ATTACHMENT 8
POWERSTREAM 2016 AUDITED FINANCIAL STATEMENTS

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Financial statements of

PowerStream Inc.

December 31, 2016

PowerStream Inc.
December 31, 2016

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Independent Auditor's Report

To the Shareholder of
PowerStream Inc.

We have audited the accompanying financial statements of PowerStream Inc., which comprise the balance sheet as at December 31, 2016, the statements of income and other comprehensive income, changes in equity and of cash flows for the year ended December 31, 2016, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with International Financial Reporting Standards, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

Our responsibility is to express an opinion on these 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 financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the 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 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 financial statements present fairly, in all material respects, the financial position of PowerStream Inc. as at December 31, 2016, and its financial performance and its cash flows for the year then ended, in accordance with International Financial Reporting Standards.

Deloitte LLP

Chartered Professional Accountants
Licensed Public Accountants
March 3, 2017

PowerStream Inc.

Balance sheet
as at December 31, 2016
(In thousands of dollars)

	2016	2015
	$	$
Assets		
Current assets		
Cash	13,972	6,859
Accounts receivable (Note 17(c))	114,383	105,563
Unbilled revenue	117,981	95,036
Due from related parties (Note 10)	23,796	13,654
Inventories (Note 6)	3,719	3,226
Income taxes receivable	8,764	9,734
Prepaids and other assets	4,832	5,208
	287,447	239,280
Long-term assets		
Property, plant and equipment (Note 7)	1,193,101	1,119,147
Intangible assets (Note 8)	50,848	53,073
Investment in a joint venture (Note 5)	8,216	8,169
Deferred tax assets (Note 20)	-	7,227
Goodwill (Note 8(b))	42,543	42,543
	1,582,155	1,469,439
Liabilities		
Current liabilities		
Short-term debt (Note 11(a))	135,000	50,000
Infrastructure Ontario financing (Note 11(b))	74,514	74,691
Customer deposits	19,711	15,991
Accounts payable and accrued liabilities (Note 9)	141,875	145,962
Due to related parties (Note 10)	19,925	19,075
Liability for subdivision development	2,589	4,820
Current portion of finance lease obligation (Note 16)	384	360
Notes payable (Note 12)	-	20,000
	393,998	330,899
Long-term liabilities		
Notes payable (Note 12)	182,430	162,430
Debentures payable (Note 12)	347,528	347,407
Finance lease obligation (Note 16)	15,712	16,095
Deferred tax liabilities [redacted]	8,952	-
Post-employment benefits obligation (Note 13)	20,295	18,309
Deferred revenue	158,386	138,406
	733,303	682,647
	1,127,301	1,013,546
Shareholders' equity		
Share capital (Note 14)	342,184	342,184
Accumulated other comprehensive income	547	2,083
Retained earnings	112,123	111,626
	454,854	455,893
	1,582,155	1,469,439

Approved on behalf of the Board on March 3, 2017

_______________ Director _______________ Director

The accompanying notes to the financial statements are an integral part of this financial statement

PowerStream Inc.
Statement of income and other comprehensive income
year ended December 31, 2016
(In thousands of dollars)

	2016	2015
	$	$
Revenue (Note 10(a))		
Sale of energy	**1,148,964**	1,021,312
Distribution revenue	**171,042**	159,438
Other revenue (Note 22)	**32,501**	32,772
Total revenue	**1,352,507**	1,213,522
Cost of power purchased	**1,133,771**	1,010,699
Operating expenses (Note 19)	**98,754**	100,218
Depreciation and amortization	**54,455**	48,931
	1,286,980	1,159,848
	65,527	53,674
Loss on derecognition of property, plant and equipment	**(1,924)**	(1,273)
Share in income from joint venture (Note 5)	**47**	837
Interest income	**414**	481
Interest expense	**(26,364)**	(24,884)
Income before income taxes	**37,700**	28,835
Income tax expense (Note 20)	**12,937**	3,390
Net income	**24,763**	25,445
Other comprehensive income		
Remeasurement of defined benefit obligation, net of tax of $554 (2015-$96) (Note 13(b))	**(1,536)**	264
Total income and other comprehensive income for the year	**23,227**	25,709

The accompanying notes to the financial statements are an integral part of this financial statement

PowerStream Inc.

Statement of changes in equity
year ended December 31, 2016
(In thousands of dollars)

	Share capital	Accumulated other comprehensive income	Retained earnings	Total
	$	$	$	$
As at January 1, 2015	327,184	1,819	114,297	443,300
Net income	-	-	25,445	25,445
Other comprehensive income,				
(net of tax of $96)	-	264	-	264
	-	264	25,445	25,709
Dividends paid	-	-	(28,116)	(28,116)
Issuance of common shares (Note 14)	15,000	-	-	15,000
Balance at December 31, 2015	342,184	2,083	111,626	455,893
Net income	-	-	24,763	24,763
Other comprehensive income,				
(net of tax of $554)	-	(1,536)	-	(1,536)
	-	(1,536)	24,763	23,227
Dividends paid	-	-	(24,266)	(24,266)
Issuance of common shares (Note 14)	-	-	-	-
Balance at December 31, 2016	**342,184**	**547**	**112,123**	**454,854**

The accompanying notes to the financial statements are an integral part of this financial statement

PowerStream Inc.
Statement of cash flows
year ended December 31, 2016
(In thousands of dollars)

	2016	2015
	$	$
Operating activities		
Net income for the year	**24,763**	25,445
Adjustments to determine cash provided by operating activities		
Share of income from joint venture (net of 2016 dividend of $Nil (2015 - $204))	**(47)**	(633)
Depreciation of property, plant and equipment	**49,098**	46,259
Amortization of intangible assets	**7,671**	4,992
Post-employment benefits expense	**543**	1,689
(Gain)/loss on disposal of property, plant and equipment	**283**	506
Amortization of deferred revenue	**(3,659)**	(3,013)
Amortization of debenture issuance costs	**121**	119
Finance costs	**25,950**	24,403
Income tax expense	**12,937**	3,390
	117,660	103,157
Net change in non-cash operating working capital (Note 21)	**(41,551)**	19,177
Cash generated from operating activities	**76,109**	122,334
Interest paid	**(25,950)**	(24,411)
Income taxes received	**4,766**	-
Post-employment benefits payments	**(647)**	(382)
	54,278	97,541
Financing activities		
Dividends paid	**(24,266)**	(28,116)
Proceeds from Infrastructure Ontario financing	**-**	7,035
Payments to Infrastructure Ontario financing	**(177)**	-
Proceeds from the issuance of common shares	**-**	15,000
Proceeds of short-term debt	**85,000**	25,000
Payment of finance lease obligation	**(359)**	(337)
	60,198	18,582
Investing activities		
Proceeds on sale of property, plant and equipment	**128**	1,185
Contributions received from customers	**23,639**	20,768
Purchase of intangible assets	**(5,446)**	(15,444)
Purchase of property, plant and equipment	**(125,684)**	(138,883)
	(107,363)	(132,374)
Increase/(decrease) in cash during the year	**7,113**	(16,251)
Cash beginning of year	**6,859**	23,110
Cash, end of year	**13,972**	6,859

The accompanying notes to the financial statements are an integral part of this financial statement

1. Description of the business

PowerStream Inc. (the "Corporation") was amalgamated on January 1, 2009, under the Business Corporations Act (Ontario) and is wholly owned by PowerStream Holdings Inc., which in turn is owned by the Corporation of the City of Vaughan (the "City of Vaughan"), through its wholly owned subsidiary, Vaughan Holdings Inc.; the Corporation of the City of Markham (the "City of Markham"), through its wholly owned subsidiary, Markham Enterprises Corporation; and the Corporation of the City of Barrie (the "City of Barrie"), through its wholly owned subsidiary, Barrie Hydro Holdings Inc. PowerStream Holdings Inc. is jointly controlled by these three municipalities. The Corporation is incorporated and domiciled in Canada with its head and registered office located at 161 Cityview Boulevard, Vaughan, ON L4H 0A9.

The principal activity of the Corporation is distribution of electricity in the service areas of Alliston, Aurora, Barrie, Beeton, Bradford, West Gwillimbury, Markham, Penetanguishene, Richmond Hill, Thornton, Tottenham and Vaughan in the Province of Ontario, under a license issued by the Ontario Energy Board ("OEB"). The Corporation is regulated under the OEB and adjustments to the distribution rates require OEB approval. Collingwood PowerStream Utility Services Corp. ("Collus PowerStream") is a joint venture between the Corporation and the Town of Collingwood. It distributes electricity in Collingwood, Thornbury, Stayner and Creemore.

As a condition of its distribution license, the Corporation is required to meet specified Conservation and Demand Management ("CDM") targets for reductions in electricity consumption and peak electricity demand. As part of this initiative, the Corporation is delivering Independent Electricity System Operator ("IESO") funded programs in order to meet its targets.

Under the Green Energy and Green Economy Act, 2009, the Corporation and other Ontario electricity distributors have new opportunities and responsibilities for enabling renewable generation.
The Corporation commenced operations of a Solar Generation Business unit, in 2010, as permitted by these changes.

2. Basis of preparation

(a) Statement of compliance

These financial statements are prepared in accordance with International Financial Reporting Standards ("IFRS"), as issued by the International Accounting Standards Board (IASB).

(b) Basis of measurement

The financial statements have been prepared on a historical cost basis.

(c) Presentation currency

The financial statements are presented in Canadian dollars, which is also the Corporation's functional currency. All financial information has been rounded to the nearest thousand, except when otherwise noted.

(d) Use of estimates and judgments

The preparation of financial statements in conformity with IFRS requires management to make estimates, assumptions and judgments that affect the application of accounting policies and the amounts reported and disclosed in the financial statements. Estimates and underlying assumptions are continually reviewed and are based on historical experience and other factors that are considered to be relevant. Actual results may differ from these estimates.

2. Basis of preparation (continued)

(d) Use of estimates and judgments (continued)

Significant sources of estimation uncertainty, assumptions and judgments include the following:

(i) Unbilled revenue

The measurement of unbilled revenue is based on an estimate of the amount of electricity delivered to customers between the date of the last bill and the end of the year.

(ii) Useful lives of depreciable assets

Depreciation and amortization expense is based on estimates of the useful lives of property, plant and equipment and intangible assets. The Corporation estimates the useful lives of its property, plant and equipment and intangible assets based on management's judgment, historical experience and an asset study conducted by an independent consulting firm.

(iii) Cash Generating Units ("CGU")

Determining CGU's for impairment testing is based on Management's judgment. This requires an estimation of the value in use. The value in use calculation requires an estimate of the future cash flows expected to arise from the CGU and a suitable discount rate in order to calculate the present value.

(iv) Valuation of financial instruments

As described in Note 17, the Corporation uses the discounted cash flow model to estimate the fair value of the financial instruments for disclosure purposes.

(v) Other areas

There are a number of other areas in which the Corporation makes estimates; these include accounts receivable, inventories, post-employment benefits and income taxes. These amounts are reported based on the amounts expected to be recovered/refunded and an appropriate allowance has been provided based on the Corporation's best estimate of unrecoverable amounts.

3. Significant accounting policies

The Corporation's financial statements are the representations of management, prepared in accordance with IFRS. The accounting policies set out below have been applied consistently to all years presented in these financial statements, unless otherwise indicated.

The financial statements reflect the following significant accounting policies:

(a) Rate regulation

The Ontario Energy Board Act, 1998 gave the Ontario Energy Board ("OEB") increased powers and responsibilities to regulate the electricity industry. These powers and responsibilities include the power to approve or fix rates for the transmission and distribution of electricity, the power to provide continued rate protection for rural and remote electricity customers and the responsibility for ensuring that distribution companies fulfill obligations to connect and service customers. The OEB may prescribe license requirements and conditions including, among other things, specified accounting records, regulatory accounting principles, and filing process requirements for rate-setting purposes.

The Corporation recognizes revenue when electricity is delivered to customers based on OEB approved rates. Operating costs and expenses are recorded when incurred, unless such costs qualify for recognition as part of an item of property, plant and equipment or as an intangible asset.

3. Significant accounting policies (continued)

(b) Revenue recognition

(i) Electricity distribution and sale

Revenue from the sale and distribution of electricity is recorded on the basis of cyclical billings based on electricity usage and also includes unbilled revenue accrued in respect of electricity delivered but not yet billed. Revenue is generally comprised of the following:

- Electricity Price and Related Rebates. The electricity price and related rebates represent a pass through of the commodity cost of electricity.
- Distribution Rate. The distribution rate is designed to recover the costs incurred by the Corporation in delivering electricity to customers, as well as the ability to earn the OEB allowed rate of return. Distribution charges are regulated by the OEB and typically comprise a fixed charge and a usage-based (consumption) charge.
- Retail Transmission Rate. The retail transmission rate represents a pass through of costs charged to the Corporation for the transmission of electricity from generating stations to the Corporation's service area. Retail transmission rates are regulated by the OEB.
- Wholesale Market Service Charge. The wholesale market service charge represents a pass through of various wholesale market support costs charged by the IESO.

(ii) Other revenue

Other revenue includes revenue from renewable generation, sale of other services, contributions from customers and performance incentive payments.

Revenue related to the sale of other services is recognized as services are rendered. Revenue related to the generation of revenue from renewable generation sources is recognized as the output is produced.

Certain items of property, plant and equipment are acquired or constructed with financial assistance in the form of contributions from developers or customers ("customer contributions"). Such contributions, whether in cash or in-kind, are recognized as deferred revenue and amortized into income over the life of the related assets. Contributions in-kind are valued at their fair value at the date of their contribution.

Performance incentive payments under Conservation and Demand Management ("CDM") programs are recognized by the Corporation when there is reasonable assurance that the program conditions have been satisfied and the incentive payment will be received.

Government grants under CDM programs are recognized when there is reasonable assurance that the grant will be received and all attached conditions will be complied with. When the grant relates to an expense item, it is recognized as income over the period necessary to match the grant on a systematic basis to the costs that it is intended to compensate.

(c) Finance and borrowing costs

Borrowing costs are calculated using the effective interest rate method and are recognized as finance costs, unless they are capitalized as part of the cost of a qualifying asset, which is an asset that takes a substantial period of time to get ready for its intended use.

3. Significant accounting policies (continued)

(d) Financial instruments

Financial assets and financial liabilities are initially recognized at fair value and are subsequently accounted for based on their classification as loans and receivables or as other liabilities. Transaction costs for financial assets classified as loans and receivables and financial liabilities classified as other liabilities are capitalized as part of the carrying value at initial recognition.

(i) Loans and receivables

Loans and receivables are non-derivative financial assets with fixed or determinable payments that are not quoted in an active market. Subsequent to initial recognition, such financial assets are carried at amortized cost using the effective interest rate method, less any impairment losses. Losses are recognized in net income when the loans and receivables are derecognized or impaired.

Loans and receivables are assessed at each reporting date to determine whether there is objective evidence of impairment. A financial asset is impaired if objective evidence indicates that a loss event has occurred after the initial recognition of the asset and the loss event has had a negative effect on estimated future cash flows of the asset which are reliably measureable.

Loans and receivables are comprised of cash, accounts receivable and amounts due from related parties.

(ii) Other liabilities

All non-derivative financial liabilities are classified as other liabilities. Subsequent to initial recognition, other liabilities are measured at amortized cost using the effective interest method.

Financial liabilities are derecognized when either the Corporation is discharged from its obligation, the obligation expires, or the obligation is cancelled or replaced by a new financial liability with substantially modified terms.

Financial liabilities are further classified as current or non-current depending on whether they will fall due within twelve months after the balance sheet date or beyond.

Other liabilities are comprised of short-term debt, Infrastructure Ontario financing, customer deposits, accounts payable and accrued liabilities, amounts due to related parties, notes payable, debentures payable and liability for subdivision development.

(e) Inventories

Inventories, which consist of parts and supplies acquired for internal construction or consumption, are valued at the lower of cost and net realizable value. Cost is determined on a weighted-moving average basis and includes expenditures incurred in acquiring the inventories and other costs to bring the inventories to their existing location and condition.

(f) Property, plant and equipment

Property, plant and equipment ("PP&E") is measured at cost less accumulated depreciation and accumulated impairment losses. Cost includes expenditures that are directly attributable to the acquisition of the asset and includes contracted services, cost of materials, direct labour and borrowing costs incurred in respect of qualifying assets constructed subsequent to January 1, 2011. When parts of an item of PP&E have different useful lives, they are accounted for as separate components of PP&E.

Major spare parts and standby equipment are recognized as items of PP&E. Property, plant and equipment in the course of construction are carried at cost, cost includes expenditures that are directly attributable to the construction of the asset. These assets are classified to the appropriate categories of property, plant and equipment when completed and ready for intended use. Depreciation on these assets commences when the assets are ready for their intended use.

(In thousands of dollars)

3. Significant accounting policies (continued)

(f) Property, plant and equipment (continued)

When items of PP&E are retired or otherwise disposed of, a gain or loss on disposal is determined by comparing the proceeds from disposal with the carrying amount of the item and is included in net income.

Depreciation of PP&E is recognized on a straight-line basis over the estimated useful life of each component of PP&E. The estimated useful lives for the current and comparative years are as follows:

Land and buildings	
Land	Indefinite
Buildings	10 to 60 years
Distribution and other assets	
Transformer stations	20 to 40 years
Transformers and meters	15 to 40 years
Plant and equipment	3 to 20 years
Other	3 to 37.5 years

Depreciation methods and useful lives are reviewed at each financial year-end and any changes are adjusted prospectively. In 2016 the useful life of solar panel inverters was changed from 10 to 20 years.

(g) Intangible assets

Intangible assets include land rights, computer software and capital contributions. Capital contributions relate to the contributions made to Hydro One for a transformer station that was built outside the City of Barrie.

