
2017-07	March 2017	Service cost components of net benefit cost associated with defined benefit plans are required to be reported in the same line as other compensation costs arising from services rendered by the Company's employees. All other components of net benefit cost are to be presented in the income statement separately from the service cost component. Only the service cost component is eligible for capitalization where applicable.	January 1, 2018	Hydro One has applied for a regulatory deferral account to maintain the capitalization of OPEB related costs. As such, there will be no material impact.

ASU	Date issued	Description	Effective date	Anticipated impact on Hydro One
2017-09	May 2017	Changes to the terms or conditions of a share-based payment award will require an entity to apply modified accounting unless the modified award meets all conditions stipulated in this ASU.	January 1, 2018	No impact
2017-11	July 2017	When determining whether certain financial instruments should be classified as liabilities or equity instruments, a down round feature no longer precludes equity classification when assessing whether the instrument is indexed to an entity's own stock.	January 1, 2019	Under assessment
2017-12	August 2017	Amendments will better align an entity's risk management activities and financial reporting for hedging relationships through changes to both the designation and measurement guidance for qualifying hedging relationships and the presentation of hedge results.	January 1, 2019	Under assessment

4. BUSINESS COMBINATIONS

Avista Corporation Purchase Agreement

On July 19, 2017, Hydro One reached an agreement to acquire Avista Corporation (Merger) for approximately $6.7 billion in an all-cash transaction. Avista Corporation is an investor-owned utility providing electric generation, transmission, and distribution services. It is headquartered in Spokane, Washington, with service areas in Washington, Idaho, Oregon, Montana and Alaska. The closing of the Merger is subject to receipt of certain regulatory and government approvals, and the satisfaction of customary closing conditions. See Note 16 - Convertible Debentures and Note 17 - Fair Value of Financial Instruments and Risk Management for details of convertible debentures and foreign exchange contract, respectively, related to financing of the Merger.

Acquisition of HOSSM

On October 31, 2016, Hydro One acquired HOSSM, an Ontario regulated electricity transmission business operating along the eastern shore of Lake Superior, north and east of Sault Ste. Marie, Ontario from Brookfield Infrastructure Holdings Inc. The total purchase price for HOSSM was approximately $376 million, including the assumption of approximately $150 million in outstanding indebtedness. During 2017, the Company completed the final determination of the fair value of assets acquired and liabilities assumed with no significant changes, which resulted in a total goodwill of approximately $157 million arising from the HOSSM acquisition. The difference between the preliminary and final purchase price allocation to fair value of assets acquired and liabilities related to a $2 million decrease in deferred income tax liabilities which resulted in a corresponding decrease to goodwill. The following table summarizes the final fair value of the assets acquired and liabilities assumed:

(millions of dollars)	
Cash and cash equivalents	5
Property, plant and equipment	221
Intangible assets	1
Regulatory assets	50
Goodwill	157
Working capital	(2)
Long-term debt	(186)
Pension and post-employment benefit liabilities, net	(5)
Deferred income taxes	(15)
	226

Goodwill arising from the HOSSM acquisition consists largely of the synergies and economies of scale expected from combining the operations of Hydro One and HOSSM. HOSSM contributed revenues of $6 million and less than $1 million of net income to the Company's consolidated financial results for the year ended December 31, 2016. All costs related to the acquisition have been expensed through the Consolidated Statements of Operations and Comprehensive Income. HOSSM's financial information was not material to the Company's consolidated financial results for the year ended December 31, 2016 and therefore, has not been disclosed on a pro forma basis.

Agreement to Purchase Orillia Power

On August 15, 2016, the Company reached an agreement to acquire Orillia Power Distribution Corporation (Orillia Power), an electricity distribution company located in Simcoe County, Ontario, from the City of Orillia for approximately $41 million, including the assumption of approximately $15 million in outstanding indebtedness and regulatory liabilities, subject to closing adjustments. The acquisition is subject to regulatory approval by the OEB.

5. DEPRECIATION AND AMORTIZATION

Year ended December 31 *(millions of dollars)*	2017	2016
Depreciation of property, plant and equipment	641	612
Asset removal costs	90	90
Amortization of intangible assets	62	56
Amortization of regulatory assets	24	20
	817	778

6. FINANCING CHARGES

Year ended December 31 *(millions of dollars)*	2017	2016
Interest on long-term debt	450	424
Interest on convertible debentures	24	—
Interest on short-term notes	6	9
Unrealized loss on foreign exchange contract	3	—
Other	14	16
Less: Interest capitalized on construction and development in progress	(56)	(54)
Interest earned on cash and cash equivalents	(2)	(2)
	439	393

7. INCOME TAXES

Income tax expense differs from the amount that would have been recorded using the combined Canadian federal and Ontario statutory income tax rate. The reconciliation between the statutory and the effective tax rates is provided as follows:

Year ended December 31 *(millions of dollars)*	2017	2016
Income before income taxes	793	885
Income taxes at statutory rate of 26.5% (2016 - 26.5%)	210	235
Increase (decrease) resulting from:		
Net temporary differences recoverable in future rates charged to customers:		
Capital cost allowance in excess of depreciation and amortization	(55)	(53)
Pension contributions in excess of pension expense	(13)	(16)
Overheads capitalized for accounting but deducted for tax purposes	(17)	(16)
Interest capitalized for accounting but deducted for tax purposes	(15)	(14)
Environmental expenditures	(6)	(5)
Other	3	5
Net temporary differences	(103)	(99)
Net permanent differences	4	3
Total income taxes	111	139

The major components of income tax expense are as follows:

Year ended December 31 *(millions of dollars)*	2017	2016
Current income taxes	26	25
Deferred income taxes	85	114
Total income taxes	111	139
Effective income tax rate	14.0%	15.7%

Deferred Income Tax Assets and Liabilities

Deferred income tax assets and liabilities 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 arise from differences between the tax basis and the carrying amounts of the assets and liabilities. At December 31, 2017 and 2016, deferred income tax assets and liabilities consisted of the following:

December 31 *(millions of dollars)*	2017	2016
Deferred income tax assets		
Depreciation and amortization in excess of capital cost allowance	125	495
Non-depreciable capital property	271	271
Post-retirement and post-employment benefits expense in excess of cash payments	561	607
Environmental expenditures	71	74
Non-capital losses	255	213
Tax credit carryforwards	49	27
Investment in subsidiaries	84	75
Other	13	3
	1,429	1,765
Less: valuation allowance	(364)	(352)
Total deferred income tax assets	1,065	1,413
Less: current portion	—	—
	1,065	1,413
Deferred income tax liabilities		
Regulatory amounts that are not recognized for tax purposes	(47)	(153)
Goodwill	(10)	(10)
Capital cost allowance in excess of depreciation and amortization	(75)	(64)
Other	(17)	(11)
Total deferred income tax liabilities	(149)	(238)
Less: current portion	—	—
	(149)	(238)
Net deferred income tax assets	916	1,175

The net deferred income tax assets are presented on the Consolidated Balance Sheets as follows:

December 31 *(millions of dollars)*	2017	2016
Long-term:		
Deferred income tax assets	987	1,235
Deferred income tax liabilities	(71)	(60)
Net deferred income tax assets	916	1,175

The valuation allowance for deferred tax assets as at December 31, 2017 was $364 million (2016 - $352 million). The valuation allowance primarily relates to temporary differences for non-depreciable assets and investments in subsidiaries. As of December 31, 2017 and 2016, the Company had non-capital losses carried forward available to reduce future years' taxable income, which expire as follows:

Year of expiry *(millions of dollars)*	2017	2016
2034	2	2
2035	222	222
2036	560	580
2037	175	—
Total losses	959	804

8. ACCOUNTS RECEIVABLE

December 31 *(millions of dollars)*	2017	2016
Accounts receivable – billed	298	431
Accounts receivable – unbilled	367	442
Accounts receivable, gross	665	873
Allowance for doubtful accounts	(29)	(35)
Accounts receivable, net	636	838

The following table shows the movements in the allowance for doubtful accounts for the years ended December 31, 2017 and 2016:

Year ended December 31 *(millions of dollars)*	2017	2016
Allowance for doubtful accounts – beginning	(35)	(61)
Write-offs	25	37
Additions to allowance for doubtful accounts	(19)	(11)
Allowance for doubtful accounts – ending	(29)	(35)

9. OTHER CURRENT ASSETS

December 31 *(millions of dollars)*	2017	2016
Regulatory assets *(Note 12)*	46	37
Materials and supplies	18	19
Prepaid expenses and other assets	41	46
	105	102

10. PROPERTY, PLANT AND EQUIPMENT

December 31, 2017 *(millions of dollars)*	Property, Plant and Equipment	Accumulated Depreciation	Construction in Progress	Total
Transmission	15,509	5,162	989	11,336
Distribution	10,213	3,513	149	6,849
Communication	1,266	853	31	444
Administration and service	1,561	857	46	750
Easements	638	70	—	568
	29,187	10,455	1,215	19,947

December 31, 2016 *(millions of dollars)*	Property, Plant and Equipment	Accumulated Depreciation	Construction in Progress	Total
Transmission	14,692	4,862	910	10,740
Distribution	9,656	3,305	243	6,594
Communication	1,233	777	20	476
Administration and service	1,632	924	61	769
Easements	628	67	—	561
	27,841	9,935	1,234	19,140

Financing charges capitalized on property, plant and equipment under construction were $54 million in 2017 (2016 - $52 million).

11. INTANGIBLE ASSETS

December 31, 2017 *(millions of dollars)*	Intangible Assets	Accumulated Amortization	Development in Progress	Total
Computer applications software	698	370	41	369
Other	5	5	—	—
	703	375	41	369

December 31, 2016 *(millions of dollars)*	Intangible Assets	Accumulated Amortization	Development in Progress	Total
Computer applications software	621	326	53	348
Other	5	4	—	1
	626	330	53	349

Financing charges capitalized to intangible assets under development were $2 million in 2017 (2016 - $2 million). The estimated annual amortization expense for intangible assets is as follows: 2018 - $67 million; 2019 - $57 million; 2020 - $40 million; 2021 - $39 million; and 2022 - $36 million.

12. REGULATORY ASSETS AND LIABILITIES

Regulatory assets and liabilities arise as a result of the rate-setting process. Hydro One has recorded the following regulatory assets and liabilities:

December 31 *(millions of dollars)*	2017	2016
Regulatory assets:		
Deferred income tax regulatory asset	1,762	1,587
Pension benefit regulatory asset	981	900
Post-retirement and post-employment benefits	36	243
Environmental	196	204
Share-based compensation	40	31
Debt premium	27	32
Foregone revenue deferral	23	—
Distribution system code exemption	10	10
B2M LP start-up costs	4	5
Retail settlement variance account	—	145
2015-2017 rate rider	—	7
Pension cost variance	—	4
Other	16	14
Total regulatory assets	3,095	3,182
Less: current portion	(46)	(37)
	3,049	3,145
Regulatory liabilities:		
Green Energy expenditure variance	60	69
External revenue variance	46	64
CDM deferral variance	28	54
Pension cost variance	23	—
2015-2017 rate rider	6	—
Deferred income tax regulatory liability	5	4
Other	17	18
Total regulatory liabilities	185	209
Less: current portion	(57)	—
	128	209

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 2017 income tax expense would have been higher by approximately $113 million (2016 - $104 million).

On September 28, 2017, the OEB issued its Decision and Order on Hydro One Networks' 2017 and 2018 transmission rates revenue requirements (Decision). In its Decision, the OEB concluded that the net deferred tax asset resulting from transition from the payments in lieu of tax regime under the *Electricity Act* (Ontario) to tax payments under the federal and provincial tax regime should not accrue entirely to Hydro One's shareholders and that a portion should be shared with ratepayers. On November 9, 2017, the OEB issued a Decision and Order that calculated the portion of the tax savings that should be shared with ratepayers. The OEB's calculation would result in an impairment of Hydro One Networks' transmission deferred income tax regulatory asset of up to approximately $515 million. If the OEB were to apply the same calculation for sharing in Hydro One Networks' 2018-2022 distribution rates, for which a decision is currently outstanding, it would result in an additional impairment of up to approximately $370 million related to Hydro One Networks' distribution deferred income tax regulatory asset. In October 2017, the Company filed a Motion to Review and Vary (Motion) the Decision and filed an appeal with the Divisional Court of Ontario (Appeal). On December 19, 2017, the OEB granted a hearing of the merits of the Motion which is scheduled for mid-February 2018. In both cases, the Company's position is that the OEB made errors of fact and law in its determination of allocation of the tax savings between the shareholders and ratepayers. The Appeal is being held in abeyance pending the outcome of the Motion. If the Decision is upheld, based on the facts known at this time, the exposure from the potential impairments would be a one-time decrease in net income of up to approximately $885 million. Based on the assumptions that the OEB applies established rate making principles in a manner consistent with its past practice and does not exercise its discretion to take other policy considerations into account, management is of the view that it is likely that the Company's Motion will be granted and the aforementioned tax savings will be allocated to the benefit of Hydro One shareholders.

Pension Benefit Regulatory Asset

In accordance with OEB rate orders, pension costs are recovered 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, OCI would have been lower by $80 million and operation, maintenance and administration expenses would have been higher by $1 million (2016 - OCI higher by $52 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, 2017 OCI would have been higher by $207 million (2016 - lower by $3 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 2017, the environmental regulatory asset increased by $1 million (2016 - decreased by $1 million) to reflect related changes in the Company's PCB liability, and increased by $7 million (2016 - $10 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, 2017 operation, maintenance and administration expenses would have been higher by $8 million (2016 - $9 million). In addition, 2017 amortization expense would have been lower by $24 million (2016 - $20 million), and 2017 financing charges would have been higher by $8 million (2016 - $8 million).

Share-based Compensation

The Company recognizes costs associated with share grant plans in a regulatory asset as management considers it probable that share grant plans' costs will be recovered in the future through the rate-setting process. In the absence of rate-regulated accounting, 2017 operation, maintenance and administration expenses would have been higher by $8 million (2016 - $9 million). Share grant costs are transferred to labour costs at the time the share grants vest and are issued, and are recovered in rates in accordance with recovery of said labour costs.

Debt Premium

The value of debt assumed in the acquisition of HOSSM has been recorded at fair value in accordance with US GAAP - Business Combinations. The OEB allows for recovery of interest at the coupon rate of the Senior Secured Bonds and a regulatory asset has been recorded for the difference between the fair value and face value of this debt. The debt premium is recovered over the remaining term of the debt.

Foregone Revenue Deferral

As part of its September 2017 decision on Hydro One Networks' transmission rate application for 2017 and 2018 rates, the OEB approved the foregone revenue account to record the difference between revenue earned under the rates approved as part of the decision, effective January 1, 2017, and revenue earned under the interim rates until the approved 2017 rates were implemented. The OEB approved a similar account for B2M LP in June 2017 to record the difference between revenue earned under the newly approved rates, effective January 1, 2017, and the revenue recorded under the interim 2017 rates. The balances of these accounts will be returned to or recovered from ratepayers, respectively, over a one-year period ending December 31, 2018. The draft rate order submitted by Hydro One Networks was approved by the OEB in November, 2017. This draft rate order reflects the September 2017 decision, including a reduction of the amount of cash taxes approved for recovery in transmission rates due to the OEB's basis to share the savings resulting from a deferred tax asset with ratepayers. The Company's position in the aforementioned Motion is that the OEB made errors of fact and law in its determination of allocation of the tax savings between the shareholders and ratepayers. Therefore, the Company has also reflected the impact of the Company's position with respect to the Motion in the Foregone Revenue Deferral account. The timing for recovery of this impact will be determined as part of the outcome of the Motion.

Distribution System Code (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 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 Networks distribution applications. In March 2015, the OEB approved the disposition of the DSC exemption deferral account balance at December 31, 2013, including accrued interest, which was recovered through the 2015-2017 Rate Rider. In addition, the OEB also approved Hydro One's request to discontinue this deferral account. There were no additions to this regulatory account in 2017 or 2016. The remaining balance in this account at December 31, 2016, including accrued interest, was requested for recovery through the 2018-2022 distribution rate application.

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 are being recovered over a four-year period which began in 2016, in accordance with the OEB decision.

Retail Settlement Variance Account (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.

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 included the balances approved for disposition by the OEB and was disposed of in accordance with the OEB decision over a 32-month period ended on December 31, 2017. The balance remaining in the account represents an over-collection to be returned to ratepayers in a future rate application. We have not requested recovery of the remaining balance of this account in the current distribution rate application.

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 deficit 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 was recovered through the 2015-2017 Rate Rider. In September 2017, the OEB approved the disposition of the transmission business portion of the total pension cost variance account as at December 31, 2015, including accrued interest, which is being recovered over a two-year period ending December 31, 2018. In the absence of rate-regulated accounting, 2017 revenue would have been higher by $24 million (2016 - $25 million).

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.

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. In September 2017, the OEB approved the disposition of the external revenue variance account as at December 31, 2015, including accrued interest, which is being returned to customers over a two-year period ending December 31, 2018.

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. The balance in the CDM deferral variance account relates to the actual 2013 and 2014 CDM compared to the amounts included in 2013 and 2014 revenue requirements, respectively. There were no additions to this regulatory account in 2017 or 2016. The balance of the account at December 31, 2015, including interest, was approved for disposition in the 2017-2018 transmission rate decision and is currently being drawn down over a 2-year period ending December 31, 2018.

13. ACCOUNTS PAYABLE AND OTHER CURRENT LIABILITIES

December 31 *(millions of dollars)*	2017	2016
Accounts payable	177	181
Accrued liabilities	572	659
Accrued interest	99	105
Regulatory liabilities *(Note 12)*	57	—
	905	945

14. OTHER LONG-TERM LIABILITIES

December 31 *(millions of dollars)*	2017	2016
Post-retirement and post-employment benefit liability *(Note 19)*	1,519	1,641
Pension benefit liability *(Note 19)*	981	900
Environmental liabilities *(Note 20)*	168	177
Asset retirement obligations *(Note 21)*	9	9
Long-term accounts payable and other liabilities	30	25
	2,707	2,752

15. 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 up to 365 days. The Commercial Paper Program is supported by Hydro One Inc.'s committed revolving credit facilities totalling $2.3 billion.

At December 31, 2017, Hydro One's consolidated committed, unsecured and undrawn credit facilities totalling $2,550 million consisted of the following:

(millions of dollars)	Maturity	Amount
Hydro One Inc.		
Revolving standby credit facility	June 2022[1]	2,300
Hydro One		
Five-year senior, revolving term credit facility	November 2021	250
Total		2,550

[1] In June 2017, the maturity date of Hydro One Inc.'s $2.3 billion credit facilities was extended from June 2021 to June 2022.

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 that no event of default has occurred or would result from such credit extension.

Long-Term Debt

The following table presents long-term debt outstanding at December 31, 2017 and 2016:

December 31 *(millions of dollars)*	2017	2016
5.18% Series 13 notes due 2017	—	600
2.78% Series 28 notes due 2018	750	750
Floating-rate Series 31 notes due 2019[1]	228	228
1.48% Series 37 notes due 2019[2]	500	500
4.40% Series 20 notes due 2020	300	300
1.62% Series 33 notes due 2020[2]	350	350
1.84% Series 34 notes due 2021	500	500
3.20% Series 25 notes due 2022	600	600
2.77% Series 35 notes due 2026	500	500
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
3.91% Series 36 notes due 2046	350	350
3.72% Series 38 notes due 2047	450	450
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
Hydro One Inc. long-term debt (a)	9,923	10,523
6.6% Senior Secured Bonds due 2023 (Face value - $110 million)	136	144
4.6% Note Payable due 2023 (Face value - $36 million)	40	40
HOSSM long-term debt (b)	176	184
	10,099	10,707
Add: Net unamortized debt premiums	14	15
Add: Unrealized mark-to-market gain[2]	(9)	(2)
Less: Deferred debt issuance costs	(37)	(40)
Total long-term debt	10,067	10,680

[1] The interest rates of the floating-rate notes are referenced to the three-month Canadian dollar bankers' acceptance rate, plus a margin.

[2] The unrealized mark-to-market net gain relates to $50 million of the Series 33 notes due 2020 and $500 million Series 37 notes due 2019. The unrealized mark-to-market net gain is offset by a $9 million (2016 - $2 million) unrealized mark-to-market net loss on the related fixed-to-floating interest-rate swap agreements, which are accounted for as fair value hedges.

(a) Hydro One Inc. long-term debt

At December 31, 2017, long-term debt of $9,923 million (2016 - $10,523 million) was outstanding, the majority of which was issued under Hydro One Inc.'s Medium Term Note (MTN) Program. The maximum authorized principal amount of notes issuable under the current MTN Program prospectus filed in December 2015 is $3.5 billion. At December 31 2017, $1.2 billion remained available for issuance until January 2018. In 2017, no long-term debt was issued and $600 million of long-term debt was repaid under the MTN Program (2016 - $2,300 million issued and $500 million repaid).

(b) HOSSM long-term debt

At December 31, 2017, long-term debt of $176 million (2016 - $184 million), with a face value of $146 million (2016 - $148 million) was held by HOSSM. In 2017, $2 million of HOSSM long-term debt was repaid (2016 - $2 million).

The total long-term debt is presented on the consolidated balance sheets as follows:

December 31 *(millions of dollars)*	2017	2016
Current liabilities:		
Long-term debt payable within one year	752	602
Long-term liabilities:		
Long-term debt	9,315	10,078
Total long-term debt	10,067	10,680

Principal and Interest Payments

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 dollars)*	Weighted Average Interest Rate *(%)*
1 year	752	2.8
2 years	731	1.6
3 years	653	2.9
4 years	503	1.9
5 years	604	3.2
	3,243	2.5
6 – 10 years	631	3.5
Over 10 years	6,195	5.2
	10,069	4.2

Interest payment obligations related to long-term debt are summarized by year in the following table:

Year	Interest Payments *(millions of dollars)*
2018	426
2019	402
2020	384
2021	370
2022	355
	1,937
2023-2027	1,672
2028+	4,081
	7,690

16. CONVERTIBLE DEBENTURES

(millions of dollars, except as otherwise noted)	
Maturity date	September 30, 2027
Coupon rate	4.00%
Conversion price per common share	$ 21.40
Carrying value at December 31, 2016	—
Receipt of Initial Instalment, net of deferred financing costs	486
Amortization of deferred financing costs	1
Carrying value at December 31, 2017	487
Face value at December 31, 2017	513

On August 9, 2017, in connection with the acquisition of Avista Corporation, the Company completed the sale of $1,540 million aggregate principal amount of 4.00% convertible unsecured subordinated debentures (Convertible Debentures) represented by instalment receipts, which included the exercise in full of the over-allotment option granted to the underwriters to purchase an additional $140 million aggregate principal amount of the Convertible Debentures (Debenture Offering).

The Convertible Debentures were sold on an instalment basis at a price of $1,000 per Convertible Debenture, of which $333 (Initial Instalment) was paid on closing of the Debenture Offering and the remaining $667 (Final Instalment) is payable on a date (Final Instalment Date) to be fixed by the Company following satisfaction of conditions precedent to the closing of the acquisition of Avista Corporation. The gross proceeds received from the Initial Instalment were $513 million. The Company incurred financing costs of

$27 million, which are being amortized to financing charges over approximately 10 years, the contractual term of the Convertible Debentures, using the effective interest rate method.

The Convertible Debentures will mature on September 30, 2027. A coupon rate of 4% is paid on the $1,540 million aggregate principal amount of the Convertible Debentures, and based on the carrying value of the Initial Instalment, this translates into an effective annual yield of 12%. After the Final Instalment Date, the interest rate will be 0%. The interest expense recorded in 2017 is $24 million.

If the Final Instalment Date occurs on a day that is prior to the first anniversary of the closing of the Debenture Offering, holders of the Convertible Debentures who have paid the Final Instalment on or before the Final Instalment Date will be entitled to receive, in addition to the payment of accrued and unpaid interest to and including the Final Instalment Date, an amount equal to the interest that would have accrued from the day following the Final Instalment Date to and including the first anniversary of the closing of the Debenture Offering had the Convertible Debentures remained outstanding and continued to accrue interest until and including such date (Make-Whole Payment). No Make-Whole Payment will be payable if the Final Instalment Date occurs on or after the first anniversary of the closing of the Debenture Offering.

At the option of the holders and provided that payment of the Final Instalment has been made, each Convertible Debenture will be convertible into common shares of the Company at any time on or after the Final Instalment Date, but prior to the earlier of maturity or redemption by the Company, at a conversion price of $21.40 per common share, being a conversion rate of 46.7290 common shares per $1,000 principal amount of Convertible Debentures. The conversion feature meets the definition of a Beneficial Conversion Feature (BCF), with an intrinsic value of approximately $92 million. Due to the contingency associated with the debentureholders' ability to exercise the conversion, the BCF has not been recognized. Between the time the contingency is resolved and the Final Instalment Date, the Company will recognize approximately $92 million of interest expense associated with amortization of the BCF.

Prior to the Final Instalment Date, the Convertible Debentures may not be redeemed by the Company, except that the Convertible Debentures will be redeemed by the Company at a price equal to their principal amount plus accrued and unpaid interest following the earlier of: (i) notification to holders that the conditions necessary to approve the acquisition of Avista Corporation will not be satisfied; (ii) termination of the acquisition agreement; and (iii) May 1, 2019 if notice of the Final Instalment Date has not been given to holders on or before April 30, 2019. Upon any such redemption, the Company will pay for each Convertible Debenture (i) $333 plus accrued and unpaid interest to the holder of the instalment receipt; and (ii) $667 to the selling debentureholder on behalf of the holder of the instalment receipt in satisfaction of the final instalment. In addition, after the Final Instalment Date, any Convertible Debentures not converted may be redeemed by the Company at a price equal to their principal amount plus any unpaid interest, which accrued prior to and including the Final Instalment Date.

At maturity, the Company will have the right to pay the principal amount due in common shares, which will be valued at 95% of their weighted average trading price on the Toronto Stock Exchange for the 20 consecutive trading days ending five trading days preceding the maturity date.

17. 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, 2017 and 2016, the Company’s carrying amounts of cash and cash equivalents, accounts receivable, due from related parties, short-term notes payable, accounts payable, and due to related parties are representative of fair value due to 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, 2017 and 2016 are as follows:

December 31 *(millions of dollars)*	2017 Carrying Value	2017 Fair Value	2016 Carrying Value	2016 Fair Value
$50 million of MTN Series 33 notes	49	49	50	50
$500 million MTN Series 37 notes	492	492	498	498
Other notes and debentures	9,526	11,027	10,132	11,462
Long-term debt, including current portion	10,067	11,568	10,680	12,010

Fair Value Measurements of Derivative Instruments

At December 31, 2017, Hydro One Inc. had interest-rate swaps in the amount of $550 million (2016 – $550 million) that were used to convert fixed-rate debt to floating-rate debt. These swaps are classified as fair value hedges. Hydro One Inc.'s fair value hedge exposure was approximately 6% (2016 – 5%) of its total long-term debt. At December 31, 2017, Hydro One Inc. had the following interest-rate swaps designated as fair value hedges:

- 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; and
- two $125 million and one $250 million fixed-to-floating interest-rate swap agreements to convert the $500 million MTN Series 37 notes maturing November 18, 2019 into three-month variable rate debt.

At December 31, 2017 and 2016, the Company had no interest-rate swaps classified as undesignated contracts.

In October 2017, the Company entered into a deal-contingent foreign exchange forward contract to convert $1.4 billion Canadian to US dollars at an initial forward rate of 1.27486 Canadian per 1.00 US dollars, and a range up to 1.28735 Canadian per 1.00 US dollars based on the settlement date. The contract is contingent on the Company closing the proposed Avista Corporation acquisition (see Note 4 - Business Combinations) and is intended to mitigate the foreign currency risk related to the portion of the Avista Corporation acquisition purchase price financed with the issuance of Convertible Debentures (see Note 16 - Convertible Debentures). If the acquisition does not close, the contract would not be completed and no amounts would be exchanged. The contract can be executed upon approval of the acquisition up to March 31, 2019. This contract is an economic hedge and does not qualify for hedge accounting. It has been accounted for as an undesignated contract.

Fair Value Hierarchy

The fair value hierarchy of financial assets and liabilities at December 31, 2017 and 2016 is as follows:

December 31, 2017 *(millions of dollars)*	Carrying Value	Fair Value	Level 1	Level 2	Level 3
Assets:					
Cash and cash equivalents	25	25	25	—	—
	25	25	25	—	—
Liabilities:					
Short-term notes payable	926	926	926	—	—
Long-term debt, including current portion	10,067	11,568	—	11,568	—
Convertible debentures	487	574	574	—	—
Derivative instruments					
Fair value hedges – interest-rate swaps	9	9	9	—	—
Foreign exchange contract	3	3	—	—	3
	11,492	13,080	1,509	11,568	3

December 31, 2016 *(millions of dollars)*	Carrying Value	Fair Value	Level 1	Level 2	Level 3
Assets:					
Cash and cash equivalents	50	50	50	—	—
	50	50	50	—	—
Liabilities:					
Short-term notes payable	469	469	469	—	—
Long-term debt, including current portion	10,680	12,010	—	12,010	—
Derivative instruments					
Fair value hedges – interest-rate swaps	2	2	2	—	—
	11,151	12,481	471	12,010	—

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 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.

The fair value of the convertible debentures is based on their closing price on December 29, 2017 (last business day in December 2017), as posted on the Toronto Stock Exchange.

The Company uses derivative instruments as an economic hedge for foreign exchange risk. The value of the foreign exchange contract is derived using valuation models commonly used for derivatives. These valuation models require a variety of inputs, including contractual terms, forward price yield curves,probability of closing the Avista Corporation acquisition, and the contract settlement of date. The Company's valuation models also reflect measurements for credit risk. The fair value of the foreign exchange contract includes significant unobservable inputs, and therefore has been classified accordingly as Level 3. The significant unobservable inputs used in the fair value measurement of the foreign exchange contract relates to the assessment of probabililty of closing the Avista Corporation acquisition and the contract settlement date.

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, 2017 and 2016.

Year ended December 31 *(millions of dollars)*	2017	2016
Fair value, beginning of year	—	—
Unrealized loss on foreign exchange contract included in financing charges *(Note 6)*	3	—
Fair value, end of year	3	—

There were no transfers between any of the fair value levels during the years ended December 31, 2017 or 2016.

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 which 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 anticipated interest rates into account. The Company is not currently exposed to material commodity price 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. The Company may also utilize interest-rate derivative instruments to lock in interest-rate levels in anticipation of future financing.

A hypothetical 100 basis points increase in 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, 2017 and 2016.

The Company is exposed to foreign exchange fluctuations as a result of entering into a deal-contingent foreign exchange forward agreement (see section Fair Value Measurements of Derivative Instruments above).This agreement is intended to mitigate the foreign currency risk related to the portion of the Avista Corporation acquisition purchase price financed with the issuance of Convertible Debentures (see Note 16 - Convertible Debentures).

For derivative instruments that are designated and qualify as fair value hedges, the gain or loss on the derivative instrument 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, 2017 and 2016 was not material.

Credit Risk

Financial assets create a risk that a counterparty will fail to discharge an obligation, causing a financial loss. At December 31, 2017 and 2016, 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 material amount of revenue from any single customer. At December 31, 2017 and 2016, there was no material accounts receivable balance due from any single customer.

At December 31, 2017, the Company’s provision for bad debts was $29 million (2016 – $35 million). Adjustments and write-offs are determined on the basis of a review of overdue accounts, taking into consideration historical experience. At December 31, 2017, approximately 5% (2016 – 6%) of the Company’s net accounts receivable were outstanding for 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; entering into master agreements which enable net settlement and the contractual right of offset; and monitoring the financial condition of counterparties. The Company monitors current 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, 2017 and 2016, the counterparty credit risk exposure on the fair value of these interest-rate swap contracts was not material. At December 31, 2017, Hydro One's credit exposure for all derivative instruments, and applicable payables and receivables, had a credit rating of investment grade, with four financial institutions as the counterparties.

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 credit facilities. The short-term liquidity under the Commercial Paper Program, revolving standby credit facilities, and anticipated levels of funds from operations are expected to be sufficient to fund normal operating requirements.

18. 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. At December 31, 2017 and 2016, the Company's capital structure was as follows:

December 31 *(millions of dollars)*	2017	2016
Long-term debt payable within one year	752	602
Short-term notes payable	926	469
Less: cash and cash equivalents	(25)	(50)
	1,653	1,021
Long-term debt	9,315	10,078
Convertible debentures	487	—
Preferred shares	418	418
Common shares	5,631	5,623
Retained earnings	4,090	3,950
Total capital	21,594	21,090

Hydro One Inc. and HOSSM have customary covenants typically associated with long-term debt. Hydro One Inc.'s long-term debt and credit facility covenants limit 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, 2017, the Company was in compliance with all financial covenants and limitations associated with the outstanding borrowings and credit facilities.

19. PENSION AND POST-RETIREMENT AND POST-EMPLOYMENT BENEFITS

Hydro One has a defined benefit pension plan (Pension Plan), a defined contribution pension plan (DC Plan), a supplemental pension plan (Supplemental Plan), and post-retirement and post-employment benefit plans.

DC Plan

Hydro One established a DC Plan effective January 1, 2016. The DC Plan covers eligible management employees hired on or after January 1, 2016, as well as management employees hired before January 1, 2016 who were not eligible or had not irrevocably elected to join the Pension Plan as of September 30, 2015. Members of the DC Plan have an option to contribute 4%, 5% or 6% of their pensionable earnings, with matching contributions by Hydro One.

Hydro One contributions to the DC Plan for the year ended December 31, 2017 were $1 million (2016 - less than $1 million). At December 31, 2017, Company contributions payable included in accrued liabilities on the Consolidated Balance Sheets were less than $1 million (2016 - less than $1 million).

Pension Plan, Supplemental Plan, and Post-Retirement and Post-Employment Plans

The Pension Plan is a defined benefit contributory plan which covers eligible regular employees of Hydro One and its subsidiaries. The Pension Plan provides benefits based on highest three-year average pensionable earnings. For management employees who commenced employment on or after January 1, 2004, and for The Society of Energy Professionals (The Society)-represented staff hired after November 17, 2005, benefits are based on highest five-year average pensionable earnings. After retirement, pensions are indexed to inflation. Membership in the Pension Plan was closed to management employees who were not eligible or had not irrevocably elected to join the Pension Plan as of September 30, 2015. These employees are eligible to join the DC Plan.

Company and employee contributions to the Pension Plan are based on actuarial valuations performed at least every three years. Annual Pension Plan contributions for 2017 of $87 million (2016 - $108 million) were based on an actuarial valuation effective December 31, 2016 (2016 - based on an actuarial valuation effective December 31, 2015) and the level of pensionable earnings. Estimated annual Pension Plan contributions for 2018 and 2019 are approximately $71 million for each year based on the actuarial valuation as at December 31, 2016 and projected levels of pensionable earnings. Future minimum contributions beyond 2019 will be based on an actuarial valuation effective no later than December 31, 2019. Contributions are payable one month in arrears. All of the contributions are expected to be in the form of cash.

The Supplemental 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 Supplemental Plan obligation is included with other post-retirement and post-employment benefit obligations on the Consolidated Balance Sheets.

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 (millions of dollars)	Pension Benefits 2017	Pension Benefits 2016	Post-Retirement and Post-Employment Benefits 2017	Post-Retirement and Post-Employment Benefits 2016
Change in projected benefit obligation				
Projected benefit obligation, beginning of year	7,774	7,683	1,690	1,610
Current service cost	147	144	49	42
Employee contributions	49	45	—	—
Interest cost	304	308	67	67
Benefits paid	(368)	(354)	(44)	(43)
Net actuarial loss (gain)	352	(52)	(197)	14
Projected benefit obligation, end of year	8,258	7,774	1,565	1,690
Change in plan assets				
Fair value of plan assets, beginning of year	6,874	6,731	—	—
Actual return on plan assets	662	370	—	—
Benefits paid	(368)	(354)	(34)	(43)
Employer contributions	87	108	34	43
Employee contributions	49	45	—	—
Administrative expenses	(27)	(26)	—	—
Fair value of plan assets, end of year	7,277	6,874	—	—
Unfunded status	981	900	1,565	1,690

Hydro One presents its benefit obligations and plan assets net on its Consolidated Balance Sheets as follows:

December 31 *(millions of dollars)*	Pension Benefits 2017	Pension Benefits 2016	Post-Retirement and Post-Employment Benefits 2017	Post-Retirement and Post-Employment Benefits 2016
Other assets[1]	1	1	—	—
Accrued liabilities	—	—	53	56
Pension benefit liability	981	900	—	—
Post-retirement and post-employment benefit liability[2]	—	—	1,519	1,641
Net unfunded status	980	899	1,572	1,697

[1] Represents the funded status of HOSSM defined benefit pension plan.

[2] Includes $7 million (2016 - $7 million) relating to HOSSM post-employment benefit plans.

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 dollars)*	2017	2016
PBO	8,258	7,774
ABO	7,614	7,094
Fair value of plan assets	7,277	6,874

On an ABO basis, the Pension Plan was funded at 96% at December 31, 2017 (2016 - 97%). On a PBO basis, the Pension Plan was funded at 88% at December 31, 2017 (2016 - 88%). 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, 2017 and 2016 for the Pension Plan:

Year ended December 31 *(millions of dollars)*	2017	2016
Current service cost	147	144
Interest cost	304	308
Expected return on plan assets, net of expenses	(442)	(432)
Amortization of actuarial losses	79	96
Net periodic benefit costs	88	116
Charged to results of operations[1]	39	48

[1] The Company accounts for pension costs consistent with their inclusion in OEB-approved rates. During the year ended December 31, 2017, pension costs of $87 million (2016 - $108 million) were attributed to labour, of which $39 million (2016 - $48 million) was charged to operations, and $48 million (2016 - $60 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, 2017 and 2016 for the post-retirement and post-employment benefit plans:

Year ended December 31 *(millions of dollars)*	2017	2016
Current service cost	49	42
Interest cost	67	67
Amortization of actuarial losses	16	15
Net periodic benefit costs	132	124
Charged to results of operations	59	55

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, 2017 and 2016:

	Pension Benefits		Post-Retirement and Post-Employment Benefits	
Year ended December 31	2017	2016	2017	2016
Significant assumptions:				
Weighted average discount rate	3.40%	3.90%	3.40%	3.90%
Rate of compensation scale escalation (long-term)	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]	—	—	4.04%	4.36%

[1] 5.26% per annum in 2018, grading down to 4.04% per annum in and after 2031 (2016 - 6.25% in 2017, 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, 2017 and 2016. 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	2017	2016
Pension Benefits:		
Weighted average expected rate of return on plan assets	6.50%	6.50%
Weighted average discount rate	3.90%	4.00%
Rate of compensation scale escalation (long-term)	2.50%	2.50%
Rate of cost of living increase	2.00%	2.00%
Average remaining service life of employees *(years)*	15	15
Post-Retirement and Post-Employment Benefits:		
Weighted average discount rate	3.90%	4.10%
Rate of compensation scale escalation (long-term)	2.50%	2.50%
Rate of cost of living increase	2.00%	2.00%
Average remaining service life of employees *(years)*	15.2	15.3
Rate of increase in health care cost trends[1]	4.36%	4.36%

[1] 6.25% per annum in 2017, grading down to 4.36% per annum in and after 2031 (2016 - 6.38% in 2016, grading down to 4.36% 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, 2017 and 2016 is as follows:

December 31 *(millions of dollars)*	2017	2016
Projected benefit obligation:		
Effect of a 1% increase in health care cost trends	250	289
Effect of a 1% decrease in health care cost trends	(189)	(221)

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, 2017 and 2016 is as follows:

Year ended December 31 *(millions of dollars)*	2017	2016
Service cost and interest cost:		
Effect of a 1% increase in health care cost trends	29	23
Effect of a 1% decrease in health care cost trends	(20)	(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, 2017 and 2016:

December 31, 2017				December 31, 2016			
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
22	24	23	24	22	24	23	24

Estimated Future Benefit Payments

At December 31, 2017, estimated future benefit payments to the participants of the Plans were:

(millions of dollars)	Pension Benefits	Post-Retirement and Post-Employment Benefits
2018	326	53
2019	335	54
2020	342	56
2021	350	57
2022	358	58
2023 through to 2027	1,886	312
Total estimated future benefit payments through to 2027	3,597	590

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 dollars)*	2017	2016
Pension Benefits:		
Actuarial loss (gain) for the year	159	35
Amortization of actuarial losses	(79)	(96)
	80	(61)
Post-Retirement and Post-Employment Benefits:		
Actuarial loss (gain) for the year	(197)	14
Amortization of actuarial losses	(16)	(15)
Amounts not subject to regulatory treatment	6	4
	(207)	3

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, 2017 and 2016:

Year ended December 31 *(millions of dollars)*	2017	2016
Pension Benefits:		
Actuarial loss	981	900
Post-Retirement and Post-Employment Benefits:		
Actuarial loss	36	243

The following table provides the components of regulatory assets at December 31 that are expected to be amortized as components of net periodic benefit costs in the following year:

	Pension Benefits		Post-Retirement and Post-Employment Benefits	
December 31 *(millions of dollars)*	2017	2016	2017	2016
Actuarial loss	84	79	2	6

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, 2017, the Pension Plan target asset allocations and weighted average asset allocations were as follows:

	Target Allocation (%)	Pension Plan Assets (%)
Equity securities	55	60
Debt securities	35	31
Other[1]	10	9
	100	100

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

At December 31, 2017, the Pension Plan held $11 million (2016 - $11 million) Hydro One corporate bonds and $415 million (2016 - $450 million) of debt securities of the Province.

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, 2017 and 2016. 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, 2017 and 2016, there were no significant concentrations (defined as greater than 10% of plan assets) of risk in the Pension Plan's assets.

The Pension Plan's Statement of Investment Beliefs and Guidelines provides guidelines and restrictions for eligible investments taking into account credit ratings, maximum investment exposure and other controls in order to limit the impact of this risk. 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 highly rated financial institutions, and also by 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, 2017 and 2016:

December 31, 2017 *(millions of dollars)*	Level 1	Level 2	Level 3	Total
Pooled funds	—	16	549	565
Cash and cash equivalents	153	—	—	153
Short-term securities	—	109	—	109
Derivative instruments	—	5	—	5
Corporate shares - Canadian	921	—	—	921
Corporate shares - Foreign	3,307	125	—	3,432
Bonds and debentures - Canadian	—	1,879	—	1,879
Bonds and debentures - Foreign	—	194	—	194
Total fair value of plan assets[1]	4,381	2,328	549	7,258

[1] At December 31, 2017, the total fair value of Pension Plan assets and liabilities excludes $28 million of interest and dividends receivable, $10 million of pension administration expenses payable, $1 million of sold investments receivable, and $1 million of purchased investments payable.

December 31, 2016 *(millions of dollars)*	Level 1	Level 2	Level 3	Total
Pooled funds	—	20	425	445
Cash and cash equivalents	146	—	—	146
Short-term securities	—	127	—	127
Corporate shares - Canadian	911	—	—	911
Corporate shares - Foreign	2,985	113	—	3,098
Bonds and debentures - Canadian	—	1,943	—	1,943
Bonds and debentures - Foreign	—	193	—	193
Total fair value of plan assets[1]	4,042	2,396	425	6,863

[1] At December 31, 2016, the total fair value of Pension Plan assets excludes $27 million of interest and dividends receivable, $15 million of purchased investments payable, $9 million of pension administration expenses payable, and $7 million of sold investments receivable.

See note 17 - 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, 2017 and 2016. The Pension Plan classifies financial instruments as Level 3 when the fair value is measured based on at least one significant input that is not observable in the markets or due to lack of liquidity in certain markets. The gains and losses presented in the table below may include changes in fair value based on both observable and unobservable inputs.

Year ended December 31 *(millions of dollars)*	2017	2016
Fair value, beginning of year	425	301
Realized and unrealized gains	(31)	23
Purchases	171	151
Sales and disbursements	(16)	(50)
Fair value, end of year	549	425

There were no significant transfers between any of the fair value levels during the years ended December 31, 2017 and 2016.

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. This sensitivity analysis resulted in negligible changes in the fair value of financial instruments classified in this level.

Valuation Techniques Used to Determine Fair Value

Pooled funds mainly consist 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 consist of demand cash deposits held with banks and cash held by the investment managers. Cash equivalents are categorized as Level 1.

Short-term securities are valued at cost plus accrued interest, which approximates fair value due to their short-term nature. Short-term securities are categorized as Level 2.

Derivative instruments are used to hedge the Pension Plan's foreign currency exposure back to Canadian dollars. The most significant currencies being hedged against the Canadian dollar are the United States dollar, Euro, and Japanese Yen. The terms to maturity of the forward exchange contracts at December 31, 2017 are within three months. 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 determined using standard interpolation methodology primarily based on the World Markets exchange rates. Derivative instruments are categorized as Level 2.

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 are presented at published closing trade quotations, and are categorized as Level 2.