Land rights held by the Corporation are effective in perpetuity and there is no foreseeable limit to the period over which the rights are expected to provide benefit to the Corporation. Land rights have therefore been assessed as having an indefinite useful life and are not amortized. Land rights are measured at cost.

Computer software and capital contributions are measured at cost less accumulated amortization and accumulated impairment losses.

Computer software and capital contributions are amortized on a straight-line basis over the estimated useful lives from the date that they are available for use. The estimated useful lives for the current and comparative periods are as follows:

Computer software	4 to 10 years
Capital contributions	17 years

Amortization methods and useful lives are reviewed at each financial year-end and adjusted prospectively.

(h) Goodwill

Goodwill represents the excess of the purchase price over the fair value assigned to the Corporation's interest of the net identifiable assets acquired on the acquisition, by predecessor corporations, of the former Richmond Hill Hydro Inc., Penetanguishene Hydro, Essa Hydro, New Tecumseth Hydro and Bradford West Gwillimbury Hydro.

Goodwill is measured at cost and is not amortized.

3. Significant accounting policies (continued)

(i) Impairment of non-financial assets

The carrying amounts of the Corporation's non-financial assets, are reviewed at each reporting date to determine whether there is any indication of impairment. If any such indication exists, then the asset's recoverable amount is estimated. Goodwill and intangible assets with indefinite lives are tested annually for impairment and when circumstances indicate that the carrying value may be impaired. An impairment loss is recognized if the carrying amount of an asset or CGU exceeds its recoverable amount.

The Corporation has two CGU's, the rate regulated business and the Permitted Generation Business unit. Two CGU's were determined, as Management views the Corporation as having two distinct lines of business.

The recoverable amount of an asset or CGU is the greater of its value in use and fair value less costs of disposal. Value in use is calculated as the present value of the estimated future cash flows expected to be derived from an asset or CGU.

For the purpose of impairment testing, assets are grouped together into the smallest group of assets that generates cash inflows that are largely independent of those from other assets or CGUs. Goodwill acquired in a business combination is allocated to groups of CGUs that are expected to benefit from the synergies of the combination.

Impairment losses are recognized in net income. Impairment losses relating to CGUs are allocated first to reduce the carrying amount of any goodwill allocated to the CGUs and then to reduce the carrying amounts of the other assets in the CGUs on a pro rata basis.

An impairment loss in respect of goodwill is not reversed. In respect of other assets, an impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depreciation or amortization, if no impairment loss had been recognized.

(j) Employee benefits

The Corporation provides both short-term employee benefits and post-employment benefits. The post-employment benefits are provided through a defined benefit plan.

A defined benefit plan is a post-retirement benefit plan that specifies either the benefits to be received by an employee, or the method of determining those benefits.

(i) Short-term employee benefits

Short-term employee benefit obligations are recognized as the related services are rendered to the Corporation. Short-term employee benefit obligations are measured on an undiscounted basis and recognized as an expense unless the amount qualifies for capitalization as part of the cost of an item of inventory, PP&E or an intangible asset.

(ii) Multi-employer defined benefit pension plan

The Corporation provides a pension plan to its full-time employees through the Ontario Municipal Employees Retirement System ("the OMERS plan"). The OMERS plan is a multi-employer defined benefit plan which provides pensions for employees of Ontario municipalities, local boards, public utilities and school boards. The OMERS plan is financed by equal contributions from participating employers and employees, and by the investment earnings of the fund.

3. Significant accounting policies (continued)

(j) Employee benefits (continued)

(ii) Multi-employer defined benefit pension plan (continued)

It is not practicable to determine the present value of the Corporation's obligation or the related current service cost under the OMERS plan as OMERS computes its obligations in accordance with an actuarial valuation in which all the benefit plans are co-mingled and therefore information for individual plans cannot be determined. As a result, the Corporation accounts for the OMERS plan as a defined contribution plan where contributions to the OMERS plan are recognized as an employee benefit expense in the periods during which services are rendered by employees.

(iii) Non-pension defined benefit plans

The Corporation provides certain health, dental and life insurance benefits under unfunded defined benefit plans to its eligible retired employees (the "defined benefit plans").

The Corporation's net obligation in respect of the defined benefit plans is calculated by estimating the amount of future benefit that employees have earned in return for their service in the current and prior periods. The calculated benefit is discounted to determine its present value. The discount rate is the yield at the reporting date on corporate bonds that have maturity dates approximating the terms of the Corporation's obligations and that are denominated in the same currency in which the benefits are expected to be paid. The calculation of the defined benefit obligation is performed by an independent qualified actuary using the projected unit credit method.

Remeasurement of the net defined benefit liability, which is comprised of actuarial gains and losses, is recognized immediately in the balance sheet with a charge or credit to other comprehensive income in the year in which they occur.

Past service costs arising from plan amendments are recognized immediately in net income at the earlier of the date the plan amendment occurs or when any related restructuring costs or termination benefits are recognized.

(k) Customer deposits

Customer deposits are collections from customers to guarantee the payment of energy bills. Deposits that are refundable to customers on demand are classified as a current liability. Interest is paid on customer deposits.

(l) Leases

Leases in which the Corporation assumes substantially all of the risks and rewards of ownership are classified as finance leases. On initial recognition, the leased asset is measured at an amount equal to the lower of its fair value and the present value of the minimum lease payments. Subsequent to initial recognition, the asset is accounted for in accordance with the accounting policy applicable to that asset. Payments under finance leases are apportioned between interest expense and a reduction of the outstanding liability.

Other leases are operating leases and are not recognized in the Corporation's balance sheet. Payments made under operating leases are recognized as an expense on a straight-line basis over the term of the lease.

3. Significant accounting policies (continued)

(m) Payment in lieu of corporate income taxes ("PILs")

Under the Electricity Act, 1998, the Corporation is required to make payments in lieu of corporate taxes to the Ontario Electricity Financial Corporation ("OEFC"). The payments in lieu of taxes are calculated on a basis as if the Corporation was a taxable company under the Income Tax Act (Canada) and the Taxation Act, 2007 (Ontario).

Income tax expense comprises current and deferred tax and is recognized in net income except to the extent that it relates to items recognized directly in other comprehensive income.

Current tax is the expected tax payable or receivable on the taxable income or loss for the year, using tax rates enacted or substantively enacted at the reporting date, and any adjustment to tax payable in respect of previous years.

Deferred tax is recognized, using the liability method, on temporary differences arising between the carrying amount of balance sheet items and their corresponding tax basis, using the substantively enacted income tax rates for the years in which the differences are expected to reverse.

In addition, deferred tax is not recognized for taxable temporary differences arising on the initial recognition of goodwill.

A deferred tax asset is recognized for deductible temporary differences, to the extent that it is probable that future taxable income will be available against which they can be utilized.

(n) Investments in joint ventures

A joint venture is a joint arrangement whereby the parties that have joint control of the arrangement have rights to the net assets of the arrangement. The Group owns 50% of Collingwood PowerStream Utility Services Corp. ("Collus PowerStream"). This investment is accounted for using the equity method and is recognized initially at cost.

Any excess cost over the acquisition of the Group's share of the net fair value of the identifiable assets and liabilities of Collus PowerStream is recognized as goodwill and included in the carrying value of the investment.

If Collus PowerStream is in a loss position, then when the Group's share of losses in Collus PowerStream equals or exceeds its interest, the Group would discontinue recognizing its share of further losses.

The financial statements include the Corporation's share of the (loss)/income and other comprehensive (loss)/income of Collus PowerStream for the year ended December 31, 2016.

4. Future accounting changes

There are a number of new standards and amendments to standards which are effective for annual periods beginning after 1 January 2017 and earlier application is permitted; however, the Corporation has not early applied the following new or amended standards in preparing these financial statements:

- IFRS 9 *Financial Instruments* - replaces the existing guidance in IAS 39 *Financial Instruments: Recognition and Measurement*. IFRS 9 includes revised guidance on the classification and measurement of financial instruments, IFRS 9 is effective for annual reporting periods beginning on or after 1 January 2018, with early adoption permitted. The Corporation has not yet assessed the impact of this standard on the financial statements.

4. Future accounting changes (continued)

- IFRS 15 *Revenue from Contracts with Customers* - In May 2014, the IASB issued IFRS 15, *Revenue from Contracts with Customers*, which clarifies the principles for recognizing revenue and cash flows arising from contracts with customers. The standard is effective for annual periods beginning on or after January 1, 2018, and is to be applied retrospectively. IFRS 15 is available for early adoption. The purpose of this standard is to remove inconsistencies and weaknesses in previous revenue requirements, improve comparability of revenue recognition practices across entities, industries, jurisdictions and capital markets, and to simplify the preparation of financial statements by reducing the number of requirements to which an entity must refer. The Corporation has determined that current accounting judgements, estimates and assumptions are acceptable under the revenue recognition criteria outlined under IFRS 15. Based on a preliminary analysis conducted, the Corporation does not anticipate any significant changes to its policy with respect to revenue recognition; however the Corporation would be required to provide additional information to meet the new disclosure requirements.
- IFRS 16, *Leases* - In January 2016, the IASB issued IFRS 16 *Leases*, which replaces the IAS 17 *Leases* and related interpretations. IFRS 16 establishes the principles for the recognition, measurement, presentation and disclosure of leases, with the objective of ensuring that lessees and lessors provide relevant information that faithfully represents those transactions. The new standard brings most leases on-balance sheet for leases under a single model, eliminating the distinction between operating and finance leases. IFRS 16 is effective for annual reporting periods beginning on or after 1 January 2019. A lessee shall either apply IFRS 16 with full retrospective effect or alternatively not restate comparative information but recognize the cumulative effect of initially applying IFRS 16 as an adjustment to opening equity at the date of initial application. Earlier application is permitted if IFRS 15 Revenue from Contracts with Customers has also been applied. The Corporation is currently evaluating the impact of the new standard.

The following new or amended standards effective for January 1, 2017 are not expected to have a significant impact on the Corporation's financial statements.

- IAS 7 Disclosure initiative – Amendments to IAS 7
- IAS 12 Recognition of Deferred Tax Assets for Unrealized losses – Amendments to IAS 12

5. Investment in a joint venture

The Corporation owns a 50% interest in Collus PowerStream, a joint venture of which the Corporation has joint control. The cost of the investment includes transaction costs and the share of Collus PowerStream's (loss)/income and other comprehensive (loss)/income since the acquisition. Collus PowerStream is involved in the distribution of electricity in Collingwood, Thornbury, Stayner and Creemore, as well as the provision of other utility services in the service area of Clearview and the Town of The Blue Mountains in the Province of Ontario. Collus PowerStream's principal place of business is the Town of Collingwood.

The following judgments were used in determining that the investment was a joint venture:

- Joint control was established by assessing that both the Corporation and the City of Collingwood have unanimous consent over relevant activities within Collus PowerStream. This was done through the agreements that were signed.
- This classification of the investment in Collus PowerStream as a joint venture was determined through analysis of the rights and obligations of the investment, specifically the legal structure.

(In thousands of dollars)

5. Investment in a joint venture (continued)

Summarized financial information for Collus PowerStream follows. There were no significant restrictions from borrowing arrangements or any commitments incurred on behalf of Collus PowerStream in relation to the Corporation.

	2016	2015
	$	$
Total assets	**32,564**	30,789
Total liabilities	**23,487**	21,722
Net revenue	**7,368**	9,368
Total income and other comprehensive income	**94**	1,674
Share of income and other comprehensive income	**47**	837

6. Inventories

During fiscal 2016, an amount of $80 (2015 - $196) was recorded as an expense for the write-down to net realizable value of obsolete or damaged inventory.

7. Property, plant and equipment

	Land and buildings	**Distribution and other assets**	**Work-in-progress**	**Total**
	$	**$**	**$**	**$**
Cost				
Balance at January 1, 2015	72,446	1,023,649	79,256	1,175,351
Additions	5,694	170,045	-	175,739
Disposals / transfers	(9)	(2,114)	(41,193)	(43,316)
Balance at December 31, 2015	78,131	1,191,580	38,063	1,307,774
Additions	165	108,555	16,823	125,543
Disposals / transfers	(2)	(3,374)	-	(3,376)
Balance at December 31, 2016	**78,294**	**1,296,761**	**54,886**	**1,429,941**
Accumulated depreciation				
Balance at January 1, 2015	4,573	138,227	-	142,800
Depreciation expense	1,263	44,996	-	46,259
Disposals	-	(432)	-	(432)
Balance at December 31, 2015	5,836	182,791	-	188,627
Depreciation expense	1,297	47,801	-	49,098
Disposals	-	(885)	-	(885)
Balance at December 31, 2016	**7,133**	**229,707**	**-**	**236,840**
Carrying amounts				
At December 31, 2015	72,295	1,008,789	38,063	1,119,147
At December 31, 2016	**71,161**	**1,067,054**	**54,886**	**1,193,101**

Included in PP&E costs is $18,101 (2015 - $18,833) of capitalized overhead and $968 (2015 - $651) of interest capitalized during the year. Interest costs have been capitalized at a rate of 3.56% (2015 - 3.75%) for rate-regulated business and at a rate of 1.68% (2015 - 1.68%) for Permitted Generation Business.

(In thousands of dollars)

7. Property, plant and equipment (continued)

The Corporation leases its operations centre under a finance lease agreement. The leased operations centre is secured as collateral against the lease obligation. At December 31, 2016, the net carrying amount of the operations centre was $13,161 (2015 - $13,894).

8. Intangible assets and goodwill

(a) Intangible assets

	Land rights	Computer software	Capital contributions	Work in progress	Total
	$	$	$	$	$
Cost					
Balance at January 1, 2015	873	16,795	4,972	31,263	53,903
Additions	26	46,681	-	-	46,707
Transfers	-	-	-	(31,263)	(31,263)
Balance at December 31, 2015	899	63,476	4,972	-	69,347
Additions	60	4,438	948	-	5,446
Transfers	-	-	-	-	-
Balance at December 31, 2016	**959**	**67,914**	**5,920**	**-**	**74,793**
Accumulated amortization					
Balance at January 1, 2015	-	10,388	894	-	11,282
Amortization expense	-	4,704	288	-	4,992
Disposals	-	-	-	-	-
Balance at December 31, 2015	-	15,092	1,182	-	16,274
Amortization expense	-	7,365	306	-	7,671
Disposals	-	-	-	-	-
Balance at December 31, 2016	**-**	**22,457**	**1,488**	**-**	**23,945**
Carrying amounts					
At December 31, 2015	899	48,384	3,790	-	53,073
At December 31, 2016	**959**	**45,457**	**4,432**	**-**	**50,848**

Included in intangible assets is $51 (2015 - $755) of interest capitalized during the year.

(b) Impairment testing of goodwill and indefinite life intangible assets

For the purpose of impairment testing, goodwill with a carrying amount of $42,543 (2015 - $42,543) and land rights with a carrying amount of $899 (2015 - $899) are allocated to the Corporation's rate regulated CGU. The Corporation tested goodwill and land rights for impairment as at December 31, 2016, in accordance with its policy described in Note 3.

The total recoverable amount of $1,259,132 being $1,151,600 and $107,532 for the rate regulated and Permitted Generation Business unit CGUs respectively, was determined based on its value-in-use.

The Corporation has used discounted cash flow analysis to determine value-in-use. The value-in-use was determined in a similar manner at December 31, 2016, and December 31, 2015.

(In thousands of dollars)

8. Intangible assets and goodwill (continued)

(b) Impairment testing of goodwill and indefinite life intangible assets (continued)

The calculation of value in use for the rate regulated CGU was based on the following key assumptions:

- Cash flows were projected based on past experience and actual operating results using a 5 year forecast with growth rates of 2.50% (2015 - 2.50%) built into the forecast. Growth rates were determined using the Bank of Canada inflation forecast.
- A pre-tax discount rate of 5.60% (2015 - 5.90%) and terminal value was used to discount the cash flows; this is derived from the Weighted Average Cost of Capital ("WACC") calculation. A discount rate increase of 0.5% would result in the carrying amount of the regulated CGU exceeding the recoverable amount by $175.

The calculation of value in use for the Permitted Generation Business unit CGU was based on the following key assumptions:

- Cash flows were projected based on past experience and actual operating results using a 5 year forecast with declining rates of 0.9% (2015 - 0.9%) built into the forecast. Declining rates were determined by the declining efficiency of solar assets due to aging.
- A pre-tax discount rate of 3.7% (2015 - 6.71%) and terminal value was used to discount the cash flows; this is derived from the cost of borrowing on solar debentures.
- A discount rate increase of 8.7% would result in the carrying amount of the Permitted Generation Business unit CGU exceeding the recoverable amount by $42.

Guidance in IAS 36 Impairment of Assets Appendix A, was applied in determining the WACC which is not asset specific.

9. Accounts payable and accrued liabilities

	2016	2015
	$	$
Accounts payable - energy purchases	**90,779**	84,149
Debt retirement charge payable - OEFC	**2,944**	4,526
Payroll payable	**7,012**	5,767
Interest payable	**3,836**	3,836
Commodity taxes payable	**89**	993
Customer receivables in credit balances	**4,372**	5,360
Other accounts payable and accrued liabilities	**32,843**	41,331
	141,875	145,962

(In thousands of dollars)

10. Related party balances and transactions

(a) Balances and transactions with jointly controlling shareholders

The amount due to/(from) related parties is comprised of amounts payable to/(receivable from) the City of Vaughan, the City of Markham, the City of Barrie and their wholly-owned subsidiaries.

Components of the amounts due to/(from) related parties are as follows:

	2016	2015
	$	$
Due from:		
City of Vaughan	**1,008**	987
City of Markham	**964**	1,366
City of Barrie	**816**	1,004
	2,788	3,357
Due to:		
City of Vaughan	**(10,309)**	(9,865)
City of Markham	**(9,195)**	(8,926)
City of Barrie	**(282)**	(282)
	(19,786)	(19,073)

Significant related party transactions with the jointly controlling shareholders not otherwise disclosed separately in the financial statements, are summarized below:

			2016			2015
	City of Vaughan	**City of Markham**	**City of Barrie**	City of Vaughan	City of Markham	City of Barrie
	$	**$**	**$**	$	$	$
Revenue						
Energy and distribution	**7,607**	**7,195**	**7,336**	6,800	6,820	7,368
Shared services	**1,832**	**1,317**	**-**	1,779	1,687	-
Total revenue	**9,439**	**8,512**	**7,336**	8,579	8,507	7,368
Expenses						
Realty taxes	**634**	**567**	**301**	615	548	269
Facilities rental and other	**23**	**78**	**52**	23	69	52
Total	**8,782**	**7,867**	**6,983**	7,941	7,890	7,047

These transactions are in the normal course of operations and are recorded at the exchange amount. The Corporation has certain operating leases with the City of Vaughan, City of Markham and City of Barrie to lease rooftops on a number of buildings for which feed-in tariff contracts have been obtained. The current year lease expense has been included in the 'Facilities rental and other' line on the table above, and the future operating lease commitments have been disclosed in Note16(b).

(In thousands of dollars)

10. Related party balances and transactions (continued)

(b) Due from related parties

The amount due from related parties, which is comprised of a receivable from PowerStream Energy Services Inc., a subsidiary of PowerStream Holdings Inc., a payable to PowerStream Holdings Inc., and a payable to Util-Assist Inc., a subsidiary of PowerStream Energy Services Inc. is as follows:

	2016	2015
	$	$
Due from:		
PowerStream Energy Services Inc.	**21,008**	10,297
Due to:		
Util- Assist Inc.	**(139)**	-
PowerStream Holdings Inc.	**-**	(2)
	(139)	(2)

Amount due from Collus PowerStream, not otherwise disclosed separately in the financial statements, is as follows:

	2016	2015
	$	$
Due from:		
Collus PowerStream	**3**	12

(c) Related party transactions

The Corporation has service level agreements with PowerStream Energy Services Inc. and Collus PowerStream, where the Corporation provides a number of back office service functions. The amount charged of $349 (2015 - $466) and $3 (2015 - $12) respectively to these entities is based on the percentage of time spent for these services.

The Corporation has a loan of $20,283 (2015 - $9,639), which is included in due from related parties with PowerStream Energy Services Inc. The interest rate payable on the loan is at 90-days bankers' acceptance rate plus 100 basis points. The loan is for a three-year term with an automatic renewal. The amount of interest charged was $308 (2015 - $192).

(d) Key management personnel compensation

Key management personnel are comprised of the Corporation's senior management team. The compensation paid or payable to key management personnel is as follows:

	2016	2015
	$	$
Short-term employment benefits and salaries	**11,372**	9,961
Post-employment benefits	**1,006**	1,019
Termination benefits	**314**	-
	12,692	10,980

(In thousands of dollars)

11. Short-term debt

(a) *Credit facilities*

On December 17, 2008, the Corporation executed an unsecured credit facility with a Canadian chartered bank. The credit facility is renewable annually. The credit facility agreement provides an extendible 364-day committed revolving credit facility of $75,000, an uncommitted demand facility of $50,000, and uncommitted Letter of Guarantee facilities of $20,000. As of December 31, 2016, the Corporation utilized $Nil (2015 - $Nil) of the 364-day committed revolving credit facilities and $30,000 (2015 - $15,000) of the uncommitted demand facility.

In addition to the above, the Corporation entered into a second unsecured credit facility agreement with a Canadian Chartered Bank that provided for a committed line of credit of up to $150,000. This committed facility matures on February 24, 2017. As of December 31, 2016, the Corporation utilized $105,000 (2015 - $35,000) of this facility.

As at December 31, 2016, the Corporation had utilized $14,999 (2015 - $14,999) of the uncommitted Letter of Guarantee facility for a letter of credit that was provided to the IESO to mitigate the risk of default on energy payments. With the opening of Ontario's electricity market to wholesale and retail competition on May 1, 2002 ("Open Access"), the IESO requires all purchasers of electricity in Ontario to provide security to mitigate the risk of their default based on their expected purchases from the IESO administered spot market. The IESO could draw on the letter of credit if the Corporation defaults on its payment. Further, as at December 31, 2016, an additional $546 (2015 - $359) of the uncommitted Letter of Guarantee facility was utilized as security for operating projects.

The 364-day committed revolving credit facility can be drawn upon by direct advances, bearing interest at the lower of prime plus 0% or Bankers' Acceptance of a stamping fee plus 95 basis points (0.95% per annum). The uncommitted demand facility bears an interest rate at the lower of prime minus 0.30% or Bankers' Acceptance stamping fee plus 68 basis points (0.68% per annum). The Letter of Guarantee facility bears a charge of 50 basis points (0.50%) per annum.

The second committed credit facility bears an interest rate at Bankers' Acceptance stamping fee plus 70 basis points (0.70% per annum), with commitment fee of 10.5 basis points applied to the unutilized balance.

The amount of short-term debt drawn on the available credit facilities consists of:

	2016	2015
	$	$
Uncommitted credit facility	**30,000**	15,000
Committed credit facility	**105,000**	35,000
	135,000	50,000

(In thousands of dollars)

11. Short-term debt (continued)

(b) Ontario Infrastructure and Lands Corporation ("Infrastructure Ontario") financing

On October 15, 2010 the Corporation secured financing with Infrastructure Ontario for its Permitted Generation Business unit. The funding was available for up to 5 years from the date that the agreement was signed, with an extension to June 30, 2017.

As at December 31, 2016, the Corporation has utilized $75,348 (2015 - $75,348) of the $90,000 financing facility, of which $3,818 (2015 - $3,995) has been transferred to a long-term debenture and $834 in principal repayments have been made to date. Principal repayments of $183 will be paid for 12 months following December 31, 2016 and therefore are classified as current liabilities. Each advance bears interest at a floating rate per annum as determined by Infrastructure Ontario. The advance interest rate at December 31, 2016 was 1.65% (2015 - 1.60%) and interest expense for the year was $1,342 (2015 - $1,015).

The amounts transferred to a long-term debenture consists of the following:

- A note in the amount of $979 bears interest at a rate of 4.09% per annum, payable on May 15 and November 15 each year, and matures on November 17, 2031.
- A note in the amount of $964 bears interest at a rate of 3.54% per annum, payable on February 15 and August 15 each year, and matures on August 1, 2032.
- A note in the amount of $2,709 bears interest at a rate of 3.85% per annum, payable on March 1 and September 1 each year, and matures on March 1, 2033.

The Corporation will pay Infrastructure Ontario a stand-by fee calculated at a rate of 25 basis points (0.25%) on the advanced balance of the committed amount should the Corporation fail to draw any funds pursuant to the agreement from Infrastructure Ontario during any period of 12 consecutive months commencing initially from October 15, 2010, and subsequently from the date of the draw of any such funds until the earlier of the facility termination date of June 30, 2017, or the full advance of the committed amount. Infrastructure Ontario financing is secured by the assets of the Permitted Generation Business unit. The financial covenants require a debt service coverage ratio of 1:1 or higher, a debt to capital ratio of 70% or lower, and a current ratio of 1:1 or higher.

This financing is presented as a current liability as a waiver related to non-compliance with the current ratio of 1:1 or higher and the debt service coverage covenants was not received.

12. Long-term debt

(a) Debentures payable

	2016	2015
	$	$
3.958% unsecured Series A debentures due July 30, 2042, interest payable in arrears semi-annually on January 30 and July 30	**198,327**	198,290
3.239% unsecured Series B debentures due November 21, 2024, interest payable in arrears semi-annually on May 21 and November 21	**149,201**	149,117
	347,528	347,407

The debentures rank *pari passu* with all of the Corporation's other senior unsubordinated and unsecured obligations.

Interest expense on these debentures payable was $12,774 (2015 - $12,767).

(In thousands of dollars)

12. Long-term debt (continued)

(a) Debentures payable (continued)

The debentures are subject to a financial covenant. This covenant requires that neither the Corporation nor any designated subsidiary may incur any funded obligation (other than non-recourse debt, capital lease obligations, intercompany indebtedness and purchase money obligations) unless the aggregate principal amount of the consolidated funded obligations does not exceed 75% of the total consolidated capitalization. As at December 31, 2016, the Corporation is in compliance with this covenant.

(b) Notes payable

	2016	2015
	$	$
Promissory note issued to the City of Vaughan	**78,236**	78,236
Deferred interest on promissory note issued to the City of Vaughan	**8,743**	8,743
Promissory note issued to the City of Markham	**67,866**	67,866
Deferred interest on promissory note issued to the City of Markham	**7,585**	7,585
Promissory note issued to the City of Barrie	**20,000**	-
Total long term notes payable	**182,430**	162,430
Less current portion		
Promissory note issued to the City of Barrie	**-**	20,000
Total short term notes payable	**-**	20,000
Total notes payable	**182,430**	182,430

Interest expense on these notes payable was $9,954 (2015 - $9,927).

On June 1, 2004, an unsecured 20 year term promissory note was issued to the City of Vaughan in the amount of $78,236. Interest thereon commenced on June 1, 2004, at an annual rate of 5.58%.

On June 1, 2004, an unsecured 20 year term promissory note was issued to the City of Markham in the amount of $67,866. Interest thereon commenced on June 1, 2004, at an annual rate of 5.58%.

On December 31, 2008, an unsecured 16 year term promissory note was issued to the City of Barrie in the amount of $20,000. Interest thereon commenced on January 1, 2009, is at an annual rate of 5.58%.

The three promissory notes are repayable 90 days following demand by the City of Vaughan, the City of Markham, and the City of Barrie, with subordination and conditions. As part of the January 31, 2017 amalgamation as disclosed in Note 26, these notes are no longer payable on demand as they must notify the Corporation 366 days in advance if payment is required. At the request of the City of Vaughan and the City of Markham, eight quarters of interest were deferred commencing October 1, 2006, and initially payable October 31, 2013. In 2013, it was agreed that this deferred interest will be repayable in full on October 31, 2018, and is subject to 4.03% interest rate.

(In thousands of dollars)

13. Post-employment benefits obligation

(a) Multi-employer defined benefit pension plan

During fiscal 2016, the expense recognized in conjunction with the OMERS plan, which is equal to contributions due for the year was $5,912 (2015 - $6,161). At December 31, 2016, $1,144 (2015 - $1,164) of contributions were payable to the OMERS plan and were included in accounts payable and accrued liabilities on the balance sheet.

As at December 31, 2015, OMERS had approximately 461,000 members, of whom approximately 532 are current employees of the Corporation. The accrued benefit obligation of the OMERS plan as shown in OMERS financial statements as at December 31, 2015 (the latest financial statements available as at the reporting date) is $81,924 million, with a funding deficit of $6,977 million. The funding deficit will result in future payments by the participating employers.

The Corporation shares in the actuarial risks of the other participating entities in the OMERS plan and its future contributions may therefore be increased due to actuarial losses relating to the other participating entities. In addition, the withdrawal of other participating entities from the OMERS plan may also result in an increase to the Corporation's future contribution requirements.

(b) Non-pension defined benefit pension plans

A reconciliation of the obligation for the defined benefit plans is as follows:

	2016	2015
	$	$
Defined benefit obligation, beginning of the year	**18,309**	17,362
Amounts recognized in net income:		
Current service cost	**1,000**	1,002
Past service cost	**(1,176)**	-
Interest expense	**719**	687
	543	1,689
Amounts recognized in other comprehensive income:		
Actuarial (gains)/losses arising from changes in demographic assumptions	**(27)**	-
Actuarial (gains)/losses arising from changes in financial assumptions	**2,505**	(360)
Actuarial (gains)/losses arising from experience adjustments	**(388)**	-
	2,090	(360)
Payments from the plan	**(647)**	(382)
Defined benefit obligation, end of the year	**20,295**	18,309

The obligation for the defined benefit plans is presented in the balance sheet as post-employment benefits.

(In thousands of dollars)

13. Post-employment benefits obligation (continued)

(b) Non-pension defined benefit pension plans (continued)

The significant actuarial assumptions used to determine the present value of the obligation for the defined benefit plans are as follows:

	2016	2015
	%	%
Discount rate	**3.90**	4.00
Rate of compensation increase	**3.50**	3.50
Medical benefits costs escalation	**6.31**	6.66
Dental benefits costs escalation	**4.60**	4.60

14. Share capital

The Corporation's authorized share capital is made up of an unlimited number of common shares, and an unlimited number of Class A non-voting common shares, all of which are without nominal or par value.

The share capital issued during the period is as follows:

	Common shares		**Class A common shares**		**Total**
	Shares issued	**$**	**Shares issued**	**$**	**$**
Balance at January 1, 2015	108,091	267,184	99,997	60,000	327,184
Issued for cash	6,068	15,000	-	-	15,000
Balance at December 31, 2015	114,159	282,184	99,997	60,000	342,184
Issued for cash	-	-	-	-	-
Balance at December 31, 2016	**114,159**	**282,184**	**99,997**	**60,000**	**342,184**

During 2016, no additional common shares were issued. In 2015 6,068 of the common shares were issued for an amount of $15,000.

Dividends

The Corporation has established a dividend policy to pay a minimum of 50% of Modified IFRS ("MIFRS", framework used for reporting to the OEB) net income to PowerStream Holdings Inc., excluding the Permitted Generation Business unit income, with consideration given to the following:

- Cash position at the beginning of the current year;
- Working capital requirements for the current year; and
- Net capital expenditures required for the current year.

The Corporation paid a dividend of $125.2 per share (2015 - $157.58) on the common shares during the year, amounting to a total dividend of $14,292 (2015 - $17,108). There is no tax effect as the dividends are paid out on an after tax basis.

14. Share capital (continued)

The Corporation has also established a dividend policy for its Permitted Generation Business unit to distribute a dividend on the Class A common shares to PowerStream Holdings Inc. determined as follows:

- The Corporation will target an IRR of 10.5% on the Permitted Generation Business Unit. As each project is completed by the Permitted Generation Business Unit, the Corporation expects to make distributions calculated with reference to the Class A common shares equity injections made by the Shareholders from time to time, provided that the amount of each dividend will be at the discretion of the Board of Directors ("Board") and may be greater or lesser than the below having regard to the financial and operating results of the Corporation as a whole;
  - For purposes of the dividend declaration that follows receipt of the unaudited IFRS financial statements for the Permitted Generation Business unit at mid-year, such amounts shall be the greater of:
    - The amounts reported in the most recent unaudited year-end IFRS financial statements for the Permitted Generation Business unit, or
    - The sum of fifty percent (50%) of the amounts reported in the most recent unaudited year-end IFRS financial statements for the Permitted Generation Business unit plus 100% of the amounts reported in the most recent unaudited mid-year IFRS financial statements for the Permitted Generation Business unit (i.e. for a six-month period).
- In the post-construction period or earlier as determined by the Board, the net free cash flow will be paid to the holders of the Class A common shares subject to the criteria listed below:
  - Dividends will be declared by the Corporation's Board of Directors after due consideration is given to the following:
    - All financial covenants on any debt issued by the Corporation.
    - Qualifications to meet external bond rating criteria and ensure no adverse impact on the current credit rating of the Corporation. The Corporation will advise the Shareholders of its credit rating from time to time (and at least on an annual basis).
    - Cash flow requirements of the Permitted Generation Business Unit of the Corporation to meet working capital requirements and short-term (2 year) plans of capital expenditures.
    - The maintenance of the planned 60/40 debt to equity ratio.

In 2016, The Corporation paid a dividend of $99.74 per share (2015 - $110.08) on the Class A common shares during the year, amounting to a total dividend of $9,974 (2015 - $11,008). There is no tax effect as the dividends are paid out on an after tax basis.

15. Insurance

The Corporation maintains appropriate types and levels of insurance with major insurers. With respect to liability insurance, the Corporation is a member of the Municipal Electricity Association Reciprocal Insurance Exchange ("MEARIE"). A reciprocal insurance exchange may be defined as a group of persons formed for the purpose of exchanging reciprocal contracts of indemnity or inter-insurance with each other. MEARIE is licensed to provide general liability insurance to its members.

Insurance premiums charged to each member consist of a levy per thousands of dollars of service revenue subject to a credit or surcharge based on each member's claims experience. The maximum coverage is $24,000 for liability insurance, $480,430 for property insurance, $15,000 for vehicle insurance, and $4,500 for credit insurance; plus $10,000 excess coverage on top of the regular liability and vehicle coverage.

(In thousands of dollars)

16. Leases

(a) Finance leases

The Corporation leases its operations centre under a 25 year lease agreement. The lease agreement includes both land and building elements. Upon entering into this lease arrangement, the Corporation classified the building element of the lease as a finance lease since it was determined that substantially all of the benefits and risks incidental to ownership of the operation centre were transferred to the Corporation (the lessee). The component of the annual basic rent related to the land is classified and recorded as an operating lease and the component related to the building is classified as a finance lease.

			2016
	Future minimum lease payments (including interest)	**Interest**	**Present value of minimum lease payments**
	$	**$**	**$**
Less than one year	**1,430**	**1,046**	**384**
Between one and five years	**7,471**	**4,771**	**2,700**
More than five years	**18,956**	**5,944**	**13,012**
	27,857	**11,761**	**16,096**

			2015
	Future minimum lease payments (including interest)	Interest	Present value of minimum lease payments
	$	$	$
Less than one year	1,430	1,070	360
Between one and five years	7,363	4,938	2,425
More than five years	20,492	6,822	13,670
	29,285	12,830	16,455

Interest on the lease obligation during fiscal 2016 amounted to $1,070 (2015 - $1,093) based on the rate of 6.57% per annum (2015 - 6.57%). Amortization of the corresponding property, plant and equipment during fiscal 2016 amounted to $733 (2015 - $731) based on the straight-line method with a useful life equal to the term of the lease (25 years). The Corporation has the option to purchase within twelve months before the expiry of the original lease in 2034, or an option of three five year lease extensions.