20. ENVIRONMENTAL LIABILITIES

The following tables show the movements in environmental liabilities for the years ended December 31, 2017 and 2016:

Year ended December 31, 2017 *(millions of dollars)*	PCB	Land Assessment and Remediation	Total
Environmental liabilities - beginning	143	61	204
Interest accretion	6	2	8
Expenditures	(16)	(8)	(24)
Revaluation adjustment	1	7	8
Environmental liabilities - ending	134	62	196
Less: current portion	(20)	(8)	(28)
	114	54	168

Year ended December 31, 2016 *(millions of dollars)*	PCB	Land Assessment and Remediation	Total
Environmental liabilities - beginning	148	59	207
Interest accretion	7	1	8
Expenditures	(11)	(9)	(20)
Revaluation adjustment	(1)	10	9
Environmental liabilities - ending	143	61	204
Less: current portion	(18)	(9)	(27)
	125	52	177

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, 2017 *(millions of dollars)*	PCB	Land Assessment and Remediation	Total
Undiscounted environmental liabilities	142	64	206
Less: discounting environmental liabilities to present value	(8)	(2)	(10)
Discounted environmental liabilities	134	62	196

December 31, 2016 *(millions of dollars)*	PCB	Land Assessment and Remediation	Total
Undiscounted environmental liabilities	158	66	224
Less: discounting environmental liabilities to present value	(15)	(5)	(20)
Discounted environmental liabilities	143	61	204

At December 31, 2017, the estimated future environmental expenditures were as follows:

(millions of dollars)	
2018	28
2019	27
2020	32
2021	34
2022	31
Thereafter	54
	206

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 $142 million (2016 - $158 million). These expenditures are expected to be incurred over the period from 2018 to 2025. As a result of its annual review of environmental liabilities, the Company recorded a revaluation adjustment in 2017 to increase the PCB environmental liability by $1 million (2016 - reduce by $1 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 $64 million (2016 - $66 million). These expenditures are expected to be incurred over the period from 2018 to 2044. As a result of its annual review of environmental liabilities, the Company recorded a revaluation adjustment in 2017 to increase the land assessment and remediation environmental liability by $7 million (2016 - $10 million).

21. 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. 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 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, 2017, Hydro One had recorded asset retirement obligations of $9 million (2016 - $9 million), primarily 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.

22. SHARE CAPITAL

Common Shares

The Company is authorized to issue an unlimited number of common shares. At December 31, 2017, the Company had 595,386,711 (2016 – 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.

The following tables present the changes to common shares during the years ended December 31, 2017 and 2016:

	Ownership by		
Year ended December 31, 2017 *(number of shares)*	Public	Province	Total
Common shares – beginning	178,196,340	416,803,660	595,000,000
Secondary offering[1]	120,000,000	(120,000,000)	—
Common shares issued - share grants[2]	371,611	—	371,611
Common shares issued - LTIP[3]	15,100	—	15,100
Sale of common shares[4]	14,391,012	(14,391,012)	—
Common shares – ending	312,974,063	282,412,648	595,386,711
	52.6%	47.4%	100%

[1] On May 17, 2017, Hydro One announced the closing of a secondary offering by the Province, on a bought deal basis, of 120 million common shares of Hydro One on the Toronto Stock Exchange. Hydro One did not receive any of the proceeds from the sale of the common shares by the Province.

[2] On April 1, 2017, Hydro One issued from treasury 371,611 common shares in accordance with provisions of the Power Workers' Union (PWU) Share Grant Plan.

[3] In 2017, Hydro One issued from treasury 15,100 common shares in accordance with provisions of the LTIP.

[4] On December 29, 2017, the Province sold 14,391,012 common shares of Hydro One to OFN Power Holdings LP, a limited partnership wholly-owned by Ontario First Nations Sovereign Wealth LP, which is in turn owned by 129 First Nations in Ontario. Hydro One did not receive any of the proceeds from the sale of the common shares by the Province.

	Ownership by		
Year ended December 31, 2016 *(number of shares)*	Public	Province	Total
Common shares – beginning	94,896,340	500,103,660	595,000,000
Secondary offering[1]	83,300,000	(83,300,000)	—
Common shares – ending	178,196,340	416,803,660	595,000,000
	29.9%	70.1%	100%

[1] On April 14, 2016, Hydro One announced the closing of a secondary offering by the Province, on a bought deal basis, of 72,434,800 common shares of Hydro One on the Toronto Stock Exchange. In addition, the Province granted the underwriters an over-allotment option to purchase up to an additional 10,865,200 common shares of Hydro One which was fully exercised and closed on April 29, 2016. Hydro One did not receive any of the proceeds from the sale of common shares by the Province.

Preferred Shares

The Company is authorized to issue an unlimited number of preferred shares, issuable in series. At December 31, 2017 and 2016, two series of preferred shares are authorized for issuance: the Series 1 preferred shares and the Series 2 preferred shares. At

December 31, 2017 and 2016, 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, 2017, no preferred share dividends 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.

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.

23. DIVIDENDS

In 2017, preferred share dividends in the amount of $18 million (2016 - $19 million) and common share dividends in the amount of $518 million (2016 - $577 million) were declared. The 2016 common share dividends include $77 million for the post-Initial Public Offering (IPO) period from November 5 to December 31, 2015, and $500 million for the year ended December 31, 2016.

24. EARNINGS PER COMMON 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 stock-based compensation plans, including the share grant plans and the LTIP, which are calculated using the treasury stock method.

Year ended December 31	2017	2016
Net income attributable to common shareholders *(millions of dollars)*	658	721
Weighted average number of shares		
Basic	595,287,586	595,000,000
Effect of dilutive stock-based compensation plans	2,234,665	1,700,823
Diluted	597,522,251	596,700,823
EPS		
Basic	$1.11	$1.21
Diluted	$1.10	$1.21

The common shares contingently issuable as a result of the Convertible Debentures are not included in diluted EPS until conditions for closing the Avista Corporation acquisition are met.

25. STOCK-BASED COMPENSATION

Share Grant Plans

Hydro One has two share grant plans (Share Grant Plans), one for the benefit of certain members of the PWU (PWU Share Grant Plan) and one for the benefit of certain members of The Society (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. 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 began on July 3, 2015, which is the date the share grant plan was 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 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 began 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 Hydro One 2015 share grants of $111 million was 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. In 2017, 371,611 common shares were granted under the Share Grant Plans (2016 - nil). Total share based compensation recognized during 2017 was $17 million (2016 - $21 million) and was recorded as a regulatory asset.

A summary of share grant activity under the Share Grant Plans during years ended December 31, 2017 and 2016 is presented below:

Year ended December 31, 2017	Share Grants *(number of common shares)*	Weighted-Average Price
Share grants outstanding - beginning	5,334,415	$20.50
Vested and issued[1]	(371,611)	—
Forfeited	(137,072)	$20.50
Share grants outstanding - ending	4,825,732	$20.50

[1] On April 1, 2017, Hydro One issued from treasury 371,611 common shares to eligible employees in accordance with provisions of the PWU Share Grant Plan.

Year ended December 31, 2016	Share Grants *(number of common shares)*	Weighted-Average Price
Share grants outstanding - beginning	5,412,354	$20.50
Forfeited	(77,939)	$20.50
Share grants outstanding - ending	5,334,415	$20.50

Directors' DSU Plan

Under the 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.

During the years ended December 31, 2017 and 2016, the Company granted awards under the Directors' DSU Plan, as follows:

Year ended December 31 *(number of DSUs)*	2017	2016
DSUs outstanding - beginning	99,083	20,525
DSUs granted	88,007	78,558
DSUs outstanding - ending	187,090	99,083

For the year ended December 31, 2017, an expense of $2 million (2016 - $2 million) was recognized in earnings with respect to the Directors' DSU Plan. At December 31, 2017, a liability of $4 million (2016 - $2 million), related to outstanding DSUs has been recorded at the closing price of the Company's common shares of $22.40 and is included in long-term accounts payable and other liabilities on the Consolidated Balance Sheets.

Management DSU Plan

Under the Management DSU Plan, eligible executive employees can elect to receive a specified proportion of their annual short-term incentive in a notional account of DSUs in lieu of cash. 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.

During the years ended December 31, 2017 and 2016, the Company granted awards under the Management DSU Plan, as follows:

Year ended December 31 *(number of DSUs)*	2017	2016
DSUs outstanding - beginning	—	—
Granted	68,897	—
Paid	(1,068)	—
DSUs outstanding - ending	67,829	—

For the year ended December 31, 2017, an expense of $2 million (2016 - $nil) was recognized in earnings with respect to the Management DSU Plan. At December 31, 2017, a liability of $2 million (2016 - $nil) related to outstanding DSUs has been recorded at the closing price of the Company's common shares of $22.40 and is included in long-term accounts payable and other liabilities on the Consolidated Balance Sheets.

Employee Share Ownership Plan

In 2015, Hydro One established Employee Share Ownership Plans (ESOP) for certain eligible management and non-represented employees (Management ESOP) and for certain eligible Society-represented staff (Society ESOP). Under the Management ESOP, the 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 matches 50% of their contributions, up to a maximum Company contribution of $25,000 per calendar year. Under the Society ESOP, the eligible Society-represented staff may contribute between 1% and 4% of their base salary towards purchasing common shares of Hydro One. The Company matches 25% of their contributions, with no maximum Company contribution per calendar year. In 2017, Company contributions made under the ESOP were $2 million (2016 - $2 million).

LTIP

Effective August 31, 2015, the Board of Directors of Hydro One adopted an LTIP. Under the LTIP, long-term incentives are granted to certain executive and management employees of Hydro One and its subsidiaries, 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 of Hydro One.

The LTIP provides flexibility to award a range of vehicles, RSUs, PSUs, 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.

During 2017 and 2016, the Company granted awards under its LTIP as follows:

	PSUs		RSUs	
Year ended December 31 *(number of units)*	2017	2016	2017	2016
Units outstanding - beginning	230,600	—	254,150	—
Units granted	303,240	235,420	242,860	258,970
Units vested	(609)	—	(14,079)	—
Units forfeited	(103,251)	(4,820)	(89,501)	(4,820)
Units outstanding - ending	429,980	230,600	393,430	254,150

The grant date total fair value of the awards granted in 2017 was $13 million (2016 - $12 million). The compensation expense related to these awards recognized by the Company during 2017 was $6 million (2016 - $3 million).

26. NONCONTROLLING INTEREST

On December 16, 2014, 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 during the years ended December 31, 2017 and 2016:

Year ended December 31, 2017 *(millions of dollars)*	Temporary Equity	Equity	Total
Noncontrolling interest - beginning	22	50	72
Distributions to noncontrolling interest	(2)	(4)	(6)
Net income attributable to noncontrolling interest	2	4	6
Noncontrolling interest - ending	22	50	72

Year ended December 31, 2016 *(millions of dollars)*	Temporary Equity	Equity	Total
Noncontrolling interest - beginning	23	52	75
Distributions to noncontrolling interest	(3)	(6)	(9)
Net income attributable to noncontrolling interest	2	4	6
Noncontrolling interest - ending	22	50	72

27. RELATED PARTY TRANSACTIONS

The Province is a shareholder of Hydro One with approximately 47.4% ownership at December 31, 2017. The IESO, Ontario Power Generation Inc. (OPG), Ontario Electricity Financial Corporation (OEFC), and the OEB, are related parties to Hydro One because they are controlled or significantly influenced by the Province. Hydro One Brampton was a related party until February 28, 2017, when it was acquired from the Province by Alectra Inc., and subsequent to the acquisition by Alectra Inc., is no longer a related party to Hydro One.

Year ended December 31 *(millions of dollars)*			
Related Party	Transaction	2017	2016
Province	Dividends paid	301	451
IESO	Power purchased	1,583	2,096
	Revenues for transmission services	1,521	1,549
	Amounts related to electricity rebates	357	—
	Distribution revenues related to rural rate protection	247	125
	Distribution revenues related to the supply of electricity to remote northern communities	32	32
	Funding received related to CDM programs	59	63
OPG	Power purchased	9	6
	Revenues related to provision of construction and equipment maintenance services	3	5
	Costs related to the purchase of services	1	1
OEFC	Power purchased from power contracts administered by the OEFC	2	1
OEB	OEB fees	8	11
Hydro One Brampton	Cost recovery from management, administrative and smart meter network services	—	3

Sales to and purchases from related parties are based on the requirements of the OEB's Affiliate Relationships Code. Outstanding balances at period end are interest-free and settled in cash.

28. CONSOLIDATED STATEMENTS OF CASH FLOWS

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

Year ended December 31 *(millions of dollars)*	2017	2016
Accounts receivable	195	(60)
Due from related parties	(95)	33
Materials and supplies	1	2
Prepaid expenses and other assets	7	(15)
Accounts payable	7	19
Accrued liabilities	(89)	53
Due to related parties	10	9
Accrued interest	(6)	9
Long-term accounts payable and other liabilities	(2)	6
Post-retirement and post-employment benefit liability	85	78
	113	134

Capital Expenditures

The following table reconciles investments in property, plant and equipment and the amounts 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 dollars)*	2017	2016
Capital investments in property, plant and equipment	(1,493)	(1,630)
Capitalized depreciation and net change in accruals included in capital investments in property, plant and equipment	26	30
Cash outflow for capital expenditures – property, plant and equipment	(1,467)	(1,600)

The following table reconciles investments in intangible assets and the amounts presented in the Consolidated Statements of Cash Flows after accounting for the net change in related accruals:

Year ended December 31 *(millions of dollars)*	2017	2016
Capital investments in intangible assets	(74)	(67)
Net change in accruals included in capital investments in intangible assets	(6)	6
Cash outflow for capital expenditures – intangible assets	(80)	(61)

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 2017, capital contributions from these reassessments totalled $9 million (2016 - $21 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.

Supplementary Information

Year ended December 31 *(millions of dollars)*	2017	2016
Net interest paid	475	418
Income taxes paid	12	32

29. CONTINGENCIES

Legal Proceedings

Hydro One is involved in various lawsuits and claims 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.

Hydro One Inc., Hydro One Networks, Hydro One Remote Communities, and Norfolk Power Distribution Inc. are defendants in a class action suit in which the representative plaintiff is seeking up to $125 million in damages related to allegations of improper billing practices. The plaintiff's motion for certification was dismissed by the court on November 28, 2017, but the plaintiff has appealed the court's decision, and it is likely that no decision will be rendered by the appeal court until the second half of 2018. At this time, an estimate of a possible loss related to this claim cannot be made.

To date, four putative class action lawsuits have been filed by purported Avista Corporation shareholders in relation to the Merger. First, *Fink v. Morris, et al.*, was filed in Washington state court and the amended complaint names as defendants Avista Corporation's directors, Hydro One, Olympus Holding Corp., Olympus Corp., and Bank of America Merrill Lynch. The suit alleges that Avista Corporation's directors breached their fiduciary duties in relation to the Merger, aided and abetted by Hydro One, Olympus Holding Corp., Olympus Corp. and Bank of America Merrill Lynch. The Washington state court issued an order staying the litigation until after the plaintiffs file an amended complaint, which must be no later than 30 days after Avista Corporation or Hydro One publicly announces that the Merger has closed. Second, *Jenß v. Avista Corp., et al., Samuel v. Avista Corp., et al., and Sharpenter v. Avista Corp., et al.*, were each filed in the US District Court for the Eastern District of Washington and named as defendants Avista Corporation and its directors; *Sharpenter* also named Hydro One, Olympus Holding Corp., and Olympus Corp. The lawsuits alleged that the preliminary proxy statement omitted material facts necessary to make the statements therein not false or misleading. *Jenß, Samuel, and Sharpenter* were all voluntarily dismissed by the respective plaintiffs with no consideration paid by any of the defendants. The one remaining class action is consistent with expectations for US merger transactions and, while there is no certainty as to outcome, Hydro One believes that the lawsuit is not material to Hydro One.

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 2017, the Company paid approximately $2 million (2016 - $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.

30. COMMITMENTS

The following table presents a summary of Hydro One's commitments under leases, outsourcing and other agreements due in the next 5 years and thereafter:

December 31, 2017 *(millions of dollars)*	Year 1	Year 2	Year 3	Year 4	Year 5	Thereafter
Outsourcing agreements	139	95	2	2	2	7
Long-term software/meter agreement	17	17	16	2	1	3
Operating lease commitments	12	7	11	6	4	4

Outsourcing Agreements

Hydro One has agreements with Inergi LP (Inergi) for the provision of back office and IT outsourcing services, including settlements, source to pay services, pay operations services, information technology and finance and accounting services, expiring on December 31, 2019, and for the provision of customer service operations outsourcing services expiring on February 28, 2018. Hydro One is currently in the process of insourcing the customer service operations services and will not be renewing the existing agreement for these services with Inergi. Agreements have been reached with The Society and the PWU to facilitate the insourcing of these services effective March 1, 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 agreement with Brookfield for these services expires in December 2024.

Long-term Software/Meter Agreement

Trilliant Holdings Inc. and Trilliant Networks (Canada) Inc. (collectively Trilliant) provide services to Hydro One for the supply, maintenance and support services for smart meters and related hardware and software, including additional software licences, as well as certain professional services. The agreement with Trilliant for these services expires in December 2025, but Hydro One has the option to renew for an additional term of five years at its sole discretion.

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, 2017, the Company made lease payments totalling $12 million (2016 - $11 million).

Other Commitments

The following table presents a summary of Hydro One's other commercial commitments by year of expiry in the next 5 years and thereafter:

December 31, 2017 *(millions of dollars)*	Year 1	Year 2	Year 3	Year 4	Year 5	Thereafter
Credit facilities	—	—	—	250	2,300	—
Letters of credit[1]	177	—	—	—	—	—
Guarantees[2]	325	—	—	—	—	—

[1] Letters of credit consist of a $154 million letter of credit related to retirement compensation arrangements, a $16 million letter of credit provided to the IESO for prudential support, $6 million in letters of credit to satisfy debt service reserve requirements, and $1 million in letters of credit for various operating purposes.

[2] Guarantees consist of prudential support provided to the IESO by Hydro One Inc. on behalf of its subsidiaries.

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. The IESO could draw on these guarantees and/or letters of credit if these purchasers 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.

31. SEGMENTED REPORTING

Hydro One has three reportable segments:

- The Transmission Segment, which comprises the transmission of 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 Segment, which comprises the delivery of electricity to end customers and certain other municipal electricity distributors; and
- Other Segment, 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 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).

Year ended December 31, 2017 *(millions of dollars)*	Transmission	Distribution	Other	Consolidated
Revenues	1,578	4,366	46	5,990
Purchased power	—	2,875	—	2,875
Operation, maintenance and administration	375	593	98	1,066
Depreciation and amortization	420	390	7	817
Income (loss) before financing charges and income taxes	783	508	(59)	1,232
Capital investments	968	588	11	1,567

Year ended December 31, 2016 *(millions of dollars)*	Transmission	Distribution	Other	Consolidated
Revenues	1,584	4,915	53	6,552
Purchased power	—	3,427	—	3,427
Operation, maintenance and administration	382	608	79	1,069
Depreciation and amortization	390	379	9	778
Income (loss) before financing charges and income taxes	812	501	(35)	1,278
Capital investments	988	703	6	1,697

Total Assets by Segment:

December 31 *(millions of dollars)*	2017	2016
Transmission	13,608	13,071
Distribution	9,259	9,379
Other	2,834	2,901
Total assets	25,701	25,351

Total Goodwill by Segment:

December 31 *(millions of dollars)*	2017	2016
Transmission *(Note 4)*	157	159
Distribution	168	168
Total goodwill	325	327

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

32. SUBSEQUENT EVENTS

Dividends

On February 12, 2018, preferred share dividends in the amount of $4 million and common share dividends in the amount of $131 million ($0.22 per common share) were declared.

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 thereto (Consolidated Financial Statements) of Hydro One Limited (Hydro One or the Company) for the year ended December 31, 2017. 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, 2017, based on information available to management as of February 12, 2018.

CONSOLIDATED FINANCIAL HIGHLIGHTS AND STATISTICS

Year ended December 31 *(millions of dollars, except as otherwise noted)*	2017	2016	Change
Revenues	5,990	6,552	(8.6%)
Purchased power	2,875	3,427	(16.1%)
Revenues, net of purchased power[1]	3,115	3,125	(0.3%)
Operation, maintenance and administration costs	1,066	1,069	(0.3%)
Depreciation and amortization	817	778	5.0%
Financing charges	439	393	11.7%
Income tax expense	111	139	(20.1%)
Net income attributable to common shareholders of Hydro One	**658**	**721**	**(8.7%)**
Basic earnings per common share (EPS)	$1.11	$1.21	(8.3%)
Diluted EPS	$1.10	$1.21	(9.1%)
Basic adjusted non-GAAP EPS (Adjusted EPS)[1]	$1.17	$1.21	(3.3%)
Diluted Adjusted EPS[1]	$1.16	$1.21	(4.1%)
Net cash from operating activities	1,716	1,656	3.6%
Funds from operations (FFO)[1]	1,579	1,494	5.7%
Capital investments	1,567	1,697	(7.7%)
Assets placed in-service	1,592	1,605	(0.8%)
Transmission: Average monthly Ontario 60-minute peak demand *(MW)*	19,587	20,690	(5.3%)
Distribution: Electricity distributed to Hydro One customers *(GWh)*	25,876	26,289	(1.6%)

	2017	2016
Debt to capitalization ratio[2]	52.9%	52.6%

[1] See section "Non-GAAP Measures" for description and reconciliation of basic and diluted Adjusted EPS, FFO and Revenues, net of purchased power.

[2] Debt to capitalization ratio has been presented at December 31, 2017 and 2016, and has been calculated as total debt (includes total long-term debt, convertible debentures and short-term borrowings, net of cash and cash equivalents) divided by total debt plus total shareholders' equity, including preferred shares but excluding any amounts related to noncontrolling interest.

OVERVIEW

Hydro One is the largest electricity transmission and distribution company in Ontario. Through its wholly-owned subsidiary, Hydro One Inc., Hydro One owns and operates substantially all of Ontario's electricity transmission network, and approximately 123,000 circuit kilometres of primary low-voltage distribution network. Hydro One has three business segments: (i) transmission; (ii) distribution; and (iii) other business.

For the year ended December 31, 2017, Hydro One's business segments accounted for the Company's total revenues, net of purchased power, as follows:

	Transmission	Distribution	Other
Percentage of Company's total revenues, net of purchased power	51%	48%	1%

At December 31, 2017, Hydro One's business segments accounted for the Company's total assets as follows:

	Transmission	Distribution	Other
Percentage of Company's total assets	53%	36%	11%

Transmission Segment

Hydro One's transmission business owns, operates and maintains Hydro One's transmission system, which accounts for approximately 98% of Ontario's transmission capacity based on revenue approved by the Ontario Energy Board (OEB). The transmission business consists of the transmission system operated by Hydro One Inc.'s subsidiaries, Hydro One Networks Inc. (Hydro One Networks) and Hydro One Sault Ste. Marie LP (HOSSM) (formerly Great Lakes Power Transmission LP), as well as 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 OEB.

	2017	2016
Electricity transmitted[1] *(MWh)*	132,090,992	136,989,747
Transmission lines spanning the province *(circuit-kilometres)*	30,290	30,259
Rate base *(millions of dollars)*	11,251	10,775
Capital investments *(millions of dollars)*	968	988
Assets placed in-service *(millions of dollars)*	889	937

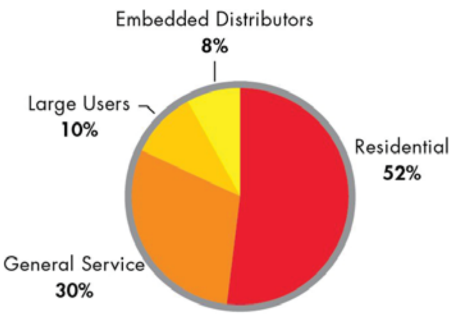
[1] Electricity transmitted represents total electricity transmission in Ontario by all transmitters.

Distribution Segment

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 are approved by the OEB.

	2017	2016
Electricity distributed to Hydro One customers *(GWh)*	25,876	26,289
Electricity distributed through Hydro One lines *(GWh)*[1]	36,525	37,394
Distribution lines spanning the province *(circuit-kilometres)*	123,361	122,599
Distribution customers *(number of customers)*	1,372,362	1,355,302
Rate base *(millions of dollars)*	7,389	7,056
Capital investments *(millions of dollars)*	588	703
Assets placed in-service *(millions of dollars)*	689	662

[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).



2017 Distribution Revenues

Other Business Segment

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 broadband connectivity. Hydro One's other business segment is not rate-regulated.

PRIMARY FACTORS AFFECTING RESULTS OF OPERATIONS

Transmission Revenues

Transmission revenues primarily consist of regulated 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 power generators and from third-party land use.

Distribution Revenues

Distribution revenues include regulated 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 the 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 revenues such as charges for late payments.

Purchased Power Costs

Purchased power costs are incurred by the distribution business and represent the cost of the electricity purchased by the Company for delivery to customers within Hydro One's distribution service territory. These costs are comprised of the following: the wholesale commodity cost of energy; the Global Adjustment, which is the difference between amounts the IESO pays energy producers for the electricity they produce and the actual fair market value of this electricity; and the wholesale market service and transmission charges levied by the 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 to provide safe and reliable electricity to the Company's residential, small business, commercial, and industrial customers across the province. These include costs related to distribution line clearing and forestry control to reduce power outages caused by trees, line maintenance and repair, land assessment and remediation, as well as issuing timely and accurate bills and responding to customer inquiries. 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 and amortization 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 and short-term borrowings, and gains and losses on interest rate swap agreements, contingent foreign exchange or other similar contracts, net of interest earned on short-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.

RESULTS OF OPERATIONS

Net Income

Net income attributable to common shareholders for the year ended December 31, 2017 of $658 million is a decrease of $63 million or 8.7% from the prior year. Significant influences on net income included:

- decrease in transmission and distribution revenues due to lower energy consumption during 2017 resulting from milder weather;
- higher transmission revenues driven by OEB's decision on the 2017-2018 transmission rates filing;
- transmission and distribution revenues were also impacted by a reduction in the 2017 allowed regulated return on equity (ROE) from 9.19% to 8.78%;
- lower OM&A costs primarily resulting from a reduction of provision for payments in lieu of property taxes following a favourable reassessment of the regulations, insurance proceeds received due to failed equipment at two transformer stations, and a tax recovery of previous year's expenses; as well as reduced vegetation management costs and lower support services costs. These factors were offset by higher consulting costs primarily related to the acquisition of Avista Corporation; and lower bad debt expense in 2016 due to revised estimates of uncollectible accounts resulting from the stabilization of the customer information system;
- increased financing charges primarily due to the issuance of convertible debentures in August 2017; as well as a higher weighted average long-term debt portfolio during 2017 compared to 2016, including long-term debt assumed as part of the HOSSM acquisition in the fourth quarter of 2016; and
- higher depreciation expense due to an increase in property, plant and equipment.

EPS and Adjusted EPS

EPS of $1.11 in 2017, compared to $1.21 in 2016. The decrease in EPS was driven by lower net income in 2017, as discussed above. Adjusted EPS, which adjusts for costs related to the Avista Corporation acquisition, was $1.17 in 2017, compared to $1.21 in 2016. The decrease in Adjusted EPS was also driven by lower net income in 2017, as discussed above, excluding the aforementioned impact related to Avista Corporation acquisition. See section "Non-GAAP Measures" for description of Adjusted EPS.

Revenues

Year ended December 31 *(millions of dollars, except as otherwise noted)*	2017	2016	Change
Transmission	1,578	1,584	(0.4%)
Distribution	4,366	4,915	(11.2%)
Other	46	53	(13.2%)
Total revenues	5,990	6,552	(8.6%)
Transmission	1,578	1,584	(0.4%)
Distribution, net of purchased power	1,491	1,488	0.2%
Other	46	53	(13.2%)
Total revenues, net of purchased power	3,115	3,125	(0.3%)
Transmission: Average monthly Ontario 60-minute peak demand *(MW)*	19,587	20,690	(5.3%)
Distribution: Electricity distributed to Hydro One customers *(GWh)*	25,876	26,289	(1.6%)

Transmission Revenues

Transmission revenues decreased by 0.4% in 2017 primarily due to the following:

- lower average monthly Ontario 60-minute peak demand mainly due to milder weather in the first three quarters of 2017;
- decreased OEB-approved transmission rates primarily reflecting a reduction in 2017 allowed ROE for the transmission business from 9.19% to 8.78%; offset by
- higher revenues driven by the OEB's decision on the 2017-2018 transmission rates filing; and
- additional revenues resulting from the acquisition of HOSSM in the fourth quarter of 2016.

Distribution Revenues, Net of Purchased Power

Distribution revenues, net of purchased power, increased by 0.2% in 2017 primarily due to the following:

- lower energy consumption mainly resulting from milder weather in the first three quarters of 2017; offset by
- higher external revenues related to Conservation and Demand Management (CDM) incentive bonus; and
- higher OEB-approved distribution rates for 2017, net of a reduction in 2017 allowed ROE for the distribution business from 9.19% to 8.78%.

OM&A Costs

Year ended December 31 *(millions of dollars)*	2017	2016	Change
Transmission	375	382	(1.8%)
Distribution	593	608	(2.5%)
Other	98	79	24.1%
	1,066	1,069	(0.3%)

<u>Transmission OM&A Costs</u>

The decrease of 1.8% in transmission OM&A costs for the year ended December 31, 2017 was primarily due to:

- a reduction of provision for payments in lieu of property taxes following a favourable reassessment of the regulation;
- lower support services costs; and
- insurance proceeds received due to equipment failures at the Fairchild and Campbell transmission stations; partially offset by
- higher volume of environmental management program work.

<u>Distribution OM&A Costs</u>

The decrease of 2.5% in distribution OM&A costs for the year ended December 31, 2017 was primarily due to:

- continued lower expenditures for vegetation management due to strategic changes to the forestry program scope that resulted in cost efficiency and improved management of the Company's rights of ways;
- lower volume of line maintenance work;
- lower spend on development and research programs; and
- a tax recovery of previous year's expenses; partially offset by
- lower bad debt expense in 2016 due to revised estimates of uncollectible accounts as a result of stabilization of the customer information system, partially offset by lower bad debt expense in 2017 attributable to lower write-offs and improved accounts receivable aging; and
- increased storm restoration costs as a result of Hurricane Irma restoration efforts in Florida. These restoration efforts had no impact on the Company's net income, as related revenues were recorded in distribution revenues during the year.

<u>Other OM&A Costs</u>

The increase in other OM&A costs for the year ended December 31, 2017 was driven by higher consulting costs primarily related to the acquisition of Avista Corporation.

Depreciation and Amortization

The increase of $39 million or 5.0% in depreciation and amortization costs for 2017 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.

Financing Charges

The increase of $46 million or 11.7% in financing charges for the year ended December 31, 2017 was primarily due to the following:

- an increase in interest expense on long-term debt driven by a higher weighted average long-term debt portfolio during 2017 including the long-term debt assumed as part of the HOSSM acquisition in the fourth quarter of 2016; partially offset by a decrease in the weighted average interest rate for long-term debt; and
- an increase in interest expense related to the Convertible Debentures issued in August 2017.

Income Tax Expense

Income tax expense for the year ended December 31, 2017 decreased by $28 million compared to 2016, and the Company realized an effective tax rate of approximately 14.0% in 2017, compared to approximately 15.7% realized in 2016. The decreases in the tax expense and the effective tax rate are primarily due to lower income before taxes in 2017.

Common Share Dividends

In 2017, the Company declared and paid cash dividends to common shareholders as follows:

Date Declared	Record Date	Payment Date	Amount per Share	Total Amount *(millions of dollars)*
February 9, 2017	March 14, 2017	March 31, 2017	$0.21	125
May 3, 2017	June 13, 2017	June 30, 2017	$0.22	131
August 8, 2017	September 12, 2017	September 29, 2017	$0.22	131
November 9, 2017	December 12, 2017	December 29, 2017	$0.22	131
				518

Following the conclusion of the fourth quarter of 2017, the Company declared a cash dividend to common shareholders as follows:

Date Declared	Record Date	Payment Date	Amount per Share	Total Amount *(millions of dollars)*
February 12, 2018	March 13, 2018	March 29, 2018	$0.22	131

SELECTED ANNUAL FINANCIAL STATISTICS

Year ended December 31 *(millions of dollars, except per share amounts)*	2017	2016	2015
Revenues	5,990	6,552	6,538
Net income attributable to common shareholders	658	721	690
Basic EPS	$1.11	$1.21	$1.39
Diluted EPS	$1.10	$1.21	$1.39
Basic Adjusted EPS	$1.17	$1.21	$1.16
Diluted Adjusted EPS	$1.16	$1.21	$1.16
Dividends per common share declared	$0.87	$0.97[1]	$1.83
Dividends per preferred share declared	$1.06	$1.12	$1.03

[1] The $0.97 per share dividends declared in 2016 included $0.13 for the post-IPO period from November 5 to December 31, 2015, and $0.84 for the year ended December 31, 2016.

December 31 *(millions of dollars)*	2017	2016	2015
Total assets	25,701	25,351	24,294
Total non-current financial liabilities	9,802	10,078	8,207

QUARTERLY RESULTS OF OPERATIONS

Quarter ended *(millions of dollars, except EPS)*	Dec 31, 2017	Sep 30, 2017	Jun 30, 2017	Mar 31, 2017	Dec 31, 2016	Sep 30, 2016	Jun 30, 2016	Mar 31, 2016
Revenues	1,439	1,522	1,371	1,658	1,614	1,706	1,546	1,686
Purchased power	662	675	649	889	858	870	803	896
Revenues, net of purchased power	777	847	722	769	756	836	743	790
Net income to common shareholders	155	219	117	167	128	233	152	208
Basic EPS	$0.26	$0.37	$0.20	$0.28	$0.22	$0.39	$0.26	$0.35
Diluted EPS	$0.26	$0.37	$0.20	$0.28	$0.21	$0.39	$0.25	$0.35
Basic Adjusted EPS[1]	$0.29	$0.40	$0.20	$0.28	$0.22	$0.39	$0.26	$0.35
Diluted Adjusted EPS[1]	$0.28	$0.40	$0.20	$0.28	$0.21	$0.39	$0.25	$0.35

[1] See section "Non-GAAP Measures" for description of Adjusted EPS.

Variations in revenues and net income over the quarters are primarily due to the impact of seasonal weather conditions on customer demand and market pricing.

CAPITAL INVESTMENTS

The Company makes capital investments to maintain the safety, reliability and integrity of its transmission and distribution system 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.

Assets Placed In-Service

The following table presents Hydro One's assets placed in-service during the year ended December 31, 2017 and 2016:

Year ended December 31 *(millions of dollars)*	2017	2016	Change
Transmission	889	937	(5.1%)
Distribution	689	662	4.1%
Other	14	6	133.3%
Total assets placed in-service	1,592	1,605	(0.8%)

Transmission Assets Placed In-Service

Transmission assets placed in-service decreased by $48 million or 5.1% during the year ended December 31, 2017 primarily due to the following:

- substantial investments of two major local area supply projects, Guelph Area Transmission Refurbishment and Toronto Midtown Transmission Reinforcement, were placed in-service in 2016;
- completion of the Advanced Distribution System project at Owen Sound transmission station in 2016;
- timing of assets placed in-service for the sustainment investments at Burlington and Bruce A transmission stations; partially offset by investments at Aylmer and Overbrook transmission stations; and
- lower volume of end-of-life transformer replacements work; partially offset by
- substantial investments of major development projects at Leamington and Holland transmission stations were placed in-service in the fourth quarter of 2017;
- higher volume of overhead lines and component refurbishments and replacements; and
- the completion of the Field Workforce Optimization (Move-to-Mobile) project in June 2017.

Distribution Assets Placed In-Service

Distribution assets placed in-service increased by $27 million or 4.1% during the year ended December 31, 2017 primarily due to the following:

- higher volume of subdivision connections due to increased demand;
- the completion of the Move-to-Mobile project in June 2017;
- the completion of an operation center in Bolton in February 2017;
- the completion of the Outage Response Management System (ORMS) project in the third quarter of 2017; and
- substantial investments that were placed in-service for the Leamington transmission station feeder development project; partially offset by
- the Advanced Metering Infrastructure Wireless Telecom project was placed in-service during 2016;
- lower volume of generation connection projects; and
- lower volume of distribution station refurbishments and spare transformer purchases.

Capital Investments

The following table presents Hydro One's capital investments during the years ended December 31, 2017 and 2016:

Year ended December 31 *(millions of dollars)*	2017	2016	Change
Transmission			
Sustaining	764	750	1.9%
Development	137	156	(12.2%)
Other	67	82	(18.3%)
	968	988	(2.0%)
Distribution			
Sustaining	280	384	(27.1%)
Development	227	217	4.6%
Other	81	102	(20.6%)
	588	703	(16.4%)
Other	11	6	83.3%
Total capital investments	1,567	1,697	(7.7%)

Transmission Capital Investments

Transmission capital investments decreased by $20 million or 2.0% during the year ended December 31, 2017. Principal impacts on the levels of capital investments included:

- construction work on Clarington Transmission Station project is substantially complete and therefore, lower investments in 2017;
- decreased investments in information technology projects, primarily due to completion of certain projects and timing of work on other projects;
- lower volume of transmission station refurbishments and component replacements work; and
- substantial completion of the Guelph Area Transmission Refurbishment project in 2016; partially offset by
- higher volume of overhead lines and component refurbishments and replacements; and
- substantial completion of the Leamington transmission station project to address the electricity needs in Windsor and Essex County.

Distribution Capital Investments

Distribution capital investments decreased by $115 million or 16.4% during the year ended December 31, 2017. Principal impacts on the levels of capital investments included:

- lower volume of work within station refurbishment programs;
- lower volume of line refurbishments and replacements work;
- lower volume of wood pole replacements;
- lower volume of fleet and work equipment purchases;
- decreased investments in information technology projects, primarily due to completion of certain projects and timing of work on other projects;
- completion of the Bolton Operation Centre; partially offset by
- higher volume of work on new connections and upgrades due to increased demand.

Major Transmission Capital Investment Projects

The following table summarizes the status of significant transmission projects as at December 31, 2017:

Project Name	Location	Type	Anticipated In-Service Date	Estimated Cost	Capital Cost To Date
Development Projects:					
Supply to Essex County Transmission Reinforcement	Windsor-Essex area Southwestern Ontario	New transmission line and station	2018	$57 million[1]	$52 million
Clarington Transmission Station	Oshawa area Southwestern Ontario	New transmission station	2018	$267 million	$223 million
East-West Tie Station Expansion	Northern Ontario	New transmission connection and station expansion	2021	$157 million	$7 million
Northwest Bulk Transmission Line	Thunder Bay Northwestern Ontario	New transmission line	2024	$350 million	$1 million
Sustainment Projects:					
Bruce A Transmission Station	Tiverton Southwestern Ontario	Station sustainment	2020	$109 million[2]	$105 million
Richview Transmission Station Circuit Breaker Replacement	Toronto Southwestern Ontario	Station sustainment	2019	$103 million	$85 million
Beck #2 Transmission Station Circuit Breaker Replacement	Niagara area Southwestern Ontario	Station sustainment	2022	$93 million	$51 million
Lennox Transmission Station Circuit Breaker Replacement	Napanee Southeastern Ontario	Station sustainment	2023	$95 million	$44 million

[1] In February 2018, the estimated cost to complete the Supply to Essex County Transmission Reinforcement project was reduced from $73 million to $57 million.
[2] The estimated cost to complete the Bruce A Transmission Station project is currently under review.

Future Capital Investments

Following is a summary of estimated capital investments by Hydro One over the years 2018 to 2022. The Company's estimates are based on management's expectations of the amount of capital expenditures that will be required to provide transmission and distribution services that are efficient, reliable, and provide value for customers, consistent with the OEB's Renewed Regulatory Framework. The 2018 transmission capital investments estimates differ from the prior year disclosures, representing an annual decrease of $122 million to reflect the OEB's focus on planning practices and the pacing of sustainment capital investments, specifically, tower coating, stations, and insulator investments, as indicated in the OEB's 2017-2018 transmission rates decision issued in September 2017. The projections and the timing of 2019-2022 expenditures are subject to approval by the OEB.

The following table summarizes Hydro One's annual projected capital investments for 2018 to 2022, by business segment:

(millions of dollars)	2018	2019	2020	2021	2022
Transmission	1,010	1,217	1,278	1,486	1,404
Distribution	641	751	715	719	805
Other	9	8	6	9	8
Total capital investments	**1,660**	**1,976**	**1,999**	**2,214**	**2,217**

The following table summarizes Hydro One's annual projected capital investments for 2018 to 2022, by category:

(millions of dollars)	2018	2019	2020	2021	2022
Sustainment	1,103	1,220	1,328	1,547	1,608
Development	340	484	487	490	430
Other[1]	217	272	184	177	179
Total capital investments	**1,660**	**1,976**	**1,999**	**2,214**	**2,217**

[1] "Other" capital expenditures consist of special projects, such as those relating to information technology.

SUMMARY OF SOURCES AND USES OF CASH

Hydro One's primary sources of cash flows are funds generated from operations, capital market debt issuances and bank credit facilities that are used to satisfy Hydro One's capital resource requirements, including the Company's capital expenditures, servicing and repayment of debt, and dividend payments.

Year ended December 31 *(millions of dollars)*	2017	2016
Cash provided by operating activities	1,716	1,656
Cash provided by (used in) financing activities	(201)	161
Cash used in investing activities	(1,540)	(1,861)
Decrease in cash and cash equivalents	(25)	(44)

Cash provided by operating activities

Cash from Operating Activities increased by $60 million during 2017 primarily due to changes in regulatory variance and deferral accounts, as well as lower energy-related receivables which decreased as a result of improved collections in 2017. These factors were partially offset by changes in accrual balances.

Cash provided by financing activities

Sources of cash

- The Company did not issue long-term debt in 2017, compared to proceeds from the issuance of $2.3 billion in 2016.
- The Company received proceeds of $3,795 million from the issuance of short-term notes in 2017, compared to $3,031 million received in 2016.
- In 2017, the Company received proceeds of $513 million, representing the first instalment of the convertible debentures issued, gross of $27 million financing costs, compared to no convertible debentures issuances in 2016.

Uses of cash

- Dividends paid in 2017 were $536 million, consisting of $518 million common share dividends and $18 million of preferred share dividends, compared to dividends of $596 million paid in 2016, consisting of $577 million common share dividends and $19 million of preferred share dividends. The 2016 common share dividends included $77 million of dividends for the post-IPO period from November 5 to December 31, 2015, and $500 million of dividends for the year ended December 31, 2016.
- The Company repaid $3,338 million of short-term notes in 2017, compared to $4,053 million repaid in 2016.
- The Company repaid $602 million of long-term debt in 2017, compared to long-term debt of $502 million repaid in 2016.

Cash used in investing activities

Uses of cash

- Capital expenditures were $114 million lower in 2017, primarily due to lower volume and timing of capital investment work.
- In 2016, the Company paid $224 million to acquire HOSSM, compared to no acquisition payments made in 2017.

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 bank 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 up to 365 days. At December 31, 2017, Hydro One Inc. had $926 million in commercial paper borrowings outstanding, compared to $469 million outstanding at December 31, 2016. In addition, the Company has revolving bank credit facilities totalling $2,550 million maturing in 2021 and 2022. 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, 2017, the Company's long-term debt in the principal amount of $10,069 million included $9,923 million of long-term debt, the majority of which was issued under Hydro One Inc.'s Medium Term Note (MTN) Program, and long-term debt in the principal amount of $146 million held by HOSSM. At December 31, 2017, the maximum authorized principal amount of notes issuable under the current MTN Program prospectus filed in December 2015 was $3.5 billion, with $1.2 billion remaining available for issuance until January 2018. The long-term debt consists of notes and debentures that mature between 2018 and 2064, and at December 31, 2017, had an average term to maturity of approximately 15.8 years and a weighted average coupon rate of 4.2%.

In March 2016, Hydro One filed a universal short form base shelf prospectus (Universal Base Shelf Prospectus) which allows the Company to offer, from time to time in one or more public offerings, up to $8.0 billion of debt, equity or other securities, or any combination thereof, during the 25-month period ending on April 30, 2018. During the second quarter of 2017, Hydro One announced the closing of a secondary offering of a portion of its common shares previously owned by the Province. See "Other Developments - Secondary Common Share Offering" for details of this transaction. Upon closing of the transaction, $3,240 million remained available under the Universal Base Shelf Prospectus.

On August 9, 2017, in connection with the acquisition of Avista Corporation, the Company completed the sale of $1,540 million aggregate principal amount of 4.00% convertible unsecured subordinated debentures (Convertible Debentures) represented by instalment receipts, which included the exercise in full of the over-allotment option granted to the underwriters to purchase an additional $140 million aggregate principal amount of the Convertible Debentures. The Convertible Debentures instalment receipts trade on the Toronto Stock Exchange under the ticker symbol "H.IR". The Convertible Debentures were sold as part of Hydro One's acquisition financing strategy to acquire Avista Corporation (see section Other Developments - Avista Corporation Purchase agreement), which includes the issuance of $1,540 million of Hydro One common shares and US$2.6 billion of Hydro One debt. The Convertible Debentures were sold to satisfy the equity component of the acquisition financing strategy.

To mitigate the foreign currency risk related to the portion of the Avista Corporation acquisition purchase price financed by the issuance of Convertible Debentures, in October 2017, the Company entered into a deal-contingent foreign exchange forward contract to convert $1.4 billion Canadian to US dollars at an initial forward rate of 1.27486 Canadian per 1.00 US dollars and a range up to 1.28735 Canadian per 1.00 US dollars based on the settlement date. The contract is contingent on the Company closing the proposed Avista Corporation acquisition. If the acquisition does not close, the contract would not be completed and no amounts would be exchanged. The contract can be executed upon approval of the acquisition up to March 31, 2019. The balance of the Avista Corporation acquisition will be financed by issuing long-term debt denominated in US dollars which will act as an economic hedge. At December 31, 2017, a fair value loss of $3 million was recorded with a corresponding derivative liability.