(In thousands of dollars)

16. Leases (continued)

(b) Operating leases

The Corporation is also committed to lease agreements for various vehicles, equipment, rooftops and the land portion of the finance lease for solar projects that have been classified as operating leases. The leases typically run for a period of 5 to 20 years.

The future minimum, non-cancellable annual lease payments (including the land portion of the operating centre lease referred to in (a) above) are as follows:

	2016	2015
	$	$
Less than one year	**3,139**	3,133
Between one and five years	**15,050**	15,558
More than five years	**28,323**	31,219
	46,512	49,910

During the year ended December 31, 2016, an expense of $3,167 (2015 - $3,138) was recognized in net income in respect of operating leases.

17. Financial instruments and risk management

(a) Fair value of financial instruments

The Corporation's accounting policies relating to the recognition and measurement of financial instruments are disclosed in Note 3(d).

The carrying amount of cash, accounts receivable, amounts due from related parties, liability for subdivision development, short-term debt, Infrastructure Ontario financing, customer deposits, accounts payable and accrued liabilities and amounts due to related parties approximates fair value because of the short maturity of these instruments. The carrying value and fair value of the Corporation's other financial instruments are as follows:

		2016		2015
Description	**Carrying value**	**Fair value**	Carrying value	Fair value
	$	**$**	$	$
Liabilities				
Notes payable	**182,430**	**217,820**	182,430	217,108
Debentures payable	**347,528**	**351,052**	347,407	348,647
	529,958	**568,872**	529,837	565,755

The carrying amounts shown in the table are included in the balance sheet under the indicated captions. In addition, the fair value of the $3,818 (2015 - $3,995) Infrastructure Ontario debentures which have been reclassified as a current liability (see Note 11), is $3,938 (2015 - $4,075) as at December 31, 2016.

(In thousands of dollars)

17. Financial instruments and risk management (continued)

(a) Fair value of financial instruments (continued)

Financial instruments which are disclosed at fair value are to be classified using a three - level hierarchy. Each level reflects the inputs used to measure the fair values disclosed of the financial liabilities, and are as follows:

- Level 1: inputs are unadjusted quoted prices of identical instruments in active markets,
- Level 2: inputs other than quoted prices included in Level 1 that are observable for the asset or liability, either directly or indirectly, and
- Level 3: inputs for the liabilities that are not based on observable market data (unobservable inputs).

The Corporation's fair value hierarchy is classified as Level 2 for notes and debentures payable. The classification for disclosure purposes has been determined in accordance with generally accepted pricing models, based on discounted cash flow analysis, with the most significant inputs being the contractual terms of the instrument and the market discount rates that reflects the credit risk of counterparties.

(b) Risk factors

The Corporation understands the risks inherent in its business and defines them broadly as anything that could impact its ability to achieve its strategic objectives. The Corporation's exposure to a variety of risks such as credit risk, interest rate risk and liquidity risk as well as related mitigation strategies have been discussed below. However, the risks described below are not exhaustive of all the risks nor will the mitigation strategies eliminate the Corporation's exposure to all risks listed.

(c) Credit risk

The Corporation's primary source of credit risk to its accounts receivable result from customers failing to discharge their obligations for electricity consumed and billed.

The Corporation has approximately 366,000 (2015 - 375,000) residential and commercial customers. In order to mitigate such potential credit risks, the Corporation has taken various measures in respect of its Energy customers such as collecting security deposits amounting to $21,249 (2015 - $17,358) in accordance with OEB guidelines, reviewing Dun & Bradstreet ("D&B") reports for the top 3000 commercial customers with an outstanding balance of $5 or more, in-house collection department as well as external collection agencies and a bad debt insurance policy for 4,500 (2015 - $4,500) related to energy receivables. Thus, the Corporation monitors and limits its exposure to such credit risks on an ongoing basis.

Pursuant to their respective terms, accounts receivable are aged as follows at December 31:

		2016		2015
	Total		Total	
	$	**%**	$	%
Less than 30 days	**87,932**	**76**	78,570	72
30 - 60 days	**16,044**	**13**	15,714	14
61 - 90 days	**6,201**	**5**	5,352	5
Greater than 91 days	**7,528**	**6**	9,576	9
Total outstanding	**117,705**	**100**	109,212	100
Less: allowance for doubtful accounts	**(3,322)**	**(3)**	(3,649)	(3)
	114,383	**97**	105,563	97

As at December 31, 2016, there was no significant concentration of credit risk with respect to any financial assets.

(In thousands of dollars)

17. Financial instruments and risk management (continued)

(d) Interest rate risk

The Corporation manages its exposure to interest rate risk by issuing long term fixed rate debt in the form of debentures, promissory notes and bank loans. It also ensures that all payment obligations are met by adopting proper capital planning.

As part of the Corporations' revolving demand operating credit facility, the Corporation may utilize the line of credit for working capital and/or capital expenditure purposes. Such short-term borrowing may expose the Corporation to short-term interest rate fluctuations as follows:

	2016	2015
364 day revolving facility		
Prime based loans	**PR*+0.0% p.a.**	PR*+0.0% p.a.
Bankers acceptances	**SF*+0.95% p.a.**	SF*+0.95% p.a.
Demand facility		
Prime based loans	**PR*–0.30% p.a.**	PR*–0.30% p.a.
Bankers acceptances	**SF*+0.68% p.a.**	SF*+0.68% p.a.
Bankers acceptances (Secondary)	**SF*+0.70% p.a.**	SF*+0.70% p.a.
Letter of guarantee facility	**0.50% p.a.**	0.50% p.a.
Infrastructure Ontario financing	**Floating rate p.a.**	Floating rate p.a.

Note: PR - Prime Rate, SF* - Stamping Fee*

A sensitivity analysis was conducted to examine the impact of a change in the prime rate or stamping fee on the short-term debt. A variation of 1% (100 basis points), with all other variables held constant, would increase or decrease the annual interest expense by approximately $1,350.

Cash balances that are not required for day to day obligations earn an interest of Prime minus 1.7% per annum. Fluctuations in this interest rate could impact the level of interest income earned by the Corporation.

(e) Liquidity risk

Liquidity risks are those risks associated with the Corporation's inability to meet obligations associated with financial liabilities such as repayment of principal or interest payments on debts.

The Corporation monitors its liquidity risks on a regular basis to ensure there is sufficient cash flow to meet the obligations as they fall due as well as minimize the interest expense. Cash flow forecasts are prepared to monitor liquidity risks. Liquidity risks associated with financial liabilities are as follows:

			2016			2015
Maturity period	**Principal***	**Interest**	**Total**	Principal*	Interest	Total
	$	**$**	**$**	$	$	$
Less than 1 year	**393,614**	**22,977**	**416,591**	330,539	23,563	354,102
1-5 years	**16,327**	**101,228**	**117,556**	16,327	111,623	127,950
6-10 years	**315,304**	**59,167**	**374,471**	295,219	76,090	371,309
Over 10 years	**198,327**	**114,646**	**312,972**	198,291	122,540	320,831
	923,572	**298,018**	**1,221,590**	840,376	333,816	1,174,192

* The principal includes $2,472 (2015 - $2,592) of unamortized deferred issuing cost.

(In thousands of dollars)

17. Financial instruments and risk management (continued)

(f) Hedging/derivative risk

The Corporation has a swap and derivative transaction policy to enable the Corporation to enter into agreements such as interest rate swaps where 100% of the floating rate risk is hedged into a fixed rate. This is done for prudent risk management purposes and not speculative purposes.

The Corporation has not entered into any such transactions during the current year or prior years.

18. Capital structure

The Corporation's main objectives in the management of capital are to:

(i) Ensure that there is access to various funding options at the lowest possible rates for the various capital initiatives and working capital requirements necessary for the rate-regulated business;

(ii) Ensure compliance with various covenants related to its short-term debt, Infrastructure Ontario financing, debentures payable and Infrastructure Ontario debentures;

(iii) Consistently maintain a high credit rating for the Corporation;

(iv) Maintain a split of approximately 60% debt, 40% equity as recommended by the OEB;

(v) Ensure interest rate fluctuations are mitigated primarily by long term borrowings as well as capital planning; and

(vi) Deliver appropriate financial returns to shareholders.

The Corporation considers shareholders' equity, long-term debt and certain short-term debt as its capital. The capital structure as at December 31, 2016 is as follows:

	2016	2015
	$	$
Short-term debt		
Short-term debt (Note 11)	**135,000**	50,000
Infrastructure Ontario financing (Note 11)	**74,514**	74,691
Notes payable (Note 12)	**-**	20,000
Long-term debt		
Debentures payable (Note 12)	**347,528**	347,407
Notes payable (Note 12)	**182,430**	162,430
Total debt	**739,472**	654,528
Shareholders' equity		
Share capital (Note 14)	**342,184**	342,184
Accumulated other comprehensive income	**547**	2,083
Retained earnings	**112,123**	111,626
Total equity	**454,854**	455,893
Total	**1,194,326**	1,110,421

(In thousands of dollars)

18. Capital structure (continued)

As at December 31, 2016, the Corporation was in compliance with covenants related to its short-term debt, bank term loan and debentures payable. The Corporation is in a temporary breach of a covenant related to Infrastructure Ontario financing and expects to receive a waiver following the reporting date. Details relating to covenants are disclosed in Note 11 and Note 12.

The Corporation is within the debt and equity requirements of the OEB. The Corporation's dividend policy is disclosed in Note 14.

19. Operating expenses

Operating expenses comprise:

	2016	2015
	$	$
Labour	**50,979**	49,121
Contract/consulting	**16,651**	17,067
Materials	**1,871**	1,896
Vehicle	**1,336**	1,399
Other	**27,917**	30,735
	98,754	100,218

20. Income taxes

(a) Income tax expense

PILs recognized in net income comprise the following:

	2016	2015
	$	$
Current tax recovery	**(3,796)**	(3,526)
Deferred tax expense	**16,733**	6,916
Income tax expense	**12,937**	3,390

(In thousands of dollars)

20. Income taxes (continued)

(a) Reconciliation of effective tax rate

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

	2016	2015
	$	$
Income before taxes	**37,700**	28,835
Statutory Canadian federal and provincial income tax rates	**26.50%**	26.50%
Expected tax provision on income at statutory rates	**9,991**	7,641
Increase (decrease) in income taxes resulting from:		
Permanent differences	**157**	67
Adjustments in respect of prior years	**3,595**	40
Scientific Research & Experimental Development tax credit	**(458)**	(1,122)
Burden filing reserve reversal	**-**	(2,800)
Other	**(348)**	(436)
Total income tax expense (recovery)	**12,937**	3,390

Statutory Canadian federal and provincial income tax rates for the current year comprise 15% (2015 - 15%) for federal corporate tax and a rate of 11.5% (2015 - 11.5%) for corporate tax in Ontario. There was no change in the federal and provincial corporate tax rates in 2016 (no change in 2015).

(b) Deferred tax balances

Deferred tax assets/(liabilities) are attributable to the following:

	2016	2015
	$	$
Employee future benefits	**5,377**	4,852
Property, plant and equipment	**(32,934)**	(13,363)
Intangible assets	**1,078**	1,102
Non-capital loss	**13,955**	10,275
Tax credit carryovers	**6,321**	3,606
Other deductible temporary differences	**(2,749)**	755
	(8,952)	7,227

(In thousands of dollars)

20. Income taxes (continued)

(b) Deferred tax balances (continued)

Movement in deferred tax balances during the year were as follows:

	2016	2015
	$	$
Balance at January 1	**7,227**	14,239
Recognized in net income	**(16,733)**	(6,916)
Recognized in OCI related to employee future benefits	**554**	(96)
Balance at December 31	**(8,952)**	7,227

21. Net change in non-cash operating working capital

	2016	2015
	$	$
Accounts receivable	**(8,820)**	(9,979)
Unbilled revenue	**(22,945)**	17,925
Due from related parties	**(10,142)**	(6,930)
Inventories	**(493)**	(141)
Prepaids and other assets	**376**	(1,079)
Customer deposits	**3,720**	1,555
Accounts payable and accrued liabilities	**(4,087)**	11,791
Due to related parties	**850**	2,146
Liability for subdivision development	**(2,231)**	(448)
Capital accruals in prior year	**5,266**	9,603
Capital accruals in current year	**(3,045)**	(5,266)
	(41,551)	19,177

22. Other revenue

	2016	2015
	$	$
Renewable generation	**17,591**	16,699
Other	**14,910**	16,073
	32,501	32,772

23. Contingencies, commitments and guarantees

(a) Contingencies- legal claims

The Corporation has been named as a defendant in several actions. No provision has been recorded in the financial statements for these potential liabilities as the Corporation expects that these claims are adequately covered by its insurance.

(b) Commitments

As at December 31, 2016, the Corporation has entered into agreements for capital projects and is committed to making payments of $14,251 in 2017.

(c) Guarantees

In the normal course of business, the Corporation enters into agreements that meet the definition of a guarantee as follows:

(i) The Corporation has provided indemnities under lease agreements for the use of various operating facilities. Under the terms of these agreements the Corporation agrees to indemnify the counterparties for various items including, but not limited to, all liabilities, loss, suits, and damages arising during, on or after the term of the agreement. The maximum amount of any potential future payment cannot be reasonably estimated.

(ii) Indemnity has been provided to all directors and/or officers of the Corporation for various items including, but not limited to, all costs to settle suits or actions due to association with the Corporation, subject to certain restrictions. The Corporation has purchased directors' and officers' liability insurance to mitigate the cost of any potential future suits or actions. The term of the indemnification is not explicitly defined, but is limited to the period over which the indemnified party served as a trustee, director or officer of the Corporation. The maximum amount of any potential future payment cannot be reasonably estimated.

(iii) In the normal course of business, the Corporation has entered into agreements that include indemnities in favor of third parties, such as purchase and sale agreements, confidentiality agreements, engagement letters with advisors and consultants, outsourcing agreements, leasing contracts, information technology agreements and service agreements. These indemnification agreements may require the Corporation to compensate counterparties for losses incurred by the counterparties as a result of breaches in representation and regulations or as a result of litigation claims or statutory sanctions that may be suffered by the counterparty as a consequence of the transaction. The terms of these indemnities are not explicitly defined and the maximum amount of any potential reimbursement cannot be reasonably estimated.

The nature of these indemnification agreements prevents the Corporation from making a reasonable estimate of the maximum exposure due to the difficulties in assessing the amount of liability which stems from the unpredictability of future events and the unlimited coverage offered to counterparties. Historically, the Corporation has not made any significant payments under such or similar indemnification agreements and therefore no amount has been accrued in the balance sheet with respect to these agreements.

(In thousands of dollars)

24. Divisional information

The Corporation consists primarily of two operating divisions: regulated operations and non-regulated operations. Non-regulated operations is comprised of the permitted generation business.

The designation of activities to the two operating divisions is based on a combination of regulatory status and the nature of the products and services provided. The accounting policies followed by the divisions are consistent with those described in the summary of significant accounting policies.

Financial information that adjusts IFRS results to show the effect of rate regulation is used by the Corporation's Board of Directors, Shareholders and regulator as well as Management. The dividends paid out of the regulated business are based on IFRS adjusted for regulatory activities.

Year ended December 31, 2016	PowerStream Inc. Regulated	Adjustment for regulatory activities	Non-regulated	Total
	$	$	$	$
Revenue				
Sale of energy	1,127,362	21,602	-	1,148,964
Distribution revenue	174,492	(3,450)	-	171,042
Other revenue	14,619	291	17,591	32,501
Total revenue	1,316,473	18,443	17,591	1,352,507
Cost of power purchased	1,127,362	6,409	-	1,133,771
Operating expenses	91,685	2,365	4,704	98,754
Depreciation and amortization	48,457	(276)	6,274	54,455
Total expenses	1,267,504	8,498	10,978	1,286,980
	48,969	9,945	6,613	65,527
Loss on derecognition of property, plant and equipment	(1,525)	(399)	-	(1,924)
Share in income from joint venture	350	(303)	-	47
Interest income	728	(314)	-	414
Interest expense	(25,548)	403	(1,219)	(26,364)
Income before income taxes	22,974	9,332	5,394	37,700
Income tax expense (recovery)	(6,442)	18,742	637	12,937
Net income	29,416	(9,410)	4,757	24,763
Other comprehensive income, net of tax	-	1,536	-	1,536
	29,416	(10,946)	4,757	23,227

(In thousands of dollars)

24. Divisional Information (continued)

Year ended December 31, 2015	PowerStream Inc. Regulated	Adjustment for regulatory activities	Non-regulated	Total
	$	$	$	$
Revenue				
Sale of energy	1,002,089	19,223	-	1,021,312
Distribution revenue	165,628	(6,190)	-	159,438
Other revenue	15,904	169	16,699	32,772
Total revenue	1,183,621	13,202	16,699	1,213,522
Cost of power purchased	1,002,089	8,610	-	1,010,699
Operating expenses	92,492	2,374	5,352	100,218
Depreciation and amortization	42,562	420	5,949	48,931
Total expenses	1,137,143	11,404	11,301	1,159,848
	46,478	1,798	5,398	53,674
Loss on derecognition of property, plant and equipment	(1,273)	-	-	(1,273)
Share in income from joint venture	350	487	-	837
Interest income	960	(479)	-	481
Interest expense	(24,140)	193	(937)	(24,884)
Income before income taxes	22,375	1,999	4,461	28,835
Income tax expense (recovery)	(4,313)	7,279	424	3,390
Net income	26,688	(5,280)	4,037	25,445
Other comprehensive income, net of tax	-	(264)	-	(264)
	26,688	(5,016)	4,037	25,709

(In thousands of dollars)

24. Divisional Information (continued)

Year ended December 31, 2016	PowerStream Inc. Regulated	Adjustment for regulatory activities	Non-regulated	Total
	$	$	$	$
Current assets				
Cash	3,740	-	10,232	13,972
Accounts receivable	114,302	-	81	114,383
Unbilled revenue	117,778	-	203	117,981
Due from related parties	25,450	-	(1,654)	23,796
Inventories	3,719	-	-	3,719
Income taxes receivable	8,764	-	-	8,764
Prepaids and other assets	4,823	-	9	4,832
	278,576	-	8,871	287,447
Long-term assets				
Property, plant and equipment	1,072,122	9,889	111,090	1,193,101
Regulatory assets	13,758	(13,758)	-	-
Intangible assets	50,824	24	-	50,848
Investment in a joint venture	9,178	(962)	-	8,216
Deferred tax assets	-	-	-	-
Goodwill	42,543	-	-	42,543
	1,188,425	(4,807)	111,090	1,294,708
Total assets	1,467,001	(4,807)	119,961	1,582,155
Current liabilities				
Short-term debt	135,000	-	-	135,000
Infrastructure Ontario financing	-	-	74,514	74,514
Customer deposits	19,711	-	-	19,711
Accounts payable and accrued liabilities	141,076	-	799	141,875
Due to related parties	19,925	-	-	19,925
Liability for subdivision development	2,589	-	-	2,589
Current portion of finance lease obligation	384	-	-	384
Notes payable	-	-	-	-
	318,685	-	75,313	393,998
Long-term liabilities				
Notes payable	182,430	-	-	182,430
Debentures payable	347,528	-	-	347,528
Regulatory liabilities	6,347	(6,347)	-	-
Finance lease obligation	15,712	-	-	15,712
Deferred tax liabilities	5,984	(894)	3,862	8,952
Post-employment benefits obligation	20,289	-	6	20,295
Deferred revenue	157,719	667	-	158,386
	736,009	(6,574)	3,868	733,303
Total liabilities	1,054,694	(6,574)	79,181	1,127,301
Shareholder's equity				
Share capital	282,184	-	60,000	342,184
Accumulated other comprehensive income	547	-	-	547
Retained earnings	129,576	1,767	(19,220)	112,123
Income before income taxes	412,307	1,767	40,780	454,854
	1,467,001	(4,807)	119,961	1,582,155

PowerStream Inc.
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December 31, 2016
(In thousands of dollars)

24. Divisional Information (continued)

Year ended December 31, 2015	PowerStream Inc. Regulated	Adjustment for regulatory activities	Non-regulated	Total
	$	$	$	$
Current assets				
Cash	6,859	-	-	6,859
Accounts receivable	105,208	-	355	105,563
Unbilled revenue	94,657	-	379	95,036
Due from related parties	5,584	-	8,070	13,654
Inventories	3,226	-	-	3,226
Income taxes receivable	9,384	350	-	9,734
Prepaids and other assets	4,079	1,120	9	5,208
	228,997	1,470	8,813	239,280
Long-term assets				
Property, plant and equipment	995,844	5,814	117,489	1,119,147
Regulatory assets	10,364	(10,364)	-	-
Intangible assets	53,019	54	-	53,073
Investment in a joint venture	8,828	(659)	-	8,169
Deferred tax assets	16,581	(3,833)	(5,521)	7,227
Goodwill	42,543	-	-	42,543
	1,127,179	(8,988)	111,968	1,230,159
Total assets	1,356,176	(7,518)	120,781	1,469,439
Current liabilities				
Short-term debt	50,000	-	-	50,000
Infrastructure Ontario financing	-	-	74,691	74,691
Customer deposits	15,991	-	-	15,991
Accounts payable and accrued liabilities	145,905	(36)	93	145,962
Due to related parties	19,075	-	-	19,075
Liability for subdivision development	4,820	-	-	4,820
Current portion of finance lease obligation	360	-	-	360
Notes payable	20,000	-	-	20,000
	256,151	(36)	74,784	330,899
Long-term liabilities				
Notes payable	162,430	-	-	162,430
Debentures payable	347,407	-	-	347,407
Regulatory liabilities	20,430	(20,430)	-	-
Finance lease obligation	16,095	-	-	16,095
Deferred tax liabilities	-	-	-	-
Post-employment benefits obligation	18,309	-	-	18,309
Deferred revenue	138,170	236	-	138,406
	702,841	(20,194)	-	682,647
Total liabilities	958,992	(20,230)	74,784	1,013,546
Shareholder's equity				
Share capital	282,184	-	60,000	342,184
Accumulated other comprehensive income	2,083	-	-	2,083
Retained earnings	112,917	12,712	(14,003)	111,626
Income before income taxes	397,184	12,712	45,997	455,893
	1,356,176	(7,518)	120,781	1,469,439

24. Divisional Information (continued)

The Corporation derecognizes all rate-regulated assets and liabilities that do not qualify for recognition under IFRS. Certain items that are presented as rate-regulated assets under Modified International International Reporting Standards ("MIFRS") qualify for recognition as other types of assets under IFRS.

(a) The most significant regulatory activities included in the regulatory adjustments are: retail settlement variances, the difference between the cost of the electricity commodity and the sales revenue at the OEB allowed rates. Specifically, these amounts include variances between the amounts charged by Hydro One and the IESO for the operation of the electricity markets and grid, as well as various wholesale market settlement charges and transmission charges as compared to the amount billed to consumers based on the OEB-approved rates. Under regulatory accounting, the Corporation would have adjusted energy sales or purchases for these variances and set up a corresponding asset or liability. Under IFRS, the Corporation recognizes these differences in future periods as an increase or decrease to distribution revenue, when these differences are allowed to be billed to customers.

(b) The OEB approved a variance account to record lost revenues associated with the delivery of Conservation and Demand Management ("CDM") programs. The variance account tracks the difference between the results of actual, verified impacts of CDM activities and the level of CDM program activities assumed in the setting of rates. The Corporation may recover or refund this revenue through future distribution rates.

(c) The OEB approved four deferral accounts to record qualifying incremental capital investments, operating, maintenance and administration expenses and funding adders approved by the OEB related to the connection of renewable generation or the development of smart grid. Under IFRS, the Corporation capitalizes or expenses these items as incurred and recognizes revenue in accordance with the Corporation's revenue recognition policy.

(d) The OEB approved a deferral account to record costs associated with replacing interval meters for its large commercial customers in order to meet amendments made to its Distribution System Code. Under IFRS, the Corporation capitalizes or expenses the amounts in the period they were incurred.

(e) The OEB requires the Corporation to accrue interest on regulatory assets and liabilities balances. Under IFRS, the Corporation recognizes the net interest on these balances in future periods as an increase or decrease to distribution revenue once approved for recovery or refund by the OEB.

(f) The OEB approved a deferral account to record any re-measurements of the post-employment net defined liability including actuarial gains or losses. Under IFRS, the Corporation recognizes any remeasurements of the post-employment net defined liability in other comprehensive income.

(g) Deferred income taxes under MIFRS are shown as regulatory liabilities or assets and are not recognized through the statement of income and other comprehensive income as is the case under IFRS.

To the extent that the OEB's future actions are different from the Corporation's expectations, the timing and amount of recovery or settlement of amounts included in the adjustment for regulatory activities could be significantly different from the amounts that are eventually recovered or settled through distribution rates in the future.

25. Prior year's comparatives

Certain of prior year's figures have been reclassified to conform to the current year's presentation.

26. Subsequent event

On January 31, 2017, the Corporation amalgamated with Horizon Holdings Inc. and Enersource Holdings Inc. to form Alectra Inc. The previous Shareholders of the Corporation, the City of Vaughan, City of Markham and City of Barrie own 46% of Alectra. This amalgamation was undertaken in order to improve the reliability of power quality, increase the investment in innovation and technologies and save residential customer money through efficiencies realized.

On February 28, 2017, Alectra Utilities Inc. is planning to purchase Hydro One Brampton Networks for a purchase price of $607 million, plus closing adjustments.

The accounting and valuation for the amalgamation and purchase is still being finalized, therefore disclosures around the amount of the purchase price and purchased assets and liabilities cannot be determined.

ATTACHMENT 9
POWERSTREAM 2015 AUDITED FINANCIAL STATEMENTS

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Financial statements of

PowerStream Inc.

December 31, 2015

PowerStream Inc.
December 31, 2015

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Independent Auditor's Report

To the Shareholder of
PowerStream Inc.

We have audited the accompanying financial statements of PowerStream Inc., which comprise the balance sheet as at December 31, 2015, the statements of income and other comprehensive income, changes in equity and of cash flows for the year ended December 31, 2015, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with International Financial Reporting Standards, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

Our responsibility is to express an opinion on these 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 financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the 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 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 financial statements present fairly, in all material respects, the financial position of PowerStream Inc. as at December 31, 2015, and its financial performance and its cash flows for the year then ended, in accordance with International Financial Reporting Standards.

Deloitte LLP

Chartered Professional Accountants
Licensed Public Accountants
March 9, 2016

PowerStream Inc.

Balance sheet

as at December 31, 2015

(In thousands of dollars)

	2015	2014
	$	$
Assets		
Current assets		
Cash	**6,859**	23,110
Accounts receivable (Note 17(c))	**105,942**	95,963
Unbilled revenue	**94,657**	112,582
Due from related parties (Note 10)	**13,654**	6,724
Inventories (Note 6)	**3,226**	3,085
Income taxes receivable	**9,734**	6,208
Prepaids and other assets	**5,208**	4,129
	239,280	251,801
Long-term assets		
Property, plant and equipment (Note 7)	**1,119,147**	1,032,551
Intangible assets (Note 8)	**53,073**	42,621
Investment in a joint venture (Note 5)	**8,169**	7,536
Deferred tax assets (Note 20)	**7,227**	14,239
Goodwill (Note 8(b))	**42,543**	42,543
	1,469,439	1,391,291
Liabilities		
Current liabilities		
Short-term debt (Note 11(a))	**50,000**	25,000
Infrastructure Ontario financing (Note 11(b))	**74,691**	67,656
Customer deposits	**15,991**	14,436
Accounts payable and accrued liabilities (Note 9)	**145,962**	134,179
Due to related parties (Note 10)	**19,075**	16,929
Liability for subdivision development	**4,820**	5,268
Current portion of finance lease obligation (Note 16)	**360**	337
Notes payable (Note 12)	**20,000**	-
	330,899	263,805
Long-term liabilities		
Notes payable (Note 12)	**162,430**	182,430
Debentures payable (Note 12)	**347,407**	347,288
Finance lease obligation (Note 16)	**16,095**	16,455
Post-employment benefits obligation (Note 13)	**18,309**	17,362
Deferred revenue	**138,406**	120,651
	682,647	684,186
	1,013,546	947,991
Shareholders' equity		
Share capital (Note 14)	**342,184**	327,184
Accumulated other comprehensive income	**2,083**	1,819
Retained earnings	**111,626**	114,297
	455,893	443,300
	1,469,439	1,391,291

Approved on behalf of the Board on March 9, 2016

________________ Director ________________ Director

PowerStream Inc.

Statement of income and other comprehensive income
year ended December 31, 2015
(In thousands of dollars)

	2015	2014
	$	$
Revenue (Note 10(a))		
Sale of energy	**1,021,312**	927,323
Distribution revenue	**159,438**	157,584
Other revenue (Note 22)	**32,772**	26,053
Total revenue	**1,213,522**	1,110,960
Cost of power purchased	**1,010,699**	941,260
Operating expenses (Note 19)	**100,218**	90,355
Depreciation and amortization	**48,931**	42,416
	1,159,848	1,074,031
	53,674	36,929
Loss on derecognition of property, plant and equipment	**(1,273)**	(2,078)
Share in income from joint venture (Note 5)	**837**	463
Interest income	**481**	401
Interest expense	**(24,884)**	(22,024)
Income before income taxes	**28,835**	13,691
Income tax expense (recovery) (Note 20)	**3,390**	(183)
Net income	**25,445**	13,874
Other comprehensive income		
Remeasurement of defined benefit obligation, net of tax of $96 (2014-$922) (Note 13(b))	**264**	2,558
Total income and other comprehensive income for the year	**25,709**	16,432

PowerStream Inc.

Statement of changes in equity
year ended December 31, 2015
(In thousands of dollars)

	Share capital	Accumulated other comprehensive income	Retained earnings	Total
	$	$	$	$
As at January 1, 2014	288,718	(739)	123,157	411,136
Net income	-	-	13,874	13,874
Other comprehensive income, (net of tax of $922)	-	2,558	-	2,558
	288,718	1,819	137,031	427,568
Dividends paid	-	-	(22,734)	(22,734)
Issuance of common shares (Note 14)	20,001	-	-	20,001
Issuance of Class A common shares (Note 14)	18,465	-	-	18,465
Balance at December 31, 2014	327,184	1,819	114,297	443,300
Net income	-	-	25,445	25,445
Other comprehensive income, (net of tax of $96)	-	264	-	264
	-	264	25,445	25,709
Dividends paid	-	-	(28,116)	(28,116)
Issuance of common shares (Note 14)	15,000	-	-	15,000
Balance at December 31, 2015	**342,184**	**2,083**	**111,626**	**455,893**

The accompanying notes to the financial statements are an integral part of this financial statement

PowerStream Inc.
Statement of cash flows
year ended December 31, 2015
(In thousands of dollars)

	2015	2014
	$	$
Operating activities		
Net income for the year	**25,445**	13,874
Adjustments to determine cash provided by operating activities		
Remeasurement of defined benefit obligation	**360**	3,480
Share of loss/(income) from joint venture (net of 2015 dividend of $204 (2014 - $183))	**(633)**	(280)
Depreciation of property, plant and equipment	**46,259**	41,298
Amortization of intangible assets	**4,992**	3,323
Post-employment benefits	**947**	(1,955)
Loss on disposal of property, plant and equipment	**506**	3,759
Amortization of deferred revenue	**(3,013)**	(2,454)
Amortization of debenture issuance costs	**119**	34
Finance costs	**24,403**	21,622
Income tax expense	**3,390**	(183)
	102,775	82,518
Net change in non-cash operating working capital (Note 21)	**19,177**	(5,445)
Cash generated from operating activities	**121,952**	77,073
Interest paid	**(24,411)**	(22,661)
	97,541	54,412
Financing activities		
Dividends paid	**(28,116)**	(22,734)
Proceeds from Infrastructure Ontario financing	**7,035**	19,341
Proceeds from the issuance of common shares	**15,000**	38,465
Proceeds from issuance of debenture (net)	**-**	149,000
Proceeds (repayment) of short-term debt	**25,000**	(45,000)
Payment of finance lease obligation	**(337)**	(315)
	18,582	138,757
Investing activities		
Proceeds on sale of property, plant and equipment	**1,185**	-
Contributions received from customers	**20,768**	21,763
Purchase of intangible assets	**(15,444)**	(17,111)
Purchase of property, plant and equipment	**(138,883)**	(167,343)
	(132,374)	(162,691)
(Decrease) increase in cash during the year	**(16,251)**	30,478
Cash (bank indebtedness), beginning of year	**23,110**	(7,368)
Cash, end of year	**6,859**	23,110

The accompanying notes to the financial statements are an integral part of this financial statement

1. Description of the business

PowerStream Inc. (the "Corporation") was amalgamated on January 1, 2009, under the Business Corporations Act (Ontario) and is wholly owned by PowerStream Holdings Inc., which in turn is owned by the Corporation of the City of Vaughan (the "City of Vaughan"), through its wholly owned subsidiary, Vaughan Holdings Inc.; the Corporation of the City of Markham (the "City of Markham"), through its wholly owned subsidiary, Markham Enterprises Corporation; and the Corporation of the City of Barrie (the "City of Barrie"), through its wholly owned subsidiary, Barrie Hydro Holdings Inc. PowerStream Holdings Inc. is jointly controlled by these three municipalities. The Corporation is incorporated and domiciled in Canada with its head and registered office located at 161 Cityview Boulevard, Vaughan, ON L4H 0A9.

The principal activity of the Corporation is distribution of electricity in the service areas of Alliston, Aurora, Barrie, Beeton, Bradford West Gwillimbury, Markham, Penetanguishene, Richmond Hill, Thornton, Tottenham and Vaughan in the Province of Ontario, under a license issued by the Ontario Energy Board ("OEB"). The Corporation is regulated under the OEB and adjustments to the distribution rates require OEB approval. Collingwood PowerStream Utility Services Corp. ("Collus PowerStream") is a joint venture between the Corporation and the Town of Collingwood. It distributes electricity in Collingwood, Thornbury, Stayner and Creemore.

As a condition of its distribution license, the Corporation is required to meet specified Conservation and Demand Management ("CDM") targets for reductions in electricity consumption and peak electricity demand. As part of this initiative, the Corporation is delivering Independent Electricity System Operator ("IESO") funded programs in order to meet its targets.

Under the Green Energy and Green Economy Act, 2009, the Corporation and other Ontario electricity distributors have new opportunities and responsibilities for enabling renewable generation.
The Corporation commenced operations of a Solar Generation Business unit, in 2010, as permitted by these changes.

2. Basis of preparation

(a) Statement of compliance

These financial statements are prepared in accordance with International Financial Reporting Standards ("IFRS"), as issued by the International Accounting Standards Board (IASB).

(b) Basis of measurement

The financial statements have been prepared on a historical cost basis.

(c) Presentation currency

The financial statements are presented in Canadian dollars, which is also the Corporation's functional currency. All financial information has been rounded to the nearest thousand, except when otherwise noted.