At December 31, 2017, the Company was in compliance with all financial covenants and limitations associated with the outstanding borrowings and credit facilities.

Credit Ratings

At December 31, 2017, Hydro One's corporate credit ratings were as follows:

Rating Agency	Corporate Credit Rating
Standard & Poor's Rating Services (S&P)[1]	A

[1] On July 19, 2017, S&P revised its outlook on the Company to negative from stable, while affirming the existing corporate credit rating.

Hydro One has not obtained a credit rating in respect of any of its securities. An issuer rating from S&P is a forward-looking opinion about an obligor's overall creditworthiness. This opinion focuses on the obligor's capacity and willingness to meet its financial commitments as they come due but it does not apply to any specific financial obligation. An obligor with a long-term credit rating of 'A' has strong capacity to meet its financial commitments but is somewhat more susceptible to the adverse effects of changes in circumstances and economic conditions than obligors in higher-rated categories.

The rating above is not a recommendation to purchase, sell or hold any of Hydro One's securities and does not comment on the market price or suitability of any of the securities for a particular investor. There can be no assurance that the rating will remain in effect for any given period of time or that the rating will not be revised or withdrawn entirely by S&P at any time in the future. Hydro One has made, and anticipates making, payments to S&P pursuant to agreements entered into with S&P in respect of the rating assigned to Hydro One and expects to make payments to S&P in the future to the extent it obtains a rating specific to any of its securities.

At December 31, 2017, Hydro One Inc.'s long-term and short-term debt ratings were as follows:

Rating Agency	Short-term Debt Rating	Long-term Debt Rating
DBRS Limited	R-1 (low)	A (high)
Moody's Investors Service (Moody's)[1]	Prime-2	A3
S&P[1]	A-1	A

[1] On July 19, 2017, S&P and Moody's revised their outlooks on Hydro One Inc. to negative from stable, while affirming the existing debt ratings.

Effect of Interest Rates

The Company is exposed to fluctuations of interest rates as its regulated return on equity (ROE) is derived using a formulaic approach that takes into account changes in benchmark interest rates for Government of Canada debt and the A-rated utility corporate bond yield spread. 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 2017, Hydro One contributed approximately $87 million to its pension plan, compared to contributions of approximately $108 million in 2016, and incurred $88 million in net periodic pension benefit costs, compared to $116 million incurred in 2016.

In May 2017, Hydro One filed an actuarial valuation of its Pension Plan as at December 31, 2016. Based on this valuation and 2017 levels of pensionable earnings, the 2017 annual Company pension contributions have decreased by approximately $17 million from $105 million as estimated at December 31, 2016, primarily due to improvements in the funded status of the plan and future actuarial assumptions, and also reflect the impact of changes implemented by management to improve the balance between employee and Company contributions to the Pension Plan. Hydro One estimates that total Company pension contributions for 2018 and 2019 will be approximately $71 million for each year.

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".

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 and commercial commitments:

December 31, 2017 *(millions of 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	10,069	752	1,384	1,107	6,826
Long-term debt – interest payments	7,690	426	786	725	5,753
Convertible debentures - principal repayments[1]	513	—	—	—	513
Convertible debentures - interest payments	601	62	123	123	293
Short-term notes payable	926	926	—	—	—
Pension contributions[2]	151	71	80	—	—
Environmental and asset retirement obligations	215	28	59	65	63
Outsourcing agreements	247	139	97	4	7
Operating lease commitments	44	12	18	10	4
Long-term software/meter agreement	56	17	33	3	3
Total contractual obligations	20,512	2,433	2,580	2,037	13,462
Other commercial commitments *(by year of expiry)*					
Credit facilities[3]	2,550	—	—	2,550	—
Letters of credit[4]	177	177	—	—	—
Guarantees[5]	325	325	—	—	—
Total other commercial commitments	3,052	502	—	2,550	—

[1] The Company expects that the Convertible Debentures will be converted to common shares upon closing of the Avista Corporation acquisition.
[2] Contributions to the Hydro One Pension Fund are generally made one month in arrears. The 2018 and 2019 minimum pension contributions are based on an actuarial valuation as at December 31, 2016 and projected levels of pensionable earnings.
[3] In June 2017, the maturity date of Hydro One Inc.'s $2.3 billion credit facilities was extended from June 2021 to June 2022.
[4] Letters of credit consist of a $154 million letter of credit related to retirement compensation arrangements, a $16 million letter of credit provided to the IESO for prudential support, $6 million in letters of credit to satisfy debt service reserve requirements, and $1 million in letters of credit for various operating purposes.
[5] Guarantees consist of prudential support provided to the IESO by Hydro One Inc. on behalf of its subsidiaries.

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 deemed 40% equity level 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 and variance accounts over specified time frames.

The following table summarizes the status of Hydro One's major regulatory proceedings:

Application	Years	Type	Status
Electricity Rates			
Hydro One Networks	2017-2018	Transmission – Cost-of-service	OEB decision received[1]
Hydro One Networks	2015-2017	Distribution – Custom	OEB decision received
Hydro One Networks	2018-2022	Distribution – Custom	OEB decision pending
B2M LP	2015-2019	Transmission – Cost-of-service	OEB decision received
HOSSM	2017-2018	Transmission – Revenue Cap	OEB decision received
Mergers Acquisitions Amalgamations and Divestitures (MAAD)			
Orillia Power Distribution Corporation	n/a	Acquisition	OEB decision pending
Leave to Construct			
East-West Tie Station Expansion	n/a	Section 92	OEB decision pending

[1] In October 2017, the Company filed a Motion to Review and Vary the OEB's decision and filed an appeal with the Divisional Court of Ontario.

The following table summarizes the key elements and status of Hydro One's electricity rate applications:

Application	Year	ROE Allowed (A) or Forecast (F)	Rate Base	Rate Application Status	Rate Order Status
Transmission					
Hydro One Networks	2017	8.78% (A)	$10,523 million	Approved in September 2017	Approved in November 2017
	2018	9.00% (A)	$11,148 million	Approved in September 2017	Approved in December 2017
B2M LP	2017	8.78% (A)	$509 million	Approved in December 2015	Approved in June 2017
	2018	9.00% (A)	$502 million	Approved in December 2015	Filed in December 2017
	2019	9.00% (F)	$496 million	Approved in December 2015	To be filed in 2018 Q4
HOSSM	2017	9.19% (A)	$218 million	Approved in September 2017	n/a
	2018	9.19% (A)	$218 million	Approved in September 2017	n/a
Distribution					
Hydro One Networks	2017	8.78% (A)	$7,190 million	Approved in March 2015	Approved in December 2016
	2018	9.00% (A)	$7,666 million	Filed in March 2017[1]	To be filed in 2018 Q4
	2019	9.00% (F)	$8,027 million	Filed in March 2017[1]	To be filed in 2018 Q4
	2020	9.00% (F)	$8,430 million	Filed in March 2017[1]	To be filed in 2019 Q4
	2021	9.00% (F)	$8,960 million	Filed in March 2017[1]	To be filed in 2020 Q4
	2022	9.00% (F)	$9,327 million	Filed in March 2017[1]	To be filed in 2021 Q4

[1] On June 7 and December 21, 2017, Hydro One Networks filed updates to the application reflecting recent financial results and other adjustments.

Electricity Rates Applications

Hydro One Networks - Transmission

On September 28, 2017, the OEB issued its Decision and Order on Hydro One Networks' 2017 and 2018 transmission rates revenue requirements (Decision), with 2017 rates effective January 1, 2017. Key changes to the application as filed included reductions in planned capital expenditures of $126 million and $122 million for 2017 and 2018, respectively, in OM&A expenses related to compensation by $15 million for each year, and in estimated tax savings from the IPO by $24 million and $26 million for 2017 and 2018, respectively. On October 10, 2017, Hydro One Networks filed a Draft Rate Order reflecting the changes outlined in the Decision.

In its Decision, the OEB concluded that the net deferred tax asset resulting from transition from the payments in lieu of tax regime under the *Electricity Act* (Ontario) to tax payments under the federal and provincial tax regime should not accrue entirely to Hydro One's shareholders and that a portion should be shared with ratepayers. On November 9, 2017, the OEB issued a Decision and Order that calculated the portion of the tax savings that should be shared with ratepayers. The OEB's calculation would result in an impairment of Hydro One Networks' transmission deferred income tax regulatory asset of up to approximately $515 million. If the OEB were to apply the same calculation for sharing in Hydro One Networks' 2018-2022 distribution rates, for which a decision is currently outstanding, it would result in an additional impairment of up to approximately $370 million related to Hydro One Networks' distribution deferred income tax regulatory asset.

In October 2017, the Company filed a Motion to Review and Vary (Motion) the Decision and filed an appeal with the Divisional Court of Ontario (Appeal). On December 19, 2017, the OEB granted a hearing of the merits of the Motion which is scheduled for mid-February 2018. In both cases, the Company's position is that the OEB made errors of fact and law in its determination of allocation of the tax savings between the shareholders and ratepayers. The Appeal is being held in abeyance pending the outcome of the Motion. If the Decision is upheld, based on the facts known at this time, the exposure from the potential impairments would be a one-time decrease in net income of up to approximately $885 million, resulting in an annual decrease to FFO in the range of $50 million to $60 million. Based on the assumptions that the OEB applies established rate making principles in a manner consistent with its past practice and does not exercise its discretion to take other policy considerations into account, management is of the view that it is likely that the Company's Motion will be granted and the aforementioned tax savings will be allocated to the benefit of Hydro One shareholders.

In October 2017, the intervenor Anwaatin Inc. also filed a Motion to Review and Vary the OEB Decision (Anwaatin Motion) alleging that the OEB breached its duty of procedural fairness, failed to respond to certain evidence, and failed to provide reasons on the capital budget as it related to reliability issues impacting Anwaatin Inc.'s constituents. The Anwaatin Motion will be heard by the OEB on February 13, 2018.

On November 23, 2017, the OEB approved the 2017 rates revenue requirement of $1,438 million. On December 20, 2017, the OEB approved the 2018 rates revenue requirement of $1,511 million, which included a $25 million increase from the approved amount, as a result of the OEB-updated cost of capital parameters. Uniform Transmission Rates (UTRs), reflecting these approved amounts, were approved by the OEB on February 1, 2018 to be effective as of January 1, 2018.

Hydro One Networks - Distribution

On March 31, 2017, Hydro One Networks filed a custom application with the OEB for 2018-2022 distribution rates under the OEB's incentive-based regulatory framework (2018-2022 Distribution Application), which was subsequently updated on June 7 and December 21, 2017. The application reflects the level of capital investments required to minimize degradation in overall system asset condition, to meet regulatory requirements, and to maintain current reliability levels. Management expects that a decision will be received in 2018.

On November 17, 2017, Hydro One filed with the OEB a request for interim rates based on current OEB-approved rates, adjusted for an updated load forecast. On December 1, 2017, the OEB denied this request and set interim rates based on current OEB-approved rates with no adjustments.

In Hydro One's December 21, 2017 update to the 2018-2022 Distribution Application, Hydro One described the impact to the proposed revenue requirement of various developments since initially filing the application. These included, without limitation, the updated cost of capital parameters and inflation factor for 2018 issued by the OEB, and reductions in the 2018 OM&A forecast and 2018-2022 capital forecasts.

B2M LP

In December 2015, the OEB approved B2M LP's revenue requirement for years 2015 to 2019, subject to annual updates in each of 2016, 2017 and 2018 to adjust its revenue requirement for the following year consistent with the OEB's updated cost of capital parameters. On June 8, 2017, the OEB approved B2M LP's Rate Order reflecting 2017 transmission revenue requirement of $34 million, effective January 1, 2017.

On February 1, 2018, the OEB issued its Decision and Rate Order for 2018 UTRs declaring the 2018 UTRs as interim, as the B2M LP application for an update to its 2018 transmission revenue requirement is still under consideration by the OEB.

HOSSM

On September 28, 2017, the OEB issued its Decision and Order on HOSSM's 2017 transmission rates application, denying the requested revenue requirement for 2017. HOSSM's 2016 approved revenue requirement of $41 million will remain in effect for 2017 and 2018.

Hydro One Remote Communities Inc.

On August 28, 2017, Hydro One Remote Communities Inc. filed an application with the OEB seeking approval of its 2018 revenue requirement of $57 million and electricity rates effective May 1, 2018. On December 14, 2017, the OEB issued a Procedural Order with key dates for filing additional materials and reply submissions. On February 7, 2018, Hydro One Remote Communities Inc. and the intervenors in the rate proceeding reached a full settlement agreement on all issues. The agreement is expected to be reviewed by the OEB for approval in March 2018. Upon the OEB's approval, new rates are expected to be implemented by May 1, 2018.

Hydro One Remote Communities Inc. is fully financed by debt and is operated as a break-even entity with no ROE.

MAAD Applications

Orillia Power MAAD Application

In August 2016, the Company reached an agreement to acquire Orillia Power Distribution Corporation (Orillia Power). The acquisition is subject to regulatory approval by the OEB. On July 27, 2017, the OEB issued a Procedural Order No.6 (Procedural Order) in the matter of Hydro One's MAAD application to acquire Orillia Power. The Procedural Order stated that the OEB has decided to delay a decision on the Orillia Power MAAD application until Hydro One defends its cost allocation proposal in the 2018-2022 Distribution Application hearing to determine if the Orillia Power acquisition is likely to cause harm to any of its current customers. Because of the timetable of the 2018-2022 Distribution Application hearing, and the time it will take to receive a decision in that hearing, the effect of the Procedural Order will be to delay the Orillia Power MAAD application decision by as much as 18 months or more. On August 14, 2017, Hydro One filed a Motion to Review and Vary the Procedural Order requesting the OEB to allow the Orillia Power MAAD application to proceed immediately in the ordinary course. On October 24, 2017, the OEB issued a Procedural Order in response to Hydro One's Motion to Review and Vary, with key dates for filing additional materials on the Motion, hearing date, and filing of reply submissions. Final argument on the Motion to Review and Vary was filed on December 13, 2017.

On January 4, 2018, the OEB issued its Decision on Hydro One's Motion to Review and Vary, granting the motion and referring the MAAD file back to the original OEB panel for reconsideration. The OEB's findings were based on both procedural unfairness and the impact that a lengthy delay will have on the operations of Orillia Power. On February 5, 2018, the OEB issued Procedural Order No. 7 directing Hydro One to file evidence or submissions on its expectations of the overall cost structures following the deferred rebasing period and the effect on Orillia Power customers by February 15, 2018.

Other Applications

East-West Tie

In 2013, NextBridge Infrastructure (NextBridge), a partnership between NextEra Energy Canada, Enbridge Inc., and Borealis Infrastructure was designated by the OEB to complete the development work for the East-West Tie Line Project, a 230 kV, 400 km transmission line connecting Hydro One's Wawa and Lakehead transmission stations. This project is necessary to ensure the reliability of electricity supply in Northwestern Ontario, and was included as a priority project in the Province's 2010 Long-Term Energy Plan. On July 31, 2017, Hydro One filed a Leave to Construct application with the OEB to perform station upgrades to its Wawa and Lakehead transmission stations (East-West Tie Station Expansion), necessary to support the East-West Tie Line Project. Hydro One is acting as an intervenor in NextBridge's East-West Tie Line Project application.

On September 22, 2017, Hydro One filed with the OEB a Letter of Intent indicating that the Company plans to file a Leave to Construct application to construct the East-West Tie Line Project. On December 21, 2017, Hydro One re-confirmed with the OEB that it still intends to file this application in early 2018.

On November 13, 2017, NextBridge filed a letter with the OEB asserting that the OEB should strictly limit Hydro One's intervenor status to matters related to interconnection of the NextBridge East-West Tie Line Project to Hydro One transmission facilities and to ensure that Hydro One does not use its status as the Province's incumbent transmitter to compete unfairly against NextBridge's Leave to Construct application.

On December 1, 2017, the IESO released its needs assessment for the East-West Tie Line Project, as requested by the Minister of Energy. The IESO has reconfirmed that the project is still the recommended solution to supply electricity in Northwestern Ontario and continues to recommend an in-service date of 2020.

On December 5, 2017, Hydro One filed a letter with the OEB in response to NextBridge's request to impose limitations on Hydro One's participation as an intervenor. In the letter, Hydro One asked that the OEB allow Hydro One's status as an intervenor in the proceeding with full intervenor rights, and that the OEB reject NextBridge's requests relating to (i) documentation provided to Hydro One, (ii) creation of a confidentiality screen, and (iii) creation of novel filing requirements for a Leave to Construct application by Hydro One.

On December 21, 2017, both NextBridge and Hydro One received interrogatories from the OEB and Intervenors related to their respective Leave to Construct applications. Hydro One submitted its responses by the January 25, 2017 due date.

Other Regulatory Developments

Fair Hydro Plan and First Nations Rate Assistance Program

In March 2017, Ontario's Minister of Energy announced the Fair Hydro Plan, which included changes to the Global Adjustment, the Rural or Remote Electricity Rate Protection (RRRP) Program, the introduction of the First Nations rate assistance program, and improving the allocation of delivery charges across the rural and urban geographies of the province. Hydro One worked collaboratively with the OEB on the First Nations rate assistance program, and was a key stakeholder in providing solutions that address both the Global Adjustment and RRRP elements. The Fair Hydro Plan came into effect on July 1, 2017 and resulted in a reduction of approximately 25% on electricity bills for typical Ontario residential customers. The Province also launched a new Affordability Fund aimed at assisting electricity customers who cannot qualify for low-income conservation programs. Additional enhancements were also made to the existing Ontario Electricity Support Program (OESP).

Hydro One customers saw the full benefits of the Fair Hydro Plan for all electricity consumed after July 1, 2017. A typical rural residential customer using 750 kWh per month will see savings on their monthly bills of 31% on average, or approximately $600 annually. These changes did not have an impact on the net income of the Company.

Hydro One continues to work with First Nations customers living on reserves to help ensure the required applications are submitted to receive the benefits associated with the First Nations rate assistance program which provides a credit on the delivery charge.

OEB Pension and Other Post-Employment Benefits Costs

On September 14, 2017, the OEB issued its final report, Regulatory Treatment of Pension and Other Post-employment Benefits (OPEBs) Costs (Report), that establishes the use of the accrual accounting method as the default method on which to set rates for pension and OPEB amounts in cost-based applications, unless that method does not result in just and reasonable rates. The Report also provides for the establishment of a variance account, effective January 1, 2018, to track the difference between the forecasted accrual amount in rates and actual cash payments made, with asymmetric carrying charges in favour of ratepayers applied to the differential.

Hydro One currently reports and recovers its pension expense on a cash basis, and maintains the accrual method with respect to OPEBs. Transitioning from the cash basis to an accrual method for pension may have material negative rate impacts for customers, including a higher cost recovered through rates, more volatility relating to the ability to predict the effect on rates, and the pension offset (cumulative difference between the cash and accrual basis which is $981 million as at December 31, 2017) having to be recovered in rates on an accelerated basis. As the Report establishes that a basis other than the accrual accounting method may be acceptable if resulting in just and reasonable rates, Hydro One believes that the cash basis treatment of pension costs would continue to be supportable.

OTHER DEVELOPMENTS

Strategy

In 2017, the Company's Board of Directors approved Hydro One's strategy which details the Company's goal to become North America's leading utility, centered around three key pillars: (i) optimization and innovation, (ii) diversification, and (iii) growth.

Common Shares

On May 17, 2017, Hydro One completed a secondary offering (Offering) by the Province, on a bought deal basis, of 120 million common shares of Hydro One. Following completion of the Offering, the Province directly held approximately 49.9% of Hydro One's total issued and outstanding common shares. This non-dilutive Offering increased the public ownership of Hydro One to approximately 50.1% or 298.6 million common shares. Hydro One did not receive any of the proceeds from the sale of the common shares by the Province.

On December 29, 2017, the Province sold 14,391,012 common shares of Hydro One, representing approximately 2.4% of the outstanding common shares, to OFN Power Holdings LP, a limited partnership wholly-owned by Ontario First Nations Sovereign Wealth LP, which is in turn owned by 129 First Nations in Ontario. After completing this transaction, the Province owns approximately 47.4% or 282.4 million common shares of Hydro One. Hydro One did not receive any of the proceeds from the sale of the common shares by the Province.

Collective Agreements

On April 7, 2017, Hydro One reached an agreement with the Canadian Union of Skilled Workers (CUSW) for a renewal of the collective agreement. The agreement is for a five-year term, covering May 1, 2017 to April 30, 2022. The agreement was ratified by the CUSW and the Hydro One Board of Directors in May 2017.

Hydro One has agreements with Inergi LP (Inergi) for the provision of back office and IT outsourcing services, including settlements, source to pay services, pay operations services, information technology and finance and accounting services, expiring on December 31, 2019, and for the provision of customer service operations outsourcing services expiring on February 28, 2018. Hydro One is currently in the process of insourcing the customer service operations services and will not be renewing the existing agreement for these services with Inergi. Agreements have been reached with The Society of Energy Professionals (the Society) and the Power Workers' Union (PWU) to facilitate the insourcing of these services effective March 1, 2018.

The current collective agreement with the PWU expires on March 31, 2018. In January 2018, Hydro One and the PWU commenced collective bargaining with the official exchange of bargaining agendas. Both sides acknowledged their commitment to working towards the timely completion of collective bargaining.

Exemptive Relief

On June 6, 2017, the Canadian securities regulatory authorities granted (i) the Minister of Energy, (ii) Ontario Power Generation Inc. (on behalf of itself and the segregated funds established as required by the *Nuclear Fuel Waste Act* (Canada)) and (iii) agencies of the Crown, provincial Crown corporations and other provincial entities (collectively, the Non-Aggregated Holders) exemptive relief, subject to certain conditions, to enable each Non-Aggregated Holder to treat securities of Hydro One that it owns or controls separately from securities of Hydro One owned or controlled by the other Non-Aggregated Holders for purposes of certain take-over bid, early warning reporting, insider reporting and control person distribution rules and certain distribution restrictions under Canadian securities laws. Hydro One was also granted relief permitting it to rely solely on insider reports and early warning reports filed by Non-Aggregated Holders when reporting beneficial ownership or control or direction over securities in an information circular or annual information form in respect of securities beneficially owned or controlled by any Non-Aggregated Holder subject to certain conditions.

Avista Corporation Purchase Agreement

On July 19, 2017, Hydro One reached an agreement to acquire Avista Corporation (Merger) for approximately $6.7 billion in an all-cash transaction. Avista Corporation is an investor-owned utility providing electric generation, transmission, and distribution services. It is headquartered in Spokane, Washington, with service areas in Washington, Idaho, Oregon, Montana and Alaska. The closing of the Merger is expected to occur in the second half of 2018, subject to receipt of certain regulatory and government approvals, and the satisfaction of customary closing conditions.

On September 14, 2017, Hydro One and Avista Corporation filed applications with state utility commissions in Washington, Idaho, Oregon, Montana, and Alaska, as well as with the Federal Energy Regulatory Commission, requesting regulatory approval of the Merger on or before August 14, 2018. On November 21, 2017, the Merger was approved by the shareholders of Avista Corporation. On January 16, 2018, the Federal Energy Regulatory Commission approved the Merger application. Required filings with a number of other agencies will be made in the coming months, including with the Committee on Foreign Investment in the United States, the

Federal Communications Commission, and the Department of Justice and the Federal Trade Commission pursuant to the *Hart-Scott-Rodino Antitrust Improvements Act of 1976*.

Convertible Debenture Offering

On August 9, 2017, in connection with the acquisition of Avista Corporation, the Company and its wholly-owned subsidiary, 2587264 Ontario Inc., completed the sale of $1,540 million aggregate principal amount of 4.00% convertible unsecured subordinated debentures represented by instalment receipts (Debenture Offering). Upon closing of the Avista Corporation transaction and conversion of the Convertible Debentures into Hydro One common shares, the Province's ownership of Hydro One will decrease to approximately 42.3%. See section "Liquidity and Financing Strategy".

The Province waived its pre-emptive right to participate in the Debenture Offering under the governance agreement entered into between Hydro One and the Province dated November 5, 2015 (Governance Agreement). In consideration of granting the waiver, Hydro One agreed that until July 19, 2018: (i) the Company shall not issue common shares pursuant to the Company's equity compensation plans and any dividend reinvestment plan in an aggregate number that exceeds 1% of the common shares outstanding as of July 19, 2017; and (ii) the Company shall not issue voting securities (or securities convertible into voting securities) pursuant to any acquisition transaction without complying with the pre-emptive right provisions of the Governance Agreement.

Litigation

Litigation Relating to the Merger

To date, four putative class action lawsuits have been filed by purported Avista Corporation shareholders in relation to the Merger. First, *Fink v. Morris, et al.*, was filed in Washington state court and the amended complaint names as defendants Avista Corporation's directors, Hydro One, Olympus Holding Corp., Olympus Corp., and Bank of America Merrill Lynch. The suit alleges that Avista Corporation's directors breached their fiduciary duties in relation to the Merger, aided and abetted by Hydro One, Olympus Holding Corp., Olympus Corp. and Bank of America Merrill Lynch. The Washington state court issued an order staying the litigation until after the plaintiffs file an amended complaint, which must be no later than 30 days after Avista Corporation or Hydro One publicly announces that the Merger has closed. Second, *Jenß v. Avista Corp., et al., Samuel v. Avista Corp., et al., and Sharpenter v. Avista Corp., et al.*, were each filed in the US District Court for the Eastern District of Washington and named as defendants Avista Corporation and its directors; *Sharpenter* also named Hydro One, Olympus Holding Corp., and Olympus Corp. The lawsuits alleged that the preliminary proxy statement omitted material facts necessary to make the statements therein not false or misleading. *Jenß, Samuel, and Sharpenter* were all voluntarily dismissed by the respective plaintiffs with no consideration paid by any of the defendants. The one remaining class action is consistent with expectations for US merger transactions and, while there is no certainty as to outcome, Hydro One believes that the lawsuit is not material to Hydro One.

Class Action Lawsuit

Hydro One Inc., Hydro One Networks, Hydro One Remote Communities Inc., and Norfolk Power Distribution Inc. are defendants in a class action suit in which the representative plaintiff is seeking up to $125 million in damages related to allegations of improper billing practices. The plaintiff's motion for certification was dismissed by the court on November 28, 2017, but the plaintiff has appealed the court's decision, and it is likely that no decision will be rendered by the appeal court until the second half of 2018. At this time, an estimate of a possible loss related to this claim cannot be made.

Appointment of Chief Financial Officer

On January 28, 2018, Mr. Paul Dobson was appointed to the position of Chief Financial Officer of Hydro One, effective March 1, 2018. Mr. Dobson was most recently the Chief Financial Officer at Direct Energy Ltd. in Houston, Texas.

HYDRO ONE WORK FORCE

Hydro One has a skilled and flexible work force of approximately 5,400 regular employees and 2,000 non-regular employees province-wide, comprising of a mix of skilled trades, 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 flexibly utilize 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, 2017:

	Regular Employees	Non-Regular Employees	Total
PWU[1]	3,362	706	4,068
The Society	1,379	35	1,414
Canadian Union of Skilled Workers (CUSW) and construction building trade unions[2]	—	1,254	1,254
Total employees represented by unions	4,741	1,995	6,736
Management and non-represented employees	681	23	704
Total employees	5,422	2,018	7,440

[1] Includes 575 non-regular "hiring hall" employees covered by the PWU agreement.
[2] The construction building trade unions have collective agreements with the Electrical Power Systems Construction Association (EPSCA).

Share-based Compensation

During 2017 and 2016, the Company granted awards under its Long-term Incentive Plan, consisting of Performance Stock Units (PSUs) and Restricted Stock Units (RSUs), all of which are equity settled. At December 31, 2017 and 2016, 429,980 and 230,600 PSUs, respectively, and 393,430 and 254,150 RSUs, respectively, were outstanding.

NON-GAAP MEASURES

FFO

FFO is defined as net cash from operating activities, adjusted for (i) changes in non-cash balances related to operations, (ii) dividends paid on preferred shares, and (iii) distributions to noncontrolling interest. Management believes that FFO is helpful as a supplemental measure of the Company's operating cash flows as it excludes timing-related fluctuations in non-cash operating working capital and cash flows not attributable to common shareholders. As such, FFO provides a consistent measure of the cash generating performance of the Company's assets.

Year ended December 31 *(millions of dollars)*	2017	2016
Net cash from operating activities	1,716	1,656
Changes in non-cash balances related to operations	(113)	(134)
Preferred share dividends	(18)	(19)
Distributions to noncontrolling interest	(6)	(9)
FFO	1,579	1,494

Adjusted Net Income and Adjusted EPS

The following basic and diluted Adjusted EPS has been calculated by management on a supplementary basis which excludes costs related to the Avista Corporation acquisition from net income. Adjusted EPS is used internally by management to assess the Company's performance and is considered useful because it excludes the impact of acquisition-related costs and provides users with a comparative basis to evaluate the current ongoing operations of the Company compared to prior year.

Year ended December 31	2017	2016
Net income attributable to common shareholders *(millions of dollars)*	658	721
Costs related to acquisition of Avista Corporation *(millions of dollars)*	36	—
Adjusted net income attributable to common shareholders *(millions of dollars)*	694	721
Weighted average number of shares		
Basic	595,287,586	595,000,000
Effect of dilutive stock-based compensation plans	2,234,665	1,700,823
Diluted	597,522,251	596,700,823
Adjusted EPS		
Basic	$1.17	$1.21
Diluted	$1.16	$1.21

Revenues, net of purchased power

Revenues, net of purchased power is defined as revenues less purchased power. Management believes that revenue, net of purchased power is helpful as a measure of net revenues for the Distribution segment, as purchased power is fully recovered through revenues.

Year ended December 31 *(millions of dollars)*	2017	2016
Revenues	5,990	6,552
Less: Purchased power	2,875	3,427
Revenues, net of purchased power	3,115	3,125

Year ended December 31 *(millions of dollars)*	2017	2016
Distribution revenues	4,366	4,915
Less: Purchased power	2,875	3,427
Distribution revenues, net of purchased power	1,491	1,488

FFO, basic and diluted Adjusted EPS, and Revenues, net of purchased power 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.

RELATED PARTY TRANSACTIONS

The Province is a shareholder of Hydro One with approximately 47.4% ownership at December 31, 2017. The IESO, Ontario Power Generation Inc. (OPG), Ontario Electricity Financial Corporation (OEFC), and the OEB, are related parties to Hydro One because they are controlled or significantly influenced by the Province. Hydro One Brampton was a related party until February 28, 2017, when it was acquired from the Province by Alectra Inc., and subsequent to the acquisition by Alectra Inc., is no longer a related party to Hydro One. The following is a summary of the Company's related party transactions during the years ended December 31, 2017 and 2016:

Year ended December 31 *(millions of dollars)*

Related Party	Transaction	2017	2016
Province	Dividends paid	301	451
IESO	Power purchased	1,583	2,096
	Revenues for transmission services	1,521	1,549
	Amounts related to electricity rebates	357	—
	Distribution revenues related to rural rate protection	247	125
	Distribution revenues related to the supply of electricity to remote northern communities	32	32
	Funding received related to CDM programs	59	63
OPG	Power purchased	9	6
	Revenues related to provision of construction and equipment maintenance services	3	5
	Costs related to the purchase of services	1	1
OEFC	Power purchased from power contracts administered by the OEFC	2	1
OEB	OEB fees	8	11
Hydro One Brampton	Cost recovery from management, administrative and smart meter network services	—	3

RISK MANAGEMENT AND RISK FACTORS

Risks Relating to Hydro One's Business

<u>Regulatory Risks and Risks Relating to Hydro One's Revenues</u>

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 outstanding or 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, costs of debt and income taxes, or to earn a particular ROE. A failure to obtain acceptable rate orders, or approvals of appropriate returns on equity and costs actually incurred, such as occurred in the September 28, 2017 and November 9, 2017 OEB decisions (details above in "Electricity Rates Applications - Hydro One Networks - Transmission"), 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 and cash flows could be impacted.

Risks Relating to Actual Performance Against Forecasts

The Company's ability to recover the actual costs of providing service and earn the allowed ROE 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, administration, capital and financing costs above those included in the Company's approved revenue requirement. The inability to obtain acceptable rate decisions or to 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 can be expected to 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 Conservation and Demand Management programs whose results exceed forecasted expectations.

Risks Relating to Rate-Setting Models for Transmission and Distribution

The OEB approves and periodically changes the ROE for transmission and distribution businesses. The OEB may in the future decide to reduce the allowed ROE for either of these businesses, modify the formula or methodology it uses to determine the ROE, or reduce the weighting of the equity component of the deemed capital structure. Any such reduction could reduce the net income of the Company.

The OEB's recent Custom Incentive Rate-setting model requires that the term of a custom rate application be a minimum five-year period. There are risks associated with forecasting key inputs such as revenues, operating expenses and capital, 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.

After rates are set as part of a Custom Incentive Rate application, the OEB expects there to be no further rate applications for annual updates within the five-year term, unless there are exceptional circumstances, with the exception of the clearance of established deferral and variance accounts. For example, the OEB does not expect to address annual rate applications for updates for cost of capital (including ROE), working capital allowance or sales volumes. If there were an increase in interest rates over the period of a rate decision and no corresponding changes were permitted to the Company's allowed cost of capital (including ROE), then the result could be a decrease in the Company's financial performance.

To the extent that the OEB approves an In-Service Variance Account for the transmission and/or distribution businesses, and should the Company fail to meet the threshold levels of in-service capital, the OEB may reclaim a corresponding portion of the Company's revenues.

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 may be 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.

Any regulatory decision by the OEB to disallow or limit the recovery of any capital expenditures 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 Regulatory Treatment of Deferred Tax Asset

As a result of leaving the PILs Regime and entering the Federal Tax Regime in connection with the IPO of the Company, 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. The OEB's September 28, 2017 and November 9, 2017 decisions (see details above in "Electricity Rates Applications - Hydro One Networks - Transmission") alter Hydro One's allocation of the tax savings resulting from the deferred tax asset. If this approach is followed (pending the outcome of the Motion and Appeal), the exposure from the potential impairment from the regulatory treatment of the deferred tax asset could be a one-time decrease in net income, resulting in annual decreases to FFO.

Risks Relating to Other Applications to the OEB

The Company is also subject to the risk that it will not obtain, or will not obtain in a timely manner, 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.

Indigenous 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)) (Reserve) lands, and lands over which Indigenous people have Aboriginal, treaty, or other legal claims. Some Indigenous 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 and/or settlement of 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 give rise to the Crown's duty to consult and potentially accommodate Indigenous 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 an Indigenous 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 citizens. 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 OEFC 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. For each permit, the Company must negotiate an agreement (in the form of a memorandum of understanding) with the First Nation, the OEFC and any members of the First Nation who have occupancy rights. The agreement includes provisions whereby the First Nation consents to the issuance of 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 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 and restore the lands 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 example, Hydro One's licensed transmission and distribution businesses are required to comply with the terms of their licences, 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 North American Electric Reliability Corporation (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, requirements 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. 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. Where insurance is available for other assets, such insurance coverage may have deductibles, limits and/or exclusions. 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 or costs related to ensuring its continued ability to transmit or distribute electricity.

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. The Company must also comply with legislative and licence requirements relating to the collection, use and disclosure of personal information and information regarding consumers, wholesalers, generators and retailers.

Cyber-attacks or unauthorized access to corporate and information technology systems 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. Due to operating critical infrastructure, Hydro One may be at greater risk of cyber-attacks from third parties (including state run or controlled parties) that could impair or incapacitate its assets. In addition, in the course of its operations, the Company collects, uses, processes and stores information which could be exposed in the event of a cyber-security incident or other unauthorized access or disclosure, such as information about customers, suppliers, counterparties, employees and other third parties.

Security and system disaster recovery controls are in place; however, 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.

Labour Relations Risk

The substantial majority of the Company's employees are represented by either the PWU or the Society. 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 reached an agreement with the PWU 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 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 five-year term, covering the period from May 1, 2017 to April 30, 2022. Additionally, the EPSCA and a number of construction unions have reached renewal agreements, to which Hydro One is bound, for a five-year term, covering the period from May 1, 2015 to April 30, 2020. Agreements have also been reached with the Society and the PWU to facilitate the insourcing of customer service operations services effective March 1, 2018. Future negotiations with unions present the risk of a labour disruption and the ability to sustain the continued supply of energy to customers. The Company also 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 requirements of providing service to customers. Any of these could have a material adverse effect on the Company.

Work Force Demographic Risk

By the end of 2017, approximately 22% of the Company's employees who are members of the Company's defined benefit and defined contribution pension plans were eligible for retirement, and by the end of 2018, approximately 20% could be eligible. These percentages are not evenly spread across the Company's work force, but tend to be most significant in the most senior levels of the Company's staff and especially among management staff. During 2017, approximately 5% of the Company's work force (up from 3% in 2016) elected to retire. Accordingly, the Company's continued success will be tied to its ability to continue to attract and retain sufficient qualified staff to replace the capability lost through retirements and meet the demands of the Company's work programs.

In addition, the Company expects the skilled labour market for its industry will remain highly competitive. Many of the Company's current and potential employees being sought after possess skills and experience that are also highly coveted 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.

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 debt principal repayments, including $752 million in 2018, $731 million in 2019, and $653 million in 2020. 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 mature within approximately one year of issuance. The Company also plans to incur continued material capital expenditures for each of 2018 and 2019. 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, an inability of the Corporation to comply with its debt covenants, 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. This risk may be further exacerbated by the funding requirements for completing the Merger. See also "Risk Factors Relating to the Merger - Sources of funding that would be used to fund the Merger may not be available".

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 ROE is derived using a formulaic approach that takes into account anticipated interest rates, but is not currently exposed to material commodity price risk. The Company is exposed to foreign exchange risk in connection with the Merger. See "Risk Factors Relating to the Merger - Foreign exchange risk". In the future, the Company may be exposed to additional foreign exchange risk in connection with other acquisitions or transactions in which it completes in a currency other than Canadian dollars. Although the Company may attempt to mitigate such risk through hedging transactions, there can be no assurance any such hedge will fully mitigate the risk of currency exchange fluctuations.

The OEB-approved adjustment formula for calculating ROE in a deemed regulatory capital structure of 60% debt and 40% equity provides for increases and decreases depending on changes in benchmark interest rates for Government of Canada debt and the A-rated utility corporate bond yield spread. The Company estimates that a decrease of 100 basis points in the combination of the forecasted long-term Government of Canada bond yield and the A-rated utility corporate bond yield spread used in determining its rate of return would reduce the Company's transmission business' 2019 net income by approximately $24 million. For the distribution business, after distribution rates are set as part of a Custom Incentive Rate application, the OEB does not expect to address annual rate applications for updates to allowed ROE, so fluctuations will have no impact to net income. 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 agreements which enable net settlement, and by monitoring the financial condition of counterparties. The Company does not trade in any energy derivatives. 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 numbers of generation facilities to the distribution network has resulted in greater than expected usage of some of the Company's equipment. 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 Indigenous 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. Failure to receive approvals for projects when spending has already occurred would result in the inability of the Company to recover the investment in the project as well as forfeit the anticipated return on investment. The assets involved may be considered impaired and result in the write off of the value of the asset, negatively impacting net income. External factors are considered in the Company's planning process. If the Company is unable to carry out capital expenditure plans in a timely manner, equipment performance may degrade, which may reduce network capacity, result in customer interruptions, compromise the reliability of the Company's networks 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

The Company is subject to provincial health and safety legislation. Findings of a failure to comply with this legislation could result in penalties and reputational risk, which could negatively impact the Company.

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. 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. Failure to obtain necessary approvals or permits could result in an inability to complete projects.

Hydro One emits certain greenhouse gases, including sulphur hexafluoride or "SF_6". There are increasing regulatory requirements and costs, along with attendant risks, associated with the release of such greenhouse gases, all of which could impose additional material costs on Hydro One.

Any 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 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, 2016, and was filed in May 2017, covering a three-year period from 2017 to 2019. Hydro One's contributions to its pension plan satisfy, and are expected to satisfy, minimum funding requirements. Contributions beyond 2019 will depend on the funded position of the plan, which is determined by investment returns, interest rates and changes in benefits and actuarial assumptions at that 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.

In 2017, the OEB released a report establishing the use of the accrual accounting method as the default method on which to set rates for pension and OPEB amounts in cost-based applications, unless that method does not result in just and reasonable rates. Hydro One currently reports and recovers its pension expense on a cash basis, and maintains the accrual method with respect to OPEBs. Transitioning from the cash basis to an accrual method for pension may have material negative rate impacts for customers or material negative impacts on the company should recovery of costs be disallowed by the OEB. See "- Other Post-Employment and Post-Retirement Benefits Risks".

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. Any element of total compensation costs which is disallowed in whole or part by the OEB and not recoverable from customers in rates could result in costs which could be material and could 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. In 2017, the OEB released a report establishing the use of the accrual accounting method as the default method on which to set rates for pension and OPEB amounts in cost-based applications, unless that method does not result in just and reasonable rates. Hydro One currently maintains the accrual accounting method with respect to OPEBs. If the OEB directed Hydro One to transition to a different accounting method for OPEBs, this could result in income volatility, due to an inability of the company to book the difference between the accrual and cash as a regulatory asset. 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

Hydro One has entered into an outsourcing arrangement with a third party for the provision of back office and IT 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 and fully transitioned, the Company could be required 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 becomes involved in, is named as a party to and is 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. See also "Other Developments - Litigation - Class Action Lawsuit" and "- Risk Factors Relating to the Merger - Legal proceedings in connection with the Merger, the outcomes of which are uncertain, could have an adverse impact on Hydro One, including by delaying or preventing the completion of the Merger".

Transmission Assets on Third-Party Lands Risk

Some of the lands on which the Company's transmission assets are located are owned by third parties, including the Province and federal Crown, and are or may become subject to land claims by First Nations. The Company requires valid occupation rights to occupy such lands (which may take the form of land use permits, easements or otherwise). If the Company does not have valid occupational rights on third-party owned lands or has occupational rights that are subject to expiry, it may incur material costs to obtain or renew such occupational rights, or if such occupational rights cannot be renewed or obtained it may incur material costs to remove and relocate its assets and restore the subject land. If the Company does not have valid occupational rights and must incur costs as a result, this could have a material adverse effect on the Company or otherwise materially adversely impact the Company's operations.

Reputational, Public Opinion and Political Risk

Reputation risk is the risk of a negative impact to Hydro One's business, operations or financial condition that could result from a deterioration of Hydro One's reputation. Hydro One's reputation could be negatively impacted by changes in public opinion (including as a result of the Merger), attitudes towards the Company's privatization, failure to deliver on its customer promises and other external forces. Adverse reputational events or political actions could have negative impacts on Hydro One's business and prospects including, but not limited to, delays or denials of requisite approvals, such as denial of requested rates, and accommodations for Hydro One's planned projects, escalated costs, legal or regulatory action, and damage to stakeholder relationships.

Risks Associated with Acquisitions

While the Company has experience in operating in the Ontario electricity market, as it pursues acquisitions outside of Ontario it will need to develop additional expertise in these new markets. Such acquisitions include inherent risks that some or all of the expected benefits may fail to materialize, or may not occur within the time periods anticipated, and Hydro One may incur material unexpected costs. Realization of the anticipated benefits will depend, in part, on the Company's ability to successfully integrate the acquired business, including the requirement to devote management attention and resources to integrating business practices and support functions. The failure to realize the anticipated benefits, the diversion of management's attention, or any delays or difficulties encountered in connection with the integration could have an adverse effect on the Company's business, results of operations, financial condition or cash flows. See "Risk Factors Relating to the Merger" for the specific risks in respect of the Company's proposed acquisition of Avista Corporation.

Risk Factors Relating to the Merger

Hydro One may fail to complete the Merger

The closing of the Merger is subject to the normal commercial risks that the Merger will not close on the terms negotiated or at all. The completion of the Merger is subject to receipt of certain regulatory and governmental approvals, including the expiration or termination of any applicable waiting period under the *Hart-Scott-Rodino Antitrust Improvements Act of 1976*, clearance of the Merger by the Committee on Foreign Investment in the United States, the approval by each of the Idaho Public Utilities Commission, the Public Service Commission of the State of Montana, the Public Utility Commission of Oregon, the Regulatory Commission of Alaska, the Washington Utilities and Transportation Commission, the United States Federal Energy Regulatory Commission and the United States Federal Communications Commission and the satisfaction or waiver of certain closing conditions contained in the Merger Agreement. The failure to obtain the required approvals or satisfy or waive the conditions contained in the Merger Agreement may result in the termination of the Merger Agreement. There is no assurance that such closing conditions will be satisfied or waived. Accordingly, there can be no assurance that Hydro One will complete the Merger in the timeframe or on the basis described herein, if at all. The termination of the Merger Agreement may have a negative effect on the price of the Instalment Receipts, the Debentures and the Hydro One common shares and will result in the redemption of the Debentures. If the closing of the Merger does not take place as contemplated, the Company could suffer adverse consequences, including the loss of investor confidence, and may incur significant costs or losses, including an obligation to pay or cause to be paid to Avista Corporation a termination fee of US$103 million.

Length of time required to complete the Merger is unknown

As described above under "Hydro One may fail to complete the Merger", the closing of the Merger is subject to the receipt of certain regulatory approvals and the satisfaction of other closing conditions contained in the Merger Agreement. There is no certainty, nor can Hydro One provide any assurance, as to when these conditions will be satisfied, if at all. A substantial delay in obtaining regulatory approvals or the imposition of unfavourable terms and/or conditions in such approvals could have a material adverse effect on Hydro One's ability to complete the Merger and on Hydro One's or Avista Corporation's business, financial condition or results of operations. In addition, in the event that such regulatory agencies imposed unfavourable terms and/or conditions on Hydro One or Avista Corporation (including the requirement to sell or divest of certain assets or limitations on the future conduct of the combined entities), Hydro One could still be required to complete the transaction on the terms set forth in the Merger Agreement.