(d) Use of estimates and judgments

The preparation of financial statements in conformity with IFRS requires management to make estimates, assumptions and judgments that affect the application of accounting policies and the amounts reported and disclosed in the financial statements. Estimates and underlying assumptions are continually reviewed and are based on historical experience and other factors that are considered to be relevant. Actual results may differ from these estimates.

2. Basis of preparation (continued)

(d) Use of estimates and judgments (continued)

Significant sources of estimation uncertainty, assumptions and judgments include the following:

(i) Unbilled revenue

The measurement of unbilled revenue is based on an estimate of the amount of electricity delivered to customers between the date of the last bill and the end of the year.

(ii) Useful lives of depreciable assets

Depreciation and amortization expense is based on estimates of the useful lives of property, plant and equipment and intangible assets. The Corporation estimates the useful lives of its property, plant and equipment and intangible assets based on management's judgment, historical experience and an asset study conducted by an independent consulting firm.

(iii) Cash Generating Units ("CGU")

Determining CGU's for impairment testing is based on Management's judgment. This requires an estimation of the value in use. The value in use calculation requires an estimate of the future cash flows expected to arise from the CGU and a suitable discount rate in order to calculate the present value.

(iv) Valuation of financial instruments

As described in Note 17, the Corporation uses the discounted cash flow model to estimate the fair value of the financial instruments for disclosure purposes.

(v) Other areas

There are a number of other areas in which the Corporation makes estimates; these include accounts receivable, inventories, post-employment benefits and income taxes. These amounts are reported based on the amounts expected to be recovered/refunded and an appropriate allowance has been provided based on the Corporation's best estimate of unrecoverable amounts.

3. Significant accounting policies

The Corporation's financial statements are the representations of management, prepared in accordance with IFRS. The accounting policies set out below have been applied consistently to all years presented in these financial statements, unless otherwise indicated.

The financial statements reflect the following significant accounting policies:

(a) Rate regulation

The Ontario Energy Board Act, 1998 gave the Ontario Energy Board ("OEB") increased powers and responsibilities to regulate the electricity industry. These powers and responsibilities include the power to approve or fix rates for the transmission and distribution of electricity, the power to provide continued rate protection for rural and remote electricity customers and the responsibility for ensuring that distribution companies fulfill obligations to connect and service customers. The OEB may prescribe license requirements and conditions including, among other things, specified accounting records, regulatory accounting principles, and filing process requirements for rate-setting purposes.

The Corporation recognizes revenue when electricity is delivered to customers based on OEB approved rates. Operating costs and expenses are recorded when incurred, unless such costs qualify for recognition as part of an item of property, plant and equipment or as an intangible asset.

3. Significant accounting policies (continued)

(b) Revenue recognition

(i) Electricity distribution and sale

Revenue from the sale and distribution of electricity is recorded on the basis of cyclical billings based on electricity usage and also includes unbilled revenue accrued in respect of electricity delivered but not yet billed. Revenue is generally comprised of the following:

- Electricity Price and Related Rebates. The electricity price and related rebates represent a pass through of the commodity cost of electricity.
- Distribution Rate. The distribution rate is designed to recover the costs incurred by the Corporation in delivering electricity to customers, as well as the ability to earn the OEB allowed rate of return. Distribution charges are regulated by the OEB and typically comprise a fixed charge and a usage-based (consumption) charge.
- Retail Transmission Rate. The retail transmission rate represents a pass through of costs charged to the Corporation for the transmission of electricity from generating stations to the Corporation's service area. Retail transmission rates are regulated by the OEB.
- Wholesale Market Service Charge. The wholesale market service charge represents a pass through of various wholesale market support costs charged by the IESO.

(ii) Other revenue

Other revenue includes revenue from renewable generation, sale of other services, contributions from customers and performance incentive payments.

Revenue related to the sale of other services is recognized as services are rendered. Revenue related to the generation of revenue from renewable generation sources is recognized as the output is produced.

Certain items of property, plant and equipment are acquired or constructed with financial assistance in the form of contributions from developers or customers ("customer contributions"). Such contributions, whether in cash or in-kind, are recognized as deferred revenue and amortized into income over the life of the related assets. Contributions in-kind are valued at their fair value at the date of their contribution.

Performance incentive payments under Conservation and Demand Management ("CDM") programs are recognized by the Corporation when there is reasonable assurance that the program conditions have been satisfied and the incentive payment will be received.

Government grants under CDM programs are recognized when there is reasonable assurance that the grant will be received and all attached conditions will be complied with. When the grant relates to an expense item, it is recognized as income over the period necessary to match the grant on a systematic basis to the costs that it is intended to compensate.

(c) Finance and borrowing costs

Finance costs comprise interest expense on borrowings and are recognized on an accrual basis using the effective interest rate method.

Borrowing costs are calculated using the effective interest rate method and are recognized as finance costs, unless they are capitalized as part of the cost of a qualifying asset, which is an asset that takes a substantial period of time to get ready for its intended use.

3. Significant accounting policies (continued)

(d) *Financial instruments*

Financial assets and financial liabilities are initially recognized at fair value and are subsequently accounted for based on their classification as loans and receivables or as other liabilities. Transaction costs for financial assets classified as loans and receivables and financial liabilities classified as other liabilities are capitalized as part of the carrying value at initial recognition.

(i) *Loans and receivables*

Loans and receivables are non-derivative financial assets with fixed or determinable payments that are not quoted in an active market. Subsequent to initial recognition, such financial assets are carried at amortized cost using the effective interest rate method, less any impairment losses. Losses are recognized in net income when the loans and receivables are derecognized or impaired.

Loans and receivables are assessed at each reporting date to determine whether there is objective evidence of impairment. A financial asset is impaired if objective evidence indicates that a loss event has occurred after the initial recognition of the asset and the loss event has had a negative effect on estimated future cash flows of the asset which are reliably measureable.

Loans and receivables are comprised of cash, accounts receivable, unbilled revenue and amounts due from related parties.

(ii) *Other liabilities*

All non-derivative financial liabilities are classified as other liabilities. Subsequent to initial recognition, other liabilities are measured at amortized cost using the effective interest method.

Financial liabilities are derecognized when either the Corporation is discharged from its obligation, the obligation expires, or the obligation is cancelled or replaced by a new financial liability with substantially modified terms.

Financial liabilities are further classified as current or non-current depending on whether they will fall due within twelve months after the balance sheet date or beyond.

Other liabilities are comprised of bank indebtedness, short-term debt, Infrastructure Ontario financing, customer deposits, accounts payable and accrued liabilities, amounts due to related parties, notes payable, debentures payable, bank term loan, Infrastructure Ontario debentures, and liability for subdivision development.

(e) *Inventories*

Inventories, which consist of parts and supplies acquired for internal construction or consumption, are valued at the lower of cost and net realizable value. Cost is determined on a weighted-moving average basis and includes expenditures incurred in acquiring the inventories and other costs to bring the inventories to their existing location and condition.

(f) *Property, plant and equipment*

Property, plant and equipment (“PP&E”) is measured at cost less accumulated depreciation and accumulated impairment losses. Cost includes expenditures that are directly attributable to the acquisition of the asset and includes contracted services, cost of materials, direct labour and borrowing costs incurred in respect of qualifying assets constructed subsequent to January 1, 2011. When parts of an item of PP&E have different useful lives, they are accounted for as separate components of PP&E.

Major spare parts and standby equipment are recognized as items of PP&E. Property, plant and equipment in the course of construction are carried at cost, cost includes expenditures that are directly attributable to the construction of the asset. These assets are classified to the appropriate categories of property, plant and equipment when completed and ready for intended use. Depreciation on these assets commences when the assets are ready for their intended use.

(In thousands of dollars)

3. Significant accounting policies (continued)

(f) Property, plant and equipment (continued)

When items of PP&E are retired or otherwise disposed of, a gain or loss on disposal is determined by comparing the proceeds from disposal with the carrying amount of the item and is included in net income.

Depreciation of PP&E is recognized on a straight-line basis over the estimated useful life of each component of PP&E. The estimated useful lives for the current and comparative years are as follows:

Land and buildings	
Land	Indefinite
Buildings	10 to 60 years
Distribution and other assets	
Transformer stations	20 to 40 years
Transformers and meters	15 to 40 years
Plant and equipment	3 to 20 years
Other	3 to 37.5 years

Depreciation methods and useful lives are reviewed at each financial year-end and any changes are adjusted prospectively.

(g) Intangible assets

Intangible assets include land rights, computer software and capital contributions. Capital contributions relate to the contributions made to Hydro One for a transformer station that was built outside the City of Barrie.

Land rights held by the Corporation are effective in perpetuity and there is no foreseeable limit to the period over which the rights are expected to provide benefit to the Corporation. Land rights have therefore been assessed as having an indefinite useful life and are not amortized. Land rights are measured at cost.

Computer software and capital contributions are measured at cost less accumulated amortization and accumulated impairment losses.

Computer software and capital contributions are amortized on a straight-line basis over the estimated useful lives from the date that they are available for use. The estimated useful lives for the current and comparative periods are as follows:

Computer software	4 to 10 years
Capital contributions	17 years

Amortization methods and useful lives are reviewed at each financial year-end and adjusted prospectively.

(h) Goodwill

Goodwill represents the excess of the purchase price over the fair value assigned to the Corporation's interest of the net identifiable assets acquired on the acquisition, by predecessor corporations, of the former Richmond Hill Hydro Inc., Penetanguishene Hydro, Essa Hydro, New Tecumseth Hydro and Bradford West Gwillimbury Hydro.

Goodwill is measured at cost and is not amortized. The Corporation's policy on goodwill arising on acquisition of an associate is described in note 3(n).

3. Significant accounting policies (continued)

(i) Impairment of non-financial assets

The carrying amounts of the Corporation's non-financial assets, are reviewed at each reporting date to determine whether there is any indication of impairment. If any such indication exists, then the asset's recoverable amount is estimated. Goodwill and intangible assets with indefinite lives are tested annually for impairment and when circumstances indicate that the carrying value may be impaired. An impairment loss is recognized if the carrying amount of an asset or CGU exceeds its recoverable amount.

The Corporation has two CGU's, the rate regulated business and the Permitted Generation Business unit. Two CGU's were determined, as Management views the Corporation as having two distinct lines of business.

The recoverable amount of an asset or CGU is the greater of its value in use and fair value less costs of disposal. Value in use is calculated as the present value of the estimated future cash flows expected to be derived from an asset or CGU.

For the purpose of impairment testing, assets are grouped together into the smallest group of assets that generates cash inflows that are largely independent of those from other assets or CGUs. Goodwill acquired in a business combination is allocated to groups of CGUs that are expected to benefit from the synergies of the combination.

Impairment losses are recognized in net income. Impairment losses relating to CGUs are allocated first to reduce the carrying amount of any goodwill allocated to the CGUs and then to reduce the carrying amounts of the other assets in the CGUs on a pro rata basis.

An impairment loss in respect of goodwill is not reversed. In respect of other assets, an impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depreciation or amortization, if no impairment loss had been recognized.

(j) Employee benefits

The Corporation provides both short-term employee benefits and post-employment benefits. The post-employment benefits are provided through a defined benefit plan.

A defined benefit plan is a post-retirement benefit plan that specifies either the benefits to be received by an employee, or the method of determining those benefits.

(i) *Short-term employee benefits*

Short-term employee benefit obligations are recognized as the related services are rendered to the Corporation. Short-term employee benefit obligations are measured on an undiscounted basis and recognized as an expense unless the amount qualifies for capitalization as part of the cost of an item of inventory, PP&E or an intangible asset.

(ii) *Multi-employer defined benefit pension plan*

The Corporation provides a pension plan to its full-time employees through the Ontario Municipal Employees Retirement System ("the OMERS plan"). The OMERS plan is a multi-employer defined benefit plan which provides pensions for employees of Ontario municipalities, local boards, public utilities and school boards. The OMERS plan is financed by equal contributions from participating employers and employees, and by the investment earnings of the fund.

3. Significant accounting policies (continued)

(j) Employee benefits (continued)

(ii) Multi-employer defined benefit pension plan (continued)

It is not practicable to determine the present value of the Corporation's obligation or the related current service cost under the OMERS plan as OMERS computes its obligations in accordance with an actuarial valuation in which all the benefit plans are co-mingled and therefore information for individual plans cannot be determined. As a result, the Corporation accounts for the OMERS plan as a defined contribution plan where contributions to the OMERS plan are recognized as an employee benefit expense in the periods during which services are rendered by employees.

(iii) Non-pension defined benefit plans

The Corporation provides certain health, dental and life insurance benefits under unfunded defined benefit plans to its eligible retired employees (the "defined benefit plans").

The Corporation's net obligation in respect of the defined benefit plans is calculated by estimating the amount of future benefit that employees have earned in return for their service in the current and prior periods. The calculated benefit is discounted to determine its present value. The discount rate is the yield at the reporting date on corporate bonds that have maturity dates approximating the terms of the Corporation's obligations and that are denominated in the same currency in which the benefits are expected to be paid. The calculation of the defined benefit obligation is performed by an independent qualified actuary using the projected unit credit method.

Remeasurement of the net defined benefit liability, which is comprised of actuarial gains and losses, is recognized immediately in the balance sheet with a charge or credit to other comprehensive income in the year in which they occur.

Past service costs arising from plan amendments is recognized immediately in net income at the earlier of the date the plan amendment occurs or when any related restructuring costs or termination benefits are recognized.

(k) Customer deposits

Customer deposits are collections from customers to guarantee the payment of energy bills. Deposits that are refundable to customers on demand are classified as a current liability. Interest is paid on customer deposits.

(l) Leases

Leases in which the Corporation assumes substantially all of the risks and rewards of ownership are classified as finance leases. On initial recognition, the leased asset is measured at an amount equal to the lower of its fair value and the present value of the minimum lease payments. Subsequent to initial recognition, the asset is accounted for in accordance with the accounting policy applicable to that asset. Payments under finance leases are apportioned between interest expense and a reduction of the outstanding liability.

Other leases are operating leases and are not recognized in the Corporation's balance sheet. Payments made under operating leases are recognized as an expense on a straight-line basis over the term of the lease.

3. Significant accounting policies (continued)

(m) Payment in lieu of corporate income taxes ("PILs")

Under the Electricity Act, 1998, the Corporation is required to make payments in lieu of corporate taxes to the Ontario Electricity Financial Corporation ("OEFC"). The payments in lieu of taxes are calculated on a basis as if the Corporation was a taxable company under the Income Tax Act (Canada) and the Taxation Act, 2007 (Ontario).

Income tax expense comprises current and deferred tax and is recognized in net income except to the extent that it relates to items recognized directly in other comprehensive income.

Current tax is the expected tax payable or receivable on the taxable income or loss for the year, using tax rates enacted or substantively enacted at the reporting date, and any adjustment to tax payable in respect of previous years.

Deferred tax is recognized, using the liability method, on temporary differences arising between the carrying amount of balance sheet items and their corresponding tax basis, using the substantively enacted income tax rates for the years in which the differences are expected to reverse.

In addition, deferred tax is not recognized for taxable temporary differences arising on the initial recognition of goodwill.

A deferred tax asset is recognized for deductible temporary differences, to the extent that it is probable that future taxable income will be available against which they can be utilized.

(n) Investments in joint ventures

A joint venture is a joint arrangement whereby the parties that have joint control of the arrangement have rights to the net assets of the arrangement. The Group owns 50% of Collingwood PowerStream Utility Services Corp. ("Collus PowerStream"). This investment is accounted for using the equity method and is recognized initially at cost.

Any excess cost over the acquisition of the Group's share of the net fair value of the identifiable assets and liabilities of Collus PowerStream is recognized as goodwill and included in the carrying value of the investment.

If Collus PowerStream is in a loss position, then when the Group's share of losses in Collus PowerStream equals or exceeds its interest, the Group would discontinue recognizing its share of further losses.

The financial statements include the Corporations's share of the (loss)/income and other comprehensive (loss)/income of Collus PowerStream for the year ended December 31, 2015.

4. Future accounting changes

There are a number of new standards and amendments to standards which are effective for annual periods beginning after 1 January 2015 and earlier application is permitted; however, the Corporation has not early applied the following new or amended standards in preparing these financial statements:

- IFRS 9 *Financial Instruments* - replaces the existing guidance in IAS 39 *Financial Instruments: Recognition and Measurement*. IFRS 9 includes revised guidance on the classification and measurement of financial instruments, IFRS 9 is effective for annual reporting periods beginning on or after 1 January 2018, with early adoption permitted. The Corporation has not yet assessed the impact of this standard on the financial statements.

- IFRS 15 *Revenue from Contracts with Customers* - this standard establishes a comprehensive framework for determining whether, how much and when revenue is recognized. It replaces existing revenue recognition guidance, including IAS 18 *Revenue*, IAS 11 *Construction Contracts* and IFRIC 18 *Transfer of Assets from Customers*. IFRS 15 is effective for annual reporting periods beginning on or after 1 January 2018, with early adoption permitted. The Corporation has not yet assessed the impact of this standard on the financial statements

(In thousands of dollars)

4. Future accounting changes (continued)

The following new or amended standards are not expected to have a significant impact on the Corporation's financial statements.

- IFRS 14, Regulatory deferral accounts
- Accounting for Acquisitions of Interests in Joint Operations (Amendments to IFRS 11)
- Clarification of Acceptable Methods of Depreciation and Amortization (Amendments to IAS 16 and IAS 38)
- Equity method in Separate Financial Statements - Amendments to IAS 27
- Sale or Contribution of Assets between an Investor and its Associate or Joint Venture (Amendments to IFRS 10 and IAS 28)*
- Annual Improvements to IFRSs 2012-2014 Cycle - various standards
- Disclosure initiative - Amendments to IAS 1

5. Investment in a joint venture

The Corporation owns a 50% interest in Collus PowerStream, a joint venture of which the Corporation has joint control. The cost of the investment includes transaction costs and the share of Collus PowerStream's (loss)/income and other comprehensive (loss)/income since the acquisition. Collus PowerStream is involved in the distribution of electricity in Collingwood, Thornbury, Stayner and Creemore, as well as the provision of other utility services in the service area of Clearview and the Town of The Blue Mountains in the Province of Ontario. Collus PowerStream's principal place of business is the Town of Collingwood.

The following judgments were used in determining that the investment was a joint venture:

- Joint control was established by assessing that both the Corporation and the City of Collingwood have unanimous consent over relevant activities within Collus PowerStream. This was done through the agreements that were signed.
- This classification of the investment in Collus PowerStream as a joint venture was determined through analysis of the rights and obligations of the investment, specifically the legal structure.

Summarized financial information for Collus PowerStream follows. There were no significant restrictions from borrowing arrangements or any commitments incurred on behalf of Collus PowerStream in relation to the Corporation.

	2015	2014
	$	$
Total assets	**30,789**	27,709
Total liabilities	**21,722**	20,876
Net revenue	**9,368**	7,452
Total income and other comprehensive income	**1,674**	925
Share of income and other comprehensive income	**837**	463

6. Inventories

During fiscal 2015, an amount of $196 (2014 - $59) was recorded as an expense for the write-down to net realizable value of obsolete or damaged inventory.

(In thousands of dollars)

7. Property, plant and equipment

	Land and buildings	Distribution and other assets		Work-in-progress	Total
	$	$		$	$
Cost					
Balance at January 1, 2014	66,263	893,391		53,110	1,012,764
Additions	6,202	134,477		26,146	166,825
Disposals	(19)	(4,219)		-	(4,238)
Balance at December 31, 2014	72,446	1,023,649		79,256	1,175,351
Additions	5,694	170,045		-	175,739
Disposals / transfers	(9)	(2,114)		(41,193)	(43,316)
Balance at December 31, 2015	**78,131**	**1,191,580**		**38,063**	**1,307,774**
Accumulated depreciation					
Balance at January 1, 2014	3,382	98,598		-	101,980
Depreciation expense	1,191	40,107		-	41,298
Disposals	-	(478)		-	(478)
Balance at December 31, 2014	4,573	138,227		-	142,800
Depreciation expense	1,263	44,996		-	46,259
Disposals	-	(432)		-	(432)
Balance at December 31, 2015	**5,836**	**182,791**		**-**	**188,627**
Carrying amounts					
At December 31, 2014	67,873	885,422	-	79,256	1,032,551
At December 31, 2015	**72,295**	**1,008,789**	**-**	**38,063**	**1,119,147**

Included in PP&E costs is $18,833 (2014 - $16,910) of capitalized expenses and $651 (2014 - $654) of interest capitalized during the year. Interest costs have been capitalized at a rate of 3.75% (2014 - 5.81%) for rate-regulated business and at a rate of 1.68% (2014 - 1.82%) for Permitted Generation Business.

The Corporation leases its operations centre under a finance lease agreement. The leased operations centre is secured as collateral against the lease obligation. At December 31, 2015, the net carrying amount of the operations centre was $13,894 (2014 - $14,624).

(In thousands of dollars)

8. Intangible assets and goodwill

(a) Intangible assets

	Land rights	Computer software	Capital contributions	Work in progress	Total
	$	$	$	$	$
Cost					
Balance at January 1, 2014	827	15,307	4,972	15,686	36,792
Additions	46	1,488	-	15,577	17,111
Disposals	-	-	-	-	-
Balance at December 31, 2014	873	16,795	4,972	31,263	53,903
Additions	26	46,681	-	-	46,707
Transfers	-	-	-	(31,263)	(31,263)
Balance at December 31, 2015	**899**	**63,476**	**4,972**	**-**	**69,347**
Accumulated amortization					
Balance at January 1, 2014	-	7,353	606	-	7,959
Amortization expense	-	3,035	288	-	3,323
Disposals	-	-	-	-	-
Balance at December 31, 2014	-	10,388	894	-	11,282
Amortization expense	-	4,704	288	-	4,992
Disposals	-	-	-	-	-
Balance at December 31, 2015	**-**	**15,092**	**1,182**	**-**	**16,274**
Carrying amounts					
At December 31, 2014	873	6,407	4,078	31,263	42,621
At December 31, 2015	**899**	**48,384**	**3,790**	**-**	**53,073**

Included in intangible assets is $755 (2014 - $797) of interest capitalized during the year.

(b) Impairment testing of goodwill and indefinite life intangible assets

For the purpose of impairment testing, goodwill with a carrying amount of $42,543 (2014 - $42,543) and land rights with a carrying amount of $899 (2014 - $873) are allocated to the Corporation's rate regulated CGU. The Corporation tested goodwill and land rights for impairment as at December 31, 2015, in accordance with its policy described in Note 3.

The total recoverable amount of $1,108,058, being $1,008,700 and $99,358 for the rate regulated and Permitted Generation Business unit CGUs respectively, was determined based on its value-in-use.

The Corporation has used discounted cash flow analysis to determine value-in-use. The value-in-use was determined in a similar manner at December 31, 2015, and December 31, 2014.

(In thousands of dollars)

8. Intangible assets and goodwill (continued)

(b) Impairment testing of goodwill and indefinite life intangible assets (continued)

The calculation of value in use for the rate regulated CGU was based on the following key assumptions:

- Cash flows were projected based on past experience and actual operating results using a 5 year forecast with growth rates of 2.50% (2014 - 2.50%) built into the forecast. Growth rates were determined using the Bank of Canada inflation forecast.
- A pre-tax discount rate of 5.90% (2014 - 5.66%) and terminal value was used to discount the cash flows; this is derived from the Weighted Average Cost of Capital ("WACC") calculation. A discount rate increase of 1% would result in the carrying amount of the regulated CGU exceeding the recoverable amount by $262.

The calculation of value in use for the Permitted Generation Business unit CGU was based on the following key assumptions:

- Cash flows were projected based on past experience and actual operating results using a 5 year forecast with declining rates of 0.9% (2014 - 2.5%) built into the forecast. Declining rates were determined by the declining efficiency of solar assets due to aging.
- A pre-tax discount rate of 6.71% (2014 - 5.50%) and terminal value was used to discount the cash flows; this is derived from the cost of borrowing on solar debentures.
- A discount rate increase of 7% would result in the carrying amount of the Permitted Generation Business unit CGU exceeding the recoverable amount by $115.

Guidance in IAS 36 Impairment of Assets Appendix A, was applied in determining the WACC which is not asset specific.

9. Accounts payable and accrued liabilities

	2015	2014
	$	$
Accounts payable - energy purchases	**84,149**	82,881
Debt retirement charge payable - OEFC	**4,526**	4,600
Payroll payable	**5,767**	6,131
Interest payable	**3,836**	3,844
Commodity taxes payable	**993**	(41)
Customer receivables in credit balances	**5,360**	4,279
Other accounts payable and accrued liabilities	**41,331**	32,485
	145,962	134,179

(In thousands of dollars)

10. Related party balances and transactions

(a) Balances and transactions with jointly controlling shareholders

The amount due to/(from) related parties is comprised of amounts payable to/(receivable from) the City of Vaughan, the City of Markham, the City of Barrie and their wholly-owned subsidiaries.

Components of the amounts due to/(from) related parties are as follows:

	2015	2014
	$	$
Due from:		
City of Vaughan	**987**	778
City of Markham	**1,366**	1,083
City of Barrie	**1,004**	1,032
	3,357	2,893
Due to:		
City of Vaughan	**(9,865)**	(8,266)
City of Markham	**(8,926)**	(8,381)
City of Barrie	**(282)**	(282)
	(19,073)	(16,929)

Significant related party transactions with the jointly controlling shareholders not otherwise disclosed separately in the financial statements, are summarized below:

	2015			2014		
	City of Vaughan	**City of Markham**	**City of Barrie**	City of Vaughan	City of Markham	City of Barrie
	$	**$**	**$**	$	$	$
Revenue						
Energy and distribution	**6,800**	**6,820**	**7,368**	6,233	6,189	7,256
Shared services	**1,779**	**1,687**	**-**	1,727	2,029	-
Total revenue	**8,579**	**8,507**	**7,368**	7,960	8,218	7,256
Expenses						
Realty taxes	**615**	**548**	**269**	640	502	268
Facilities rental and other	**23**	**69**	**52**	5	66	42
Total	**7,941**	**7,890**	**7,047**	7,315	7,650	6,946

These transactions are in the normal course of operations and are recorded at the exchange amount. The Corporation has certain operating leases with the City of Vaughan, City of Markham and City of Barrie to lease rooftops on a number of buildings for which feed-in tariff contracts have been obtained. The current year lease expense has been included in the ‘Facilities rental and other’ line on the table above, and the future operating lease commitments have been disclosed in Note16(b).

(In thousands of dollars)

10. Related party balances and transactions (continued)

(b) Inter-company balances

The Corporation also has an intercompany loan with PowerStream Energy Services Inc., the interest rate payable on the loan is at a banker's acceptance rate plus 160 basis points.

The amount due from inter-company related parties, which is comprised of a receivable from PowerStream Energy Services Inc., a subsidiary of PowerStream Holdings Inc., and a payable to PowerStream Holdings Inc., is as follows:

	2015	2014
	$	$
Due from:		
PowerStream Holdings Inc.	**-**	30
PowerStream Energy Services Inc.	**10,297**	3,801
Due to:		
PowerStream Holdings Inc.	**(2)**	-

Amount due from Collus PowerStream, not otherwise disclosed separately in the financial statements, is as follows:

	2015	2014
	$	$
Due from:		
Collus PowerStream	**12**	12

(c) Inter-company transactions

The Corporation has service level agreements with PowerStream Energy Services Inc. and Collus PowerStream, where the Corporation provides a number of back office service functions. The amount charged of $466 (2014 - $567) and $12 (2014 - $12) respectively to these entities is based on the percentage of time spent for these services.

The Corporation also has an intercompany loan of $9,639 (2014 - $3,063) with PowerStream Energy Services Inc. The interest rate payable on the loan is at 90-days bankers' acceptance rate plus 160 basis points. The loan is for a three-year term with an automatic renewal. The amount of interest charged was $192 (2014 - $171)

(In thousands of dollars)

10. Related party balances and transactions (continued)

(d) Key management personnel compensation

Key management personnel are comprised of the Corporation's senior management team. The compensation paid or payable to key management personnel is as follows:

	2015	2014
	$	$
Short-term employment benefits and salaries	**8,301**	8,225
Post-employment benefits	**1,019**	1,006
	9,320	9,231

11. Short-term debt

(a) Credit facilities

On December 17, 2008, the Corporation executed an unsecured credit facility with a Canadian chartered bank. The credit facility is renewable annually. The credit facility agreement provides an extendible 364-day committed revolving credit facility of $75,000, an uncommitted demand facility of $50,000, and uncommitted Letter of Guarantee facilities of $20,000. As of December 31, 2015, the Corporation utilized $Nil (2014 - $ Nil) of the 364-day committed revolving credit facilities and $15,000 (2014-$Nil) of the uncommitted demand facility.

In addition to the above, the Corporation entered into a second unsecured credit facility agreement with a Canadian Chartered Bank that provided for a committed line of credit of up to $150,000. This committed facility matures on February 12, 2017. As of December 31, 2015, the Corporation utilized $35,000 (2014 - $25,000) of this facility.

As at December 31, 2015, the Corporation had utilized $14,999 (2014 - $14,999) of the uncommitted Letter of Guarantee facility for a letter of credit that was provided to the IESO to mitigate the risk of default on energy payments. With the opening of Ontario's electricity market to wholesale and retail competition on May 1, 2002 ("Open Access"), the IESO requires all purchasers of electricity in Ontario to provide security to mitigate the risk of their default based on their expected purchases from the IESO administered spot market. The IESO could draw on the letter of credit if the Corporation defaults on its payment. Further, as at December 31, 2015, an additional $359 (2014 - $364) of the uncommitted Letter of Guarantee facility was utilized as security for operating projects.

The 364-day committed revolving credit facility can be drawn upon by direct advances, bearing interest at the lower of prime plus 0% or Bankers' Acceptance of a stamping fee plus 95 basis points (0.95% per annum). The uncommitted demand facility bears an interest rate at the lower of prime minus 0.30% or Bankers' Acceptance stamping fee plus 68 basis points (0.68% per annum). The Letter of Guarantee facility bears a charge of 50 basis points (0.50%) per annum.

The second committed credit facility bears an interest rate at Bankers' Acceptance stamping fee plus 70 basis points (0.70% per annum), with commitment fee of 10.5 basis points applied to the unutilized balance.

The amount of short-term debt drawn on the available credit facilities consists of:

	2015	2014
	$	$
Uncommitted credit facility	**15,000**	-
Committed credit facility	**35,000**	25,000
	50,000	25,000

(In thousands of dollars)

11. Short-term debt (continued)

(b) Ontario Infrastructure and Lands Corporation ("Infrastructure Ontario") financing

On October 15, 2010 the Corporation secured financing with Infrastructure Ontario for its Permitted Generation Business unit. The funding is available for up to 5 years from the date that the agreement was signed, with an extension to March 31, 2016.

As at December 31, 2015, the Corporation has utilized $75,348 (2014 - $68,015) of the $90,000 financing facility, of which $3,995 (2014 - $4,293) has been transferred to a long-term debenture and $657 in principal repayments have been made to date. Principal repayments of $177 will be paid for 12 months following December 31, 2015 and therefore are classified as current liabilities. Each advance bears interest at a floating rate per annum as determined by Infrastructure Ontario. The advance interest rate at December 31, 2015 was 1.60% (2014 - 1.86%) and interest expense for the year was $1,015 (2014 - $654).

A note in the amount of $979 bears interest at a rate of 4.09% per annum, payable on May 15 and November 15 each year, and matures on November 17, 2031.

A note in the amount of $964 bears interest at a rate of 3.54% per annum, payable on February 15 and August 15 each year, and matures on August 1, 2032.

A note in the amount of $2,709 bears interest at a rate of 3.85% per annum, payable on March 1 and September 1 each year, and matures on March 1, 2033.

The Corporation will pay Infrastructure Ontario a stand-by fee calculated at a rate of 25 basis points (0.25%) on the advanced balance of the committed amount should the Corporation fail to draw any funds pursuant to the agreement from Infrastructure Ontario during any period of 12 consecutive months commencing initially from October 15, 2010, and subsequently from the date of the draw of any such funds until the earlier of the facility termination date March 31, 2016, or the full advance of the committed amount. Infrastructure Ontario financing is secured by the assets of the Permitted Generation Business unit. The financial covenants require a debt service coverage ratio of 1:1 or higher, a debt to capital ratio of 70% or lower, and a current ratio of 1:1 or higher.

This financing is presented as a current liability as a waiver related to non-compliance with the current ratio of 1:1 or higher and the debt service coverage covenants was not received.

12. Long-term debt

(a) Debentures payable

	2015	2014
	$	$
3.958% unsecured Series A debentures due July 30, 2042, interest payable in arrears semi-annually on January 30 and July 30	**198,290**	198,256
3.239% unsecured Series B debentures due November 21, 2024, interest payable in arrears semi-annually on May 21 and November 21	**149,117**	149,032
	347,407	347,288

The debentures rank *pari passu* with all of the Corporation's other senior unsubordinated and unsecured obligations.

Interest expense on these debentures payable was $12,767 (2014 - $8,476).

(In thousands of dollars)

12. Long-term debt (continued)

(a) Debentures payable (continued)

The debentures are subject to a financial covenant. This covenant requires that neither the Corporation nor any designated subsidiary may incur any funded obligation (other than non-recourse debt, capital lease obligations, intercompany indebtedness and purchase money obligations) unless the aggregate principal amount of the consolidated funded obligations does not exceed 75% of the total consolidated capitalization. As at December 31, 2015, the Corporation is in compliance with this covenant.

(b) Notes payable

	2015	2014
	$	$
Promissory note issued to the City of Vaughan	**78,236**	78,236
Deferred interest on promissory note issued to the City of Vaughan	**8,743**	8,743
Promissory note issued to the City of Markham	**67,866**	67,866
Deferred interest on promissory note issued to the City of Markham	**7,585**	7,585
Promissory note issued to the City of Barrie	**-**	20,000
Total long term notes payable	**162,430**	182,430
Less current portion		
Promissory note issued to the City of Barrie	**20,000**	-
Total short term notes payable	**20,000**	-
Total notes payable	**182,430**	182,430

Interest expense on these notes payable was $9,927 (2014 - $9,927).

On June 1, 2004, an unsecured 20 year term promissory note was issued to the City of Vaughan in the amount of $78,236. Interest thereon commenced on June 1, 2004, at an annual rate of 5.58%.

On June 1, 2004, an unsecured 20 year term promissory note was issued to the City of Markham in the amount of $67,866. Interest thereon commenced on June 1, 2004, at an annual rate of 5.58%.

On December 31, 2008, an unsecured 16 year term promissory note was issued to the City of Barrie in the amount of $20,000. Interest thereon commenced on January 1, 2009, is at an annual rate of 5.58%.

The three promissory notes are repayable 90 days following demand by the City of Vaughan, the City of Markham, and the City of Barrie, with subordination and conditions. The City of Vaughan and City of Markham notes have been classified as long-term as they will not demand repayment before January 1, 2017. The City of Barrie promissory notes have been classified as short term as there is a potential that the City of Barrie will call the promissory note during 2016.

At the request of the City of Vaughan and the City of Markham, eight quarters of interest were deferred commencing October 1, 2006, and initially payable October 31, 2013. In 2013, it was agreed that this deferred interest will be repayable in full on October 31, 2018, and is subject to 4.03% interest rate.