Hydro One intends to complete the Merger as soon as practicable after obtaining the required regulatory approvals and satisfying the other required closing conditions.

Foreign exchange risk

The cash consideration for the Merger is required to be paid in US dollars, while funds raised in the Debenture Offering, which will constitute a portion of the funds ultimately used to finance the Merger, are denominated in Canadian dollars. As a result, increases in the value of the US dollar versus the Canadian dollar prior to payment of the final instalment will increase the purchase price translated in Canadian dollars and thereby reduce the proportion of the purchase price for the Merger ultimately obtained by Hydro One under the Debenture Offering, which could cause a failure to realize the anticipated benefits of the Merger. This risk has been partially mitigated through entering into a foreign exchange forward agreement to convert $1.4 billion Canadian to US dollars which is contingent upon the closing of the Merger.

In addition, the operations of Avista Corporation are conducted in US dollars. Following the Merger, the consolidated net earnings and cash flows of Hydro One will be impacted to a much greater extent by movements in the US dollar relative to the Canadian dollar. In particular, decreases in the value of the US dollar versus the Canadian dollar following the Merger could negatively impact the Company's net earnings as reported in Canadian dollars, which could cause a failure to realize the anticipated benefits of the Merger.

Additional demands will be placed on Hydro One as a result of the Merger

As a result of the pursuit and completion of the Merger, additional demands will be placed on the Company's managerial, operational and financial personnel and systems. No assurance can be given that the Company's systems, procedures and controls will be adequate to support the expansion of the Company's operations resulting from the Merger. The Company's future operating results will be affected by the ability of its officers and key employees to manage changing business conditions and to maintain its operational and financial controls and reporting systems.

Sources of funding that would be used to fund the Merger may not be available

Hydro One intends to finance the cash purchase price of the Merger and the Merger-related expenses at the closing of the Merger with a combination of some or all of the following: (i) net proceeds of the first instalment (to the extent available) and final instalment under the Debenture Offering; (ii) net proceeds of any subsequent bond or other debt offerings; (iii) amounts drawn under Hydro

One's $250 million credit facility; and (iv) existing cash on hand and other sources available to the Company. There is no guarantee that adequate sources of funding will be available to Hydro One or its affiliates at the desired time or at all, or on cost-efficient terms. The inability to obtain adequate sources of funding to fund the Merger may result in Hydro One being unable to complete the Merger or may negatively impact Hydro One, including its ability to finance the Merger. In addition, any movement in interest rates or changes in tax rates that could affect the underlying after-tax cost of any financing may affect the expected accretion of the Merger.

Hydro One expects to incur significant Merger-related expenses

Hydro One expects to incur a number of costs associated with completing the Merger. The substantial majority of these costs will be non-recurring expenses resulting from the Merger and will consist of transaction costs related to the Merger, including costs relating to the financing of the Merger and obtaining regulatory approvals. Additional unanticipated costs may be incurred.

Legal proceedings in connection with the Merger, the outcomes of which are uncertain, could have an adverse impact on Hydro One, including by delaying or preventing the completion of the Merger

One of the four putative class action lawsuits commenced since the announcement of the Merger is still in existence, namely a putative class action lawsuit that has been filed in Washington state court which names Hydro One, Olympus Holding Corp. and Olympus Corp. as defendants and alleges that they aided and abetted Avista Corporation's directors' breach of their fiduciary duties in connection with the Merger. The court issued an order staying the litigation until after the plaintiffs file an amended complaint, which must be no later than 30 days after Avista Corporation or Hydro One publicly announces that the Merger has closed. The plaintiffs in the lawsuit are seeking to enjoin the Merger and may pursue other remedies, including monetary damages and attorneys' fees. The lawsuit and other potential legal proceedings could have an adverse impact on Hydro One, including by delaying or preventing the Merger from becoming effective. See also "Other Developments - Litigation - Litigation Relating to the Merger".

Risk Factors Relating to the Post-Merger Business and Operations of Hydro One and Avista Corporation

Hydro One will substantially increase its amount of indebtedness following the Merger

After giving effect to the Merger, Hydro One will have a significant amount of debt, including approximately US$1.9 billion of debt of Avista Corporation assumed by Hydro One as a result of the Merger. As of March 31, 2017, on a *pro forma* basis after giving effect to the Merger, but assuming conversion of all Debentures to Hydro One common shares (*pro formas* assumed no exercise of the Over-Allotment Option), Hydro One would have had approximately $17,098 million of total indebtedness outstanding. Hydro One's substantially increased amount of indebtedness following the Merger may adversely affect Hydro One's cash flow and ability to operate its business.

The Offering could result in a downgrade of Hydro One's credit ratings

The change in the capital structure of Hydro One as a result of the Merger and the Debenture Offering or otherwise could cause credit rating agencies which rate the outstanding debt obligations of Hydro One and Hydro One Inc. to re-evaluate and potentially downgrade their current credit ratings, which could increase the Company's borrowing costs.

Risks Relating to the Company's Relationship with the Province

Ownership and Continued Influence by the Province and Voting Power; Share Ownership Restrictions

The Province currently owns approximately 47.4% of the outstanding 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). 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 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.

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.

Nomination of Directors and Confirmation of Chief Executive Officer and Chair

Although director nominees (other than the Chief Executive Officer) 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

Although the Province has indicated that it does not intend to sell further common shares of Hydro One, the registration rights agreement between Hydro One and the Province dated November 5, 2015 (available on SEDAR at www.sedar.com) 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 AND JUDGMENTS

The preparation of Hydro One Consolidated Financial Statements requires the Company to make key estimates and critical 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 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. At the end of each month, electricity delivered to customers since the date of the last billed meter reading is estimated, and the corresponding unbilled revenue is recorded. The unbilled revenue estimate is affected by energy consumption, weather, and changes in the composition of customer classes.

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:

<u>Weighted Average Discount Rate</u>

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, 2017 decreased to 3.40% (from 3.90% at December 31, 2016) for pension benefits and decreased to 3.40% (from 3.90% at December 31, 2016) for the post-retirement and post-employment plans. The decrease in the discount rate has resulted in a corresponding increase in employee future benefits liabilities for the pension, 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.

<u>Expected Rate of Return on Plan Assets</u>

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. The Company believes 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.

<u>Rate of Cost of Living Increase</u>

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 1.80% per annum as at December 31, 2016 to approximately 1.60% per annum as at December 31, 2017. 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, 2017.

Salary Increase Assumptions

Salary increases should reflect general wage increases plus an allowance for merit and promotional increases for current members of the plan, and should be consistent with the assumptions for consumer price inflation and real wage growth in the economy. The merit and promotion scale was developed based on the salary increase assumption review performed in 2017. The review considers actual salary experience from 2002 to 2016 using valuation data for all active members as at December 31, 2016, based on age and service and Hydro One's expectation of future salary increases. Additionally, the salary scale reflect negotiated salary rate increases over the contract period.

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 used at December 31, 2017 is 95% of 2014 Canadian Pensioners Mortality Private Sector table projected generationally using improvement Scale B.

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. For the post-retirement benefit plans, a trend study of historical Hydro One experience was conducted in 2017, which resulted in a change in the prescription drug, dental and hospital trends to be used for 2017 year-end reporting purposes. A 1% increase in the health care cost trends would result in a $29 million increase in 2017 interest cost plus service cost, and a $250 million increase in the benefit liability at December 31, 2017.

Valuation of Deferred Tax Assets

Hydro One assesses the likelihood of realizing deferred tax assets by reviewing all readily available current and historical information, including a forecast of future taxable income. To the extent management considers it is more likely than not that some portion or all of the deferred tax assets will not be realized, a valuation allowance is recognized.

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. The Company regularly monitors the assets of its unregulated Hydro One Telecom subsidiary for indications of impairment. As at December 31, 2017, 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, 2017. Goodwill represents the cost of acquired distribution and transmission companies that is in excess of the fair value of the net identifiable assets acquired at the acquisition date.

DISCLOSURE CONTROLS AND PROCEDURES AND INTERNAL CONTROL OVER FINANCIAL REPORTING

Disclosure controls and procedures are part of a broad internal control framework integral to ensuring that the Company fairly presents in all material respects the financial condition, results of operations and cash flows of the Company for the periods presented in this MD&A and the Company's Annual Report. Disclosure controls and procedures include processes designed to ensure that information is recorded, processed, summarized and reported on a timely basis to the Company's management, including its Chief Executive and Chief Financial Officers, as appropriate, to make timely decisions regarding required disclosure. At the direction of the Company's Chief Executive Officer and the Senior Vice President, Finance, acting in the capacity of Chief Financial Officer, management evaluated disclosure controls and procedures as of the end of the period covered by this report. Based on that evaluation, management concluded that the Company's disclosure controls and procedures were effective at a reasonable level of assurance as at December 31, 2017.

Internal control over financial reporting is a subset of the internal control framework designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with US GAAP. The Company's internal control over financial reporting framework includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and disposition of the assets of the Company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with US GAAP, and that receipts and expenditures of the Company are being made only in accordance with authorization of management and directors of the Company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the Company's assets that could have a material effect on the Company's consolidated financial statements.

The Company's management, at the direction of the Chief Executive Officer and with the participation of the Senior Vice President, Finance, acting in the capacity of Chief Financial Officer, evaluated the effectiveness of the design and operation of internal control over financial reporting based on the framework and criteria established in the Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on that evaluation, management concluded that the Company's internal control over financial reporting was effective at a reasonable level of assurance as at December 31, 2017.

Together, disclosure controls and procedures and internal control over financial reporting provide internal control over reporting and disclosure. Internal control, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives and due to its inherent limitations, may not prevent or detect all misrepresentations. Furthermore, the effectiveness of internal control is affected by change and subject to the risk that internal control effectiveness may change over time.

The role of Chief Financial Officer was vacated effective May 19, 2017. Responsibilities of the Chief Financial Officer have been temporarily assigned to other senior executives with full oversight provided by the Chief Executive Officer. This model is expected to remain in place until Paul Dobson assumes the role of the new Chief Financial Officer on March 1, 2018. There were no significant changes in the design of the Company's internal control over financial reporting during the three months ended December 31, 2017 that have materially affected, or are reasonably likely to materially affect, the operation of the Company's internal control over financial reporting.

Management will continue to monitor its systems of internal control over reporting and disclosure and may make modifications from time to time as considered necessary.

NEW ACCOUNTING PRONOUNCEMENTS

The following tables present Accounting Standards Updates (ASUs) issued by the Financial Accounting Standards Board that are applicable to Hydro One:

Recently Adopted Accounting Guidance

ASU	Date issued	Description	Effective date	Anticipated impact on Hydro One
2016-06	March 2016	Contingent call (put) options that are assessed to accelerate the payment of principal on debt instruments need to meet the criteria of being "clearly and closely related" to their debt hosts.	January 1, 2017	No impact upon adoption

Recently Issued Accounting Guidance Not Yet Adopted

ASU	Date issued	Description	Effective date	Anticipated impact on Hydro One
2014-09 2015-14 2016-08 2016-10 2016-12 2016-20 2017-05 2017-10 2017-13 2017-14	May 2014 – November 2017	ASU 2014-09 was issued in May 2014 and provides guidance on revenue recognition relating to 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. ASU 2015-14 deferred the effective date of ASU 2014-09 by one year. Additional ASUs were issued in 2016 and 2017 that simplify transition and provide clarity on certain aspects of the new standard.	January 1, 2018	Hydro One has completed the review of all its revenue streams and has concluded that there will be no material impact upon adoption.
2016-02 2018-01	February 2016 – January 2018	Lessees are required to recognize the rights and obligations resulting from operating leases as assets (right to use the underlying asset for the term of the lease) and liabilities (obligation to make future lease payments) on the balance sheet. ASU 2018-01 permits an entity to elect an optional practical expedient to not evaluate under Topic 842 land easements that exist or expired before the entity's adoption of Topic 842 and that were not previously accounted for as leases under Topic 840.	January 1, 2019	An initial assessment is currently underway encompassing a review of existing leases, which will be followed by a review of relevant contracts. No quantitative determination has been made at this time. The Company is on track for implementation of this standard by the effective date.
2016-15	August 2016	The amendments provide guidance for eight specific cash flow issues with the objective of reducing the existing diversity in practice.	January 1, 2018	No material impact
2017-01	January 2017	The amendment clarifies the definition of a business and provides additional guidance on evaluating whether transactions should be accounted for as acquisitions (or disposals) of assets or businesses.	January 1, 2018	No material impact
2017-04	January 2017	The amendment removes the second step of the current two-step goodwill impairment test to simplify the process of testing goodwill.	January 1, 2020	Under assessment
2017-07	March 2017	Service cost components of net benefit cost associated with defined benefit plans are required to be reported in the same line as other compensation costs arising from services rendered by the Company's employees. All other components of net benefit cost are to be presented in the income statement separately from the service cost component. Only the service cost component is eligible for capitalization where applicable.	January 1, 2018	Hydro One has applied for a regulatory deferral account to maintain the capitalization of OPEB related costs. As such, there will be no material impact.
2017-09	May 2017	Changes to the terms or conditions of a share-based payment award will require an entity to apply modified accounting unless the modified award meets all conditions stipulated in this ASU.	January 1, 2018	No impact
2017-11	July 2017	When determining whether certain financial instruments should be classified as liabilities or equity instruments, a down round feature no longer precludes equity classification when assessing whether the instrument is indexed to an entity's own stock.	January 1, 2019	Under assessment
2017-12	August 2017	Amendments will better align an entity's risk management activities and financial reporting for hedging relationships through changes to both the designation and measurement guidance for qualifying hedging relationships and the presentation of hedge results.	January 1, 2019	Under assessment

SUMMARY OF FOURTH QUARTER RESULTS OF OPERATIONS

Three months ended December 31 *(millions of dollars, except EPS)*	2017	2016	Change
Revenues			
Distribution	1,049	1,228	(14.6%)
Transmission	379	373	1.6%
Other	11	13	(15.4%)
	1,439	1,614	(10.8%)
Costs			
Purchased power	662	858	(22.8%)
OM&A			
Distribution	146	163	(10.4%)
Transmission	79	98	(19.4%)
Other	19	26	(26.9%)
	244	287	(15.0%)
Depreciation and amortization	214	204	4.9%
	1,120	1,349	(17.0%)
Income before financing charges and income taxes	**319**	**265**	**20.4%**
Financing charges	119	101	17.8%
Income before income taxes	**200**	**164**	**22.0%**
Income taxes	38	29	31.0%
Net income	**162**	**135**	**20.0%**
Net income attributable to common shareholders of Hydro One	**155**	**128**	**21.1%**
Basic EPS	$0.26	$0.22	18.2%
Diluted EPS	$0.26	$0.21	23.8%
Basic Adjusted EPS	$0.29	$0.22	31.8%
Diluted Adjusted EPS	$0.28	$0.21	33.3%
Capital Investments			
Distribution	161	201	(19.9%)
Transmission	267	274	(2.6%)
Other	3	2	50.0%
	431	**477**	**(9.6%)**
Assets Placed In-Service			
Distribution	207	211	(1.9%)
Transmission	522	488	7.0%
Other	4	0	100.0%
	733	**699**	**4.9%**

Net Income

Net income attributable to common shareholders for the quarter ended December 31, 2017 of $155 million is an increase of $27 million or 21.1% from the prior year. Significant influences on net income included:

- increase in distribution revenues due to higher energy consumption;
- higher transmission revenues driven by OEB's decision on the 2017-2018 transmission rates filing;
- transmission and distribution revenues were also impacted by a reduction in the 2017 allowed regulated return on equity (ROE) from 9.19% to 8.78%;
- lower OM&A costs primarily resulting from a reduction of provision for payments in lieu of property taxes following a favourable reassessment of the regulations, insurance proceeds received on failed equipment at two transformer stations, a tax recovery of previous year's expenses, lower support services costs, and reduced vegetation management costs;
- higher depreciation expense due to an increase in rate base; and
- increased financing charges primarily due to the issuance of Convertible Debentures in August 2017.

EPS and Adjusted EPS

EPS was $0.26 in the three months ended December 31, 2017, compared to $0.22 in the prior year. The increase in EPS was driven by higher net income for the fourth quarter of 2017, as discussed above. Adjusted EPS, which adjusts for costs related to Avista Corporation acquisition, was $0.29 in the three months ended December 31, 2017, compared to $0.22 in the prior year. The increase in Adjusted EPS was also driven by higher net income for the fourth quarter of 2017, net of aforementioned impact related to Avista Corporation acquisition.

Revenues

The quarterly increase of $6 million or 1.6% in transmission revenues was primarily due to higher revenues driven by the OEB's decision on the 2017-2018 transmission rates filing, partially offset by lower OEB-approved transmission rates.

The quarterly increase of $17 million or 4.6% in distribution revenues, net of purchased power, was primarily due to higher energy consumption mainly resulting from colder weather in the fourth quarter of 2017; and higher external revenues related to CDM incentive bonus; partially offset by reduction in 2017 allowed ROE for the distribution business.

OM&A Costs

The quarterly decrease of $19 million or 19.4% in transmission OM&A costs was primarily due to a reduction of provision for payments in lieu of property taxes following a favourable reassessment of the regulations, lower support services costs, and insurance proceeds received due to equipment failures at the Fairchild and Campbell transmission stations.

The quarterly decrease of $17 million or 10.4% in distribution OM&A costs was primarily due to lower expenditures for vegetation management programs due to strategic changes to the forestry program scope that resulted in cost efficiency and improved management of the Company's rights of ways; lower bad debt expense attributable to lower write-offs and improved accounts receivable aging; and a tax recovery of previous year's expenses.

A further decrease of $7 million in other OM&A is primarily due to lower corporate organizational costs in the other segment.

Depreciation and Amortization

The increase of $10 million or 4.9% in depreciation and amortization costs for the fourth quarter of 2017 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.

Financing Charges

The quarterly increase of $18 million or 17.8% in financing charges was primarily due to an increase in interest expense related to the Convertible Debentures issued in August 2017; partially offset by a decrease in interest expense on long-term debt resulting from a decrease in weighted average long-term debt outstanding during the quarter, together with a decrease in the weighted average interest rate.

Income Taxes

Income tax expense for the fourth quarter of 2017 increased by $9 million compared to 2016, and the Company realized an effective tax rate of approximately 19.0% in the fourth quarter of 2017, compared to approximately 17.7% realized in 2016. The increase in the tax expense is primarily due to higher income before taxes in the fourth quarter of 2017.

Capital Investments

The decrease in transmission capital investments during the fourth quarter was primarily due to the following:

- lower volume and timing of spare transformer equipment purchases;
- timing and substantial completion of major development projects, including Guelph Area Transmission Refurbishment, Midtown Transmission Reinforcement, and Holland and Hawthorne transmission stations; and
- timing of work related to the Clarington Transmission Station project; partially offset by
- timing on work on station refurbishments and equipment replacement projects; and
- timing of work at Leamington transmission station.

The decrease in distribution capital investments during the fourth quarter was primarily due to the following:

- timing of capital contributions for jointly used facilities and lower volume of line relocation work;
- substantial completion of work on the Bolton Operation Centre in the fourth quarter of 2016;
- lower volume of work within distribution station refurbishment programs;
- timing of information technology projects including e-Billing and website redesign;
- lower volume of line refurbishments and replacements work; and
- lower volume of fleet and work equipment purchases; partially offset by
- high volume of work on new connections and upgrades due to increased demand.

Assets Placed In-Service

The increase in transmission assets placed in-service during the fourth quarter was primarily due to the following:

- substantial investments of major development projects at Leamington and Holland transmission stations were placed in-service in the fourth quarter of 2017;
- higher volume of investments for overhead lines and component refurbishments and replacement programs;
- timing of assets placed in-service for sustainment investment projects including the transformer asset replacement project at Overbrook transmission station and the breaker replacement project at Richview transmission station; partially offset by
- a large number of cumulative sustainment investments that were placed in-service in the fourth quarter of 2016 at the Bruce A and Burlington transmission stations;
- timing of investments that were placed in-service for the Advanced Distribution System project; and
- timing of assets that were placed in-service in the fourth quarter of 2016 for certain information technology development projects.

The decrease in distribution assets placed in-service during the fourth quarter was primarily due to the following:

- timing of distribution station refurbishments and spare transformer purchases; and
- lower volume of work on distribution generation connection projects; partially offset by
- higher volume of subdivision connections due to increased demand; and
- substantial investments that were placed in-service in the fourth quarter of 2017 for the Leamington transmission station feeder development project.

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, regulatory and economic environments in which it operates, and include beliefs and assumptions made by the management of the Company. Such statements include, but are not limited to, statements regarding: the Company's transmission and distribution rate applications, including resulting decisions, rates and expected impacts and timing; the Company's liquidity and capital resources and operational requirements; the standby credit facilities; expectations regarding the Company's financing activities; the Company's maturing debt; ongoing and planned projects and initiatives, including expected results and completion dates; expected future capital investments, including expected timing and investment plans; contractual obligations and other commercial commitments; the OEB; the Motion and the Appeal; the Anwaatin Motion; the East-West Tie Line Project and related regulatory application; collective agreements; Inergi outsourcing and customer service operations arrangements; the pension plan, future pension contributions, valuations and expected impacts; impacts of OEB treatment of pension and OPEBs costs; dividends; credit ratings; Hydro One's strategy and goals; effect of interest rates; non-GAAP measures; critical accounting estimates, including environmental liabilities, regulatory assets and liabilities, and employee future benefits; occupational rights; internal control over financial reporting and disclosure; the Fair Hydro Plan and First Nations Rate Assistance Program, including expected outcomes and impacts; recent accounting-related guidance; the Universal Base Shelf Prospectus; the Convertible Debentures; the Province's waiver of its pre-emptive right under the Governance Agreement to participate in the Debenture Offering; the Company's acquisitions and mergers, including Orillia Power and Avista Corporation; the appointment of Hydro One's new Chief Financial Officer; risk associated with acquisitions; cyber and data security; expectations related to work force demographics; the Company's financing strategy and foreign currency hedging relating to the acquisition of Avista Corporation; class action litigation, including litigation relating to the Merger; the risk that the Company may fail to complete the Merger; risk related to the length of time required to complete the Merger; foreign exchange risk; risks related to additional demands placed on Hydro One as a result of the Merger; risks related to availability of planned sources of funding to be used to fund the Merger; risks and expectations related to Hydro One incurring significant Merger-related expenses; risks and expectations related to Hydro One substantially increasing its amount of indebtedness following the Merger; the Province's ownership of HydroOne; future sales of shares of Hydro One; and reputational, public opinion and political risk. 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 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 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 maintaining a complex information technology system infrastructure;
- the risks related to the Company's work force 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;
- 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 functions currently outsourced if agreements 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 investments, 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, including the Company's Annual Information Form, is available on SEDAR at www.sedar.com and the Company's website at www.HydroOne.com/Investors.

HYDRO ONE NETWORKS INC.

DISTRIBUTION BUSINESS

FINANCIAL STATEMENTS

DECEMBER 31, 2017

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, 2017, 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, 2017 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 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 27, 2018

HYDRO ONE NETWORKS INC.
DISTRIBUTION BUSINESS
STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME
For the years ended December 31, 2017 and 2016

Year ended December 31 *(millions of Canadian dollars)*	2017	2016
Revenues		
Energy sales	4,005	4,609
Rural rate protection *(Note 23)*	247	125
Other	63	58
	4,315	4,792
Costs		
Purchased power *(Note 23)*	2,875	3,365
Operation, maintenance and administration *(Note 23)*	567	567
Depreciation and amortization *(Note 5)*	388	375
	3,830	4,307
Income before financing charges and income taxes	**485**	**485**
Financing charges *(Notes 6, 23)*	165	156
Income before income taxes	**320**	**329**
Income taxes *(Note 7)*	55	58
Net income	**265**	**271**
Other comprehensive income	—	—
Comprehensive income	**265**	**271**

See accompanying notes to Financial Statements.

HYDRO ONE NETWORKS INC.
DISTRIBUTION BUSINESS
BALANCE SHEETS
At December 31, 2017 and 2016

December 31 *(millions of Canadian dollars)*	2017	2016
Assets		
Current assets:		
Cash and cash equivalents	—	9
Accounts receivable *(Note 8)*	588	786
Due from related parties *(Note 23)*	138	33
Other current assets *(Note 9)*	38	44
	764	872
Property, plant and equipment *(Note 10)*	7,324	7,098
Other long-term assets:		
Regulatory assets *(Note 12)*	638	867
Intangible assets *(Note 11)*	289	268
Goodwill	168	168
Other assets	1	1
	1,096	1,304
Total assets	**9,184**	**9,274**
Liabilities		
Current liabilities:		
Inter-company demand facility *(Note 23)*	167	74
Long-term debt payable within one year *(Notes 15, 16, 23)*	337	195
Accounts payable and other current liabilities *(Note 13)*	679	638
Due to related parties *(Note 23)*	218	178
	1,401	1,085
Long-term liabilities:		
Long-term debt *(Notes 15, 16, 23)*	3,498	3,837
Deferred income tax liabilities *(Note 7)*	499	492
Regulatory liabilities *(Note 12)*	84	81
Other long-term liabilities *(Note 14)*	934	1,013
	5,015	5,423
Total liabilities	**6,416**	**6,508**
Contingencies and Commitments *(Notes 25, 26)*		
Subsequent Events *(Note 27)*		
Excess of assets over liabilities *(Notes 17, 21)*	2,768	2,766
Total liabilities and excess of assets over liabilities	**9,184**	**9,274**

See accompanying notes to Financial Statements.

On behalf of the Board of Directors:

Philip Orsino
Chair, Audit Committee

Mayo Schmidt
Director

HYDRO ONE NETWORKS INC.
DISTRIBUTION BUSINESS
STATEMENTS OF CASH FLOWS
For the years ended December 31, 2017 and 2016

Year ended December 31 *(millions of Canadian dollars)*	2017	2016
Operating activities		
Net income	265	271
Environmental expenditures	(15)	(12)
Adjustments for non-cash items:		
Depreciation and amortization (excluding asset removal costs)	337	320
Regulatory assets and liabilities	172	(11)
Deferred income taxes	(44)	36
Other	5	4
Changes in non-cash balances related to operations *(Note 24)*	219	126
Net cash from operating activities	**939**	**734**
Financing activities		
Long-term debt issued	—	1,050
Long-term debt repaid	(195)	(200)
Payments to finance dividends and return on stated capital	(263)	(293)
Change in inter-company demand facility	92	(613)
Other	—	(5)
Net cash used in financing activities	**(366)**	**(61)**
Investing activities		
Capital expenditures *(Note 24)*		
Property, plant and equipment	(522)	(635)
Intangible assets	(56)	(38)
Other	(4)	7
Net cash used in investing activities	**(582)**	**(666)**
Net change in cash and cash equivalents	(9)	7
Cash and cash equivalents, beginning of year	9	2
Cash and cash equivalents, end of year	**—**	**9**

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 Hydro One Limited. 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 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 and as a result, may not be suitable for any other purpose. Consolidated Financial Statements of Hydro One for the year ended December 31, 2017 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 27, 2018, 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 27 - 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, asset impairments, contingencies, and deferred income tax assets and liabilities. Actual results may differ significantly from these estimates.

Rate Setting

In March 2015, the OEB approved Hydro One Networks' distribution revenue requirements of $1,326 million for 2015, $1,430 million for 2016 and $1,486 million for 2017. The OEB has subsequently approved updated revenue requirements of $1,410 million for 2016 and $1,415 million for 2017.

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 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 include its regulatory assets and liabilities in setting 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 would 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. At the end of each month, electricity delivered to customers since the date of the last billed meter reading is estimated, and the corresponding unbilled revenue is recorded. 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 billed accounts receivable by applying internally developed loss rates to the outstanding receivable balances by aging category. Loss rates applied to the billed 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 allowance for doubtful accounts is affected by changes in volume, prices and economic conditions.

Income Taxes

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 using new information about recognition or measurement as it becomes available.

Deferred Income Taxes

Deferred income taxes are provided for using the liability method. Under this method, deferred income tax liabilities are recognized on all taxable temporary differences between the tax bases and carrying amounts of assets and liabilities. Deferred income tax assets are recognized for deductible temporary differences between tax bases and carrying amounts of assets and liabilities, the carry forward unused tax credits and tax losses to the extent that it is more-likely-than-not that these deductions, credits, and losses can be utilized. Deferred income tax assets and liabilities are measured 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.

Management reassesses the deferred income tax assets at each balance sheet date and reduces the amount to the extent that it is more-likely-than-not that the deferred income tax asset will not 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 records regulatory assets and liabilities associated with deferred income tax assets and liabilities 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, 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 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 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 most recent review resulted in changes to rates effective January 1, 2015 for Hydro One Networks' distribution business. 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
Property, plant and equipment:			
Distribution	46 years	1% - 7%	2%
Communication	8 years	1% - 15%	10%
Administration and service	20 years	1% - 20%	6%
Intangible assets	10 years	10%	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.

Acquisitions and Goodwill

The Company accounts for business acquisitions using the acquisition method of accounting and, accordingly, the assets and liabilities of the acquired entities are primarily measured at their estimated fair value at the date of acquisition. Costs associated with pending acquisitions are expensed as incurred. Goodwill represents the cost of acquired 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.

Based on assessment performed as at September 30, 2017, the Company has concluded that goodwill was not impaired at December 31, 2017.

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, 2017 and 2016, 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 net of related debt on the 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 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; 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 16 - 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 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. 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 on 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 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 Statements of Operations and Comprehensive Income. The changes in fair value of the undesignated derivative instruments are reflected in results of operations.

Embedded derivative instruments are separated from their host contracts and are 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, 2017 or 2016.

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. 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 Hydro One's 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 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.

Hydro One recognizes its contributions to the defined contribution pension plan as pension expense, with a portion being capitalized as part of labour costs included in capital expenditures. The expensed amount is included in operation, maintenance and administration costs in the Consolidated Statements of Operations and Comprehensive Income.

<u>Defined Benefit Pension</u>

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.

<u>Post-retirement and Post-employment Benefits</u>

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 AOCI. A regulatory asset is recognized because management considers it to be probable that post-retirement and post-employment benefit costs will be recovered in the future through the rate-setting process.

Post-retirement and post-employment benefits are recorded and included in rates on an accrual basis. Costs are determined by independent actuaries using the projected benefit method prorated on service and based on assumptions that reflect management’s best estimates. Past service costs from plan amendments are amortized to results of operations based on the expected average remaining service period.

For post-retirement benefits, all actuarial gains or losses are deferred using the “corridor” approach. The amount calculated above the “corridor” is amortized to results of operations on a straight-line basis over the expected average remaining service life of active 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 the 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 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.

Stock-Based Compensation

Share Grant Plans

The Company measures share grant plans based on fair value of share grants as estimated based on the grant date Hydro One Limited common 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. Costs are transferred from the regulatory asset to labour costs at the time the share grants vest and are issued, and are recovered in rates. Forfeitures are recognized as they occur.

Deferred Share Unit (DSU) Plans

The Company records the liabilities associated with the Directors' and Management DSU Plans 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 Hydro One Limited common share closing price at the end of each reporting period.

Long-term Incentive Plan (LTIP)

The Company measures the restricted share units (RSUs) and performance share units (PSUs), issued under Hydro One Limited's LTIP, at fair value based on the grant date Hydro One Limited common share price. The related compensation expense is recognized over the vesting period on a straight-line basis. Forfeitures are recognized as they occur.

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 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. The Distribution Business 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 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 have been recorded 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 Distribution Business' 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.

3. NEW ACCOUNTING PRONOUNCEMENTS

The following tables present Accounting Standards Updates (ASUs) issued by the Financial Accounting Standards Board that are applicable to Hydro One Networks:

Recently Adopted Accounting Guidance

ASU	Date issued	Description	Effective date	Anticipated impact on Hydro One
2016-06	March 2016	Contingent call (put) options that are assessed to accelerate the payment of principal on debt instruments need to meet the criteria of being "clearly and closely related" to their debt hosts.	January 1, 2017	No impact upon adoption

Recently Issued Accounting Guidance Not Yet Adopted

ASU	Date issued	Description	Effective date	Anticipated impact on Hydro One
2014-09 2015-14 2016-08 2016-10 2016-12 2016-20 2017-05 2017-10 2017-13 2017-14	May 2014 – November 2017	ASU 2014-09 was issued in May 2014 and provides guidance on revenue recognition relating to 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. ASU 2015-14 deferred the effective date of ASU 2014-09 by one year. Additional ASUs were issued in 2016 and 2017 that simplify transition and provide clarity on certain aspects of the new standard.	January 1, 2018	Hydro One Networks has completed the review of all its revenue streams and has concluded that there will be no material impact upon adoption.
2016-02 2018-01	February 2016 – January 2018	Lessees are required to recognize the rights and obligations resulting from operating leases as assets (right to use the underlying asset for the term of the lease) and liabilities (obligation to make future lease payments) on the balance sheet. ASU 2018-01 permits an entity to elect an optional practical expedient to not evaluate under Topic 842 land easements that exist or expired before the entity's adoption of Topic 842 and that were not previously accounted for as leases under Topic 840.	January 1, 2019	An initial assessment is currently underway encompassing a review of existing leases, which will be followed by a review of relevant contracts. No quantitative determination has been made at this time. The Company is on track for implementation of this standard by the effective date.
2016-15	August 2016	The amendments provide guidance for eight specific cash flow issues with the objective of reducing the existing diversity in practice.	January 1, 2018	No material impact
2017-01	January 2017	The amendment clarifies the definition of a business and provides additional guidance on evaluating whether transactions should be accounted for as acquisitions (or disposals) of assets or businesses.	January 1, 2018	No material impact
2017-04	January 2017	The amendment removes the second step of the current two-step goodwill impairment test to simplify the process of testing goodwill.	January 1, 2020	Under assessment

ASU	Date issued	Description	Effective date	Anticipated impact on Hydro One
2017-07	March 2017	Service cost components of net benefit cost associated with defined benefit plans are required to be reported in the same line as other compensation costs arising from services rendered by the Company's employees. All other components of net benefit cost are to be presented in the income statement separately from the service cost component. Only the service cost component is eligible for capitalization where applicable.	January 1, 2018	Hydro One Networks has applied for a regulatory deferral account to maintain the capitalization of OPEB related costs. As such, there will be no material impact.
2017-09	May 2017	Changes to the terms or conditions of a share-based payment award will require an entity to apply modified accounting unless the modified award meets all conditions stipulated in this ASU.	January 1, 2018	No impact
2017-11	July 2017	When determining whether certain financial instruments should be classified as liabilities or equity instruments, a down round feature no longer precludes equity classification when assessing whether the instrument is indexed to an entity's own stock.	January 1, 2019	Under assessment
2017-12	August 2017	Amendments will better align an entity's risk management activities and financial reporting for hedging relationships through changes to both the designation and measurement guidance for qualifying hedging relationships and the presentation of hedge results.	January 1, 2019	Under assessment

4. BUSINESS COMBINATIONS

Haldimand Hydro Transfer

On August 31, 2016, the common shares of Haldimand County Utilities Inc. (Haldimand Hydro) were transferred to Hydro One Networks by Hydro One. The transfer was accounted as a non-monetary transfer, based on Haldimand Hydro's carrying values at August 31, 2016. On September 1, 2016, Haldimand Hydro 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, 2016:

(millions of dollars)	
Working capital	10
Property, plant and equipment	52
Intangible assets	1
Deferred tax assets	1
Goodwill	33
Inter-company demand facility	(18)
Regulatory liabilities	(3)
	76

Woodstock Hydro Transfer

On August 31, 2016, the common shares of Woodstock Hydro Holdings Inc. (Woodstock Hydro) were transferred to Hydro One Networks by Hydro One. The transfer was accounted as a non-monetary transfer, based on Woodstock Hydro's carrying values at August 31, 2016. On September 1, 2016, Woodstock Hydro 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, 2016:

(millions of dollars)	
Working capital	9
Property, plant and equipment	28
Deferred tax assets	2
Goodwill	22
Inter-company demand facility	(23)
Regulatory liabilities	(3)
Post-retirement and post-employment benefit liability	(1)
Other long-term liabilities	(1)
	33

5. DEPRECIATION AND AMORTIZATION

Year ended December 31 *(millions of dollars)*	2017	2016
Depreciation of property, plant and equipment	278	269
Asset removal costs	51	55
Amortization of intangible assets	44	39
Amortization of regulatory assets	15	12
	388	375

6. FINANCING CHARGES

Year ended December 31 *(millions of dollars)*	2017	2016
Interest on long-term debt *(Note 23)*	170	161
Interest on inter-company demand facility *(Note 23)*	2	4
Other	4	3
Less: Interest capitalized on construction and development in progress	(11)	(12)
	165	156

7. INCOME TAXES

Income tax expense differs from the amount that would have been recorded using the combined Canadian federal and Ontario statutory income tax rate. The reconciliation between the statutory and the effective tax rates is provided as follows:

Year ended December 31 *(millions of dollars)*	2017	2016
Income before income taxes	320	329
Income taxes at statutory rate of 26.5% (2016 - 26.5%)	85	87
Increase (decrease) resulting from:		
Net temporary differences recoverable in future rates charged to customers:		
Capital cost allowance in excess of depreciation and amortization	(15)	(12)
Pension contributions in excess of pension expense	(6)	(7)
Overheads capitalized for accounting but deducted for tax purposes	(7)	(7)
Interest capitalized for accounting but deducted for tax purposes	(3)	(3)
Environmental expenditures	(4)	(3)
Post-retirement and post-employment benefit expense in excess of cash payments	3	3
Other	1	(1)
Net temporary differences	(31)	(30)
Net permanent differences	1	1
Total income taxes	55	58

The major components of income tax expense are as follows:

Year ended December 31 *(millions of dollars)*	2017	2016
Current income taxes	99	22
Deferred income taxes	(44)	36
Total income taxes	55	58
Effective income tax rate	17.2%	17.6%

Deferred Income Tax Assets and Liabilities

Deferred income tax assets and liabilities 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 arise from differences between the tax basis and the carrying amounts of the assets and liabilities. At December 31, 2017 and 2016, deferred income tax assets and liabilities consisted of the following:

December 31 *(millions of dollars)*	2017	2016
Deferred income tax assets (liabilities)		
Capital cost allowance in excess of depreciation and amortization	(808)	(740)
Regulatory amounts that are not recognized for tax purposes	(17)	(109)
Goodwill	(10)	(10)
Post-retirement and post-employment benefits expense in excess of cash payments	311	337
Environmental expenditures	30	34
Non-capital losses	1	1
Other	(6)	(5)
Total deferred income tax liabilities	(499)	(492)

8. ACCOUNTS RECEIVABLE

December 31 *(millions of dollars)*	2017	2016
Accounts receivable – billed	276	396
Accounts receivable – unbilled	341	425
Accounts receivable, gross	617	821
Allowance for doubtful accounts	(29)	(35)
Accounts receivable, net	588	786

The following table shows the movements in the allowance for doubtful accounts for the years ended December 31, 2017 and 2016:

Year ended December 31 *(millions of dollars)*	2017	2016
Allowance for doubtful accounts – beginning	(35)	(59)
Write-offs	25	35
Additions to allowance for doubtful accounts	(19)	(11)
Allowance for doubtful accounts – ending	(29)	(35)

9. OTHER CURRENT ASSETS

December 31 *(millions of dollars)*	2017	2016
Regulatory assets *(Note 12)*	22	24
Prepaid expenses and other assets	12	16
Materials and supplies	4	4
	38	44

10. PROPERTY, PLANT AND EQUIPMENT

December 31, 2017 *(millions of dollars)*	Property, Plant and Equipment[1]	Accumulated Depreciation	Construction in Progress	Total
Distribution	10,155	3,488	147	6,814
Communication	145	99	2	48
Administration and service	991	561	25	455
Easements	11	4	—	7
	11,302	4,152	174	7,324

[1] Includes future use assets totalling $57 million.

December 31, 2016 *(millions of dollars)*	Property, Plant and Equipment[1]	Accumulated Depreciation	Construction in Progress	Total
Distribution	9,607	3,281	242	6,568
Communication	135	81	—	54
Administration and service	1,057	621	32	468
Easements	11	3	—	8
	10,810	3,986	274	7,098

[1] Includes future use assets totalling $51 million.

Financing charges capitalized on property, plant and equipment under construction were $9 million in 2017 (2016 - $11 million).

11. INTANGIBLE ASSETS

December 31, 2017 *(millions of dollars)*	Intangible Assets	Accumulated Amortization	Development in Progress	Total
Computer applications software	428	201	23	250
Other	49	12	2	39
	477	213	25	289

December 31, 2016 *(millions of dollars)*	Intangible Assets	Accumulated Amortization	Development in Progress	Total
Computer applications software	384	177	30	237
Other	37	9	3	31
	421	186	33	268

Financing charges capitalized to intangible assets under development were $2 million in 2017 (2016 - $1 million). The estimated annual amortization expense for intangible assets is as follows: 2018 - $47 million; 2019 - $43 million; 2020 - $34 million; 2021 - $33 million; and 2022 - $32 million.

12. REGULATORY ASSETS AND LIABILITIES

Regulatory assets and liabilities arise as a result of the rate-setting process. The Distribution Business has recorded the following regulatory assets and liabilities:

December 31 *(millions of dollars)*	2017	2016
Regulatory assets:		
Deferred income tax regulatory asset	513	462
Environmental	83	95
Stock-based compensation	20	17
Post-retirement and post-employment benefits	20	136
Distribution system code exemption	10	10
Retail settlement variance accounts	—	145
2015-2017 rate rider	—	7
Pension cost variance	—	8
Other	14	11
Total regulatory assets	660	891
Less: current portion	(22)	(24)
	638	867
Regulatory liabilities:		
Green Energy expenditure variance	60	69
Pension cost variance	13	—
2015-2017 rate rider	6	—
PST savings deferral	4	5
Other	12	7
Total regulatory liabilities	95	81
Less: current portion	(11)	—
	84	81

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 2017 income tax expense would have been higher by approximately $38 million (2016 - $31 million).

On September 28, 2017, the OEB issued its Decision and Order on Hydro One Networks' 2017 and 2018 transmission rates revenue requirements (Decision). In its Decision, the OEB concluded that the net deferred tax asset resulting from transition from the payments in lieu of tax regime under the Electricity Act (Ontario) to tax payments under the federal and provincial tax regime should not accrue entirely to Hydro One's shareholders and that a portion should be shared with ratepayers. On November 9, 2017, the OEB issued a Decision and Order that calculated the portion of the tax savings that should be shared with ratepayers. The OEB's calculation would result in an impairment of Hydro One Networks' transmission deferred income tax regulatory asset of up to approximately $515 million. If the OEB were to apply the same calculation for sharing in Hydro One Networks' 2018-2022 distribution rates, for which a decision is currently outstanding, it would result in an impairment of up to approximately $370 million related to Hydro One Networks' distribution deferred income tax regulatory asset. In October 2017, the Company filed a Motion to Review and Vary (Motion) the Decision and filed an appeal with the Divisional Court of Ontario (Appeal). On December 19, 2017, the OEB granted a hearing of the merits of the Motion which was held on February 12, 2018. In both cases, the Company's position is that the OEB made errors of fact and law in its determination of allocation of the tax savings between the shareholders and ratepayers. The Appeal is being held in abeyance pending the outcome of the Motion. If the Decision is upheld, based on the facts known at this time, the exposure from the potential impairments would be a one-time decrease in net income of up to approximately $370 million. Based on the assumptions that the OEB applies established rate making principles in a manner consistent with its past practice and does not exercise its discretion to take other policy considerations into account, management is of the view that it is likely that the Company’s Motion will be granted and the aforementioned tax savings will be allocated to the benefit of Hydro One shareholders.

Environmental

The Distribution Business 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 2017, the environmental regulatory asset increased by $2 million (2016 - decreased by $6 million) to reflect related changes in the Company’s PCB liability, and decreased by $3 million (2016 - $5 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 the Distribution Business' actual environmental expenditures. In the absence of rate-regulated accounting, 2017 operation, maintenance and administration expenses would have been lower by $1 million (2016 - $11 million). In addition, 2017 amortization expense would have been lower by $15 million (2016 - $12 million), and 2017 financing charges would have been higher by $4 million (2016 - $4 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, 2017 OCI would have been higher by $116 million (2016 - lower by $2 million).

Stock-Based Compensation

The Distribution Business recognizes costs associated with share grant plans in a regulatory asset as management considers it probable that share grant plans' costs will be recovered in the future through the rate-setting process. In the absence of rate-regulated accounting, 2017 operation, maintenance and administration expenses would have been higher by $4 million (2016 - $5 million). Share grant costs are transferred to labour costs at the time the share grants vest and are issued, and are recovered in rates in accordance with recovery of said labour costs.

Distribution System Code (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 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 Networks distribution applications. In March 2015, the OEB approved the disposition of the DSC exemption deferral account balance at December 31, 2013, including accrued interest, which was recovered through the 2015-2017 Rate Rider. In addition, the OEB also approved Hydro One's request to discontinue this deferral account. There were no additions to this regulatory account in 2017 or 2016. The remaining balance in this account at December 31, 2016, including accrued interest, was requested for recovery through the 2018-2022 distribution rate application.

Retail Settlement Variance Account (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.

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 included the balances approved for disposition by the OEB and was disposed of in accordance with the OEB decision over a 32-month period ended on December 31, 2017. The balance remaining in the account represents an over-collection to be returned to ratepayers in a future rate application. We have not requested recovery of the remaining balance of this account in the current distribution rate application.

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.

Pension Cost Variance

A pension cost variance account was established for the Distribution Business 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 deficit of pension costs paid as compared to OEB-approved amounts. In September 2017, the OEB approved the disposition of the distribution business portion of the total pension cost variance account as at December 31, 2015, including accrued interest, which is being recovered over a two-year period ending December 31, 2018. In the absence of rate-regulated accounting, 2017 revenue would have been higher by $21 million (2016 - $15 million).

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.

13. ACCOUNTS PAYABLE AND OTHER CURRENT LIABILITIES

December 31 *(millions of dollars)*	2017	2016
Accrued liabilities	562	529
Accounts payable	66	67
Accrued interest *(Note 23)*	40	42
Regulatory liabilities *(Note 12)*	11	—
	679	638

14. OTHER LONG-TERM LIABILITIES

December 31 *(millions of dollars)*	2017	2016
Post-retirement and post-employment benefit liability *(Note 18)*	838	906
Environmental liabilities *(Note 19)*	66	79
Long-term inter-company payable *(Note 23)*	18	14
Long-term accounts payable and other liabilities	8	10
Asset retirement obligations *(Note 20)*	4	4
	934	1,013

15. 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, and are allocated between the Company's transmission and distribution businesses. The following table presents long-term debt allocated to the Distribution Business outstanding at December 31, 2017 and 2016:

December 31 *(millions of dollars)*	2017	2016
Long-term debt	3,846	4,041
Add: Net unamortized debt premiums	8	8
Add: Unrealized mark-to-market gain[1]	(4)	(1)
Less: Deferred debt issuance costs	(15)	(16)
Less: Long-term debt payable within one year	(337)	(195)
Long-term debt	3,498	3,837

[1] The unrealized mark-to-market net gain relates to $30 million of notes due in 2020 and $200 million notes due in 2019. The unrealized mark-to-market net gain is offset by a $4 million (2016 - $1 million) unrealized mark-to-market net loss on the related fixed-to-floating interest-rate swap agreements, which are accounted for as fair value hedges.

In 2017, Hydro One did not issue any long-term debt. In 2016, Hydro One issued $2,300 million of long-term debt under its MTN Program, of which $2,290 million was mirrored down to Hydro One Networks and $1,050 million was allocated to the Company's Distribution Business.

In 2017, Hydro One repaid $600 million (2016 – $500 million) of maturing long-term debt under its MTN Program. On the same date, Hydro One Networks repaid inter-company debt of $600 million (2016 – $500 million) to Hydro One, of which $195 million (2016 – $200 million) was allocated to the Company's Distribution Business.

Principal and Interest Payments

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 dollars)*	Weighted Average Interest Rate *(%)*
1 year	337	2.8
2 years	291	1.8
3 years	150	3.9
4 years	250	2.1
5 years	261	3.2
	1,289	2.6
6 – 10 years	245	3.0
Over 10 years	2,312	5.2
	3,846	4.2

Interest payment obligations related to long-term debt are summarized by year in the following table:

Year	Interest Payments *(millions of dollars)*
2018	162
2019	151
2020	145
2021	140
2022	132
	730
2023-2027	630
2028+	1,588
	2,948

16. 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 Networks 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, 2017 and 2016, the carrying amounts of accounts receivable, due from related parties, inter-company demand facility, accounts payable, and due to related parties are representative of fair value due to 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, 2017 and 2016 are as follows:

December 31 *(millions of dollars)*	2017 Carrying Value	2017 Fair Value	2016 Carrying Value	2016 Fair Value
$30 million notes due 2020	29	29	30	30
$200 million notes due 2019	197	197	199	199
Other notes and debentures	3,609	4,159	3,803	4,291
Long-term debt, including current portion	3,835	4,385	4,032	4,520

Fair Value Measurements of Derivative Instruments

Hydro One enters into interest-rate swaps agreements with respect to its long-term debt. The terms of certain of these interest-rate swap agreements are mirrored down to Hydro One Networks, and are allocated between the Company's transmission and distribution businesses.

At December 31, 2017, the Distribution Business' share of the Company's derivative instruments include $230 million (2016 – $230 million) of interest-rate swaps that were used to convert fixed-rate debt to floating-rate debt. These swaps are classified as fair value hedges. The Distribution Business' fair value hedge exposure was approximately 6% (2016 – 6%) of its total long-term debt. At December 31, 2017, the Distribution Business' interest-rate swaps designated as fair value hedges were as follows:

- a $30 million fixed-to-floating interest-rate swap agreement to convert $30 million of the $350 million notes maturing April 30, 2020 into three-month variable rate debt; and
- $200 million fixed-to-floating interest-rate swap agreements to convert the $200 million notes maturing November 18, 2019 into three-month variable rate debt.

At December 31, 2017 and 2016, the Company had no interest-rate swaps classified as undesignated contracts.

Fair Value Hierarchy

The fair value hierarchy of financial assets and liabilities at December 31, 2017 and 2016 is as follows:

December 31, 2017 *(millions of dollars)*	Carrying Value	Fair Value	Level 1	Level 2	Level 3
Liabilities:					
Inter-company demand facility	167	167	167	—	—
Long-term debt, including current portion	3,835	4,385	—	4,385	—
Derivative instruments					
Fair value hedges – interest-rate swaps	4	4	—	4	—
	4,006	4,556	167	4,389	—

December 31, 2016 *(millions of dollars)*	Carrying Value	Fair Value	Level 1	Level 2	Level 3
Assets:					
Cash and cash equivalents	9	9	9	—	—
	9	9	9	—	—
Liabilities:					
Inter-company demand facility	74	74	74	—	—
Long-term debt, including current portion	4,032	4,520	—	4,520	—
Derivative instruments					
Fair value hedges – interest-rate swaps	1	1	—	1	—
	4,107	4,595	74	4,521	—

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 transfers between any of the fair value levels during the years ended December 31, 2017 or 2016.

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 which 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 anticipated interest rates into account. The Company is not currently exposed to material commodity price risk or material foreign exchange 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. The Company may also utilize interest-rate derivative instruments to lock in interest-rate levels in anticipation of future financing.

A hypothetical 100 basis points increase in interest rates associated with variable-rate debt would not have resulted in a significant decrease in Distribution Business' net income for the years ended December 31, 2017 and 2016.

For derivative instruments that are designated and qualify as fair value hedges, the gain or loss on the derivative instrument 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, 2017 and 2016 was not material.

Credit Risk

Financial assets create a risk that a counterparty will fail to discharge an obligation, causing a financial loss. At December 31, 2017 and 2016, there were no significant concentrations of credit risk with respect to any class of financial assets. The Distribution Business' revenue is earned from a broad base of customers. As a result, the Distribution Business did not earn a material amount of revenue from any single customer. At December 31, 2017 and 2016, there was no material accounts receivable balance due from any single customer.

At December 31, 2017, the Company's provision for bad debts was $29 million (2016 – $35 million). Adjustments and write-offs are determined on the basis of a review of overdue accounts, taking into consideration historical experience. At December 31, 2017, approximately 5% (2016 – 6%) of the Distribution Business' net accounts receivable were outstanding for 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; entering into master agreements which enable net settlement and the contractual right of offset; and monitoring the financial condition of counterparties. Hydro One monitors current credit exposure to counterparties both on an individual and an aggregate basis. The Company's counterparty credit risk profile is consistent with Hydro One. The Distribution Business' credit risk for accounts receivable is limited to the carrying amounts on the 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, 2017 and 2016, the counterparty credit risk exposure on the fair value of these interest-rate swap contracts was not material. At December 31, 2017, Hydro One's credit exposure for all derivative instruments, and applicable payables and receivables, had a credit rating of investment grade, with four financial institutions as the counterparties.

Liquidity Risk

Liquidity risk refers to the Company's ability to meet its financial obligations as they come due. Hydro One Networks 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 is expected to be sufficient to fund normal operating requirements.

17. CAPITAL MANAGEMENT

The Distribution Business' 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. At December 31, 2017 and 2016, the Distribution Business' capital structure was as follows:

December 31 *(millions of dollars)*	2017	2016
Long-term debt payable within one year	337	195
Inter-company demand facility	167	74
Less: cash and cash equivalents	—	9
	504	260
Long-term debt	3,498	3,837
Excess of assets over liabilities	2,768	2,766
Total capital	6,770	6,863

The following table shows the movements in the excess of assets over liabilities for the years ended December 31, 2017 and 2016:

Year ended December 31 *(millions of dollars)*	2017	2016
Excess of assets over liabilities - beginning	2,766	2,679
Net income	265	271
Payments to Hydro One to finance dividends and return of stated capital	(263)	(293)
Transfers *(Note 4)*	—	109
Excess of assets over liabilities - ending	2,768	2,766

18. PENSION AND POST-RETIREMENT AND POST-EMPLOYMENT BENEFITS

Hydro One has a defined benefit pension plan (Pension Plan), a defined contribution pension plan (DC Plan), a supplemental pension plan (Supplemental Plan), and post-retirement and post-employment benefit plans.

DC Plan

Hydro One established a DC Plan effective January 1, 2016. The DC Plan covers eligible management employees hired on or after January 1, 2016, as well as management employees hired before January 1, 2016 who were not eligible or had not irrevocably elected to join the Pension Plan as of September 30, 2015. Members of the DC Plan have an option to contribute 4%, 5% or 6% of their pensionable earnings, with matching contributions by Hydro One.

Hydro One Networks contributions to the DC Plan for the year ended December 31, 2017 were less than $1 million (2016 - less than $1 million). At December 31, 2017 and 2016, Company contributions payable included in accrued liabilities on the Balance Sheets were not significant.

Pension Plan and Supplemental Plan

The Pension Plan is a defined benefit contributory plan which covers eligible regular employees of Hydro One and its subsidiaries. The Pension Plan provides benefits based on highest three-year average pensionable earnings. For management employees who commenced employment on or after January 1, 2004, and for The Society of Energy Professionals (The Society)-represented staff hired after November 17, 2005, benefits are based on highest five-year average pensionable earnings. After retirement, pensions are indexed to inflation. Membership in the Pension Plan was closed to management employees who were not eligible or had not irrevocably elected to join the Pension Plan as of September 30, 2015. These employees are eligible to join the DC Plan.

Hydro One and employee contributions to the Pension Plan are based on actuarial valuations performed at least every three years. Annual Pension Plan contributions for 2017 of $87 million (2016 - $108 million) were based on an actuarial valuation effective December 31, 2016 (2016 - based on an actuarial valuation effective December 31, 2015) and the level of pensionable earnings. Estimated annual Pension Plan contributions for 2018 and 2019 are approximately $71 million for each year based on the actuarial valuation as at December 31, 2016 and projected levels of pensionable earnings. Future minimum contributions beyond 2019 will be based on an actuarial valuation effective no later than December 31, 2019. Contributions are payable one month in arrears. All of the contributions are expected to be in the form of cash.

The Supplemental 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 Supplemental Plan obligation is included with other post-retirement and post-employment benefit obligations on the Balance Sheets.

At December 31, 2017, the present value of Hydro One's projected pension benefit obligation was estimated to be $8,258 million (2016 - $7,774 million). The fair value of pension plan assets available for these benefits was $7,277 million (2016 - $6,874 million).

Post-Retirement and Post-Employment Plans

During the year ended December 31, 2017, the Distribution Business charged $35 million (2016 - $33 million) of post-retirement and post-employment benefit costs to operation, and capitalized $35 million (2016 - $35 million) as part of the cost of property, plant and equipment and intangible assets. Benefits paid in 2017 were $24 million (2016 - $24 million). In addition, the associated post-retirement and post-employment benefits regulatory asset was decreased by $116 million (2016 - increased by $2 million).

The Distribution Business presents its post-retirement and post-employment benefit liabilities on its Balance Sheets as follows:

December 31 *(millions of dollars)*	2017	2016
Accrued liabilities	26	28
Post-retirement and post-employment benefit liability	838	906
Net unfunded status	864	934

19. ENVIRONMENTAL LIABILITIES

The following tables show the movements in environmental liabilities for the years ended December 31, 2017 and 2016:

Year ended December 31, 2017 *(millions of dollars)*	PCB	Land Assessment and Remediation	Total
Environmental liabilities - beginning	66	29	95
Interest accretion	3	1	4
Expenditures	(10)	(5)	(15)
Revaluation adjustment	2	(3)	(1)
Environmental liabilities - ending	61	22	83
Less: current portion	(12)	(5)	(17)
	49	17	66

Year ended December 31, 2016 *(millions of dollars)*	PCB	Land Assessment and Remediation	Total
Environmental liabilities - beginning	77	37	114
Interest accretion	3	1	4
Expenditures	(8)	(4)	(12)
Revaluation adjustment	(6)	(5)	(11)
Environmental liabilities - ending	66	29	95
Less: current portion	(10)	(6)	(16)
	56	23	79

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, 2017 *(millions of dollars)*	PCB	Land Assessment and Remediation	Total
Undiscounted environmental liabilities	64	23	87
Less: discounting environmental liabilities to present value	(3)	(1)	(4)
Discounted environmental liabilities	61	22	83

December 31, 2016 *(millions of dollars)*	PCB	Land Assessment and Remediation	Total
Undiscounted environmental liabilities	73	29	102
Less: discounting environmental liabilities to present value	(7)	—	(7)
Discounted environmental liabilities	66	29	95

At December 31, 2017, the estimated future environmental expenditures were as follows:

(millions of dollars)	
2018	17
2019	14
2020	16
2021	15
2022	13
Thereafter	12
	87

The Distribution Business 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 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, 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 Distribution Business' best estimate of the total estimated future expenditures to comply with current PCB regulations is $64 million (2016 - $73 million). These expenditures are expected to be incurred over the period from 2018 to 2025. As a result of its annual review of environmental liabilities, the Distribution Business recorded a revaluation adjustment in 2017 to increase the PCB environmental liability by $2 million (2016 - decrease by $6 million).

Land Assessment and Remediation

The Distribution Business' best estimate of the total estimated future expenditures to complete its land assessment and remediation program is $22 million (2016 - $29 million). These expenditures are expected to be incurred over the period from 2018 to 2023. As a result of its annual review of environmental liabilities, the Distribution Business recorded a revaluation adjustment in 2017 to reduce the land assessment and remediation environmental liability by $3 million (2016 - $5 million).

20. ASSET RETIREMENT OBLIGATIONS

Hydro One Networks records a liability for the estimated future expenditures for the removal and disposal of asbestos-containing materials installed in some of its facilities. 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 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 Distribution Business' 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, 2017, Hydro One Networks had recorded asset retirement obligations of $4 million (2016 - $4 million) related to its Distribution Business, primarily 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.

21. HYDRO ONE NETWORKS' SHARE CAPITAL

Hydro One Networks is authorized to issue an unlimited number of common and preferred shares. At December 31, 2017 and 2016, Hydro One Networks had 207,577,181 common shares issued and outstanding and no preferred shares issued and outstanding.

During 2017, Hydro One Networks declared common share dividends in the amount of $2 million (2016 – $2 million) and made a return of stated capital of $509 million (2016 – $609 million) to Hydro One. The amount allocated to the Distribution Business to finance these dividends and return of stated capital was $263 million (2016 – $293 million).

22. 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

Hydro One Limited has two share grant plans (Share Grant Plans), one for the benefit of certain members of the PWU (PWU Share Grant Plan) and one for the benefit of certain members of The Society (Society Share Grant Plan).

The PWU Share Grant Plan provides for the issuance of common shares of Hydro One Limited 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. 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 began on July 3, 2015, which is the date the share grant plan was 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 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 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 began 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 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 2015 share grants to employees of Hydro One Networks and allocated to the Distribution Business was $59 million. The fair value was 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. In 2017, 186,489 common shares were granted under the Share Grant Plans (2016 - $nil) to eligible employees of Hydro One Networks and allocated to the Distribution Business. Total stock-based compensation recognized by the Distribution Business during 2017 was $8 million (2016 - $12 million) and was recorded as a regulatory asset.

A summary of the Distribution Business' share grant activity under the Share Grant Plans during 2017 and 2016 is presented below:

Year ended December 31, 2017	Share Grants *(number of common shares)*	Weighted-Average Price
Share grants outstanding - beginning	2,853,079	$20.50
Vested and issued[1]	(186,489)	—
Forfeited	(67,420)	$20.50
Share grants outstanding - ending	2,599,170	$20.50

[1] On April 1, 2017, Hydro One Limited issued from treasury 186,489 common shares to eligible Hydro One Networks employees, which were allocated to the Distribution Business, in accordance with provisions of the PWU Share Grant Plan.

Year ended December 31, 2016	Share Grants *(number of common shares)*	Weighted-Average Price
Share grants outstanding - beginning	2,869,396	$20.50
Forfeited[1]	(43,317)	$20.50
Share grants outstanding - ending	2,826,079	$20.50

[1]Includes shares forfeited as well as shares transferred corresponding to transfer of employees between affiliate companies.

Directors' DSU Plan

Under the 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 Limited'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 Hydro One Limited common share and is entitled to accrue Hydro One Limited common share dividend equivalents in the form of additional DSUs at the time dividends are paid, subsequent to declaration by Hydro One Limited's Board of Directors.

During 2017 and 2016, Directors' DSU Plan awards granted by Hydro One Limited that related to Hydro One Networks' Distribution Business were as follows:

Year ended December 31 *(number of DSUs)*	2017	2016
DSUs outstanding - beginning	53,481	11,079
DSUs granted	20,787	42,402
DSUs outstanding - ending	74,268	53,481

For the year ended December 31, 2017, an expense of $nil (2016 - $1 million) was recognized in earnings by the Distribution Business with respect to the Directors' DSU Plan. At December 31, 2017, a liability of $1 million (2016 - $1 million), related to outstanding DSUs has been recorded at the closing price of Hydro One Limited's common shares of $22.40 and is included in long-term accounts payable and other liabilities on the Balance Sheets.

Management DSU Plan

Under the Management DSU Plan, eligible employees can elect to receive a specified proportion of their annual short-term incentive in a notional account of DSUs in lieu of cash. Each DSU represents a unit with an underlying value equivalent to the value of one common share of Hydro One Limited 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 Limited's Board of Directors.

During 2017 and 2016, Management DSU Plan awards granted by Hydro One Limited that related to Hydro One Networks' Distribution Business were as follows:

Year ended December 31 *(number of DSUs)*	2017	2016
DSUs outstanding - beginning	—	—
Granted	25,601	—
Paid	(439)	—
DSUs outstanding - ending	25,162	—

For the year ended December 31, 2017, an expense of $1 million (2016 - $nil) was recognized in earnings by the Distribution Business with respect to the Management DSU Plan. At December 31, 2017, a liability of $1 million (2016 - $nil) related to outstanding DSUs has been recorded at the closing price of Hydro One Limited common shares of $22.40 and is included in long-term accounts payable and other liabilities on the Balance Sheets.

Employee Share Ownership Plan

In 2015, Hydro One Limited established Employee Share Ownership Plans (ESOP) for certain eligible management and non-represented employees (Management ESOP) and for certain eligible Society-represented staff (Society ESOP). Under the Management ESOP, the eligible management and non-represented employees may contribute between 1% and 6% of their base salary towards purchasing common shares of Hydro One Limited. The Company matches 50% of their contributions, up to a maximum Company contribution of $25,000 per calendar year. Under the Society ESOP, the eligible Society-represented staff may contribute between 1% and 4% of their base salary towards purchasing common shares of Hydro One Limited. The Company matches 25% of their contributions, with no maximum Company contribution per calendar year. In 2017, Company contributions made under the ESOP for the Distribution Business were $1 million (2016 - $1 million).

LTIP

Effective August 31, 2015, the Board of Directors of Hydro One Limited adopted an LTIP. Under the LTIP, long-term incentives are 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 RSUs, PSUs, stock options, share appreciation rights, restricted shares, deferred share units and other stock-based awards. The mix of vehicles is intended to vary by role to recognize the level of executive accountability for overall business performance.

During 2017 and 2016, LTIP awards granted by Hydro One Limited that related to Hydro One Networks' Distribution Business were as follows:

	PSUs		RSUs	
Year ended December 31 *(number of units)*	2017	2016	2017	2016
Units outstanding - beginning	74,063	—	83,394	—
Units granted	118,467	77,348	96,697	86,679
Units vested	(276)	—	(7,054)	—
Units forfeited	(23,764)	(3,285)	(21,547)	(3,285)
Units outstanding - ending	168,490	74,063	151,490	83,394

The grant date total fair value of the awards granted in 2017 was $5 million (2016 - $4 million). The compensation expense related to these awards recognized by the Distribution Business during 2017 was $2 million (2016 - $1 million).

23. RELATED PARTY TRANSACTIONS

The Distribution Business is a separately regulated business of Hydro One Networks which is indirectly owned by Hydro One Limited. The Province is a shareholder of Hydro One Limited with approximately 47.4% ownership at December 31, 2017. The IESO, Ontario Power Generation Inc. (OPG), OEFC, and the OEB, are related parties to Hydro One Networks because they are controlled or significantly influenced by the Province.

Year ended December 31 *(millions of dollars)*

Related Party	Transaction	2017	2016
IESO	Power purchased	1,583	2,044
	Amounts related to electricity rebates	357	—
	Distribution revenues related to rural rate protection	247	125
	Funding received related to Conservation and Demand Management programs	59	63
OPG	Power purchased	9	6
OEFC	Power purchased from power contracts administered by the OEFC	2	1
OEB	OEB fees	5	6
Hydro One Brampton[1]	Revenues from management, administrative and smart meter network services	—	3
Hydro One Limited and its subsidiaries[2]	Revenues for services provided	1	4
	Services received - costs expensed	16	15
	Interest expense on long-term debt	170	161
	Interest expense on inter-company demand facility	2	4
	Payments to finance dividends and return of stated capital	263	293
	Stock-based compensation costs	10	13

[1] On February 28, 2017, Hydro One Brampton was acquired by Alectra Inc. from the Province, and as such, effective this date, Hydro One Brampton is no longer a related party to Hydro One.

[2] In 2016, Hydro One transferred the assets and liabilities of Haldimand Hydro and Woodstock Hydro to Hydro One Networks' Distribution Business. See note 4.

The amounts due to and from related parties at December 31, 2017 and 2016 are as follows:

December 31 *(millions of dollars)*	2017	2016
Inter-company demand facility	(167)	(74)
Due from related parties	138	33
Due to related parties	(218)	(178)
Accrued interest	(40)	(42)
Long-term inter-company payable	(18)	(14)
Long-term debt, including current portion	(3,835)	(4,032)

24. STATEMENTS OF CASH FLOWS

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

Year ended December 31 *(millions of dollars)*	2017	2016
Accounts receivable	198	(48)
Due from related parties	(105)	27
Materials and supplies	—	2
Other assets	4	(8)
Accounts payable	10	(1)
Accrued liabilities	32	50
Due to related parties	40	50
Accrued interest	(2)	6
Long-term accounts payable and other liabilities	(6)	7
Post-retirement and post-employment benefit liability	48	41
	219	126

Capital Expenditures

The following table reconciles investments in property, plant and equipment and the amounts presented in the Statements of Cash Flows after accounting for capitalized depreciation and the net change in related accruals:

Year ended December 31 *(millions of dollars)*	2017	2016
Capital investments in property, plant and equipment	(537)	(655)
Capitalized depreciation and net change in accruals included in capital investments in property, plant and equipment	15	20
Cash outflow for capital expenditures – property, plant and equipment	(522)	(635)

The following table reconciles investments in intangible assets and the amounts presented in the Statements of Cash Flows after accounting for the net change in related accruals:

Year ended December 31 *(millions of dollars)*	2017	2016
Capital investments in intangible assets	(48)	(44)
Net change in accruals included in capital investments in intangible assets	(8)	6
Cash outflow for capital expenditures – intangible assets	(56)	(38)

Supplementary Information

Year ended December 31 *(millions of dollars)*	2017	2016
Net interest paid	172	155
Income taxes paid	16	10

25. CONTINGENCIES

Hydro One Networks is involved in various lawsuits and claims 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 financial position, results of operations or cash flows.

Hydro One and certain of its subsidiaries, including Hydro One Networks, are defendants in a class action suit in which the representative plaintiff is seeking up to $125 million in damages related to allegations of improper billing practices. The plaintiff's motion for certification was dismissed by the court on November 28, 2017, but the plaintiff has appealed the court's decision, and it is likely that no decision will be rendered by the appeal court until the second half of 2018. At this time, 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.

26. 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.

27. SUBSEQUENT EVENTS

Payments to Finance Dividends and Return of Stated Capital

On February 12, 2018, Hydro One Networks declared common share dividends in the amount of $1 million, and a return of stated capital in the amount of $131 million was approved. The amount allocated to the Distribution Business to finance these payments was $81 million.

Building Owners and Managers Association Toronto Interrogatory # 39

Issue:

Issue 3: Is the overall increase in the distribution revenue requirement from 2018 to 2022 reasonable?

Issue 1: Has Hydro One responded appropriately to all relevant OEB directions from previous proceedings?

Issue 41: Has Hydro One demonstrated improvements in presenting its compensation costs and showing efficiency and value for dollar associated with its compensation costs (excluding executive compensation)?

Reference:

Hydro One Consolidated Business Plan, December 2, Page: 4

Interrogatory:

a) Is the $11 million included in the table, or is it additional to the costs, eg. 2018 $312 million in the table?

b) Is there a more detailed treatment of corporate common costs? See, in particular, last paragraph. Please provide a detailed breakdown of each of the lines in the table on p4, with particular attention to the larger items, such as Planning, Customer and Corporate Relations, Network Operating. Please provide the appropriate ratio for each of the lines, and the most recent B&V study. Please provide the cost of the custom service to the DSP.

c) Has the Internal Audit completed its review of same or all of the eight recommendations? Please file once this is completed.

d) Please update the table and chart to September 30, 2017.

Response:

a) Yes the $11 million is included in the table.

b) Please refer to Exhibit C1, Schedule 1, Tab 7 for more details on Common Corporate Functions and Services, Exhibit C1, Tab 1, Schedule 8 for Planning, Exhibit C1, Tab 1, Schedule 9 for Information Technology ("IT") and Exhibit C1, Tab 1, Schedule 4 for Operations OM&A.

c) Referring to the Hydro One Consolidated Plan on page 4 provided in Exhibit A-3-1-2, there are no recommendations identified for Audit to review.

d) The Corporate Common Costs 2016 to 2022 table from the 2017-2022 Consolidated Business Plan is updated to reflect 2016 and 2017 actuals:

Total Corporate Common Costs 2016 to 2022

Corporate Common Cost $M	2016 Act	2017 Act	2018	2019	2020	2021	2022	CAGR
Audit	$ 5	$ 7	$ 7	$ 7	$ 7	$ 7	$ 7	6.7%
Corporate Management	$ 18	$ 28	$ 23	$ 24	$ 24	$ 24	$ 24	5.3%
Customer and Corporate Relations	$ 41	$ 53	$ 52	$ 52	$ 52	$ 52	$ 52	4.1%
Facilities Real Estate	$ 9	$ 8	$ 9	$ 10	$ 10	$ 10	$ 10	1.7%
Finance Total	$ 29	$ 25	$ 33	$ 33	$ 31	$ 31	$ 32	1.6%
Finance Inergi	$ 11	$ 11	$ 12	$ 12	$ 13	$ 13	$ 13	2.6%
General Counsel and Secretary	$ 10	$ 9	$ 10	$ 10	$ 10	$ 11	$ 11	1.1%
Information Solutions Division	$ 24	$ 21	$ 21	$ 21	$ 21	$ 22	$ 22	-1.2%
Network Operating	$ 45	$ 44	$ 49	$ 50	$ 50	$ 51	$ 51	2.2%
Operations COO Office	$ 4	$ 10	$ 4	$ 4	$ 4	$ 4	$ 4	-0.2%
People & Culture	$ 16	$ 18	$ 16	$ 16	$ 17	$ 17	$ 17	1.3%
Planning	$ 49	$ 48	$ 52	$ 52	$ 52	$ 52	$ 53	1.2%
Regulatory Affairs	$ 23	$ 21	$ 23	$ 19	$ 19	$ 19	$ 21	-1.8%
Strategic Services	$ 1	$ 2	$ 2	$ 2	$ 2	$ 2	$ 2	12.7%
Total	**$ 285**	**$ 305**	**$ 312**	**$ 310**	**$ 312**	**$ 315**	**$ 320**	**1.9%**

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

Canadian Manufacturers & Exporters Interrogatory # 46

Issue:

Issue 3: Is the overall increase in the distribution revenue requirement from 2018 to 2022 reasonable?

Reference:

C1-07-01
EB-2016-0160 Decision and Order dated November 9, 2017

Interrogatory:

a) What is the impact on the 2018 distribution revenue requirement if Hydro One were to quantify and reflect the OEB findings in the November 9, 2017 EB-2016-0160 Decision and Order related to the regulatory income taxes recoverable from ratepayers.

Response:

In the November 9, 2017 EB-2016-0160 Decision and Order, OEB ordered Hydro One to give ratepayers an allocation of the future tax savings based on benefits follow costs "Actual FMV Sales and Payments" allocation factor that was established in the September 28, 2017 EB-2016-0160 Decision and Order ("September Decision"). After the Province sale of 2.4% of Hydro One Limited ("HOL") shares to First Nation on January 4, 2018, 52.6% of the Province shares in HOL were sold and owned by new shareholders. Using the same methodology as illustrated in the September Decision, the benefits follow costs allocation ratio in favour of shareholders for Distribution is estimated to be 63.8% and is calculated as follows:

Actual FMV Sales and Payment Ratios - Distribution			
	52.6% Sold		
Actual Payment Proportions toward FMV bump			
- By new shareholders	52.6%	4,171.0	2,194
- Departure tax on remainder	47.4%	984.0	466
			2,660
Ratio: Actual FMV Sales & Payments/FMV Bump		$2,660/$4,171 =	63.8%

Based on this updated ratio, the revised regulatory income taxes for 2018 would be reduced from $65.4 million as reported in Exhibit Q, Tab 1, Schedule 1 to $41.7 million.

This was noted in Procedural Order No. 2 of this proceeding which stated:

> "The OEB understands that Hydro One's proposed treatment of tax savings resulting from the Government of Ontario's decision to sell its ownership interest in Hydro One Limited by way of an IPO and subsequent sale of shares in this Distribution Rates Application is consistent with its proposed approach to those savings in the Transmission application. That is, Hydro One does not intend to apply any tax savings resulting from the IPO to reduce Hydro One's distribution revenue requirement. As Hydro One notes "Neither the departure tax nor the change in tax regime will have any impact on ratepayers. For regulatory purposes, income tax expenses will continue to be calculated according to the method prescribed by the Board's 2006 EDR Tax Model and 2006 EDR Handbook, Section 7.1 "OEB 2006 Regulatory Taxes Expense Methodology"1. The OEB does not intend to have that matter re-litigated in the current proceeding while the motion and appeal are pending. Accordingly, the OEB will not permit the Tax Savings Determination issue to be addressed in the distribution case, pending the outcomes of the Hydro One Motion and Appeal." (Decision on Issues List, Interim Rates and Procedural Order No. 2, December 1, 2017, page 3-4)

Building Owners and Managers Association Toronto Interrogatory # 17

Issue:

Issue 4: Are the rate and bill impacts in each customer class in each year in the 2018 to 2022 period reasonable?

Issue 3: Is the overall increase in the distribution revenue requirement from 2018 to 2022 reasonable?

Issue 29: Are the proposed capital expenditures resulting from the Distribution System Plan appropriate, and have they been adequately planned and paced?

Issue 51: Are the revenue-to-cost ratios for all rate classes over the 2018 – 2022 period appropriate?

Reference:

A-03-01

Interrogatory:

a) p2 - Please provide the forecast percentage rate increase for each year over the period 2018 to 2022, commencing with the 2018 rates over existing 2017 rates.

   i. Please provide the derivation underlying calculations of the 4.7% as the 3.0% of the cited at lines 19 and 20.
   ii. Please provide the same data as in (i) for historical years 2017 over 2016, 2016 over 2015, 2015 over 2014, 2014 over 2013, and 2013 over 2012.

b) p23 - What are 2016 Actual Revenue Requirement relative to Board-approved Revenue Requirement?

c) What are the 2017 actual OM&A to date (September 30, 2017)? Extend revenue to date?

d) p5 – Please provide the derivation of the 4.2% reduction in capital expenditures from 2017 Board-approved levels. What is the year to date and current forecast 2017 actual capital expenditures?

e) Please confirm that for residential customers in 2018, the distribution rate is determined to the extent of 75% by customer charge, which does not vary with electricity consumption on demand.

f) Please show the corresponding bill increases for section **Error! Reference source not found.** above

Response:

a) The forecast percentage rate increase of 4.9% shown in the reference A-03-01 was subsequently updated to 6.1% as shown on page 3 of Exhibit Q-01-01 filed with the Board on December, 21, 2017. The answers below are provided based on Hydro One's current proposal as per Exhibit Q-01-01.

The forecast percentage rate increases are provided in the table below as requested.

2018 increase over 2017	2019 increase over 2018	2020 increase over 2019	2021 increase over 2020	2022 increase over 2021
6.1%	3.6%	2.9%	2.4%	2.2%

i. The Derivation of 6.1% is the combined impact of a 3.1% increase in 2018 revenue requirement plus riders and other revenues over the equivalent amounts in 2017, plus a 3.0% increase due to the revenue deficiency associated with rebasing the load forecast in 2018. The calculations are shown in the table below. Details of the revenue deficiency associated with the load forecast impact of 3.0% is provided in the response to Exhibit I-19-BOMA-19 part h).

	2017	2018
Revenue Requirement	1,467.6	1,517.1
Rate Riders	11.1	6.2
Other revenue impacts	(52.7)	(53.6)
Rates Revenue Requirement	**1,426.0**	**1,469.7**
Rates Increase over 2017		3.1%
Load Impact		3.0%
Rate Increase Required		6.1%

ii. Please see the table below for the information requested.

	2013 over 2012	**2014 over 2013**	**2015 over 2014**	**2016 over 2015**	**2017 over 2016**
Change in Revenue	1.1%	3.5%	11.2%	6.3%	0.4%
Load Impact	0% *	0% *	0.7%	-0.5%	-0.8%
Total	**1.1%**	**3.5%**	**11.9%**	**5.8%**	**-0.4%**

* IRM years – no changes to load forecast.

b) Please refer to the following exhibits where actuals have been filed. For 2016 actual OM&A, please refer to Exhibit C1, Tab 1, Schedule 1. For actual depreciation expense, please refer to C1, Tab 6, Schedule 1. For actual calculation of utility income taxes, please refer to Exhibit C1, Tab 7, Schedule 2, Attachment 3. For actual external revenues, please refer to Exhibit E1, Tab 1, Schedule 2.

c) Please refer to I-38-SEC-70 for 2017 year-end actual OM&A values.

d) The 4.2% reduction in capital expenditures is captured in the 2017 Bridge Variance column of Exhibit A-03-01 (Table 9). 2017 actuals will be made available at a later date.

e) No that is not correct. As shown in the evidence at Exhibit H1, Tab 1, Schedule 2, page 1, the fixed customer charges collected from the residential classes in 2018 account for 83% of UR class revenue, 65% of the R1 class revenue, 68% of the R2 class revenue, and 66% of the Seasonal class revenue.

f) The bill increases for each rate class corresponding with the proposed revenue requirement and load forecast for all years of this application are provided in Table 1 of Exhibit H1, Tab 4, Schedule 1 of the evidence.

Energy Probe Research Foundation Interrogatory # 12

Issue:
Issue 14: Is Hydro One's proposed integration of the Acquired Utilities in 2021 appropriate?

Reference:
A-07-01 Page: 1-11

Interrogatory:
Please provide service area savings for the acquired utilities for 2017.

Response:

At the time of filing the 2017 year-end actual values were not available. The tables below now reflect 2017 actual numbers.

Table 1: NPDI Service Area Savings

$/Million	2014	2015	2016	2017
OM&A Status Quo Forecast	5.7	5.8	5.9	6.0
Hydro One MAAD Application Forecast	5.8	2.6	2.7	2.7
Hydro One Actual	7.2	5.9	2.7	2.2
Projected Savings	(0.1)	3.2	3.2	3.3
Actual Savings	(1.5)	(0.1)	3.2	3.8
Capital Status Quo Forecast	5.0	4.7	4.6	4.4
Hydro One Forecast	3.1	2.9	2.9	3.0
Hydro One Actual	3.5	2.1	0.9	1.7
Projected Savings	1.9	1.8	1.7	1.4
Actual Savings	1.5	2.6	3.7	2.7

Table 2: HCHI Service Area Savings

$/Million	2015	2016	2017
OM&A Status Quo Forecast	8. 2	8.3	8.5
Hydro One MAAD Application Forecast	6.4	4.4	4.5
Hydro One Actual	7.7	6.0	3.9
Projected Savings	1.8	4.0	4.0
Actual Savings	0.5	2.3	4.6
Capital Status Quo Forecast	6.4	6.1	5.4
Hydro One Forecast	4.2	3.2	3.3
Hydro One Actual	6.9	4.6	3.5
Projected Savings	2.2	2.9	2.1
Actual Savings	(0.5)	1.5	1.9

Table 3: WHSI Service Area Savings

$/Million	2015	2016	2017
OM&A Status Quo Forecast	3.9	4.6	4.0
Hydro One MAAD Application Forecast (excluding overhead corporate costs)	1.7	2.2	1.6
Hydro One Actual (excluding overhead corporate costs)	4.2	3.8	2.0
Hydro One Actual (including overhead corporate costs)	N/A[1]	4.0	2.3
Projected Savings	2.3	2.3	2.4
Actual Savings (excluding overheads)	(0.3)	0.8	2.0
Actual Savings (including overheads)	N/A	0.6	1.7
Capital Status Quo Forecast	2.4	2.5	2.5
Hydro One MAAD Application Forecast (excluding overhead corporate costs)	2.2	2.9	3.2
Hydro One Actual (excluding overhead corporate costs)	2.2	3.1	1.7
Hydro One Actual (including overhead corporate costs)	N/A[1]	3.2	2.3
Projected Savings	0.2	(0.5)	(0.7)
Actual Savings (excluding overhead corporate costs)	0.2	(0.6)	0.8
Actual Savings (including overhead corporate costs)	N/A	(0.7)	0.2

[1] 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.

Building Owners and Managers Association Toronto Interrogatory # 34

Issue:

Issue 17: Does the application adequately incorporate and reflect the four outcomes identified in the Rate Handbook: customer focus, operational effectiveness, public policy responsiveness, and financial performance?

Reference:

A-03-01-01 Page: 22

Interrogatory:

Is there a final version of the Productivity and Outcome Measure Scorecard relative to the current forecast? Please file it.

Response:

Please refer to Exhibit I-18-SEC-29.

Energy Probe Research Foundation Interrogatory # 15

Issue:

Issue 17: Does the application adequately incorporate and reflect the four outcomes identified in the Rate Handbook: customer focus, operational effectiveness, public policy responsiveness, and financial performance?

Reference:

C1-01-01 Page: 7

Interrogatory:

Please provide net bad debt levels from 2013 to 2017.

Response:

2014 to 2016 Net Bad Debt levels are provided in Exhibit C1, Tab 1, Schedule 5, Table 1. The 2013 Net Bad Debt level was $32.8 million, as provided in Exhibit C1, Tab 2, Schedule 5, Table 2 of Hydro One's last custom distribution application (EB-2013-0416). 2017 Net Bad Debt figures are provided in Exhibit I-38-SEC-70.

School Energy Coalition Interrogatory # 29

Issue:

Issue 18: Are the metrics in the proposed additional scorecard measures appropriate and do they adequately reflect appropriate outcomes?

Reference:

B1-01-01 Section 1.4 Page: 29-43

Interrogatory:

The performance measures contained in Table 16 include a number of measures not included on the proposed OEB Scorecard (p.3). Please provide a single table that shows all performance measures with actual performance from 2011-2016, and targets for 2017-2022.

Response:

All measures in Exhibit B1, Tab 1, Schedule 1, DSP Section 1.4, pp. 29-43, Table 16 are included in either the Electricity Distributor Scorecard or the proposed Dx OEB Scorecard.

Please refer to the updated Electricity Distributor Scorecard and the Dx OEB Scorecard below.

Please note the following regarding the information provided in the scorecards below:

- The OEB revised the reporting methodology for SAIDI and SAIFI to exclude Loss of Supply and Force Majeure. SAIDI and SAIFI results prior to 2012 were not restated.

- The Net Cumulative Energy Savings measure is based on the 2015-2020 Conservation First Framework. The Electricity Distributor Scorecard was revised to show targets for the same period.

- The Net Cumulative Energy Savings results shown for 2017 will be confirmed by the IESO in Q3-2018.

- For the Electricity Distributor Scorecard, consistent with the evidence filed, Hydro One cannot provide targets for the measures in the Financial Ratios Performance Category or measures which are reported by third-parties[1].

- For the Dx OEB Scorecard, consistent with the evidence filed, and due to the denominator variable for OM&A Dollars per Customer and OM&A Dollars per km of Line, Hydro One cannot provide targets for 2018 to 2022. Please refer to Exhibit Q, Tab 1, Schedule 1, Attachment 1, p 16 for the OM&A budget for 2018 to 2022.

- 2017 results for measures in the Financial Ratios Performance Category of the Electricity Distributor Scorecard or in the Cost Control category of the Dx OEB Scorecards cannot be provided at this time.

- Targets for System Reliability Measures in the Dx OEB Scorecard beyond 2018 have not currently been developed (e.g. SAIDI & SAIFI for Urban, Rural).

[1] All measures contained in the Safety and Cost Control Performance Categories

Electricity Distributor Scorecard

Performance Outcomes	Performance Categories	Measures	ACTUALS 2011	2012	2013	2014	2015	2016	2017	TARGETS 2017	2018	2019	2020	2021	2022
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%	98.60%	98.06%	98.0%	98.0%	98.0%	98.0%	98.0%	98.0%
		Scheduled Appointments Met On Time	93.90%	98.60%	98.40%	99.30%	98.50%	99.50%	98.94%	99.0%	99.0%	99.0%	99.0%	99.0%	99.0%
		Telephone Calls Answered On Time	81.40%	83.40%	63.90%	69.60%	76.40%	74.20%	81.85%	80.0%	80.0%	80.0%	80.0%	80.0%	80.0%
	Customer Satisfaction	First Contact Resolution*			78.30%	79.00%	82.00%	82.00%	85.00%	85.0%	86.0%	87.0%	87.0%	88.0%	88.0%
		Billing Accuracy				94.63%	98.59%	99.04%	99.28%	99.0%	99.0%	99.0%	99.0%	99.0%	99.0%
		Customer Satisfaction Survey Results*			87.00%	85.00%	85.00%	84.00%	85.00%	86.0%	87.0%	87.5%	88.0%	88.5%	89.0%
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%	81.00%	81.00%	N/A	N/A	N/A	N/A	N/A	N/A
		Level of Compliance with Ontario Regulation 22/04 [1]	NI	NI	NI	NI	C	NI	C	C	C	C	C	C	C
		Serious Electrical Incident Index — Number of General Public Incidents	8	6	7	4	5	11	8	N/A	N/A	N/A	N/A	N/A	4
		Serious Electrical Incident Index — Rate per 10, 100, 1000km of line	0.066	0.051	0.059	0.033	0.042	0.091	0.007	N/A	N/A	N/A	N/A	N/A	N/A
	System Reliability**	Average Number of Hours that Power to a Customer is Interrupted [2]		6.98	6.88	7.49	7.65	7.83	7.95	7.5	7.0	6.7	6.4	6.1	5.8
		Average Number of Times that Power to a Customer is Interrupted [2]		2.61	2.49	2.70	2.63	2.47	2.32	2.6	2.4	2.3	2.2	2.1	2.0
	Asset Management	Distribution System Plan Implementation Progress*			Under Review	97%	116%	105%	103%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
	Cost Control	Efficiency Assessment		5	5	5	5	4	August	5	5	5	5	5	5
		Total Cost per Customer [3]	$1,072	$1,041	$1,046	$ 1,069	$ 983	$ 987	August	N/A, PEG	N/A, PEG	N/A, PEG	N/A, PEG	N/A, PEG	N/A, PEG
		Total Cost per km of Line [3]	$11,064	$10,741	$10,682	$ 10,916	$ 10,198	$ 10,551	August	N/A, PEG	N/A, PEG	N/A, PEG	N/A, PEG	N/A, PEG	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%	42.50%	60.50%***	60.5%	75.9%	88.9%	101.0%	N/A, See Footnote	N/A, See Footnote
	Connection of Renewable Generation	Renewable Generation Connection Impact Assessments Completed On Time	95.79%	99.39%	100.00%	100.00%	100.00%	100.00%	99.71%	99.0%	99.0%	99.0%	99.0%	99.0%	99.0%
		New Micro-embedded Generation Facilities Connected On Time			99.71%	100.00%	99.78%	99.22%	99.77%	99.0%	99.0%	99.0%	99.0%	99.0%	99.0%
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	0.80	0.55	N/A	N/A	N/A	N/A	N/A	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	1.46	1.39	N/A	N/A	N/A	N/A	N/A	N/A
		Profitability: Regulatory Return on Equity — Deemed (included in rates)	9.66%	9.66%	9.66%	9.66%	9.30%	9.19%	8.78%	N/A	N/A	N/A	N/A	N/A	N/A
		Profitability: Regulatory Return on Equity — Achieved	8.80%	8.72%	8.00%	6.26%	8.77%	8.41%	7.94%	N/A	N/A	N/A	N/A	N/A	N/A

Notes:
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 distributors' reported information. These figures were generated by the Board based on the total cost benchmarking analysis conducted by Pacific Economics Group Research, LLC and based on the distributor's annual 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. Since the Framework ends in 2020, the target for this application aligns with the end year of 2020.
*Self-defined metric; no common industry standard.
**System Reliability Measures were restated under the direction of the OEB to exclude both Loss of Supply and Force Majeure - results prior to 2012 were not restated.
***To be verified by the IESO.

Dx OEB Scorecard

										Target					
RRFE Outcomes		Measure	2011	2012	2013	2014	2015	2016	2017	2017	2018	2019	2020	2021	2022
Customer Focus	Customer Satisfaction	Customer Satisfaction - Perception Survey %	77%	78%	80%	67%	70%	66%	71%	72%	74%	75%	75%	76%	76%
		Handling of Unplanned Outages Satisfaction %	81%	79%	78%	75%	76%	75%	76%	76%	77%	78%	78%	79%	79%
		Call Centre Customer Satisfaction %	85%	84%	82%	81%	85%	86%	90%	86%	87%	88%	88%	89%	89%
		My Account Customer Satisfaction %	81%	84%	64%	75%	78%	79%	78%	81%	83%	84%	84%	85%	85%
Operational Effectiveness	Cost Control	Pole Replacement - Gross Cost Per Unit in $	8,541	8,441	7,824	8,928	8,392	8,350	8,431	8,640	8,733	8,908	9,080	9,256	9,437
		Vegetation Management - Gross Cyclical Cost per km $	New Program						7,888	New Program	3,600	3,643	3,687	2,400	2,428
		Station Refurbishments - Net Cost per MVA in $*	386,000	-	318,000	348,000	500,000	557,000	443,000	461,000	454,000	447,000	440,000	434,000	427,000
		OM&A dollars per customer	456	451	498	551	453	455	430	449	455	TBD	TBD	TBD	TBD
		OM&A dollars per km of line**	4,723	4,676	5,109	5,654	4,719	4,773	4,605	4,712	4,773	TBD	TBD	TBD	TBD
	System Reliability	Number of Line Equipment Caused Interruptions	7,681	7,316	7,266	8,311	8,164	7,674	8,786	8,200	8,200	TBD	TBD	TBD	TBD
		Number of Vegetation Caused Interruptions	6,113	6,953	5,791	6,540	6,944	7,439	7,800	6,900	6,500	TBD	TBD	TBD	TBD
		Number of Substation Caused Interruptions	159	144	129	158	141	103	123	145	145	TBD	TBD	TBD	TBD
		SAIDI - Rural - duration in hours	8.2	8.2	8.1	8.6	9.1	9.1	9.4	9.1	9.0	TBD	TBD	TBD	TBD
		SAIFI - Rural - frequency of outages	3.3	3.3	3.0	3.4	3.4	3.1	3.0	3.4	3.4	TBD	TBD	TBD	TBD
		SAIDI - Urban - duration in hours	2.7	3.2	2.2	2.8	2.8	2.4	2.4	2.8	2.8	TBD	TBD	TBD	TBD
		SAIFI - Urban - frequency of outages	1.6	1.7	1.6	2.3	1.4	1.6	1.4	1.7	1.7	TBD	TBD	TBD	TBD
		Large Customer Interruption Frequency (LDA's) - frequency of outages	New Measure		118	147	228	136	N/A***	143	143	TBD	TBD	TBD	TBD

*There were no station refurbishment units matching the criteria completed in 2012

**Number of line kms are based on the annual OEB Yearbook of Electricity Distributors' report, with 2017 and 2018 targets based on 2015 line km actuals.

***Please refer to Undertaking JT 3.1-1. Hydro One recommended a normalized metric and provided the 2017 actual results in the Undertaking response.

Association of Major Power Consumers in Ontario Interrogatory # 12

Issue:

Issue 19: Are the proposals for performance monitoring and reporting adequate and do the outcomes adequately reflect customer expectations?

Reference:

B1-01-01 Section 1.4 Page: 3 - Table 8 Distribution OEB Scorecard

Interrogatory:

a) Please update Table 8 to reflect 2017 actuals and any other evidence updates.
b) Please provide the calculation that underpins the 2011 to 2018 data for the following measures: pole replacement Gross Cost per Unit ($); Station Refurbishments Gross Cost per MVA ($).
c) Vegetation Management Measure: please provide the historical unit costs prior to the development of a new program.
d) Please provide the calculation for the most current Vegetation Management targets in 2017 and 2018.
e) Please provide the subset of asset outages that make up the total number of Line Equipment Caused Interruptions, i.e. provide the number of outages caused by each sub-equipment component for each of the years 2011 to 2017.
f) Does Vegetation Caused Interruption mean the same thing as Tree Contacts. If not please provide the inputs to the total number of Vegetation caused interruptions for the years 2011 to 2017, i.e. provide the type of vegetation caused outages on line equipment and the number of interruptions for each.
g) Does Vegetation Caused outages include vegetation outages during storm events that are not classified as Force Majeure events?
h) Please provide the subset of asset outages that make up the total number of Substation Caused Interruptions, i.e. provide the number of outages caused by each sub-equipment component for each of the years 2011 to 2017.
i) Please explain why Hydro One adjustments to the Vegetation Management program make year over year unit cost comparisons impossible.

Response:

Table 8 – Distribution OEB Scorecard, Revised for 2017 Actuals

RRFE Outcomes		Measure	2011	2012	2013	2014	2015	2016	2017
Customer Focus	Customer Satisfaction	Customer Satisfaction - Perception Survey %	77%	78%	80%	67%	70%	66%	71%
		Handling of Unplanned Outages Satisfaction %	81%	79%	78%	75%	76%	75%	76%
		Call Centre Customer Satisfaction %	85%	84%	82%	81%	85%	86%	90%
		My Account Customer Satisfaction %	81%	84%	64%	75%	78%	79%	78%
Operational Effectiveness	Cost Control	Pole Replacement - Gross Cost Per Unit in $	8,541	8,441	7,824	8,928	8,392	8,350	8,431
		Vegetation Management - Gross Cyclical Cost per km $			New Program				7,888
		Station Refurbishments - Net Cost per MVA in $*	386,000	-	318,000	348,000	500,000	557,000	443,000
		OM&A dollars per customer	456	451	498	551	453	455	430
		OM&A dollars per km of line**	4,723	4,676	5,109	5,654	4,719	4,773	4,605
	System Reliability	Number of Line Equipment Caused Interruptions	7,681	7,316	7,266	8,311	8,164	7,674	8,786
		Number of Vegetation Caused Interruptions	6,113	6,953	5,791	6,540	6,944	7,439	7,800
		Number of Substation Caused Interruptions	159	144	129	158	141	103	123
		SAIDI - Rural - duration in hours	8.2	8.2	8.1	8.6	9.1	9.1	9.4
		SAIFI - Rural - frequency of outages	3.3	3.3	3.0	3.4	3.4	3.1	3.0
		SAIDI - Urban - duration in hours	2.7	3.2	2.2	2.8	2.8	2.4	2.4
		SAIFI - Urban - frequency of outages	1.6	1.7	1.6	2.3	1.4	1.6	1.4
		Large Customer Interruption Frequency (LDA's) - frequency of outages	New Measure		118	147	228	136	N/A***

*There were no station refurbishment units matching the criteria completed in 2012
**Number of line kms are based on the annual OEB Yearbook of Electricity Distributors' report, with 2017 and 2018 targets based on 2015 line km actuals.
***Please refer to Undertaking JT 3.1-1. Hydro One recommended a normalized metric and provided the 2017 actual results in the Undertaking response.

a) The calculations that underpins the data for Pole Replacement Gross Cost per Unit ($) and Station Refurbishment Gross Cost per MVA ($) are provided in Exhibit B1, Tab 1, Schedule 1, DSP Section 1.4.1 (5.2.3 A and B) Methods and Measures, pp.6-7.

b) Please refer to Exhibit I-18-SEC-030.

d) The gross cyclical unit cost measure is based on the $3,000/km cost calculated by Clear Path in Exhibit Q, Tab 1, Schedule 1, Attachment 2, Section 5.2 Cost Modeling. The Clear Path estimate was increased by Hydro One by $600 to reflect the increased travel time between defects compared to historical programs, an increase in job planning costs to support the detailed workload data, and the expected transition costs outlined in Exhibit I-10-CME-027.

e) Hydro One does not report customer interruptions to the level of granularity required for equipment subcomponent failures.

f) Yes.

g) Specifically for Table 8 – Yes.

h) Hydro One does not report customer interruptions to the level of granularity required for equipment subcomponent failures.

i) Comparisons between the vegetation management strategy used up to 2016 and the new strategy outlined in Exhibit Q, Tab 1, Schedule 1 are possible. However, there are significant differences in the scope of work which account for the differences in unit prices. Comparisons are provided in attachment 4, Exhibit I-3-SEC-004, Hydro One Board Memo on the Optimal Cycle Protocol, Table 2 and Exhibit Q, Tab 1, Schedule 1, Attachment 2, Section 1.4 Forecast Workload and Cost.

Association of Major Power Consumers in Ontario Interrogatory # 22

Issue:

Issue 24: Does Hydro One's investment planning process consider appropriate planning criteria? Does it adequately address the condition of distribution assets, service quality and system reliability?

Reference:

B1-01-01 Section 2.1 Page: 32

Preamble: The evidence states that Hydro One performs a comparison between the actual investment costs and accomplishments and the proposed investment plan throughout the year and at the end of the investment plan years.

Interrogatory:

a) Please provide this analysis for the years 2014 to 2017.

b) Please provide the % of planned capital work undertaken for each of the years 2012 to 2017.

Response:

a) Please refer to Exhibit I-24-SEC-42 for the comparison between proposed and actual investment costs.

   Table 1 compares the accomplishments reflected in Hydro One's last custom distribution application (EB-2013-0416) and actual accomplishments. (Note that 2012-2014 were IRM years.)

Table 1

Asset/Project Type	ISD	2015 Variance	2016 Variance	2017 Variance
Transformer Replacements	S-01	2	-3	-1
Transformer Spares	S-01	14	-20	-21
MUS Trailer Replacements	S-02	-2	-3	-1
MUS Purchases	S-02	-1	-1	0
Stations targeted for Spill Containment	S-03	-1	-1	-2
Feeders identified for Recloser Upgrades	S-05	-13	-9	-8
Station Refurbishments	S-07	-8	-27	-29
Pole Replacements	S-10	237	-903	-3558
PCB Lines Equipment Replacements	S-11	-366	-653	-2200
Large Sustainment Initiatives	S-12	1	-5	-9
Development Capital - New Connections	D-01	-2391	87	1423
Development Capital - Service Upgrades	D-01	-594	-424	-719
Development Capital - Service Cancellations	D-01	-911	1670	-1556
Upgrades Driven by Load Growth	D-02	-9	-6	2
Asset Life Cycle Optimization and Operational Efficiency	D-05	-5	-3	0
Reliability Improvements	D-06	-1	-2	-1
Distribution Station Security Upgrades	C-05	-3	0	-3

b) For the 2013-2016 period, please refer to Tables 54-55 in section 3.2 of the DSP (Exhibit B1, Tab 1, Schedule 1) on pages 2509-2512 of 2930. For 2017 figures, please refer to Exhibit I-24-AMPCO-033. Note that 2012 was an IRM year, so no proposed figure is available.

Association of Major Power Consumers in Ontario Interrogatory # 33

Issue:

Issue 24: Does Hydro One's investment planning process consider appropriate planning criteria? Does it adequately address the condition of distribution assets, service quality and system reliability?

Reference:

B1-01-01 Section 3.6 Page: 1-3

Interrogatory:

a) Page 1 Table 63: Please update the table to reflect 2017 actuals and evidence updates and provide an excel version of the table.

b) Page 2: Please provide Hydro One's definition of end-of-life compared to expected service life.

c) Page 2: Please provide the annual amount ($) of System Access work: (1) deferred; (2) cancelled; and (3) advanced for each of the years 2012 to 2017.

d) Page 3: Please provide the annual amount ($) of System Service work: (1) deferred; (2) cancelled; and (3) advanced for each of the years 2012 to 2017.

Response:

a) An excel version of Table 63 with 2017 actuals can be found in the updated Exhibit I-24-AMPCO-33 Attachment 1.

b) Broadly speaking, end-of-life means that the asset's condition has deteriorated to the point that there is a significant probability of failure in the near term. Expected service life is how long an asset would be reasonably expected to remain in service from the time it is placed in service.

c) The majority of System Access investments are non-discretionary and Hydro One completes this work at a time specified by a third party (new customer, road authority, private land owner, etc.). Hydro One does not have discretion to advance, defer or cancel System Access spending.

d) OEB approved figures are not available for 2012-2014 as these were IRM years.

System Service work ($M)

	2015	**2016**	**2017**
Deferred	48.5	25.9	30.1[1]
Cancelled	0	0	0
Advanced	0	0	0

[1]2017 System Service deferred work includes $22M in General Plant funding for the 2017 Leamington TS Capital Contribution (EB-2013-0416, Exhibit D2-2-2 page 3 of 5) that was inaccurately categorized as System Service.

School Energy Coalition Interrogatory # 38

Issue:

Issue 24: Does Hydro One's investment planning process consider appropriate planning criteria? Does it adequately address the condition of distribution assets, service quality and system reliability?

Reference:

B1-01-01 Section 3.2, Tables 54-55

Interrogatory:

Please provide revised versions of Tables 54 and 55 by adding a column under the 2017 heading showing 2017 actuals.

Response:

I-24-SEC-038 Attachment 1 DSP_Table_54-57.xlsx contains revised versions of Tables 54 and 55 that include 2017 actuals.

School Energy Coalition Interrogatory # 42

Issue:

Issue 24: Does Hydro One's investment planning process consider appropriate planning criteria? Does it adequately address the condition of distribution assets, service quality and system reliability?

Reference:

B1

Interrogatory:

Please complete the shaded cells in the attached excel spreadsheet.

Response:

Please refer to the updated Exhibit I-24-SEC-42-01. The subtotals for 2015, 2016 and 2017 Sustainment, Development, Operations, Customer Service and Common Corporate Costs capital as well as the total capital shown in the attachment will not match up to those reflected in DSP Section 3.2 Table 55. This is because only investments included in EB-2013-0416 have been reported.

2018-2022 forecasts cannot be provided in the format presented. ISDs referenced in Exhibit I-24-SEC-42-01 are as per the 2013 filing; investments in future years are categorized into new ISD groups that cannot be accurately mapped to the old groups. For future forecasts of Sustainment, Development, Operations, Customer Service, and Common Corporate investments, please refer to DSP Section 3.2.

Witness: BRADLEY Darlene

OEB Staff Interrogatory # 159

Issue:

Issue 26: Does the Distribution System Plan address the trade-offs between capital and OM&A spending over the course of the plan period?

Reference:

B1-01-01 Section 3.8 Page: 2611 and 2617
(5.4.5.2) Attachments: Material Investments, ISD: SR-06 Distribution Station Refurbishment
EB-2013-0416 Exhibit D2/Tab2/Schedule 3 –S-07 Station Refurbishment

Interrogatory:

SR-06 Distribution Station Refurbishment

Start Date:	Q1 2018	**Priority:**	Medium
In-Service Date:	Program	**Plan Period Cost ($M):**	148.1
Primary Trigger:	Failure Risk		
Secondary Trigger:	Capacity Upgrade		

($ Millions)	2018	2019	2020	2021	2022	Total
Capital* and Minor Fixed Assets	16.2	31.8	36.4	37.1	37.8	159.3
Less Removals	1.1	2.2	2.5	2.6	2.6	11.1
Gross Investment Cost	**15.0**	**29.6**	**33.8**	**34.5**	**35.2**	**148.1**
Less Capital Contributions	0.0	0.0	0.0	0.0	0.0	0.0
Net Investment Cost	**15.0**	**29.6**	**33.8**	**34.5**	**35.2**	**148.1**

**Includes Overhead at current rates.*

a) Please explain how this program is related to and coordinated with SR-01 and SR-04.

b) Please confirm that the proposed distribution station refurbishment plan calls for an average of 15 distribution stations to be refurbished each year over the 5-year test period, for a total program spending of $148.1 million, even though this investment plan is identified as having medium priority.
    i. Please explain why so much investment is being planned for a medium priority program.

c) Is it possible for Hydro One to reduce the investment plan by refurbishing only the highest risk distribution stations, or by reducing the plan from 15 distribution stations per year to 10 stations per year over the 5-year test period?

d) In EB-2013-0416, the investment S-07 Station Refurbishment provided several stations planned for refurbishment. Several of these stations are repeated in this application, in investment SR-06 Distribution Station Refurbishment. Please provide an explanation why these stations were not completed as planned in the last application under investment S-07.

e) Please provide a list of stations refurbished in the last three years. The list should include the station name, estimated cost of the station refurbishment, actual cost of the station refurbishment, and an explanation for material variance between estimated and actual cost.

f) For each station refurbishment project provided for the last three year please provide the scope of work to be completed at each station.

Response:

a) All three programs address the replacement of station components but under different conditions, as summarized below. T hese three programs are coordinated during the investment planning process to ensure work is integrated and there is no duplication.

- SR-01 Distribution Stations Demand Capital program replaces major station components on an unplanned/demand basis where the component is failing or has already failed.
- SR-04 Distribution Station Component Replacement program replaces minor station components (switches, structures, station service, fencing and ground grid) on a planned basis based on the condition of the asset.
- SR-06 Distribution Station Refurbishment program replaces or refurbishes major station components (transformers, reclosers, high voltage and low voltage structures) on a planned basis based on the condition of the station assets.

b) Confirmed. As described in ISD SR-06 in Exhibit B1, Tab 1, Schedule 1, DSP Section 3.8; the distribution station refurbishment plan is a medium priority investment and calls for refurbishment of approximately 15 stations per year for a total cost of $148.1 million.

The program is considered a medium priority program in context to all the investments in the proposed plan based on the risk assessment and investment optimization of the Investment

Planning Process described in Exhibit B1, Tab 1, Schedule 1, Section 2.1.4.2. The funding level proposed for this program is based on maintaining the number of stations that are classified as high risk (based on condition assessments) at a stable level.

c) It is possible for Hydro One to target only 10 stations per year for refurbishment and refurbish the highest risk stations first. If 10 station refurbishments were completed per year the average age of the transformer fleet would increase and it is expected that the overall condition of the fleet would deteriorate. As the condition of the fleet deteriorates, it is expected that there would be a corresponding increase in transformer failures which would lead to increased costs in other investments such as: SR-01, SR-02 and SR-03. It is also expected that this will result in higher investment levels beyond the five year term which would be funded by future ratepayers.

d) Station refurbishment projects from EB-2013-0416 S-07 that appear in SR-06 of this application were deferred due to a reprioritization of investments. Please refer to interrogatory response Exhibit I-23-Staff-84 part (c) for further details on the reprioritization process.

e) & f) A list of stations refurbished in the last three years is provided in the table below detailing the costs and scope of work at each station. A variance explanation has been provided for all the material variances (>20%). The major causes for variance from the unit cost are that the unit cost did not consider the following items: dual transformer stations, additional requirements for 115kV connected stations, spill containment, significant expansion of existing station, and installing new HV and LV structures.

Station Name	In Service Year	Estimated Cost ($M)	Actual Cost ($M)	Variance ($M)	Variance Explanation	Scope
Wilsonville DS	2014	2.4	2.9	0.5	Increase as unit cost did not consider expansion of existing site with new HV and LV structures.	Install new 7.5MVA transformer with ULTC. Expand existing site, install new HV and LV structures, reclosers, fence, and ground grid.
Meaford DS #2	2014	2.4	2.8	0.4		Install new 7.5MVA transformer. Expand existing site, install new HV/LV and exit structures, reclosers, fence, and ground grid.
Brighton DS #2	2014	2.4	2.3	-0.1		Replace transformer with spare 7.5MVA unit. Install new reclosers and ground grid. Keep existing HV and LV structures.
Cache Bay DS	2014	2.4	2.3	-0.1		Install new 7.5MVA transformer with ULTC. Install new reclosers, ground grid and fence. Keep existing HV and LV structures.
Oxley DS	2014	2.4	2.3	-0.1		Install new 5MVA transformer. Install new HV and LV structures, reclosers, fence and ground grid. Acquire additional land.
Brockville Parkdale DS	2014	1.9	2.2	0.3		Install iMDS with 7.5MVA transformer. Install new civil structure, HV/LV ingress/egress, and ground grid.
Huntsville RS	2014	2.4	2.2	-0.2		Install new 25MVA regulator transformer with spill containment. Install new 4 pole regulating station structure, fence, ground grid
Berkeley DS	2014	1.0	0.5	-0.5	Decrease as unit cost did not consider use of a non-ULTC transformer.	Replace existing transformer (3 single phase units) with a new 5MVA 3 phase bank.
Currie DS	2014	2.4	1.7	-0.7	Decrease as unit cost did not consider use of a non-ULTC transformer.	Install new 7.5MVA transformer. Expand existing site, install new reclosers, fence, ground grid, LV and exit structures. Keep existing HV structure.

Station Name	In Service Year	Estimated Cost ($M)	Actual Cost ($M)	Variance ($M)	Variance Explanation	Scope
Bothwell DS #2	2014	2.4	0.9	-1.5	Decrease as unit cost did not consider the use of a spare transformer.	Replace transformer with a spare 5MVA unit. Install new reclosers and ground grid. Keep existing HV and LV structures.
Crow River DS	2015	2.4	6.4	4.0	Increase as unit cost did not consider dual transformer station or connection to 115kV system with revenue metering.	Install two new 7.5MVA new transformers. Expand existing site, install new fence, yard lighting, and ground grid. Modify existing LV structures to increase clearances. Install new revenue metering with transfer scheme.
Red Lake DS	2015	2.4	6.0	3.6	Increase as unit cost did not consider spill containment for 4 transformers.	Refurbish existing transformers. Install spill containment around 4 existing transformers. Expand existing site, install new LV exit structures, reclosers, fence and ground grid.
Abitibi Canyon DS	2015	2.4	5.4	3.0	Increase as unit cost did not consider dual transformer stations.	Refurbish two existing 5MVA transformers and re-install on new concrete pads. Install new LV MUS exit structures, reclosers, station fence, and ground grid. Keep existing HV/LV structures. Soil remediation as required
Kirkland Lake Woods DS	2015	2.4	3.7	1.3	Increase as unit cost did not consider expansion of existing site with new LV and exit structures.	Install spare 5MVA transformer and switchgear Expand existing site, install new LV structure, exit structure, reclosers, fence, and ground grid. Keep HV structure.
Trenton Bay DS	2015	2.4	4.2	1.8	Increase as unit cost did not consider expansion of existing site with new HV and LV structures and demolition of existing building.	Install new 7.5MVA transformer with ULTC. Install new HV and LV structures, reclosers, ground grid and fence. Acquire new land. Demolish building that contained the equipment.
Barwick DS	2015	2.4	4.5	2.1	Increase as unit cost did not consider dual transformer stations.	Install two 6MVA repaired transformers. Expand existing site, install new reclosers, fence and ground grid. Keep existing HV and LV structures.

Witness: GARZOUZI Lyla

Station Name	In Service Year	Estimated Cost ($M)	Actual Cost ($M)	Variance ($M)	Variance Explanation	Scope
Nestor Falls DS	2015	2.4	3.5	1.1	Increase as unit cost did not consider expansion of existing site or connection to 115kV system with revenue metering.	Install new 7.5MVA transformer with ULTC. Expand existing site, install new HV and LV structures, reclosers, fence, and ground. Incorporate revenue metering to new design including at MUS facilities.
Kemble DS	2015	2.4	3.0	0.6	Increase as unit cost did not consider expansion of existing site and dual transformer stations.	Install two new 7.5MVA transformers. Expand existing site, install new LV exit structures, reclosers, fence, and ground grid. Keep existing HV and LV structures.
Longlac West DS	2015	2.4	2.9	0.5	Increase as unit cost did not consider expansion of existing site.	Install new 10MVA transformer and spare regulator transformer with new 4 pole structure. Expand existing site, install new recloser, fence. Keep existing HV and LV structures.
Bobcaygeon Duke DS	2015	2.4	3.3	0.9	Increase as unit cost did not consider reengineering of structure to mount new components and establishing proper grounding in bedrock.	Install new 7.5MVA transformer. Replace fuses with reclosers. Keep existing HV and LV structures.
Campbellford Industrial DS	2015	1.9	2.3	0.4	Costs higher than anticipated as this was part of iMDS pilot program.	Install new iMDS with 5MVA transformer. Install new civil structure, HV/LV ingress/egress, and ground grid.
Merlin DS	2015	2.4	2.8	0.4		Install new 5MVA transformer with ULTC. Expand existing site, install new reclosers, fence, ground grid. Keep existing HV/LV structures.
Tilbury Peltier DS	2015	2.4	2.6	0.2		Install new 5MVA transformer. Expand existing site, install new HV and LV structures, reclosers, fence, and ground grid.
Meaford Thompson DS	2015	1.9	2.4	0.5	Costs higher than anticipated as project was part of iMDS pilot.	Install new iMDS with 5MVA transformer. Install new civil structure, HV/LV ingress/egress, fence and ground grid.

Witness: GARZOUZI Lyla

Station Name	In Service Year	Estimated Cost ($M)	Actual Cost ($M)	Variance ($M)	Variance Explanation	Scope
Lindsay Eastview DS	2015	1.9	2.3	0.4		Install new iMDS with 5MVA transformer. Install new civil structure, HV/LV ingress/egress.
Maxville George DS	2015	2.4	2.3	-0.1		Install new 7.5MVA transformer. Expand existing site, install new reclosers, fence, ground grid. Keep existing HV/LV structures.
Aguasabon DS	2015	1.0	0.9	-0.1		Replace existing hot spare transformer with new 7.5MVA unit.
St.Williams DS	2015	2.4	2.2	-0.2		Install new 7.5MVA transformer with ULTC. Expand existing site, install new HV and LV structures, reclosers, fence and ground grid.
Geraldton South DS	2015	1.9	2.1	0.2		Install new iMDS with 5MVA transformer. Install new civil structure, HV/LV ingress/egress, fence and ground grid.
Bolsover DS	2015	2.4	2.2	-0.2		Install new 7.5MVA transformer. Install new reclosers and ground grid. Keep existing HV and LV structures.
Meaford Louisa DS	2015	1.9	2.1	0.2		Install new iMDS with 5MVA transformer. Install new civil structure, HV/LV ingress/egress, fence and ground grid.
Larder Lake DS	2015	2.4	2.5	0.1		Replace transformer with a spare 5MVA unit. Replace fuses with reclosers. Install new ground grid. Keep existing HV and LV structures.
Essex DS	2015	2.4	2.0	-0.4		Install new 5MVA transformer with ULTC. Install new reclosers, ground grid and fence. Keep existing HV and LV structures.
Owen Sound 3rd Ave DS	2015	1.9	1.8	-0.1		Install new iMDS with 5MVA transformer. Install new civil structure, HV/LV ingress/egress.

Station Name	In Service Year	Estimated Cost ($M)	Actual Cost ($M)	Variance ($M)	Variance Explanation	Scope
Trenton Frankford DS	2015	1.9	1.8	-0.1		Install new iMDS with 7.5MVA transformer. Install new civil structure, HV/LV ingress/egress, fence.
Havelock Industrial DS	2015	1.9	1.7	-0.2		Install new iMDS with 5MVA transformer. Install new civil structure, HV/LV ingress/egress.
Highgate DS	2015	2.4	1.6	-0.8	Decrease as unit cost did not consider use of a non-ULTC transformer.	Install new 5MVA transformers. Expand existing site, install new reclosers, fence, ground grid. Keep existing HV / LV structures.
Otonabee DS	2015	2.4	1.5	-0.9	Decrease as unit cost did not consider the use of a spare transformer.	Install spare 5MVA transformer. Install new reclosers and ground grid. Keep existing HV/ LV structures.
Kenogami DS	2015	2.4	1.7	-0.7	Decrease as unit cost did not consider the use of a spare transformer.	Install spare 10MVA transformer and reclosers. Keep existing HV and LV structures.
Lindsay Eglinton DS	2016	2.4	7.4	5.0	Increase as unit cost did not consider spill containment, soil remediation and landscaping required to obtain approval from municipality.	Install new 5MVA transformer with spill containment. Install new LV structure, reclosers, and ground grid. Keep HV structure. Complete soil remediation and landscaping.
Deep River DS	2016	2.4	5.1	2.7	Increase as unit cost did not consider dual transformer station or connection to 115kV system with revenue metering.	Install two new 7.5MVA transformers with ULTC. Install new reclosers, fence and ground grid. Keep existing HV and LV structures.
Shining Tree DS	2016	2.4	4.2	1.8	Increase as unit cost did not consider expansion of existing site or connection to 115kV system with revenue metering.	Install new 7.5MVA transformer with ULTC. Expand existing site, install new LV structures, reclosers, fence and ground grid. Keep existing HV structures. Reconfigure existing metering to accommodate new structure and MUS facilities.
Little Current DS	2016	2.4	3.8	1.4	Increase as unit cost did not consider development of new land, new HV and LV structures.	Install new 7.5MVA transformer with ULTC, Install new HV and LV structures, reclosers, ground grid, fence, drainage. Acquire new land.

Witness: GARZOUZI Lyla

Station Name	In Service Year	Estimated Cost ($M)	Actual Cost ($M)	Variance ($M)	Variance Explanation	Scope
Wyoming Churchill DS	2016	2.4	3.7	1.3	Increase as unit cost did not consider expansion of existing site with new HV and LV structures.	Install new 5MVA transformer with ULTC. Expand existing site, install new HV and LV structures, reclosers, fence, and ground grid.
Perrault Falls DS	2016	2.4	3.9	1.5	Increase as unit cost did not consider expansion of existing site, new HV and LV structures and connection to 115kV system with revenue metering.	Install new 7.5MVA transformer with ULTC. Expand existing site, install new HV/ LV structures, reclosers, fence, ground grid, new revenue metering to meter at main structure and MUS facilities.
Fiddlers Green DS	2016	2.4	3.1	0.7	Increase as unit cost did not consider expansion of existing site with new HV and LV structures.	Install new 7.5MVA transformer with ULTC. Expand existing site, install new HV and LV structures, reclosers, fence, and ground grid.
Brockville Water DS	2016	2.4	3.0	0.6	Increase as unit cost did not consider non-standard stations with minimal space requiring unique design.	Install new 7.5MVA pad mount transformer. Remove existing switchgear and install pad mount reclosers.
Appin DS	2016	2.4	2.8	0.4		Install new 5MVA pad mount transformer. Install new HV and LV structures, reclosers, fence and ground grid. Acquire additional land. Remove approximately 1km of off road 28kV circuit and replace with 600m of on road circuit.
Abbey DS	2016	2.4	2.5	0.1		Install new 5MVA transformer with ULTC. Install new transformer pad, reclosers, ground grid and fence. Keep existing HV/LV structures.
Post Creek DS	2016	2.4	2.2	-0.2		Install new 7.5MVA transformer with ULTC. Expand existing site, install new HV and LV structures, reclosers, fence, and ground grid.
Dorchester DS	2017	2.4	1.4	-1.0	No site expansion, no new structures.	At existing site replace transformer with a new 5MVA unit. Install new reclosers and ground grid. Keep existing HV and LV structures.

Station Name	In Service Year	Estimated Cost ($M)	Actual Cost ($M)	Variance ($M)	Variance Explanation	Scope
Newboro DS	2017	2.4	2.2	-0.2		At existing site replace transformer with a new 7.5MVA unit. Install new LV structure, reclosers and station ground. Keep existing HV structure and fence.
Plattsville DS	2017	2.4	3.1	0.7	Development of new land, new HV and LV structures.	Acquire new land and install new HV and LV structures, 5MVA transformer with ULTC, reclosers, ground grid, fence and drainage. Remove all equipment from existing site.
Lindsay Denniston DS	2017	1.9	2.4	0.5	Site expansion required to fit iMDS.	Expand existing site install new civil structure, HV/LV ingress/egress and iMDS with 5MVA transformer. Remove existing HV structure, switchgear and transformer.
Whitney DS	2017	2.4	2.9	0.5	Expansion of existing site and addition of exit structures.	Expand existing site, install new fence and ground grid. Install new 7.5MVA transformer with ULTC. Keep existing HV and LV structures. Add LV exit structures. Replace existing reclosers.

Building Owners and Managers Association Toronto Interrogatory # 24

Issue:

Issue 28: Has Hydro One appropriately incorporated Regional Planning in its Distribution System Plan?

Reference:

A-03-01 Page: 26 Table 9

Interrogatory:

a) Why is the general plant forecast consistently substantially underestimated over the years 2015, 2016, and 2017? Please explain fully.

b) What have system renewal expenditures been to September 30, 2017, or the most recent date you have? What is the most current forecast for 2017 year end capex (the 252.2 on year end 2016 estimate)?

Response:

a) Please refer to Exhibit I-29-Staff-165 part (c).

b) Refer to the updated Exhibit I-24-SEC-38.

Canadian Manufacturers & Exporters Interrogatory # 24

Issue:

Issue 29: Are the proposed capital expenditures resulting from the Distribution System Plan appropriate, and have they been adequately planned and paced?

Reference:

B1-01-01 Section 3.2 Page 1 and 2, Table 54 and 55

Interrogatory:

a) If possible, please provide updates to Table 54 and 55 with 2017 actuals.

b) If that information is not available, when will it become available?

Response:

a) Refer to the updated I-24-SEC-038.

b) N/A

School Energy Coalition Interrogatory # 65

Issue:

Issue 29: Are the proposed capital expenditures resulting from the Distribution System Plan appropriate, and have they been adequately planned and paced?

Reference:

B1

Interrogatory:

Please provide a chart that shows for each material capital project undertaken between 2015 and 2017, its original forecasted cost to be incurred in 2015-2017 and its actual cost. Please provide an explanation for all variances +/- 5%

Response:

2017 actuals have been provided in the updated documents referenced below.

For Distribution Station Refurbishments please refer to Exhibit I-26-Staff-159, part f).

For Distribution Lines Sustainment initiatives please refer to Exhibit I-24-Staff-115, part b).

For Life Cycle Optimization and Operational Efficiency Projects and Reliability Improvements please refer to Exhibit I-29-SEC-65, Attachment 1.

For System Upgrades Driven by Load Growth please refer to Exhibit I-30-Staff-175, part a)

Past Filing (2015-2019)				Current Project Identification Infromation		
Exhibit	Project Description	Year (2013 filing)	Cost $M (2013 filing)	Status	Cost ($M)	Cost Variance (short)
EB-2013-D2-2-3 Ref#D-05	44kV Extension to Coniston, Sudbury	2015	2.8	completed 2017	2.8	
EB-2013-D2-2-3 Ref#D-05	Belle River DS Voltage Conversion, Belle River	2015	1.1	completed 2017	2.1	More detailed cost estimate was developed.
EB-2013-D2-2-3 Ref#D-05	Mattawa Voltage Converson, Mattawa	2015	1	completed 2017	3.0	More detailed cost estimate was developed.
EB-2013-D2-2-3 Ref#D-06	Allanburg TS M7 Feeder Upgrades, Thorold	2015	1	Need met through another project	NA	Need met through another project, M6 tie to offload some M7 load.
EB-2013-D2-2-3 Ref#D-06	Brant TS M21 to Wolverton DS F1 Tie Line	2019	1.2	Need met through another project	NA	Met objective with more cost effective altenative with project cost under $1M.
Life Cycle Optimization not Identified in Plan	Bob-Lo DS Voltage Conversion	NA	NA	completed 2017	2.4	NA
Life Cycle Optimization not Identified in Plan	Edgeware TS M3 - Re-establishment	NA	NA	completed 2017	2.1	NA
Life Cycle Optimization not Identified in Plan	Port Arthur M6 Resupply of Port Arthur f2	NA	NA	completed 2015	1.7	NA
Life Cycle Optimization not Identified in Plan	Bobcaygeon Area Study Implementation	NA	NA	completed 2016	1.4	NA

OEB Staff Interrogatory # 175

Issue:

Issue 30: Are the proposed capital expenditures for System Renewal, System Service, System Access and General Plant appropriately based on the Distribution System Plan?

Reference:

B1-01-01 Section 3.8 Page: 2662
(5.4.5.2) Attachments: Material Investments, ISD: SS-02 System Upgrades Driven by Load Growth
EB-2013-0416 Exhibit D2/Tab2/Schedule 3 –D-02 System Upgrades Driven by Load Growth

Interrogatory:

"Investment Need:
Over time, new customers connect to the system, and load growth occurs as a result. This also occurs due to increased loading at some existing customers who may increase their service sizes. This places additional stress on the elements of the distribution system. Increases in distribution station and feeder loading can lead to system elements operating at or exceeding their maximum equipment ratings or violate other planning criteria such as voltage or protection limits during periods of heavy load."

a) Please provide in Excel format a list of projects from EB-2013-0416 D-02 System Upgrades Driven by Load Growth completed in the last three years. This list should include the project name, forecast project cost, actual project cost, and explanation for material cost variances.

b) Is a business case available for each of the projects listed in ISD SS-02? If no, please provide an explanation as to why not. If yes, please provide the business case(s). It is expected the business case(s) will address the following items:

- List of assets at end-of-life, complete with asset technical specifications, asset analytic results, age, and recent deficiency reports
- Reliability metrics for stations and feeders involved in each project
- Station and feeder capacity
- Number of customers affected
- Proposed options, including scope of work, benefits, costs, and expected efficiency savings.

c) There are several projects that are listed in EB-2013-0416 D-02 System Upgrades Driven by Load Growth for the years 2015-2017 that seem to be repeated in SS-02 System Upgrades Driven by Load Growth. Please explain why the repeat projects were not completed in the approved year and provide an explanation on where the approved capital was spent in place of these projects.

d) For each project identified in (c) please provide the business case(s) used in EB-2013-0416 with the same information requested in (b).

Response:

a) Please refer to Attachment 1 of this Exhibit for a list of projects from EB-2013-0416 D-02 System Upgrades Driven by Load Growth completed in the last three years.

b) No. A business case summary document is prepared after the individual project has been determined to be a priority and for the purposes of authorizing the expenditure of funds for execution. At this point in time, most of the SS-02 System Upgrades Driven by Load Growth projects are planned to be in service at a future date beyond which necessitates the production of a Business Case for the purpose of authorizing the expenditure of funds for execution. Business Cases that are available can be found in Attachment 2 of this Exhibit.

c) These projects were not completed as capital was redirected to other higher priority capital investments through Hydro One’s Investment Planning Process. DSP Section 2.1 explains Hydro One’s Investment Planning Process in detail. As described in DSP Section 2.1 this process occurs on an annual basis, “Hydro One’s planning process is an ongoing cyclical process that develops an annual budget for OM&A and capital investments and a five-year planning forecast consistent with the Board’s filing requirement of a consolidated five-year capital plan. All investments follow this same process.” The redirected capital for these projects funded part of Hydro One’s total 2015 and 2016 actual and 2017 forecast capital expenditures. DSP Section 3.6 summarizes the result of implementing the cyclical investment planning process. DSP Section 3.6.1 summarizes the variances between forecast and historical budgets by OEB Investment Category.

d) A business case summary document is prepared after the individual project has been determined to be a priority and for the purposes of authorizing the expenditure of funds for execution. There are no Business Cases available for the projects identified in part c) as they were reprioritized and did not require authorization for the expenditure of funds for execution between 2015 and 2017.

In Reference to Exhibit EB-2013-D2-2-3 Ref#D-02			**Current Project Status**		
Project Description	**Year**	**Cost Estimate ($M)**	**Status**	**Cost ($M)**	**Cost Variance**
Clark TS M2 Feeder Reinforcement, Ilderton	2015	2.1	Completed	1.5	Scope was reduced based on more detailed engineering analysis.
Commerce Way TS M3 Feeder Reinforcement, Woodstock Surrounding Area	2015	2.1	Completed	2.6	More detailed cost estimate was developed.
Courtice DS Upgrades, Courtice, Clarington Township	2015	3	Completed	3.8 Note 2	More detailed cost estimate was developed.
Courtice DS Voltage Conversion, Courtice, Clarington Township	2015	1.8	Completed		
Nobleton DS Upgrade, Nobleton, King Township	2015	3	Completed 2017	5.0	More detailed cost estimate was developed.
Owen Sound TS M28 Feeder Reinforcement, Northern Bruce Pennisula	2015	1	Completed 2017	1.2	
Brown Hill TS New Feeder Development, Queensville, East Gwillimbury	2015	3.5	Completed 2017	8.4 Note 1	More detailed cost estimate was developed.
Brown Hill TS M4 Feeder Reinforcement, Georgina Township	2016	1.9	Completed 2017		
Allanburg TS M7 Feeder Reinforcement, Thorold	2016	1	Need met by another project	N/A	Need met through another project. Tie made to M6 to offload M7
Beckwith DS Upgrades, South of Carleton Place (Mississippi Mills)	2016	2.2	Complete	2.7	More detailed cost estimate was developed.
Massey DS F3 Feeder Reinforcement, North Shore Algoma	2016	1	Completed	1.5	More detailed cost estimate was developed.

Note 1:
Note 2: Combined project cost for both Courtice DS Upgrades and Courtice DS Voltage Conversion.

Building Owners and Managers Association Toronto Interrogatory # 153

Issue:
Issue 32: Are the methodologies used to determine the distribution Overhead Capitalization Rate for 2018 and onward appropriate?

Reference:
Financial Statements

Interrogatory:
a) Please provide copies of HONI's first quarter and second quarter financial statements, and when available (likely around November 7, 2017), its third quarter financial statements, including the MDAs and press releases.

b) The June 30, 2017 statement shows that assets placed in service by June 30, 2017 were $310 million. What is the most recent estimate (with date) of 2017 year end assets in service? The same document shows first half capex at $289 million. What is the most recent estimate (to date) of 2017 year end capex?

c) In the second quarter (p1), p1 states that security deposits were returned to customers with positive payment history. How many customers in each rate class received return of security deposits? What was the total dollar amount of deposits returned? Were the security deposits held in trust or otherwise separated from cash on hand?

Response:
a) Hydro One Networks does not have quarterly financial statements. The Hydro One Limited and Hydro One Inc. first, second and third quarter financial statements, MD&A and press release are provided.

b) 2017 Hydro One Inc. and Hydro One Limited Financial Statements and MD&A are provided in the updated Exhibit I, Tab 1, Schedule SEP-1 Attachments 1 to 4

c) Hydro One returned all security deposits for residential customers regardless of payment history, amounting to $1.7 million. Furthermore, Hydro One no longer requires a security deposit for residential customers. For general service customers, Hydro One returned security deposits to any customer with good payment history in the last 12 months. This amounted to $10.7 million. The security deposits were held in Hydro One's account. The security deposits were not held-in-trust or in a segregated account.

Association of Major Power Consumers in Ontario Interrogatory # 52

Issue:

Issue 33: Are the amounts proposed for the rate base from 2018 to 2022 appropriate?

Reference:

D1-01-02 In Service Additions

Interrogatory:

a) Please update Tables 1 and 2.

Response:

a) Table 1 below has been updated with 2017 Actuals.

Table 1: In-Service Capital Additions 2013-2017 ($M)
OEB Approved and Actual/Forecast (updated for 2017 Actuals)

	Historic								Bridge		
	2013	2014	2015			2016			2017		
	Actual		OEB Approved	Actual	Variance	OEB Approved	Actual	Variance	OEB Approved	Actual	Variance (Act)
Sustaining	296.6	324.8	294.2	420.2	126.0	311.9	371.1	59.2	335.7	322.8	-13.0
Development	194.1	187.6	218.9	216.9	-2.0	200.8	168.3	-32.5	211.2	216.5	5.3
Operations	1.4	5.0	11.1	7.0	-4.1	8.1	-0.3	-8.4	16.4	14.0	-2.4
Customer Service	13.9	1.4	46.0	16.6	-29.4	20.6	6.5	-14.1	27.7	10.9	-16.7
Common & Other	223.4	96.6	86.5	100.5	14.1	80.4	109.3	28.9	105.0	116.8	11.8
Total	**729.3**	**615.3**	**656.7**	**761.3**	**104.6**	**621.8**	**654.9**	**33.2**	**696.0**	**681.0**	**-15.0**

Please refer to Exhibit Q, Tab 1, Schedule 1 Table 6 (filed 2017-12-21) for an updated In-Service Capital Addition forecast.

School Energy Coalition Interrogatory # 67

Issue:

Issue 33: Are the amounts proposed for the rate base from 2018 to 2022 appropriate?

Reference:

D1-01-01 Tables 1-4

Appendix 2-BA

Interrogatory:

Please provide an update to the following tables and appendices to reflect 2017 actuals:

a) [D1-1-1] Tables 1-4

b) Appendix 2-BA

Response:

a) Please see tables 1-4 below based on information presented in Exhibit Q and updated to reflect 2017 actuals:

Table 1: 2017 Board-approved versus 2017 Historic Year Forecast Rate Base (Updated for 2017 Actuals) ($ Millions)

Rate Base Component	2017 Historic Year	2017 Board-approved	Variance
Mid-Year Gross Plant	11,296.7	11,239.1	57.6
Less: Mid-Year Accumulated Depreciation	(4,250.4)	(4,311.7)	61.3
Mid-Year Net Utility Plant	7,046.3	6,927.4	118.9
Cash Working Capital	310.2	255.7	54.5
Materials & Supply Inventory	4.0	6.8	(2.7)
Total Rate Base	**7,360.5**	**7,189.9**	**170.7**

Witness: JODOIN Joel

Table 2: Distribution Rate Base (Updated for 2017 Actuals) ($ Millions)

Description	Test				
	2018	**2019**	**2020**	**2021**	**2022**
Mid-Year Gross Plant	11,834.3	12,413.5	13,072.2	13,917.1	14,595.9
Mid-Year Accumulated Depreciation	(4,468.7)	(4,703.5)	(4,972.4)	(5,317.5)	(5,646.5)
Mid-Year Net Plant	**7,365.6**	**7,710.0**	**8,099.8**	**8,599.6**	**8,949.4**
Cash Working Capital	321.2	335.7	348.3	378.5	395.3
Materials and Supply Inventory	4.1	5.5	6.5	5.9	5.5
Distribution Rate Base	**7,690.9**	**8,051.2**	**8,454.5**	**8,984.0**	**9,350.2**

Table 3: Continuity of Fixed Assets Summary - Rate Base (Updated for 2017 Actuals) ($ Millions)

Description	Historic Years			
	2014	**2015**	**2016**	**2017**
Opening Gross Asset Balance	9,256.2	9,832.0	10,533.1	11,087.3
In-Service Additions	623.7	755.3	654.8	687.2
Retirements	(38.7)	(36.1)	(87.6)	(127.2)
Sales	(10.2)	(18.5)	(15.2)	(24.8)
Transfers	1.0	0.4	2.1	2.6
Closing Gross Asset Balance	**9,832.0**	**10,533.1**	**11,087.3**	**11,625.1**
Less Future Use Land	(0.3)	(0.3)	(1.3)	(1.3)
Less Provincial Funded Assets	(28.4)	(42.9)	(56.3)	(60.1)
Gross Asset Balance for Mid-Year Rate Base	**9,803.3**	**10,489.9**	**11,029.6**	**11,563.7**

Table 4: Forecast of Fixed Assets Summary - Rate Base (Updated for 2017 Actuals)
($ Millions)

Description	Test	Forecast			
	2018	**2019**	**2020**	**2021**	**2022**
Opening Gross Asset Balance	11,625.1	12,171.4	12,792.8	13,496.3	14,313.3
Integration of Acquired Utilities				175.6	
In-Service Additions	635.1	755.2	748.5	704.6	784.4
Retirements	(89.4)	(134.4)	(45.6)	(63.9)	(62.7)
Sales	0.0	0.0	0.0	0.0	0.0
Transfers	0.6	0.6	0.6	0.6	0.0
Closing Gross Asset Balance	**12,171.4**	**12,792.8**	**13,496.3**	**14,313.3**	**15,035.0**
Less Future Use Land	(1.3)	(1.3)	(1.3)	(1.3)	(1.3)
Less Provincial Funded Assets	(65.3)	(69.3)	(72.7)	(75.6)	(78.2)
Gross Assets for Mid-Year Rate Base	**12,104.8**	**12,722.2**	**13,422.3**	**14,236.4**	**14,955.5**
Mid-Year Gross Asset Balance (1)	**11,834.3**	**12,413.5**	**13,072.2**	**13,829.3**	**14,595.9**

Notes: (1) Mid-year gross asset balance is calculated only for the test years.

b) Please refer to the filed MS Excel I-33-SEC-067-01 which includes asset continuity schedule for 2014-2022 updated for 2017 actuals.

Association of Major Power Consumers in Ontario Interrogatory # 37

Issue:

Issue 38: Are the proposed OM&A spending levels for Sustainment, Development, Operations, Customer Care, Common Corporate and Property Taxes and Rights Payments, appropriate, including consideration of factors considered in the Distribution System Plan?

Reference:

C1-01-02 Tables 1 - 5

Interrogatory:

a) Please update Tables 1 to 5 with 2017 actuals.

Response:

a) Please see below for the updated Tables 1 to 5 to reflect the 2017 actuals.

Table 1: Summary of Sustaining OM&A ($ Millions)

Description	Historic					Bridge		Test
	2014	2015		2016		2017		2018
	Actual	Actual	Approved	Actual	Approved	Actual	Approved	Forecast
Stations	25.7	25.3	27.6	23.8	28.4	23.9	28.9	24.8
Lines	145.2	144.7	141.3	141.4	149.7	135.5	152.4	153.8
Meters, Telecom and Control	14.2	16.6	18.5	16.2	18.7	18.4	18.5	18.6
Vegetation Management	140.6	118.0	129.0	142.3	164.6	126.9	167.3	149.6
Total	**325.7**	**304.6**	**316.5**	**323.7**	**361.4**	**304.7**	**367.1**	**346.7**

Table 2: Stations Sustaining OM&A ($ Millions)

Description	Historic					Bridge		Test
	2014	2015		2016		2017		2018
	Actual	Actual	Approved	Actual	Approved	Actual	Approved	Forecast
Stations Demand and Planned Corrective Maintenance	8.2	10.3	9.4	10.3	10.0	11.0	10.2	9.8
Planned Preventive Station Maintenance	8.7	9.1	12.5	9.5	12.2	8.3	12.4	10.8
Land Assessment and Remediation	8.8	6.0	5.7	4.0	6.2	4.6	6.3	4.1
Total	**25.7**	**25.3**	**27.6**	**23.8**	**28.4**	**23.9**	**28.9**	**24.8**

Table 3: Lines Sustaining OM&A ($Millions)

Description	Historic					Bridge		Test
	2014	2015		2016		2017		2018
	Actual	Actual	Approved	Actual	Approved	Actual	Approved	Forecast
Trouble Calls	77.1	72.9	64.8	68.8	65.9	67.3	67.7	77.9
Underground Cable Locates	23.8	20.9	17.9	10.9	17.4	11.6	16.9	14.6
Disconnects/ Reconnects	11.9	12.5	9.7	13.5	9.9	13.9	10.1	12.5
Line Maintenance	12.3	14.9	23.5	19.1	23.9	11.1	24.4	17.5
PCB Equipment and Waste Storage	5.1	7.7	11.3	10.8	18.3	12.7	18.7	15.4
Other Services	15.0	15.8	14.1	18.4	14.3	18.9	14.7	15.8
Total	**145.2**	**144.7**	**141.3**	**141.4**	**149.7**	**135.5**	**152.4**	**153.8**

Table 4: Meters, Telecom and Control Sustaining OM&A ($ Millions)

Description	Historic					Bridge		Test
	2014	2015		2016		2017		2018
	Actual	Actual	Approved	Actual	Approved	Actual	Approved	Forecast
Retail Revenue Meters	8.4	10.9	12.6	10.7	12.7	11.3	12.3	9.1
Wholesale Revenue Meters	2.2	2.1	2.4	1.8	2.4	2.1	2.5	3.1
Telecom, Monitoring and Control	3.5	3.6	3.5	3.7	3.6	5.0	3.7	6.4
Total	**14.2**	**16.6**	**18.5**	**16.2**	**18.7**	**18.4**	**18.5**	**18.6**

Table 5: Vegetation Management Sustaining OM&A ($ Millions)

Description	Historic					Bridge		Test
	2014	2015		2016		2017		2018
	Actual	Actual	Approved	Actual	Approved	Actual	Approved	Forecast*
Landowner Notification	9.2	6.6	7.3	6.9	10.1	0.0	10.0	0.0
Line Clearing	97.9	93.7	82.4	87.4	104.6	0.0	107.3	0.0
Brush Control	23.9	7.7	31.6	35.0	42.8	0.0	42.8	0.0
Cycle Clearing	0.0	0.0	0.0	0.0	0.0	80.8	0.0	79.9
Tactical Maintenance	0.0	0.0	0.0	0.0	0.0	20.3	0.0	57.4
Demand Vegetation Management	9.5	9.9	7.4	13.0	6.8	17.6	6.9	10.2
Hazard Tree Removal	0.2	0.0	0.3	0.0	0.3	8.2	0.3	2.1
Total	**140.6**	**118.0**	**129.0**	**142.3**	**164.6**	**126.9**	**167.3**	**149.6**

** As noted in Exhibit Q, Tab 1, Schedule 1, Hydro One has reorganized the structure of the vegetation management program focusing on a defect approach that maintains corridors on a three-year cycle. This new vegetation management strategy will consist of three components: (i) defect correction program; (ii) public safety and reliability program; and (iii) quality assurance and quality control program.*

Consumers Council of Canada Interrogatory # 36

Issue:

Issue 38: Are the proposed OM&A spending levels for Sustainment, Development, Operations, Customer Care, Common Corporate and Property Taxes and Rights Payments, appropriate, including consideration of factors considered in the Distribution System Plan?

Reference:

A-04-01 Page 6

Interrogatory:

Please provide a detailed budget for the 2018 External Relations Department. Please provide the actual costs incurred by this department in 2015, 2016, and 2017.

Response:

The costs for the External Relations department throughout 2015 to 2018 are as outlined below:

- 2015 Actual Costs – $1.9M
- 2016 Actual Costs – $1.9M
- 2017 Actual Costs – $2.8M including just under $1M for corporate memberships (which were distributed through several different groups and have now been consolidated).
- 2018 Budget – $2M

School Energy Coalition Interrogatory # 69

Issue:

Issue 38: Are the proposed OM&A spending levels for Sustainment, Development, Operations, Customer Care, Common Corporate and Property Taxes and Rights Payments, appropriate, including consideration of factors considered in the Distribution System Plan?

Reference:

C1-01-01
C1-01-02

Interrogatory:

For each of the following tables, please add a column, showing 2017 actuals to the end of Q3.

a) C1-1-1, p.2, Table 1

b) C1-1-2, p.29, Table 5

Response:

Please refer to I-38-SEC-70 for these updated tables.

School Energy Coalition Interrogatory # 70

Issue:
Issue 38: Are the proposed OM&A spending levels for Sustainment, Development, Operations, Customer Care, Common Corporate and Property Taxes and Rights Payments, appropriate, including consideration of factors considered in the Distribution System Plan?

Reference:
C1-01-01

Interrogatory:
Please provide revised versions of the following tables by adding a column under the 2017 heading showing 2017 actuals:

a) [C1-1-1] Tables 1

b) [C1-1-2] Tables 1-5

c) [C1-1-3] Table 1

d) [C1-1-4] Table 1

e) [C1-1-5] Table 1

f) [C1-1-5] Table 2

g) [C1-1-6] Tables 1-4

h) [C1-1-7] Tables 1-2

Response:

a) [C1-1-1] Tables 1

Table 1: Summary of Recoverable OM&A Expenses ($ Millions)

Description	Historic					Bridge		Test
	2014 IRM	2015		2016		2017		2018
	Actual	Actual	Approved	Actual	Approved	Actual	Approved	Forecast
Sustainment	325.7	304.6	316.5	323.7	361.4	304.7	367.1	346.7
Development	11.0	10.9	15.4	11.9	17.8	8.8	17.0	11.0
Operations	29.5	27.6	35.8	31.5	39.4	31.9	37.5	36.7
Customer Care	209.3	155.4	111.7	118.8	110.9	123.4	111.6	128.7
Common Corporate Costs and Other	94.4	69.1	59.0	72.0	54.8	84.9	54.7	53.9
Property Taxes & Rights Payments	4.6	4.8	4.7	4.6	4.9	5.0	5.0	4.9
Total	**674.5**	**572.5**	**543.1**	**562.6**	**589.1**	**558.7**	**593.0**	**576.7**
% Change (year-over-year)		*-15.1%*	*-19.5%*	*-1.7%*	*8.5%*	*-0.7%*	*0.7%*	*2.1%*
% Change (Test vs. 2016 Actual)						*-0.7%*		*2.5%*

"Approved" figures reflect OEB-directed reductions to Sustainment OM&A and Common Corporate Costs and Other OM&A line items (specifically, budgets for vegetation management, LEAP funding, and compensation).

b) [C1-1-2] Tables 1-5

Please see Exhibit I-38-AMPCO-037.

c) [C1-1-3] Table 1

Table 1: Summary of Development OM&A ($ Millions)

Description	Historic					Bridge		Test
	2014	2015		2016		2017		2018
	Actual	Actual	Approved	Actual	Approved	Actual	Approved	Forecast
Engineering and Technical Studies	4.0	3.8	4.7	4.2	4.7	3.5	4.7	1.7
Distributed Generation Connections	2.6	2.5	2.2	2.5	2.0	2.6	2.0	2.9
Distribution Standards Program	3.9	3.4	5.6	3.3	5.8	0.9	6.0	4.5
Research Development and Demonstration*	0.4	1.2	2.9	1.8	5.2	1.7	4.3	1.6

Customer Power Quality Program	0.0	0.0	0.0	0.1	0.0	0.1	0.0	0.2
Total	**11.0**	**10.9**	**15.4**	**11.9**	**17.8**	**8.8**	**17.0**	**11.0**

** In 2016, investments in smart grid related studies were integrated under the new Research Development and Demonstration ("RD&D") program; as such costs associated with these studies prior to 2016 have been included under RD&D in the above table.*

d) [C1-1-4] Table 1

Table 1: Summary of Operations OM&A ($ Millions)

Description	**Historic**					**Bridge**		**Test**
	2014	**2015**		**2016**		**2017**		**2018**
	Actual	**Actual**	**Approved**	**Actual**	**Approved**	**Actual**	**Approved**	**Forecast**
Operations	17.7	18.1	16.9	19.6	17.1	21.2	17.1	18.5
Operations Support	4.6	4.4	5.4	4.8	5.4	3.4	5.5	4.9
Environment, Health and Safety	1.4	1.5	2.7	1.6	2.8	1.8	2.6	1.8
Smart Grid*	5.9	3.5	11.0	5.6	14.1	5.5	12.4	11.5
Total*	**29.5**	**27.6**	**35.8**	**31.5**	**39.4**	**31.9**	**37.5**	**36.7**

*Rounding Errors account for up to $0.1 million in variance

e) [C1-1-5] Table 1

Table 1: Summary of Customer Care OM&A Allocated to Distribution ($ Millions)

Description	Historic					Bridge		Test
	2014 IRM	2015		2016		2017		2018
	Actual	Actual	Approved	Actual	Approved	Actual	Approved	Forecast
Call Center Operations (1)	79.5	56.4	38.5	41.5	38.8	44.0	39.9	44.5
Meter Reading	23.5	18.7	14.9	17.8	14.3	18.8	14.0	19.2
Third Party Support (2)	13.6	13.2	12.2	14.1	12.5	14.1	12.9	14.6
Field Support	4.9	12.0	7.1	14.0	7.3	7.2	7.5	8.1
Regulatory Compliance (LEAP)	2.2	4.2	2.1	4.1	2.2	3.7	2.3	4.3
Net Bad Debt	66.8	29.5	15.5	6.8	15.4	16.1	14.4	18.2
Customer Care Staffing (3)	18.9	21.5	21.3	20.5	20.4	19.4	20.6	19.8
Total Customer Care OM&A (4)	**209.3**	**155.4**	**111.6**	**118.8**	**110.9**	**123.4**	**111.6**	**128.7**

(1) Previously referred to as "Customer Service Operations", "Customer Operations" and "Settlements".
(2) Previously referred to as "Service Support" and "Service Enhancements".
(3) Previously referred to "Customer Service Management", "Customer Business Relations", "Customer Care Management", "Customer Experience", and "Conservation and Demand Management".
(4) Costs associated with the Smart Grid Pilot are now included in the Exhibit C1, Tab 1, Schedule 4 (Operations OM&A) Exhibit.

f) [C1-1-5] Table 2

Table 2: Call Centre Operations OM&A Allocated to Distribution ($ Millions)

Description	Historic					Bridge		Test
	2014 IRM	2015		2016		2017		2018
	Actual	Actual	Approved	Actual	Approved	Actual	Approved	Forecast
Call Center Operations	79.5	56.4	38.5	41.5	38.8	44.0	39.9	44.5

g) [C1-1-6] Tables 1-4 (There are only Tables 1 and 2)

Table 1: Summary of Total Common Corporate OM&A Costs ($ Millions)

	Historic			Actual	Test
Description	**2014 IRM**	**2015**	**2016**	**2017**	**2018**
Planning	47.6	47.4	45.1	44.3	47.5
Common Corporate Functions & Services	173.9	187.5	186.6	191.2	201.3
Information Technology	166.0	142.5	143.8	145.1	137.9
Cost of External Revenue	15.6	14.2	9.1	13.8	8.9
Other OM&A*	(266.1)	(235.8)	(242.8)	(253.0)	(282.2)
Total	**137.1**	**155.8**	**141.7**	**141.4**	**113.5**

*Includes the pension adjustment described in Exhibit C1, Tab 1, Schedule 7.

Table 2: Summary of Common Corporate OM&A Costs Allocated to Distribution ($ Millions)

	Historic					Bridge		Test
Description	**2014 IRM**	**2015**		**2016**		**2017**		**2018**
	Actual	Actual	Approved	Actual	Approved	Actual	Approved	Forecast
Planning	15.0	16.4	18.4	12.2	17.8	12.3	17.6	13.3
Common Corporate Functions & Services	76.8	80.5	77.3	85.8	76.8	86.9	76.7	88.0
Information Technology	109.3	85.8	85.7	85.3	86.4	85.7	86.1	80.4

Cost of External Revenue	4.5	5.4	2.1	4.3	2.1	10.2	2.1	4.6
Other OM&A*	(111.3)	(119.0)	(124.4)	(115.5)	(128.3)	(110.2)	(127.8)	(132.3)
Total	**94.4**	**69.1**	**59.0**	**72.0**	**54.8**	**84.9**	**54.7**	**53.9**

*OEB-directed reductions for compensation are reflected in this line item. Includes the pension adjustment described in Exhibit C1, Tab 1, Schedule 7.

h) [C1-1-7] Tables 1-2

Table 1: Summary of Total Common Corporate Functions and Services OM&A ($ Millions)

	Historic			Bridge	Test
Description	**2014 IRM**	**2015**	**2016**	**2017**	**2018**
	Actual	**Actual**	**Actual**	**Actual***	**Forecast**
Corporate Management	9.2	16.4	16.1	27.6	23.3
Finance	40.0	39.1	38.1	34.6	40.4
People and Culture	12.8	13.6	15.6	17.9	16.2
Corporate Relations	19.5	17.3	15.2	13.4	17.5
General Counsel and Secretariat	8.7	8.6	10.1	8.5	10.1
Regulatory Affairs	23.0	24.1	23.3	21.0	22.9
Security Management	3.5	4.2	4.6	4.4	4.5
Internal Audit	3.6	4.2	4.9	6.8	6.9
Real Estate and Facilities	53.6	60.0	58.6	56.9	59.5
Total CCF&S Costs	**173.9**	**187.5**	**186.6**	**191.2**	**201.3**

Table 2: Summary of Common Corporate Functions and Services OM&A Allocated to Distribution ($ Millions)

Description	**Historic**					**Bridge**		**Test**
	2014 IRM	**2015**		**2016**		**2017**		**2018**
	Actual	**Actual**	**Approved**	**Actual**	**Approved**	**Actual***	**Approved**	**Forecast**
Corporate Management	2.4	2.4	2.4	4.3	2.4	7.3	2.4	5.7
Finance	16.4	16.2	18.0	16.6	17.6	14.5	17.3	16.3
People and Culture	5.8	6.8	5.7	7.3	5.4	8.7	5.4	7.7
Corporate Relations	10.5	9.6	6.6	7.6	6.6	9.3	6.6	8.3
General Counsel and Secretariat	3.8	3.6	4.1	4.5	4.1	3.8	4.2	4.3

Regulatory Affairs	13.0	13.6	12.0	14.0	12.4	12.3	12.1	13.0
Security Management	1.9	2.2	2.5	2.5	2.4	2.1	2.4	2.4
Internal Audit	1.2	1.6	1.1	2.2	1.1	3.1	1.1	3.1
Real Estate and Facilities	21.8	24.5	24.8	26.9	24.7	25.7	25.2	27.3
Total CCF&S Costs	**76.8**	**80.5**	**77.3**	**85.8**	**76.8**	**86.9**	**76.7**	**88.0**

*There is a significant decrease in Corporate Relations in 2017 actuals due to transfer of CDM resources from Corporate Relations to Customer Care.

OEB Staff Interrogatory # 183

Issue:

Issue 38: Are the proposed OM&A spending levels for Sustainment, Development, Operations, Customer Care, Common Corporate and Property Taxes and Rights Payments, appropriate, including consideration of factors considered in the Distribution System Plan?

Reference:

C1-01-01

Interrogatory:

Please update the OM&A schedules for 2017 actuals and for any other changes that may have taken place since the application was filed. Please highlight and explain any significant changes to the evidence.

Response:

Please refer to Exhibit Q1, Tab 1, Schedule 1. Please refer to Exhibit I-38-SEC-070 for OM&A schedules updated for 2017 actuals.

Vulnerable Energy Consumers Coalition Interrogatory # 41

Issue:

Issue 38: Are the proposed OM&A spending levels for Sustainment, Development, Operations, Customer Care, Common Corporate and Property Taxes and Rights Payments, appropriate, including consideration of factors considered in the Distribution System Plan?

Reference:

Q-01-01-01 Page: 20

Interrogatory:

a) Please update the Scorecard to show 2017 actual results.

Response:

a) Please refer to Exhibit I-18-SEC-029.

Vulnerable Energy Consumers Coalition Interrogatory # 43

Issue:

Issue 38: Are the proposed OM&A spending levels for Sustainment, Development, Operations, Customer Care, Common Corporate and Property Taxes and Rights Payments, appropriate, including consideration of factors considered in the Distribution System Plan?

Reference:

C1-01-01 Table 1

Interrogatory:

a) Please update Table 1 for 2017 actual (unaudited) results.

Response:

a) Please refer to Exhibit I-38-SEC-070.

Vulnerable Energy Consumers Coalition Interrogatory # 44

Issue:

Issue 38: Are the proposed OM&A spending levels for Sustainment, Development, Operations, Customer Care, Common Corporate and Property Taxes and Rights Payments, appropriate, including consideration of factors considered in the Distribution System Plan?

Reference:

C1-01-01 Page: 8
C1-01-05 Page: 8-9

Interrogatory:

a) What were the actual customer care costs in 2017?

b) Please explain how the bad debt provision forecast for 2018 was calculated.

c) Hydro One states that it expects to "return closer to historical norms". What is the historical norm or target bad debt provision expected by the end of the rate period (2022).

d) Please explain what DSC changes related to interval meters and monthly billing are driving increases to customer care. What are the incremental costs in 2018 related to these factors?

Response:

a) 2017 actuals are provided in Interrogatory Exhibit I-38-SEC-70.

b) Hydro One's bad debt provision rates reflect the company's best estimate of overdue accounts receivable balances and amounts that will be uncollectable or written off in the future. This is based on the aging of accounts receivables, the probability of default, and historical trends. The 2018 forecast was derived based on the 2018 revenue forecast and historical Net Bad Debt.

c) In 2012, prior to the implementation of Hydro One's new Customer Information System, and the subsequent variations in Net Bad Debt, Hydro One's Net Bad Debt as a percentage of revenue was 0.54%. In 2018, Hydro One's Net Bad Debt as a percentage of revenue is projected to decline to 0.41%.

d) As per Exhibit C1, Tab 1, Schedule 5 (Customer Care OM&A), expenditures in 2017 and 2018 are forecast to be higher than OEB-approved historical levels as a result of Distribution System Code amendments relating to interval meters and monthly billing (EB-2013-0311, EB-2014-0198), requiring distributors to install an interval meter on any installation that is forecast to have a monthly average peak demand during a calendar year of over 50 kW and to comply with mandatory requirements for monthly billing, billing accuracy and estimated billing requirements. As a result, meter reading costs are expected to increase by approximately $1 million.

School Energy Coalition Interrogatory # 85

Issue:

Issue 40: Are the proposed 2018 human resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels, appropriate (excluding executive compensation)?

Reference:

C1-02-01 Attachment 8; Page: 2-3

Interrogatory:

Please provide a revised version of the Tables on p.2-3 to show 2017 actuals. Please also provide those tables in excel format.

Response:

Please see attached table, originally found in Exhibit C1-02-01 Attachment 8, which has been updated with 2016 and 2017 actuals.

Estimated Compensation - Transmission (as per J10.2)

MCP	2013	2014	2015	2016	2017	2018
Base Pay	33,809,609	33,403,974	34,123,844	34,091,032	35,298,709	35,382,042
Burdens	22,652,438	22,440,789	23,186,431	17,902,495	18,705,201	18,961,872
Other Allowances	1,996,627	3,122,164	1,862,959	2,637,233	3,062,736	1,964,916
Short Term Incentive	4,374,928	4,078,670	4,403,218	4,348,379	5,832,719	7,575,929
Long Term Incentive				941,353	2,763,137	4,271,137
Employee Share Ownership				981,455	991,270	1,001,182
Transmission Total	**62,833,601**	**63,045,596**	**63,576,452**	**60,901,946**	**66,653,771**	**69,157,078**

Society	2013	2014	2015	2016	2017	2018
Base Pay	59,219,915	66,479,040	65,846,926	64,411,295	66,370,462	66,432,079
Overtime	2,223,563	3,234,367	2,892,349	3,200,440	5,681,135	2,503,795
Lump Sums				658,568	1,312,146	-
Burdens	39,677,343	44,660,619	44,741,596	33,824,815	35,170,489	35,602,144
Share Grants						974,271
Transmission Total	**101,120,821**	**114,374,026**	**113,480,871**	**102,095,119**	**108,534,232**	**105,512,289**

PWU	2013	2014	2015	2016	2017	2018
Base Pay	134,138,104	143,634,042	143,273,208	140,448,539	145,187,699	153,432,958
Overtime	22,835,014	27,775,994	24,488,731	21,165,314	30,886,629	22,986,409
Lump Sums			1,345,306	2,810,715	-	-
Burdens	89,872,530	96,493,350	97,351,119	73,754,858	76,936,670	82,227,477
Share Grants					2,755,969	2,650,016
Transmission Total	**246,845,648**	**267,903,386**	**266,458,363**	**238,179,425**	**255,766,967**	**261,296,861**

Temporary Resources	2013	2014	2015	2016	2017	2018
Casual Trades	44,489,030	52,518,110	50,641,118	53,902,338	54,643,500	62,340,282
MCP	530,830	719,625	826,616	910,290	484,304	649,603
Society	1,315,390	1,342,574	1,479,288	1,260,658	1,294,916	1,323,249
PWU	2,945,762	2,141,011	2,033,436	2,759,291	2,113,901	2,945,744
Overtime	5,347,679	7,972,313	6,685,080	3,563,237	5,812,726	7,602,294
Other Allowances	6,723,983	7,920,057	7,480,599	7,827,542	8,125,785	9,182,714
Burdens	3,889,760	4,610,969	4,467,202	4,520,985	4,691,908	5,548,041
Transmission Total	**65,242,434**	**77,224,661**	**73,613,339**	**74,744,340**	**77,167,040**	**89,591,926**

Transmission Total Compensation	**476,042,503**	**522,547,669**	**517,129,026**	**475,920,831**	**508,122,011**	**525,558,154**

	2013	2014	2015	2016	2017	2018
Estimated Labour in Capital Exp	317,396,377	362,360,860	362,315,956	348,419,331	334,305,691	351,973,855
Estimated Labour in OM&A	158,646,126	160,186,809	154,813,070	127,501,500	173,816,320	173,584,299
Transmission Total Compensation	**476,042,503**	**522,547,669**	**517,129,026**	**475,920,831**	**508,122,011**	**525,558,154**

Pension / OPEB	2013	2014	2015	2016	2017	2018
Pension	79,000,000	77,000,000	77,000,000	50,000,000	49,000,000	46,000,000
OPEB	53,000,000	57,000,000	51,000,000	44,000,000	52,000,000	50,000,000

Estimated Compensation - Distribution (as per J10.2)

MCP	2013	2014	2015	2016	2017	2018
Base Pay	41,032,642	37,516,023	39,364,708	37,121,880	37,280,483	40,277,208
Burdens	27,491,870	25,203,264	26,747,488	19,494,108	19,755,367	21,585,279
Other Allowances	2,423,183	3,506,504	2,149,079	2,871,695	3,234,687	2,236,766
Short Term Incentive	5,309,580	4,580,756	5,079,481	4,734,970	6,160,185	8,624,071
Long Term Incentive				941,353	2,763,137	4,271,137
Employee Share Ownership				981,455	991,270	1,001,182
Distribution Total	**76,257,275**	**70,806,548**	**73,340,755**	**66,145,461**	**70,185,129**	**77,995,643**

Society	2013	2014	2015	2016	2017	2018
Base Pay	71,871,566	74,662,651	75,959,938	70,137,754	70,096,697	75,623,070
Overtime	3,995,108	4,431,085	3,840,011	9,354,688	8,521,702	3,755,693
Lump Sums				717,118	1,385,814	-
Burdens	48,153,949	50,158,369	51,613,173	36,831,996	37,145,065	40,527,761
Share Grants						1,109,063
Distribution Total	**124,020,624**	**129,252,105**	**131,413,122**	**117,041,556**	**117,149,278**	**121,015,587**

PWU	2013	2014	2015	2016	2017	2018
Base Pay	162,795,162	161,315,481	165,277,630	152,935,057	153,338,967	174,660,668
Overtime	41,027,999	38,053,133	32,512,322	61,864,894	46,329,944	34,479,614
Lump Sums			1,551,922	3,060,600	-	-
Burdens	109,072,759	108,371,740	112,302,659	80,312,002	81,256,123	93,603,789
Share Grants					2,910,697	3,016,650
Distribution Total	**312,895,920**	**307,740,355**	**311,644,534**	**298,172,553**	**283,835,732**	**305,760,721**

Temporary Resources	2013	2014	2015	2016	2017	2018
Casual Trades	53,993,598	58,983,122	58,418,766	58,694,502	57,711,349	70,965,166
MCP	644,235	808,211	953,571	991,219	511,494	739,477
Society	1,596,408	1,507,846	1,706,482	1,372,736	1,367,617	1,506,322
PWU	3,575,089	2,404,571	2,345,739	3,004,605	2,232,582	3,353,293
Overtime	9,608,253	10,922,075	8,875,407	10,415,120	8,719,088	11,403,441
Other Allowances	8,160,485	8,895,021	8,629,497	8,523,446	8,581,991	10,453,158
Burdens	4,918,450	5,303,574	5,228,467	5,343,651	5,122,351	6,497,117
Distribution Total	**82,496,518**	**88,824,420**	**86,157,929**	**88,345,279**	**84,246,472**	**104,917,974**

Distribution Total Compensation	**595,670,336**	**596,623,428**	**602,556,339**	**569,704,850**	**555,416,609**	**609,689,925**

	2013	2014	2015	2016	2017	2018
Estimated Labour in Capital Exp	397,156,988	413,728,721	422,168,870	417,078,156	365,421,945	408,318,112
Estimated Labour in OM&A	198,513,348	182,894,707	180,387,470	152,626,694	189,994,665	201,371,813
Distribution Total Compensation	**595,670,336**	**596,623,428**	**602,556,339**	**569,704,850**	**555,416,609**	**609,689,925**

Pension / OPEB	2013	2014	2015	2016	2017	2018
Pension	76,000,000	91,000,000	95,000,000	54,000,000	51,000,000	52,000,000
OPEB	61,000,000	60,000,000	62,000,000	56,000,000	54,000,000	57,000,000

Estimated Compensation - Transmission and Distribution (as per J10.2)

MCP	2013	2014	2015	2016	2017	2018
Base Pay	74,842,250	70,919,997	73,488,551	71,212,912	72,579,193	75,659,250
Burdens	50,144,308	47,644,054	49,933,919	37,396,603	38,460,568	40,547,151
Other Allowances	4,419,810	6,628,668	4,012,037	5,508,929	6,297,423	4,201,682
Short Term Incentive	9,684,508	8,659,426	9,482,699	9,083,349	11,992,903	16,200,000
Long Term Incentive				1,882,705	5,526,273	8,542,273
Employee Share Ownership				1,962,910	1,982,539	2,002,365
Transmission + Distribution Total	**139,090,876**	**133,852,144**	**136,917,207**	**127,047,407**	**136,838,900**	**147,152,721**

Society	2013	2014	2015	2016	2017	2018
Base Pay	131,091,481	141,141,692	141,806,864	134,549,048	136,467,160	142,055,149
Overtime	6,218,672	7,665,451	6,732,360	12,555,128	14,202,836	6,259,488
Lump Sums				1,375,686	2,697,960	-
Burdens	87,831,292	94,818,988	96,354,769	70,656,812	72,315,554	76,129,905
Share Grants						2,083,333
Transmission + Distribution Total	**225,141,445**	**243,626,131**	**244,893,993**	**219,136,674**	**225,683,510**	**226,527,876**

PWU	2013	2014	2015	2016	2017	2018
Base Pay	296,933,266	304,949,524	308,550,838	293,383,595	298,526,666	328,093,626
Overtime	63,863,013	65,829,127	57,001,053	83,030,208	77,216,573	57,466,023
Lump Sums			2,897,228	5,871,315	-	-
Burdens	198,945,288	204,865,090	209,653,778	154,066,860	158,192,793	175,831,266
Share Grants					5,666,667	5,666,667
Transmission + Distribution Total	**559,741,568**	**575,643,741**	**578,102,897**	**536,351,978**	**539,602,699**	**567,057,582**

Temporary Resources	2013	2014	2015	2016	2017	2018
Casual Trades	98,482,627	111,501,232	109,059,885	112,596,840	112,354,849	133,305,447
MCP	1,175,065	1,527,837	1,780,187	1,901,508	995,798	1,389,080
Society	2,911,798	2,850,420	3,185,769	2,633,393	2,662,533	2,829,571
PWU	6,520,851	4,545,582	4,379,175	5,763,897	4,346,483	6,299,037
Overtime	14,955,932	18,894,389	15,560,487	13,978,358	14,531,814	19,005,736
Other Allowances	14,884,468	16,815,079	16,110,096	16,350,988	16,707,776	19,635,872
Burdens	8,808,209	9,914,543	9,695,669	9,864,636	9,814,258	12,045,157
Transmission + Distribution Total	**147,738,951**	**166,049,081**	**159,771,268**	**163,089,620**	**161,413,512**	**194,509,900**

Tx + Dx Total Compensation	1,071,712,840	1,119,171,097	1,119,685,365	1,045,625,680	1,063,538,621	1,135,248,079

	2013	2014	2015	2016	2017	2018
Estimated Labour in Capital Exp	714,553,365	776,089,581	784,484,826	765,497,487	699,727,635	760,291,966
Estimated Labour in OM&A	357,159,474	343,081,516	335,200,540	280,128,193	363,810,985	374,956,112
Tx + Dx Total Compensation	**1,071,712,840**	**1,119,171,097**	**1,119,685,365**	**1,045,625,680**	**1,063,538,621**	**1,135,248,079**

Pension / OPEB	2013	2014	2015	2016	2017	2018
Pension	155,000,000	168,000,000	172,000,000	104,000,000	100,000,000	98,000,000
OPEB	114,000,000	117,000,000	113,000,000	100,000,000	106,000,000	107,000,000

Energy Probe Research Foundation Interrogatory # 59

Issue:

Issue 41: Has Hydro One demonstrated improvements in presenting its compensation costs and showing efficiency and value for dollar associated with its compensation costs (excluding executive compensation)?

Reference:

C1-01-05 Page: 10 Table 9

Interrogatory:

Please update these figures with the most recent information and provide data back to 2010.

Response:

2010 to 2013 cost per customer calculations are provided below based on information provided in Hydro One's last custom distribution application (see Exhibit C1, Tab 2, Schedule 5, Table 1 in EB-2013-0416).

Customer Service	**2010 Actual**	**2011 Actual**	**2012 Actual**	**2013 Actual**
Total OM&A (Million) *	112.2	112.9	115.9	138.8
Number of Customers (Million)	1.21	1.22	1.24	1.29
Customer Care OM&A Cost per Customer	**$93**	**$93**	**$93**	**$108**

** Costs associated with the Smart Grid Pilot are now included in the Exhibit C1, Tab 1, Schedule 4 (Operations OM&A) Exhibit.*

2014 to 2016 cost per customer calculations are provided in EB-2017-0049 (Exhibit C1, Tab 1, Schedule 5, Table 9).

Witness: MERALI Imran

Table 9: Customer Care OM&A Allocated to Distribution Cost per Customer

Customer Service	Historic			Bridge	Test
	2014 Actual	2015 Actual	2016 Actual	2017 Forecast	2018 Forecast
Total OM&A (Million)	$209.3	$155.4	$118.8	$132.6	$131.6
Number of Customers (Million)	1.27	1.27	1.28	1.29	1.30
Customer Care OM&A Cost per Customer	**$165**	**$122**	**$93**	**$103**	**$101**

2017 cost per customer calculations are provide below, based on a detailed breakdown provided in Exhibit I-38-SEC-70.

Customer Service	**2017 Actual**
Total OM&A (Million) *	123.4
Number of Customers (Million)	1.29
Customer Care OM&A Cost per Customer	**$96**

Vulnerable Energy Consumers Coalition Interrogatory # 58

Issue:

Issue 42: Is the updated executive compensation information filed by Hydro One in the distribution proceeding on December 21, 2017 consistent with the OEB's findings on executive compensation in the EB-2016-0160 Transmission Decision?

Reference:

E1-01-02 Page: 5-8 - Table 4

Interrogatory:

a) What were the actual 2017 volumes and revenues for each Rate Code? If year-end values are not available, provide the most current year-to-date values and indicate the period covered?

b) Please indicate the specific adjustments that were made to the revenues forecast for 2021-2022 to account for the integration of Norfolk Power, Haldimand Hydro and & Woodstock Hydro in 2021.

Response:

a) E1-01-02 Table 4 with 2017 Actuals is summarized below and excludes the update from I-46-Staff-234.

Rate Code	Description	Bridge Year 2017		Bridge Year 2017		Details
		Volume Forecast	Revenue Forecast	Actual Volume	Actual Revenue	
2	Statement of Account	4,167	$62,500	7,578	$0	Hydro One did not charge customers for these services in 2017
4	Duplicate Invoices for Previous Billing	1,250	$18,750	12,645	$0	Hydro One did not charge customers for these services in 2017
5	Request for other billing information	4,167	$62,500	7,578	$0	Hydro One did not charge customers for these services in 2017
6a	Easement Letter (Letter Request)	727	$10,905	844	$12,660	
6b	Easement Letter (Web Request)	3,429	$82,296	0	$0	The payment system on the website went offline in November 2016. The system is expected to be online again in June 2018. Therefore, customers were not charged for this service during this time period.
7	Income Tax Letter	1,250	$18,750	12,645	$0	Hydro One did not charge customers for these services in 2017

Rate Code	Description	Bridge Year 2017		Bridge Year 2017		Details
		Volume Forecast	Revenue Forecast	Actual Volume	Actual Revenue	
9	Account History	4,167	$62,500	7,578	$0	Hydro One did not charge customers for these services in 2017
10	Credit Reference / Credit check (plus credit agency costs)	7,500	$112,500	19,262	$0	Hydro One did not charge customers for these services in 2017
11	Returned Cheque Charge	6,026	$90,383	8,450	$126,747	
14	Account Set Up Charge / Change of occupancy charge (Plus Credit Agency Costs, if applicable)	96,753	$2,902,590	131,690	$3,950,697	
15	Special Meter Reads (retailer requested off-cycle read)	100	$3,000	11	$330	
16	Collection of Account Charge - No Disconnection	2,000	$60,000	2,214	$66,420	
18 & 19	Collection - Disconnect / Reconnect at Meter & Install/Remove Load Control Device - During Regular Hours	22,330	$1,451,450	10,640	$691,631	
20 & 21	Collection - Disconnect / Reconnect at Meter & Install/Remove Load Control Device - After Regular Hours	410	$75,850	269	$49,728	
22	Collection - Disconnect/Reconnect at Pole - During Regular Hours	1,710	$316,350	405	$74,981	
23	Collection - Disconnect/Reconnect at Pole - After Regular Hours	168	$69,720	115	$47,808	
24	Meter Dispute Charge - Measurement Canada	50	$1,500	26	$776	

Rate Code	Description	Bridge Year 2017		Bridge Year 2017		Details
		Volume Forecast	Revenue Forecast	Actual Volume	Actual Revenue	
31a	Vacant Premise - Move in with Reconnect of Electrical Service at Meter	2,625	$0	3,133	$0	
31b	Vacant Premise - Move in with Reconnect of Electrical Service at Pole	0	$0	0	$0	
32	Reconnect completed after regular hours (customer/ contract driven) - at Meter	90	$0	0	$0	
33	Reconnect completed after regular hours (customer/contract driven) - at Pole	60	$0	0	$0	
46a	Retailer Services – Establishing Service Agreements (rates as per the Handbook)		$376,638		$375,612	
46b	Retailer Services – Other (includes Bill Ready for Retailers and Service Transaction Requests) as per the Handbook		$188,319		$185,003	
52	Late Payment Charge		$12,776,871		$12,108,516	
	Total		**$18,767,102**		**$17,690,908**	

b) Please refer to Exhibit I-42-VECC-63 regarding streetlight revenue from the acquired LDCs (Norfolk Power, Haldimand Hydro and Woodstock Hydro) in 2021 and 2022.

Acquired LDC Joint Use attachments were included in the regulated revenue projections for 2021 and 2022, as shown in Exhibit E1-01-02. For Norfolk Power, the estimated number of Joint Use telecom attachments is 4,337, with estimated revenue of $211k. For Haldimand Hydro, the estimated number of Joint Use telecom attachments is 5,935, with estimated revenue of $288k. For Woodstock Hydro, the estimated number of Joint Use telecom attachments is 2,143, with estimated revenue of $104k.

For all other services, acquired LDCs were included in Hydro One's 2018 to 2022 projection.

Canadian Manufacturers & Exporters Interrogatory # 40

Issue:

Issue 44: Is Hydro One's proposed depreciation expense for 2018 and further years appropriate?

Reference:

C1-06-01 Updated

Interrogatory:

a) What is driving the nearly 50% increase in amortization expense shown in the Environmental row in Table 3 for 2017 as compared to 2016?

b) Based on the most recent actual data available, has this increase materialized in 2017?

Response:

a) The increase between 2016 actual and 2017 forecast is due to a higher amount of PCB Inspection and Testing on overhead transformers. For more information see Exhibit C1, Tab 1, Schedule 2, page 19, line 24. Actual spend in 2016 was lower than anticipated due to a redirection to higher priority investments. 2017 forecast restores funding to planned levels.

b) 2017 actual amortization expense was $13.9 million.

OEB Staff Interrogatory # 218

Issue:

Issue 44: Is Hydro One's proposed depreciation expense for 2018 and further years appropriate?

Reference:

C1-06-01 Section 5.1

Interrogatory:

From the evidence filed in the above reference, it is not clear what actually underpins Hydro One's estimate for the amortization related to its environmental costs.

a) Please explain how this balance is estimated and provide evidence that supports the estimate for the test period.

b) Please provide a table that compares the amount collected in rates over the last 5 years (2013-2017) with respect to amortization of environmental costs and the actual amortization as per the audited financial statements for the same period.

Response:

a) The estimates for amortization related to environmental costs are built up from the work programs required to be completed:
   - PCB Oil Sampling and Oil Retrofill for Distributing and Regulating Stations (Ex C1, Tab 1, Sch 2, Pg 10, Ln 3).
   - Land Assessment and Remediation (Ex C1, Tab 1, Sch 2, Pg 11, Ln 24).
   - Overhead Equipment PCB Inspection, Testing, and Waste Management (Ex C1, Tab 1, Sch 2, Pg 19, Ln 24).

b)

$ in Millions	**2013(1)**	**2014(1)**	**2015(2)**	**2016(2)**	**2017(2)(3)**
Amount Collected in Rates	16.9	16.9	14.2	22.0	22.4
Amortization per Audited Financial Statements	8.5	11.1	10.5	12.0	13.9

1. Represents the amount approved for 2011 as part of the prior COS application (EB-2009-0096) in Exhibit C1, Tab 6, Schedule 1, Table 2. 2013 and 2014 were IRM years and therefore approved amounts are based on the 2011 values.
2. Source of amount collected in rates: 2015-2017: EB-2013-0416; Exhibit C1, Tab 6, Schedule 1, Table 2.

3. The Amortization disclosed in the 2017 Dx Audited Financial Statements of $15M also includes expenditures relating to Norfolk Power's environmental provision, and these expenditures have been excluded from this amount.

Canadian Manufacturers & Exporters Interrogatory # 67

Issue:
Issue 45: Are the proposed other revenues for 2018 – 2022 appropriate?

Reference:
E1-01-02 Updated

Interrogatory:
a) Please update the 2017 bridge year column in Table 3 to reflect actual year-to-date information for the latest period available in 2017 and the forecast for the remainder of the year.

b) Based on the year-to-date information provided for 2017 in part (a) above, please provide the year-to-date figures in the same level of detail as shown in Table 3 for the corresponding period in 2016.

Response:
a) Table 3 has been updated with 2017 actual revenue.

Table 3: Regulated Revenues ($ Millions)

Description	Historical capital years			Bridge Year	Test Years				
	2014	2015	2016	2017	2018	2019	2020	2021	2022
Retail Service capital revenues*	9.5	22.3	24.5	17.9	21.2	21.3	21.4	21.6	21.7
Sentinel Lights	2.8	3.0	3.2	3.1	2.9	2.7	2.5	2.3	2.0
Joint Use	8.0	8.2	19.5	13.0	14.9	16.1	16.4	17.3	17.6
Other External Work*	4.1	2.8	3.1	2.0	2.3	2.3	2.4	2.4	2.4
Generator Studies	1.0	1.4	1.3	1.7	1.7	1.5	1.6	1.6	1.7
Total	**25.4**	**37.7**	**51.6**	**37.7**	**42.9**	**43.9**	**44.2**	**45.1**	**45.4**

b) The 2017 data in part a) shows the full year's revenue, as does the 2016 data in the table.

Energy Probe Research Foundation Interrogatory # 71

Issue:

Issue 57: Are the proposed amounts, disposition and continuance of Hydro One's existing deferral and variance accounts appropriate?

Reference:

A-03-01 Page: 35 – Table 16

Interrogatory:

Please update the deferral account balances at the end of 2017 if they are materially different.

Response:

Updated 2017 balances are provided below:

Disposition of Regulatory Account Balances ($ Millions)		
Description	**US of A Account Ref.**	**Balance as at Dec. 31, 2017 (Note 1)**
Retail Service Variance Accounts	1550 to 1589	29.6
Retail Cost Variance Accounts	1518/ 1548	1.2
Pension Cost Differential Account	2405	-13.2
Tax Rate Changes Account	1592	-3.3
OEB Cost Differential Account	1508	-3.6
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	-12.2
Distribution System Code (DSC) Exemption Deferral Account	1508	9.7
Total Regulatory Accounts for Disposition		**7.8**

Exhibit Reference: F1-2-1

Note 1: As noted in Exhibit F1-1-1, the 2017 balances included in the application were calculated by applying simple interest on the forecast December 31, 2016 year-end balance using the Board's prescribed 4th quarter interest rate of 1.1%, as per the Bankers' Acceptances three-month rate plus a spread of 25 basis points. The 2017 balances provided in the table above are the actual balances at December 31, 2017 and are therefore reflective of all transactions that have occurred up to that point in time.

UNDERTAKING – JT 1.17-6

Reference

Exhibit I, Tab 45, Schedule CME-67

The interrogatory deals with other revenues and requested that Table 3 in Exhibit E1, Tab 1, Schedule 2, Updated be updated with 2017 actuals. The response indicates that 2017 actual data is not yet available, but will be provided once it is available.

Undertaking

a) In addition to providing the actual 2017 data when it is available for Table 3, please also provide an updated Table 1 from Exhibit E1, Tab 1, Schedule 2.

b) For each line item in Tables 1 and 3, please indicate if there is a deferral or variance account that deals with any difference between the forecast and actuals over the forecast horizon.

Response

a) Refer to I-45-CME-67 for updates to E1-1-2 Table 3. E1-1-2 Table 1 has been updated below.

Description	Historic					Bridge	
	2014	2015		2016		2017	
	Actual	Actual	Approved	Actual	Approved	Actual	Approved
Regulated Revenues	25.4	37.7	39.4	51.6	40.4	37.7	42.5
Unregulated Revenues	6.5	6.5	6.7	7.0	6.6	13.8	6.5
Sub-Total External Revenue	**31.9**	**44.2**	**46.1**	**58.6**	**47.0**	**51.5**	**49.0**
Standard Supply Service Charge	3.7	3.7	3.6	3.6	3.7	3.7	3.7
Total External Revenue and Other	**35.6**	**47.9**	**49.7**	**62.2**	**50.7**	**55.2**	**52.7**

b) Hydro One does not have variance accounts for distribution external revenue.

Witness: BOLDT John

UNDERTAKING – JT 2.17

Undertaking

To confirm whether the presentation at Attachment 6 of Exhibit I, Tab 6, Schedule Anwaatin 1, would have been given to a First Nations and Métis engagement session on February 18th, 2018.

Response

This is confirmed.

The First Nations Engagement Session held on February 21, 2018 focused on: Customer Service including Affordability; Procurement & Business Partnerships; Employment and Training; and Transmission & Distribution Planning & Reliability Performance.

Three presentations are attached which were delivered at the First Nations Engagement session in February 2018:

1. Diversity & Inclusion at Hydro One;
2. First Nations Reliability Performance Overview; and
3. Customer Programs – Get Local, First Nations Delivery Credit, Ontario Energy Support Program.

The overall tone of the engagement session was cordial and the feedback heard by First Nations at the February 21, 2018 engagement session focused on: the need to continue open dialogue with Hydro One to address business and revenue generation opportunities within First Nations' traditional territories, and distribution and transmission reliability performance issues impacting First Nations communities. The participating First Nations also expressed an interest to plan and develop jointly with Hydro One, through the Chiefs of Ontario's Committee on Energy, the next Hydro One's First Nations provincial engagement session. See Attachment 4 to this response for a copy of the February 21, 2018 First Nations engagement session report.

The second attachment has been redacted for non-distribution-related content.

2nd Annual Hydro One and First Nations Engagement Session
Slivernightingale Room, Casino Rama
Wednesday, February 21, 2018

SESSION REPORT

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WELCOME

Mr. Phil Goulais, Session Facilitator, called the meeting to order and introduced Elder Mryna Watson, Chippewas of Rama First Nation. Elder Watson provided the opening prayer. Mr. Goulais introduced Chief Rodney Noganosh, Chippewas of Rama First Nation, to provide welcoming remarks. Chief Noganosh welcomed the participants to their territory and thanked them for coming. He specifically thanked their leadership who had been working on a new relationship with Hydro One. He thanked Hydro One for the reduction in delivery rates for First Nations communities and he was looking forward to working together to address more issues for the betterment of their First Nation communities.

Welcome remarks were also provided by Mayor Steve Clarke, City of Orillia. He welcomed all participants and stated that they had a strong working relationship with the Chippewas of Rama First Nations and met on a regular basis to discuss issues in common. He said that he had learned a lot about First Nations and continued to learn; he stated that relationships were built on true collaboration. He also welcomed the representatives from Hydro One; the City of Orillia had recently gone through negotiations with Hydro One and he welcomed them back to the city.

Chief Ava Hill, Six Nations, provided welcoming remarks on behalf of the Chiefs of Ontario Chiefs Committee on Energy (CCOE). She thanked them all for taking the time to attend this important session. She provided background information on the CCOE stating that Government of Ontario wanted to sell Hydro One shares and the Chiefs wanted to be part of that. Resulting discussions brought up many issues that First Nations had with Hydro One so two committees were set up - one to deal with purchasing the Hydro One shares and the other to deal with outstanding grievances. The grievance one was further split into two groups – one to deal with high hydro rates and the other to deal with hydro lines crossing First Nation lands for which compensation was required. Chief Hill stated that these groups were not negotiating on behalf of First Nations but rather facilitating a relationship between the First Nations and Hydro One..

She mentioned that high hydro rates have been on ongoing issue in her community and they appreciated the commitment that Hydro One had made to eliminate the delivery charge to First Nation community homes. This had a huge impact on First Nation community members. She also mentioned that Hydro One staff had come to her community to talk with members about how to deal with their outstanding hydro bills. This could be done in any community served by Hydro One. She stated that the next priority for the CCOE is to work towards delivery charge relief for all Band owned buildings on the First Nations and then they would work on getting the same commitment for privately owned businesses on the reserve. Once the band owned buidings and businesses has been resolved, she explained that they will then work on getting the same commitment for off-reserve members.

On December 29, 2017, an agreement was reached with the Government of Ontario for the First Nations to purchase just over 14 million of Hydro One shares worth $260M. She said that they were proud of this partnership that would benefit future generations. She said that the work they had undertaken with Hydro One was reconciliation in action; reconciliation involved everyone, she said, not just First Nations and government. They all had a mutual interest in addressing the challenges and First Nations needed to come up with their own solutions she said and take advantage of their opportunities.

Chief Hill stated that they needed to deal with racism that still existed today in Canada; a change of attitude is needed, Canadians needed to be educated about First Nations.

She acknowledged the efforts of Hydro One; the operations of Hydro One had changed since the new executive team had come in. She also recognized the work of the Chief Committee on Energy and encouraged all the chiefs in the room to lobby the Government of Ontario to support work they still need to do with Hydro One. She also encouraged them to review the Long-Term Energy Plan in detail, as there was a lot going on in the province. She thanked the Chiefs for their strength and perseverance in continuing this work.

HYDRO ONE ADDRESS

Mr. Ferio Pugliese, Executive Vice President, Customer Care and Corporate Affairs, Hydro One, provided opening remarks on behalf of Hydro One. He thanked the Elder for her prayer and Chief Noganosh for welcoming them all to their territory. He also thanked Chief Hill for her opening remarks and highlighted her leadership on the CCOE and he thanked them all for coming and taking time out of their busy schedules. He said that this day was designed for the participants and it was a second one of what they wanted to host on an annual basis. Last year, they held a candid dialogue and he hoped that they could do the same this year.

In the last few years, Hydro One has gone through a IPO process which took them from a Crown Corporation to a privately held company. He said that they gave them increased opportunities to develop partnerships and the flexibility to grow their business. They have also changed their organization to a focus on putting the customer first; they provided a life sustaining service and they had to improve as an organization. Their work with First Nation communities was identified as a priority for Hydro One and he believed that they have made some significant progress.

He said that there have been three areas of focus including: education for the public, communities and leadership around how electricity generation and distribution worked in Ontario; advocacy to support First Nations such as the advocacy work undertaken by Hydro One on the First Nation delivery credit work with the Ontario Energy Board last year; and, First Nations engagement and outreach including community visits. They have also completed training with First Nations administrators on billing, collections and other issues and that had worked well.

Mr. Pugliese stated that they were also open to talking about capital projects and mentioned the Niagara Reinforcement Project (NRP) as an example. They had been paying for an asset that was not complete and not in service but now they would work together on this and there would be significant benefits for all involved. Indigenous procurement was another example. A6N was a Joint Venture between Six Nations of the Grand River Development Corporation (51% ownership) and Aecon Group Inc. (49% ownership). The company performs utility related work in southwestern Ontario. He said that Hydro One has delivered $23M last year in Indigenous procurement and this will be increased in future years.

He stated that the First Nations were valued partners; he encouraged them to take a look at Ontario's Long-Term Energy Plan. There were many opportunities for economic development but also it provides information on how the energy system was changing in the province. Their focus was on capacity building for everyone and on sustainability. He thanked them all for attending this session and he looked forward to ongoing engagements in their communities or regions.

INTRODUCTIONS

1. **Mr. Phil Goulais, Facilitator, Nipissing First Nation:** Personal introduction
2. **Mr. Stan Judge, Consultation Officer, Shawanaga First Nation:** Personal introduction
3. **Chief Elaine Johnston, Serpent River First Nation:** Chief Johnston thanked Hydro One for coming to her community for outreach, as this was positive experience.
4. **Ms. Amelia Williams, Chiefs of Ontario:** Personal introduction
5. **Amy Lickers, Chiefs of Ontario:** Personal introduction
6. **Chief Bruce D. Archibald, Taykwa Tagamou Nation:** Personal introduction
7. **Chief Rodney Noganosh, Chippewas of Rama First Nation:** Chief Noganosh mentioned that they had recently passed their land code vote with 91% of the membership's support.
8. **Councilor Dan Shilling, First Nation Manager, Chippewas of Rama First Nation:** Personal Introduction
9. **Elder Myrna Watson, Chippewas of Rama First Nation:** Personal introduction
10. **Chief Ava Hill, Six Nations of the Grand River:** Personal Introduction
11. **Councilor Wray Maracle, Six Nations of the Grand River:** Personal introduction
12. **Darryl Hill, A6N Utilities LP:** Personal introduction
13. **Daniel Charbonneau, Indigenous Relations, Hydro One:** Personal introduction
14. **Brian George, Indigenous Network Circle, Hydro One:** Personal introduction
15. **Kevin Hill, Indigenous Network Circle, Hydro One:** Personal introduction
16. **Kyla Thistle, Contract Officer, Supply Chain, Hydro One:** Personal introduction
17. **Ferio Pugliese, Vice President, Customer Care and Corporate Affairs, Hydro One:** Personal introduction
18. **George Kakeway, Indigenous Relations, Hydro One:** Personal introduction
19. **Susan Wylie, Director, Supply Chain, Hydro One:** Personal introduction
20. **Cesar Martinez, Customer Care Manager, Hydro One:** Personal introduction
21. **Tania Jacko, Energy Advisor, Whitefish River First Nation:** Personal introduction
22. **Joel Strickland, Vice-President, Longnorth Capital Group:** Personal introduction
23. **Jake Linklater, President, Longnorth Capital Group:** Personal introduction
24. **Chief Rick Allen, Constance Lake First Nation:** Personal Introduction
25. **Councilor Peggy Mansur, Chippewas of Nawash First Nation:** Personal introduction
26. **Michael Harney, Economic Development Officer, Nipissing First Nation:** Personal introduction
27. **Jay Armitage, Hydro One:** Personal introduction
28. **Steven Mantifel, Hydro One:** Personal introduction
29. **Chief Jason Fisher, Moose Deer Point First Nation:** Personal introduction
30. **Chief Gerry Duquette Jr., Dokis First Nation:** Personal introduction
31. **Chief Lloyd Myke, Magnetewan First Nation:** Personal introduction
32. **Chief Warren Tabobondung, Wasauksing First Nation:** Personal introduction
33. **Councilor Richard Jason, Shawanaga First Nation:** Personal Introduction
34. **Harvey Thunderchild, Wahnapitae First Nation:** Personal Introduction

35. **Shane Innes, Hydro One:** Personal introduction
36. **Kevin Hill, Indigenous Network Circle, Hydro One:** Personal introduction
37. **Councilor Gary Smith, Naicatchewenin First Nation:** Personal introduction
38. **Chief Robin McGinnis, Rainy River First Nation:** Personal introduction
39. **Chief Steve Miller, Atikamekshang Anishnawbek:** Personal Introduction
40. **Grand Chief Francis Kavanagh, Treaty #3:** Personal introduction
41. **Chief Wayne Smith, Naicatchewenin First Nation:** Personal introduction
42. **Stan Kapashesit, Moose Cree First Nation:** Personal introduction
43. **Derek Chum, Indigenous Relations, Hydro One:** Personal introduction
44. **Tausha Esquega, Indigenous Relations, Hydro One:** Personal introduction.
45. **Chief Edward Wawia, Red Rock Indian Band:** Personal introduction
46. **Jeff Corbiere, Renewable Energy Coordinator, M'Chigeeng First Nation:** Personal introduction.
47. **Albalina Metatawabin, General Manager, Mushkegowuk Tribal Council:** Personal introduction.
48. **Chief R. Donald Maracle, Mohawks of the Bay of Quinte:** Personal introduction.
49. **Chief Philip Franks, Wahta Mohawks:** Personal introduction
50. **Christine Goulais, Hydro One:** Personal introduction.
51. **Councilor Larry Sault, Mississaugas of the New Credit First Nation:** Personal introduction.
52. **Councilor Lawrence Solomon, Sagamok Anishnawbek First Nation:** Personal introduction.
53. **Marlene Stiles, Economic Development Officer, Chippewas of Georgina Island First Nation:** Personal introduction.
54. **Chief James R. Marsden, Alderville First Nation:** Personal introduction.
55. **David Mowat, Mississaugas of Scugog Island First Nation:** Personal introduction.
56. **Councilor Patrick Brennan, Henvey Inlet First Nation:** Personal introduction.
57. **Chief Andrew Aguonie, Sheguiandah First Nation:** Personal introduction.
58. **Chief Dean Roy, Sheshegwaning First Nation:** Personal introduction.
59. **Councilor Jim Meness, Algonquins of Pikwakanagan First Nation:** Personal introduction.
60. **Jeff Smith, Hydro One:** Personal introduction.
61. **Erika Dawson, Hydro One:** Personal introduction.
62. **Councilor Ted Williams, Chippewas of Rama First Nation:** Personal introduction.
63. **Chief Vanessa Powassin, Animakee Wa Zhing #37:** Personal introduction.
64. **Robin Koistinen, Temagami First Nation:** Personal introduction.
65. **Councilor Laurie Hockaday, Curve Lake First Nation:** Personal introduction.
66. **Warren Lister, Vice President, Customer Service, Hydro One:** Personal introduction.
67. **Councilor Anthony Petten, Ginoogaming First Nation:** Personal introduction.
68. **Councilor Ernest Waboose, Ginoogaming First Nation:** Personal introduction.
69. **Gary Allen, Executive Director, Grand Council Treaty #3:** Personal introduction.
70. **Sarah Luce, S. Barnett and Associates (Wabigoon Lake First Nation):** Personal introduction.
71. **Chief Gregory Nadjiwon, Chippewas of Nawash Unceded First Nation:** Personal introduction.
72. **Chief A. Myeengun Henry, Chippewas of the Thames First Nation:** Personal introduction.

73. **Valerie George, Consultation Coordinator, Chippewas of Kettle and Stoney Point First Nation:** Personal introduction.
74. **Sara Jane Souliere, Indigenous Relations, Hydro One** : Present
75. **Chief Reginald Niganobe, Mississaugas #8 First Nation:** Personal introduction.
76. **Ron Allen, Nigigoonsiminikaaning First Nation:** Personal introduction.
77. **Chief Daniel Miskokomon, Bkejwanong Territory (Walpole Island):** Personal introduction.
78. **Vivian Yoanidis, Director, Recruitment, Diversity & Inclusion, Hydro One:** Personal introduction.
79. **Alicia Sayers, Hydro One:** Personal introduction.
80. **Chief Joel Babin, Wahgoshig First Nation:** Personal introduction.
81. **Bruno Jesus, Director, Strategy and Integrated Planning, Hydro One:** Personal introduction.
82. **Chief Duke Peltier, Wikwemikong Unceded First Nation:** Personal introduction.
83. **Tabatha Bull, Senior Manager, First Nations and Metis Relations, Independent Electricity System Operator**: Personal introduction.
84. **Erika Dawson, Indigenous Relations, Hydro One:** Present
85. **Emily Spitzer, Indigenous Relations, Hydro One:** Present

HYDRO ONE CUSTOMER SERVICE

Mr. Cesar Martinez, Customer Care Manager, Hydro One, provided an overview of his powerpoint presentation entitled “Customer Programs”. To date, he explained, they had visited over 1,500 customers in 35 Communities across the province. In addition, there have been a reduction of customers in arrears by 2,400 since January 2017, a reduction from 8,900 to 6,500. Hydro One launched a blitz in August 2017 to reach out to customers who were not receiving the First Nations Delivery Credit. Since then, they had reduced that number by 1,600 to a total of 4,891. He asked for assistance in making sure that their members registered with their status cards for the delivery credit, as there were still approximately 5000 customers who were not registered. They had also doubled the Ontario Electricity Support Program (OESP) enrollments for First Nations customers through their local efforts from 1,600 to 3,400. Enrollment in these programs should be much higher and stated that Hydro One could work with First Nation customers to take advantage of their programs.

He provided a list of those communities where there were customers who had not yet signed up for the First Nations Delivery Credit (FNDC). Hydro One will be attempting to have 100% enrollment in FNDC by the end of 2018 to ensure all customers are receiving the full benefit of the credit. In order to achieve this, Hydro One needed the support of the First Nations and they would also be looking at increasing their local visits, identify seasonal properties where non-status residents live (which do not qualify for the FNDC) and initiating social media and other marketing campaigns. It was important because the credit was significant and he gave an example of a bill which took the total charge from $699 to $ 399 from the previous year in the same month.

Mr. Martinez encouraged them to get in touch with Hydro One to request a local session which could include one-on-one meetings with customers, assist with enrollments in the different programs and answer any questions or concerns that local customers might have.

Chief Elaine Johnston: Chief Johnston asked that the specific numbers for her First Nation could be sent to her so they would know how many have been enrolled for the FNDC and how many more need to enroll. Mr. Martinez stated that this could be sent to her.

Chief ______: The Chief asked when they could expect that this FNDC would be available to their off-reserve members, as it should apply to all First Nations. Mr. Martinez said that some of their other programs do apply off-reserve and could be accessed by off-reserve members but the FNDC, at this point in time, was only for on-reserve residents. Chief Ava Hill, Chiefs Committee on Energy, added that they were working on this and that they were proceeding in stages. They next stage was an attempt to get the FNDC apply to all band owned buildings, then for private businesses on-reserve and then they were going to work on getting the same benefit for their off-reserve members. She said they agreed that the benefit should be available to all First Nations regardless of where they resided and she asked that all the leaders lobby the province whenever possible.

Chief R. Donald Maracle: Chief Maracle asked how many people had not yet signed up for the FNDC and the response was that there were approximately 5000. The Chief asked if their 911 addresses had been sent and the response was that they had not. The Chief said that the Chiefs Committee on Energy would work on asking their Chiefs to send their 911 lists and Mr. Martinez said that these could be sent to Chris Cooley or himself.

Robin Koistinen, Temagami First Nation: Ms. Koistinen suggested that these First Nation customers might also be being charge tax and asked how retroactive that would be if they provided the information to take that off their bills. She also asked about how retroactive for the FNDC or the OESP. Mr. Martinez mentioned that for the OESP, it would not be retroactive; he also noted that people have to re-enroll for that after two years so that was something they had to work on as well. Benefit for the FNDC could go back to July 2017. For the taxes, he believed that it went back on during the current fiscal year.

Chief Elaine Johnston: Chief Johnston said that she had some concerns with providing the 911 lists as there were issues with this since it did not always co-relate to the residences. She also added that if the First Nations were not enrolling again for the OESP, maybe it was a communication issue. Mr. Martinez agreed that it was likely a communication issue; the letter goes out by mail 90 days before but people were not reading it. They needed to look at communicating this information in different ways.

Councilor Peggy Mansur, Chippewas of Nawash First Nation: Councilor Mansur asked if there were any representatives in the room from the welfare administrator organizations and was told that there was not. She suggested that they might want to increase their communications with this group and some others who would be relevant to these discussions. Mr. Martinez said that there was some communication but not enough; they have attempted to reach out to the welfare administrators in the communities when they were there. Councilor Mansur suggested that more cooperation was needed in coordinating community visits. Mr. Martinez agreed with this and would look at different groups that they could meet with locally and regionally.

Valerie George, Chippewas of Kettle and Stoney Point First Nation: Ms. George asked if they could get an extension on the OESP re-enrollment deadline. Mr. Martinez stated that there was no deadline but he said that they would look at the letter again to check for clarity and also follow up with those customers who have not re-enrolled. Hydro One also wanted to talk to the Ontario Energy Board about making that transition easier for the customer.

CHIEFS OF ONTARIO ADDRESS

Ms. Amy Lickers, Chiefs of Ontario, provided an overview of her powerpoint presentation entitled "Ontario First Nations Sovereign Wealth LP – Update February 2018". Ms. Lickers explained that she was from Six Nations and she worked at the Chiefs of Ontario; she worked with a number of Chiefs Committee there. For the past few years, she said, they have been working on an agreement with the province to acquire Hydro One shares. 129 First Nations have signed on to be shareholders in Hydro One; she provided the ownership structure and an overview of the agreement.

Currently they had an interim board of directors in place and they were in the process of electing board members and they were hoping to ratify a new board at the All Ontario Chiefs Conference in June 2018. She asked that they contact their PTO for suggestions on who should be on the board. She said that they will grow the fund to $90M or 12 years, whichever comes first, so there was time for more discussions around a funding formula.

Chief _______: The Chief asked about if the First Nation did not have a PTO, how could they follow up on that. Ms. Lickers noted that there were a number of Independent First Nations and they have formed a group and suggested that could be avenue to participate.

PROGRESS ON PROCUREMENT/BUSINESS PARTNERSHIPS PANEL

Ms. Susan Wylie, Director, Supply Chain, Hydro One, introduced the panel including: Mr. Darryl Hill, A6N Utilities LP; Mr. Brian Johnson, Aecon-Six Nations Joint Venture; Chief Reginald Niganobe, Mississaugas #8 First Nation; and, Ron Allen, Nigigoonsiminikaaning First Nation.

<u>What are the top three challenges in working with Hydro One?</u>

Mr. Johnson stated that it was getting through a complicated procurement process. There were a number of documents needed and they were fortunate to have a partner in Aecon with a lot of resources to assist in getting that done. He suggested that stronger relationships would be helpful. Mr. Hill stated that they needed to meet with everyone involved in the project and clearly set out the milestones for the project. There were challenges to being a small company like theirs. Ms. Wylie stated that they could look additional education programs and more relationship building around the document requirements for procurement.

Mr. Johnson also suggested that they needed an avenue or process to identify the skills sets available in different Indigenous businesses. Ms. Wylie stated that they had been working with

Indigenous Relations to build that directory and outreach activities were being undertaken to have a better working knowledge of the business out there when the projects come up.

Mr. Allen noted that there were issues with Aboriginal set asides, as it was very hard to get in there and there seemed to be many different ways to get screened out as an Indigenous business. Ms. Wylie noted that Mr. Pugliese had mentioned their commitments and they were undertaking more outreach activities to get to know the capacity out there. Hydro One had committed to establishing a set aside process in 2018.

Chief Niganobe stated that they had experienced the procurement issues that have been mentioned and added that they had to build their capacity in order to take advantage of procurement opportunities.

What advice do you have for Hydro One in working with the communities to build community capacity and enhance opportunities for Indigenous businesses?

Mr. Hill suggested that they should have more Indigenous people to make those initial introductions and a good retention plan to keep them on. Mr. Johnson added that they should hold their contractors to socially responsible behaviour around engaging with Indigenous communities where there were projects on the First Nation's territory. It was also suggested that Hydro One should measure and know how their contractors do in this.

Ms. Wylie asked how they could support communities through increased communications. Mr. Allen stated that they needed support for their basic programs to get their people driver's licenses and they also needed to address employment issues such as working with unions. Ms. Wylie suggested that they could bring in their Labour Relations team to address that needs. Mr. Hill stated that they worked with unions every day and suggested that they could help with that.

Final Panel Comments

Chief Niganobe suggested that they could do more regional liaison; he said that they had trouble finding skilled labour but they do have people who could do more. Mr. Allen stated that they had a hard time with relationship building so they could use some help with that. Mr. Johnson said that they wanted to be part of the solution and wanted to provide even more opportunities to community businesses. Their goal was to hire 100% from Six Nations and to achieve that, they needed the help of their partners. Mr. Hill added that they had a good partnership with AECON and they wanted to ensure their community members would get more experience. He thanked Chief Ava Hill for her support and they looked forward to sharing their experiences with other First Nations.

Chief Daniel Miskokomon, Bkejwanong Territory (Walpole Island): The Chief asked about maintaining cash flow and if they had a line of credit. Mr. Johnson agreed that this was challenging but, in their situation, their partner was AECON so they did not have to worry. Smaller companies would have trouble with this and he would suggest quicker milestone payments and keeping the lines of communication open to explain the situations

Councilor Larry Sault, Mississaugas of the New Credit First Nation: Councilor Sault stated that what he was seeing in the community was that they always looked for employees who had to have grade 12, but this was not always necessary depending on the position. They also should work with people to get their driver's licenses and those who have criminal records from the past. He also said that they should be challenging the unions on First Nation rights; First Nations have portable rights.

HYDRO ONE DIVERSITY AND INCLUSION

Vivian Yoanidis, Director, Recruitment, Diversity & Inclusion, Hydro One, provided an overview of her PowerPoint presentation entitled "Diversity and Inclusion at Hydro One". She provided information on Hydro One's Diversity and Inclusion Strategy, which had three main goals: to build a diverse workforce; to create a culture of inclusion; and, to be a leader in diversity and inclusion in the energy sector. She explained that background on the establishment of the Indigenous Network Circle. She also provided an overview of the company's commitment which included the following: hiring a Diversity & Inclusion Consultant to focus on Indigenous Outreach, Recruitment and Inclusion; hiring more Indigenous employees (regular hires, co-op/Internship, new graduates, Summer Outreach Program); visiting communities across the province sharing information about recruitment requirements and career opportunities; working with Hydro One Indigenous employees to educate and raise cultural awareness within the organization; engaging Indigenous communities in a dialogue regarding training and development partnerships; and, researching and adopting, as required, Indigenous employment and retention industry best practices.

Panel – Hydro One's Indigenous Network Circle

Mr. Kevin Hill introduced himself saying that he was from Six Nations, adding that he has been with Hydro One for many years and he was happy to see the focus on the Indigenous employees. He spoke to the importance of Indigenous Circle Network; he was proud to sit in a room with other First Nations people at Hydro One. As staff, it was important to have those links to their people.

Mr. Brian George stated that he was from Saugeen and had been a forester for Hydro One for 12 years. The Indigenous Circle Network was a good way for them to get involved in organization and they could provide more support for employees particularly new First Nation employees coming in.

Mr. Charles Doxtator-Young stated that he was from Six Nations. He stated that it was not easy coming from the reserve and joining Hydro One; it seemed far from where he thought he should be but it was important to provide for his family. The Network was a good way for him to be involved and promote careers at Hydro One to their First Nation youth.

Ms. Alicia Sayers stated that she was from Garden River First Nation and had been with Hydro One since 2009. As a young person, she said, she did not know what Hydro One was or what they did but she was not from a community served by Hydro One. She had started there in a summer position and she became fascinated by what Hydro One did so she joined the company full time when she graduated. She felt very isolated; she felt alone. She was happy to be part of the Network and they were there for the right reasons. She said that she believed in the company and what they were doing.

Steven Mantifel, Hydro One: Mr. Mantifel stated that the Network was new and he asked the panelists how they planned on engaging other Hydro One staff. Mr. Doxtator-Young responded that they have not yet set goals for the Network, as they were still building it. To him, he said, it made sense to make those connections because they wanted to share information with non-First Nations employees as well as First Nations employees. He said they were not quite there yet but the idea of non-First Nations group of employees, an ad-hoc committee, to feed into the Network was discussed.

Ms. Amy Lickers, Chiefs of Ontario: Ms. Lickers asked if the panelists had ideas for promoting First Nations employment outside of Hydro One. Mr. Doxtator-Young said that, in Hydro One, they had staff that worked on this so this was happening but they wanted to support that through the Network's activities. Mr. Hill noted that they could also develop their own Network webpage to distribute information as well as encouraging more apprenticeships so people will look to Hydro One for training.

Chief Joel Babin, Wahgoshig First Nation: Chief Babin mentioned that he had a number of issues with Hydro One and he was not sure of the timing to bring them up. He felt that one department at Hydro One for Indigenous Relations was not enough; it should be throughout the organization. He felt that they were trying to dictate the relationship with the First Nations.

Councilor Dan Shilling, First Nation Manager, Chippewas of Rama First Nation: Councilor Shilling stated that he wanted to commend the panelists. In terms of First Nations employment in Hydro One, he asked if they had specific targets they would attempt to reach. If they did not set goals, he felt that this could turn into a token project with no real results. Ms. Yoanidis stated that it was difficult as they needed to self-identify as First Nations or Metis. She did not feel it would be a token project as it has been a long time coming; they wanted to increase the current number of 2.3%. They did not have a hard target in mind but wanted to increase that.

Chief Daniel Miskokomon, Bkejwanong Territory (Walpole Island): The Chief mentioned that he really enjoyed the presentations and stated that their youth needed to hear these presentations. He also mentioned that when Hydro One staffs come into the communities or territories, they should have a certain number of Indigenous staff with knowledge of the area to deal with any issues. He said that their people could work in their territory and they would be role models seen by the youth. Mr. Doxtator-Young said the Hydro One had their own program such as apprenticeships and it was a difficult process to go through because they had to leave home. He agreed it was not perfect but they had to put their time in and pay their dues. The Chief agreed and said that their youth needed to be aware of the challenges and presentations such as these would have a positive impact.

HYDRO ONE TRANSMISSION AND DISTRIBUTION PLANNING

Bruno Jesus, Director, Strategy and Integrated Planning, Hydro One, provided an overview of his powerpoint presentation entitled "First Nations – Reliability Performance Overview". He provided detailed information on the distribution grid modernization and an overview of the work that will take place in the community.

Chief Edward Wawia, Red Rock Indian Band: The Chief asked about the Ring of Fire Transmission lines and if Hydro One was involved in that. Mr. Jesus responded that they probably were but he was not sure. He said that he could find out. Now confirmed Hydro One is not currently building any transmission lines to supply the Ring of Fire area.

Chief _____________: The Chief stated that coordinating the communications was key within the community when the power goes out; they needed to let their communities know when they can expect the power to come back on. Mr. Jesus stated that they were looking at working with a central coordinating person when the power goes out.

Chief R. Donald Maracle, Mohawks of the Bay of Quinte: The Chief asked about the frequent power outages on his territory and asked if this could be because of defective equipment. Mr. Jesus said that he was note sure because they would have to look specifically at that case but during storms, they do have outages and Hydro One responds as quickly as possible. The Chief then asked what the plans were to address the issues of climate change. Mr. Jesus stated that they had met with the Ministry of Environment and they have established a committee to look at that. He said that the transmission usually performed well but the distribution networks were not as resilient.

Robin Koistinen, Temagami First Nation: Ms. Koistinen said that they wanted to talk about traditional territories and the transmission lines that cross these territories. There were established Indigenous rights and interests in their traditional territories and they need to be aware when work was taking place in these territories. When notifying the First Nation was delayed, the proponents then try to rush through and identify any issues they may have. The First Nations have to be more involved earlier on in the process. It was a concern that the First Nation was not involved when the lines went in and now they were not being consulted on the huge plans for refurbishment. They wanted to identify opportunities for their people in this work and address issues of consultation/accommodation.

Chief Joel Babin, Wahgoshig First Nation: The Chief stated that his First Nation was looking at creative solutions and making their own investments but it was difficult to work with Hydro One to get the upgrades for their systems to supply their needs for economic development. They were trying to grow their community but they ended up waiting for Hydro One. Mr. Jesus said that he wanted to learn what the issues were and suggested they talk off line.

Chief Duke Peltier, Wikwemikong Unceded First Nation: The Chief provided an overview of his community's issue with ongoing and lengthy power outages. In some situation, the weather was very cold and the community members were asking a number of questions around the reliability of their hydro. He suggested that maybe they should look at resourcing support stations for those with ongoing and lengthy outages – warming stations, food for people, supporting those with health issues, etc. The community was large regional centre and he believed that they needed their own substation. They need to talk to Hydro One about this as it very challenging to the community not only residents but business who are attempting economic development initiatives. Mr. Jesus suggested that they need to discuss this.

INDEPENDENT ELECTRICITY SYSTEM OPERATOR

Tabatha Bull, Senior Manager, First Nations and Metis Relations, Independent Electricity System Operator (IESO), provide a brief overview of her powerpoint presentation entitled "Looking Ahead – Opportunities for First Nation Communities through the Implementation of the LTEP". She explained that the government's Long-Term Energy Plan (LTEP) was released on October 26, 2017 along with two directives to the IESO for the completion of an LTEP Implementation Plan by January 31, 2018. The IESO delivered its' implementation plan, *Putting Ontario's Long-Term Energy Plan Into Action*, informed by public engagement, to the Minister on January 31, 2018. The Implementation Plan outlined the objective and scope of each of the directed initiatives to enable LTEP policy objectives and provided key implementation milestones.

Key to their implementation plan was supporting Indigenous capacity and leadership, encouraging an innovative sector and delivering a flexible and efficient system. She then provided an overview of the Energy Support Programs (ESP). She explained that the next steps included: engagement plans would be developed for each initiative; the conservation report and recommendations were nearing completion and the report would be posted publicly; Energy Support Programs (Public Webinar February 22nd at 10:00 am and further engagement on revised programs) and, continued and ongoing engagement with communities.

Chief Joel Babin, Wahgoshig First Nation: The Chief asked a question around the connection costs process that IESO had with Hydro One. Ms. Bull stated that IESO had no authority to change those costs because it was a standard; they could not go outside of that. They could be directed by the Ministry but they could not do this on their own. She added that they were working with communities to identify other sources of funding and mentioned NRCan as a potential source.

OPEN FACILITATED DISCUSSIONS

Participants were given the opportunity to provide their comments:

Tania Jacko, Energy Advisor, Whitefish River First Nation stated that her community appreciated the Delivery Credit, as this brought a lot of relief to many in the community. It was a positive step to building a stronger relationship. There were a lot of good suggestions today; she suggested that the conservation programs should be extended and make them accessible to low and moderate income households. She also encouraged Hydro One to use more Indigenous contractors. Mr. Pugliese stated that they were looking at expanding their affordability funding and also looking at launching pilots for additional home assistance. It was noted that there was more information on the Affordability Fund on the website.

Chief Warren Tabobondung, Wasauksing First Nation, thanked Hydro One for what had been over the last year and also thanked the Chief Committee on Energy for moving their issues forward. He wanted to mention again the transmission lines and distribution network that cut through their traditional territories and this needed to be addressed. These lines had an impact on their traditional land use activities. He stated that he hoped the dialogue tables would continue and he was grateful for the relief that the First Nation Delivery Credit had provided to his community. There was still a lot of work to do.

Chief Daniel Miskokomon, Bkejwanong Territory (Walpole Island) stated that he wanted to see the identification of milestones in their relationship, increased number of Indigenous employees for example, because they needed to be able to evaluate that.

Chief Elaine Johnston, Serpent River First Nation, stated that since she was part of the Chiefs Committee on Energy, she has learned a lot about their energy system and she felt that these dialogues were valuable. Hydro One should have an Indigenous Relations that not only looked at legal issues but also policy issues. They needed to look at land issues and transmission lines. She thanked them for the information that they could share with their communities. She mentioned the priorities areas of the CCOE in terms of expanding the application of the delivery credit.

Robin Koistinen, Temagami First Nation, thanked the CCOE for the work they have done already and she asked Hydro One could not just go ahead and expand delivery credit to band owned buildings, private business on reserve and also off-reserve members. She said that Mr. Pugliese had mentioned that since they changed from being a crown corporation, they had more flexibility. She asked why the province could dictate on that. Mr. Pugliese stated that they still worked in a regulated environment so they had to follow the same rate process involving the Ontario Energy Board; they could make recommendations for a change in policy. The OEB considered what was best for all rate-payers in Ontario. Amy Lickers mentioned that impact of the provincial budget on the delivery credit and stated that this was why they were lobbying around the provincial budget; this will have to be ongoing.

Chief Joel Babin, Wahgoshig First Nation, stated that Hydro One had taken the first step towards developing a meaningful relationship with Fist Nations. However, he felt that there was very little opportunity for participation of First Nation leadership in the agenda for this meeting; they had issues they wanted to discuss and he did not feel that they participated as equal partners in this session. He admitted that there would be some very uncomfortable conversations that need to take place. For the next meeting, he encouraged them to let First Nations state their concerns in their own voice.

Michael Harney, Nipissing First Nation, stated that they were thankful for the delivery credit but he did feel comfortable that this would last over time. There might be changes with a change in government so he wanted to see this strengthened; maybe they needed to look at generating their own electricity and work with the grid to provide that to their communities.

Chief A. Myeengun Henry, Chippewas of the Thames First Nation, asked what caused this change at Hydro One and when funds were made available to programs, where did this come from. Mr. Pugliese stated that he has only been with the company since September 2016; when the company was privatized, a new Board was brought in. There was also a new executive team brought in and the key values focused on communities and customers. There was also a conversation around Indigenous communities because they served many of them. The organizational mandate was changed and they believed it was important to engage with these communities as equal partners. Leveraging opportunities to grow economically was good for everyone. Each board meeting, they discuss Indigenous issues and they have a committee of the Board that worked on this.

Chief R. Donald Maracle, Mohawks of the Bay of Quinte, stated that they were thankful for the delivery credit and the programs but this did not settle past grievances where lands had been taken fraudulently from First Nations. There was no extinguishment of First Nations rights. First Nations want to look at revenue streams and innovative ways to address past grievances. Mr. Pugliese stated that they are open to that and encouraged them to look at the LTEP for other opportunities as well.

Chief Rick Allen, Constance Lake First Nation, asked for clarification around when they could expect a response from Hydro One on negotiating compensation for past grievances. Mr. Pugliese stated that they have to work on those situations on a case by case basis and they were in these conversations now. They were happy to talk about these situations as they arise.

Robin Koistinen, Temagami First Nation, asked that if, in the spirit of an open and transparent relationship, Hydro One could share existing agreements that have been negotiated on compensation for transmission lines. Mr. Pugliese said that they could not share specific details of each community's terms; often the community itself wanted that privacy. He encouraged her that if her community wanted to have this conversation to come talk to them.

WRAP UP

Chief Ava Hill was provided the opportunity to provide closing comments. She said that she too was still learning about energy in order to help the community. She thanked all the presenters and mentioned that she particularly enjoyed the panel presentation of Indigenous employees of Hydro One. She felt that this panel was inspirational; their young people needed to see these examples. She said that they would be looking in more detail at compensation for transmission lines and she appreciated the opportunity to learn more about hydro transmission and distribution today. She said that her community had an agreement that could be shared with others. She said that it was important that they were able to continue these discussions and she liked the format of the session. She suggested that, for future meetings, the Chiefs Committee on Energy could assist with the development of the agenda. The CCOE would be working on pushing the FNDC to include band building in the near future and she suggested that they could meet regularly with Hydro One to continue to strengthen that relationship but also work on finding solutions to address their issues.

Mr. Pugliese said that he could see that their leadership role was a challenging one and stated the importance of not only talking about solutions but acting on those. He said that he welcomed the establishment of a joint group to work on next year's session agenda and they very much looked forward to further strengthening that relationship. They had a more powerful voice when they could work collectively. Increasing ways of tracking the success of their relationship was a good idea and he was confident that they could be the benchmark for success in North America.

A closing prayer was provided by Elder Watson.
Meeting adjourned.

ANNEX A

Hydro One Second Annual First Nations Engagement Session

Chippewas of Rama First Nation, Casino Rama Silvernightingale Room

Goal:	Reinforce working relationships between First Nation communities and Hydro One through continuous engagement and constructive dialogue.
Objectives:	a) Share information on key progress made since February 2017. b) Discuss priorities moving forward in 2018.
Facilitator:	Phil Goulais Advisory & Contract Services
Report Writer:	Carolyn Hunter Hunter-Courchene Consulting Group Inc.
Graphic Recorder:	Disa Kauk, Thinklink Graphics

8:00 – 8:30	**Networking Breakfast (30 minutes)**
8:30 – 8:45	**Opening Prayer from Elder Myrna Watson** **Welcoming Remarks** • Chief Rodney Noganosh Chippewas of Rama First Nation (10 minutes)
8:45 – 9:05	**Opening Remarks** • Mayor Steve Clarke City of Orillia (10 minutes) • Chief Ava Hill on behalf of the Chiefs Committee on Energy (10 minutes)
9:05 – 9:20	**Hydro One Address** • Ferio Pugliese Executive Vice President Customer Care and Corporate Affairs (15 minutes)
9:20 – 9:35	**Round of Introduction** (15 minutes)
9:35 – 10:00	**Hydro One Customer Service** • Cesar Martinez, Customer Care Manager, Progress on Get Local Initiatives - First Nations Delivery Credit, Ontario Electricity Support Program, Conservation Programing, etc. (15 minutes) • Qs & As (10 minutes)
10:00 – 10:15	**Health Break and Networking** (15 minutes)
10:15 – 10:45	**Chiefs of Ontario Address** • Amy Lickers, Director, Economic and Sustainable Community Development: Progress on Ontario First Nations Sovereign Wealth LP (15 minutes) • Qs & As (15 minutes)

10:45 – 11:30	**Progress on Procurement/Business Partnerships Panel** Facilitator: Susan Wylie Director, Supply Chain Panelists: Darryl Hill, A6N Utilities LP; Bryan Johnston, Aecon-Six Nations Joint Venture; Chief Reginald Niganobe, Mississauga#8 First Nations & Ron Allen, Nigigoonsiminikaaning First Nation (30 minutes) • Qs & As (15 minutes)
11:30 – 12:00	**Hydro One Diversity & Inclusion** • Vivian Yoanidis, Director Diversity & Inclusion: Progress on Diversity & Inclusion Strategy and on Indigenous Leadership Learning Program (10 minutes) • Alicia Sayers, Kevin Hill, Brian George & Charles Doxtater-Young from the Indigenous Network Circle (10 minutes) • Qs & As (10 minutes)
12:00 – 13:00	**Networking Lunch** (60 minutes)
13:00 – 14:00	**Hydro One Transmission and Distribution Planning** • Bruno Jesus, Director, Strategy & Integrated Planning: First Nations Reliability Performance Overview (30 minutes) • Qs & As (30 minutes)
14:00 – 14:45	**Independent Electricity System Operator** • Tabatha Bull, Senior Manager, First Nation and Métis Relations: Progress on key Indigenous energy programs (30 minutes) • Qs & As (15 minutes)
14:45 – 15:30	**Open Facilitated Discussions** • Phil Goulais, Facilitator: *What are Hydro One & First Nations Priorities for 2018?* (45 minutes)
15:30 – 15:45	**Health Break and Networking** (15 minutes)
15:45 – 16:00	**Closing Remarks** • Chief Ava Hill on behalf of the Chiefs Committee on Energy (5 minutes) • Ferio Pugliese Executive Vice President Customer Care and Corporate Affairs (5 minutes) **Closing Prayer from Elder Myrna Watson**
16:00 -17:00	**Networking**
17:00 – 18:00	**Dinner**
18:00 – 19:00	**Mr. Don Burnstick Comedy Show Performance / Networking**