(In thousands of dollars)

13. Post-employment benefits obligation

(a) Multi-employer defined benefit pension plan

During fiscal 2015, the expense recognized in conjunction with the OMERS plan, which is equal to contributions due for the year was $6,161 (2014 - $5,782). At December 31, 2015, $1,164 (2014 - $853) of contributions were payable to the OMERS plan and were included in accounts payable and accrued liabilities on the balance sheet.

As at December 31, 2014, OMERS had approximately 450,000 members, of whom approximately 550 are current employees of the Corporation. The accrued benefit obligation of the OMERS plan as shown in OMERS financial statements as at December 31, 2014 (the latest financial statements available as at the reporting date) is $76,924 million, with a funding deficit of $7,078 million. The funding deficit will result in future payments by the participating employers.

The Corporation shares in the actuarial risks of the other participating entities in the OMERS plan and its future contributions may therefore be increased due to actuarial losses relating to the other participating entities. In addition, the withdrawal of other participating entities from the OMERS plan may also result in an increase to the Corporation's future contribution requirements.

(b) Non-pension defined benefit pension plans

A reconciliation of the obligation for the defined benefit plans is as follows:

	2015	2014
	$	$
Defined benefit obligation, beginning of the year	**17,362**	19,317
Amounts recognized in net income:		
Current service cost	**1,002**	915
Interest expense	**687**	909
	1,689	1,824
Amounts recognized in other comprehensive income:		
Actuarial (gains)/losses arising from changes in demographic assumptions	**-**	(1,364)
Actuarial (gains)/losses arising from changes in financial assumptions	**(360)**	(2,116)
	(360)	(3,480)
Payments from the plan	**(382)**	(299)
Defined benefit obligation, end of the year	**18,309**	17,362

The obligation for the defined benefit plans is presented in the balance sheet as post-employment benefits.

(In thousands of dollars)

13. Post-employment benefits obligation (continued)

(b) Non-pension defined benefit pension plans (continued)

The significant actuarial assumptions used to determine the present value of the obligation for the defined benefit plans are as follows:

	2015	2014
	%	%
Discount rate	**4.00**	4.00
Rate of compensation increase	**3.50**	3.50
Medical benefits costs escalation	**6.66**	4.60 - 7. 00
Dental benefits costs escalation	**4.60**	4.60

14. Share capital

The Corporation's authorized share capital is made up of an unlimited number of common shares, and an unlimited number of Class A non-voting common shares, all of which are without nominal or par value.

The share capital issued during the period is as follows:

	Common shares		**Class A common shares**		**Total**
	Shares issued	**$**	**Shares issued**	**$**	**$**
Balance at January 1, 2014	100,000	247,183	69,223	41,535	288,718
Issued for cash	8,091	20,001	30,774	18,465	38,466
Balance at December 31, 2014	108,091	267,184	99,997	60,000	327,184
Issued for cash	6,068	15,000	-	-	15,000
Balance at December 31, 2015	**114,159**	**282,184**	**99,997**	**60,000**	**342,184**

On November 23, 2010, a Subscription Agreement was signed between the Corporation and its Shareholders for new Class A common shares for the purposes of the Shareholders providing equity for the Corporation's Permitted Generation business unit. The articles of incorporation and shareholders agreement were amended in order to proceed with the subscription agreement. This Subscription Agreement expired on December 31, 2011 and as such, a revised Subscription Agreement was signed between the Corporation and its Shareholders on January 1, 2012 to extend the equity financing in respect of the Corporation's Permitted Generation Business unit. The maximum amount of Class A common shares that are available under the subscription agreement is 100,000.

On November 1, 2013, a Unanimous Shareholders Agreement was signed between the Corporation and its Shareholders, superseding the existing revised Subscription Agreement. This ensured a reorganization of the Corporation becoming a wholly owned subsidiary of the newly established Group, PowerStream Holdings Inc. In effect, the total 114,159 common shares and 99,997 Class A common shares of the Corporation are wholly owned by PowerStream Holdings Inc.

During 2015, an additional 6,068 (2014 - 8,091) of the common shares were issued for an amount of $15,000 (2014 - $20,001).

14. Share capital (continued)

Dividends

The Corporation has established a dividend policy to pay a minimum of 50% of Modified IFRS ("MIFRS", framework used for reporting to the OEB) net income to PowerStream Holdings Inc., excluding the Permitted Generation Business unit income, with consideration given to the following:

- Cash position at the beginning of the current year;
- Working capital requirements for the current year; and
- Net capital expenditures required for the current year.

The Corporation paid a dividend of $157.58 per share (2014 - $165.75) on the common shares during the year, amounting to a total dividend of $17,108 (2014 - $16,575). There is no tax effect as the dividends are paid out on an after tax basis.

The Corporation has also established a dividend policy for its Permitted Generation Business unit to distribute a dividend on the Class A common shares to PowerStream Holdings Inc. determined as follows:

- The Corporation will target an IRR of 10.5% on the Permitted Generation Business Unit. As each project is completed by the Permitted Generation Business Unit, the Corporation expects to make distributions calculated with reference to the Class A common shares equity injections made by the Shareholders from time to time, provided that the amount of each dividend will be at the discretion of the Board of Directors ("Board") and may be greater or lesser than the below having regard to the financial and operating results of the Corporation as a whole;
    - For purposes of the dividend declaration that follows receipt of the unaudited IFRS financial statements for the Permitted Generation Business unit at mid-year, such amounts shall be the greater of:
        - The amounts reported in the most recent unaudited year-end IFRS financial statements for the Permitted Generation Business unit, or
        - The sum of fifty percent (50%) of the amounts reported in the most recent unaudited year-end IFRS financial statements for the Permitted Generation Business unit plus 100% of the amounts reported in the most recent unaudited mid-year IFRS financial statements for the Permitted Generation Business unit (i.e. for a six-month period).
- In the post-construction period or earlier as determined by the Board, the net free cash flow will be paid to the holders of the Class A common shares subject to the criteria listed below:
    - Dividends will be declared by the Corporation's Board of Directors after due consideration is given to the following:
        - All financial covenants on any debt issued by the Corporation.
        - Qualifications to meet external bond rating criteria and ensure no adverse impact on the current credit rating of the Corporation. The Corporation will advise the Shareholders of its credit rating from time to time (and at least on an annual basis).
        - Cash flow requirements of the Permitted Generation Business Unit of the Corporation to meet working capital requirements and short-term (2 year) plans of capital expenditures.
        - The maintenance of the planned 60/40 debt to equity ratio.

In 2015, The Corporation paid a dividend of $110.08 per share (2014 - $88.97) on the Class A common shares during the year, amounting to a total dividend of $11,008 (2014 - $6,159). There is no tax effect as the dividends are paid out on an after tax basis.

(In thousands of dollars)

15. Insurance

The Corporation maintains appropriate types and levels of insurance with major insurers. With respect to liability insurance, the Corporation is a member of the Municipal Electricity Association Reciprocal Insurance Exchange (“MEARIE”). A reciprocal insurance exchange may be defined as a group of persons formed for the purpose of exchanging reciprocal contracts of indemnity or inter-insurance with each other. MEARIE is licensed to provide general liability insurance to its members.

Insurance premiums charged to each member consist of a levy per thousands of dollars of service revenue subject to a credit or surcharge based on each member’s claims experience. The maximum coverage is $24,000 for liability insurance, $499,217 for property insurance, $15,000 for vehicle insurance, and $4,500 for credit insurance; plus $10,000 excess coverage on top of the regular liability and vehicle coverage.

16. Leases

(a) Finance leases

The Corporation leases its operations centre under a 25 year lease agreement. The lease agreement includes both land and building elements. Upon entering into this lease arrangement, the Corporation classified the building element of the lease as a finance lease since it was determined that substantially all of the benefits and risks incidental to ownership of the operation centre were transferred to the Corporation (the lessee). The component of the annual basic rent related to the land is classified and recorded as an operating lease and the component related to the building is classified as a finance lease.

			2015
	Future minimum lease payments (including interest)	**Interest**	**Present value of minimum lease payments**
	$	**$**	**$**
Less than one year	**1,430**	**1,070**	**360**
Between one and five years	**7,363**	**4,938**	**2,425**
More than five years	**20,492**	**6,822**	**13,670**
	29,285	**12,830**	**16,455**

			2014
	Future minimum lease payments (including interest)	Interest	Present value of minimum lease payments
	$	$	$
Less than one year	1,430	1,093	337
Between one and five years	7,257	5,089	2,168
More than five years	22,029	7,742	14,287
	30,716	13,924	16,792

(In thousands of dollars)

16. Leases (continued)

(a) Finance leases (continued)

Interest on the lease obligation during fiscal 2015 amounted to $1,093 (2014 - $1,115) based on the rate of 6.57% per annum (2014 - 6.57%). Amortization of the corresponding property, plant and equipment during fiscal 2015 amounted to $731 (2014 - $731) based on the straight-line method with a useful life equal to the term of the lease (25 years). The Corporation has the option to purchase within twelve months before the expiry of the original lease in 2034, or an option of three five year lease extensions.

(b) Operating leases

The Corporation is also committed to lease agreements for various vehicles, equipment, rooftops and the land portion of the finance lease for solar projects that have been classified as operating leases. The leases typically run for a period of 5 to 20 years.

The future minimum, non-cancellable annual lease payments (including the land portion of the operating centre lease referred to in (a) above) are as follows:

	2015	2014
	$	$
Less than one year	**3,133**	3,141
Between one and five years	**15,558**	15,548
More than five years	**31,219**	34,363
	49,910	53,052

During the year ended December 31, 2015, an expense of $3,138 (2014 - $3,126) was recognized in net income in respect of operating leases.

17. Financial instruments and risk management

(a) Fair value of financial instruments

The Corporation's accounting policies relating to the recognition and measurement of financial instruments are disclosed in Note 3(d).

The carrying amount of cash, accounts receivable, unbilled revenue, amounts due from related parties, bank indebtedness, liability for subdivision development, short-term debt, short- term Infrastructure Ontario financing, customer deposits, accounts payable and accrued liabilities and amounts due to related parties approximates fair value because of the short maturity of these instruments. The carrying value and fair value of the Corporation's other financial instruments are as follows:

		2015		2014
Description	**Carrying value**	**Fair value**	Carrying value	Fair value
	$	**$**	$	$
Liabilities				
Notes payable	**182,430**	**217,108**	182,430	219,338
Debentures payable	**347,407**	**348,647**	347,288	353,756
	529,837	**565,755**	529,718	573,094

The carrying amounts shown in the table are included in the balance sheet under the indicated captions. In addition, the fair value of the $3,995 (2014 - $4,293) Infrastructure Ontario debentures which have been reclassified as a current liability (see Note 11), is $4,075 (2014 - $4,324) as at December 31, 2015.

(In thousands of dollars)

17. Financial instruments and risk management (continued)

(a) Fair value of financial instruments (continued)

Financial instruments which are disclosed at fair value are to be classified using a three - level hierarchy. Each level reflects the inputs used to measure the fair values disclosed of the financial liabilities, and are as follows:

- Level 1: inputs are unadjusted quoted prices of identical instruments in active markets,
- Level 2: inputs other than quoted prices included in Level 1 that are observable for the asset or liability, either directly or indirectly, and
- Level 3: inputs for the liabilities that are not based on observable market data (unobservable inputs).

The Corporation's fair value hierarchy is classified as Level 2 for notes and debentures payable. The classification for disclosure purposes has been determined in accordance with generally accepted pricing models, based on discounted cash flow analysis, with the most significant inputs being the contractual terms of the instrument discounted, and the market discount rates that reflects the credit risk of counterparties.

(b) Risk factors

The Corporation understands the risks inherent in its business and defines them broadly as anything that could impact its ability to achieve its strategic objectives. The Corporation's exposure to a variety of risks such as credit risk, interest rate risk and liquidity risk as well as related mitigation strategies have been discussed below. However, the risks described below are not exhaustive of all the risks nor will the mitigation strategies eliminate the Corporation's exposure to all risks listed.

(c) Credit risk

The Corporation's primary source of credit risk to its accounts receivable result from customers failing to discharge their dues for electricity consumed and billed.

The Corporation has approximately 375,000 (2014 - 370,000) residential and commercial customers. In order to mitigate such potential credit risks, the Corporation has taken various measures in respect of its Energy customers such as collecting security deposits amounting to $17,358 (2014 - $15,964) in accordance with OEB guidelines, reviewing Dun & Bradstreet ("D&B") reports for the top 3000 commercial customers with an outstanding balance of $5 or more, in-house collection department as well as external collection agencies and a bad debt insurance policy for $4,500 (2014 - $4,500) related to energy receivables. Thus, the Corporation monitors and limits its exposure to such credit risks on an ongoing basis.

Pursuant to their respective terms, accounts receivable are aged as follows at December 31:

	2015		2014	
	Total		Total	
	$	**%**	$	%
Less than 30 days	**78,949**	**72**	78,146	80
30 - 60 days	**15,714**	**14**	12,803	13
61 - 90 days	**5,352**	**5**	3,469	4
Greater than 91 days	**9,576**	**9**	3,186	3
Total outstanding	**109,591**	**100**	97,604	100
Less: allowance for doubtful accounts	**(3,649)**	**(3)**	(1,641)	(2)
	105,942	**97**	95,963	98

As at December 31, 2015, there was no significant concentration of credit risk with respect to any financial assets.

(In thousands of dollars)

17. Financial instruments and risk management (continued)

(d) Interest rate risk

The Corporation manages its exposure to interest rate risk by issuing long term fixed rate debt in the form of debentures, promissory notes and bank loans. It also ensures that all payment obligations are met by adopting proper capital planning.

As part of the Corporations' revolving demand operating credit facility, the Corporation may utilize the line of credit for working capital and/or capital expenditure purposes. Such short-term borrowing may expose the Corporation to short-term interest rate fluctuations as follows:

	2015	2014
364 day revolving facility		
Prime based loans	**PR*+0.0% p.a.**	PR*+0.0% p.a.
Bankers Acceptances	**SF*+0.95% p.a.**	SF*+0.95% p.a.
Demand facility		
Prime based loans	**PR*–0.30% p.a.**	PR*–0.30% p.a.
Bankers acceptances	**SF*+0.68% p.a.**	SF*+0.68% p.a.
Bankers acceptances (Secondary)	**SF*+0.70% p.a.**	SF*+0.70% p.a.
Letter of guarantee facility	**0.50% p.a.**	0.50% p.a.
Infrastructure Ontario financing	**Floating rate p.a.**	Floating rate p.a.

Note: PR - Prime Rate, SF* - Stamping Fee*

A sensitivity analysis was conducted to examine the impact of a change in the prime rate or stamping fee on the short-term debt. A variation of 1% (100 basis points), with all other variables held constant, would increase or decrease the annual interest expense by approximately $455.

Cash balances that are not required for day to day obligations earn an interest of Prime minus 1.7% per annum. Fluctuations in this interest rate could impact the level of interest income earned by the Corporation.

(e) Liquidity risk

Liquidity risks are those risks associated with the Corporation's inability to meet obligations associated with financial liabilities such as repayment of principal or interest payments on debts.

The Corporation monitors its liquidity risks on a regular basis to ensure there is sufficient cash flow to meet the obligations as they fall due as well as minimize the interest expense. Cash flow forecasts are prepared to monitor liquidity risks. Liquidity risks associated with financial liabilities are as follows:

			2015			2014
Maturity period	**Principal***	**Interest**	**Total**	Principal*	Interest	Total
	$	**$**	**$**	$	$	$
Less than 1 year	**325,719**	**23,563**	**349,282**	254,072	24,533	278,605
1-5 years	**16,327**	**111,623**	**127,950**	17,283	112,299	129,582
6-10 years	**295,219**	**76,090**	**371,309**	316,291	90,242	406,533
Over 10 years	**198,291**	**122,540**	**320,831**	200,315	130,442	330,757
	835,556	**333,816**	**1,169,372**	787,961	357,516	1,145,477

* The principal includes $2,592 (2014 - $2,712) of unamortized deferred issuing cost.

(In thousands of dollars)

17. Financial instruments and risk management (continued)

(f) Hedging/derivative risk

The Corporation has a swap and derivative transaction policy to enable the Corporation to enter into agreements such as interest rate swaps where 100% of the floating rate risk is hedged into a fixed rate. This is done for prudent risk management purposes and not speculative purposes.

The Corporation has not entered into any such transactions during the current year or prior years.

18. Capital structure

The Corporation's main objectives in the management of capital are to:

(i) Ensure that there is access to various funding options at the lowest possible rates for the various capital initiatives and working capital requirements necessary for the rate-regulated business;

(ii) Ensure compliance with various covenants related to its short-term debt, Infrastructure Ontario financing, bank term loan, debentures payable and Infrastructure Ontario debentures;

(iii) Consistently maintain a high credit rating for the Corporation;

(iv) Maintain a split of approximately 60% debt, 40% equity as recommended by the OEB;

(v) Ensure interest rate fluctuations are mitigated primarily by long term borrowings as well as capital planning; and

(vi) Deliver appropriate financial returns to shareholders.

The Corporation considers shareholders' equity, long-term debt and certain short-term debt as its capital. The capital structure as at December 31, 2015 is as follows:

	2015	2014
	$	$
Short-term debt		
Short-term debt (Note 11)	**50,000**	25,000
Infrastructure Ontario financing (Note 11)	**74,691**	67,656
Notes payable (Note 12)	**20,000**	-
Long-term debt		
Debentures payable (Note 12)	**347,407**	347,288
Notes payable (Note 12)	**162,430**	182,430
Total debt	**654,528**	622,374
Shareholders' equity		
Share capital (Note 14)	**342,184**	327,184
Accumulated other comprehensive income	**2,083**	1,819
Retained earnings	**111,626**	114,297
Total equity	**455,893**	443,300
Total	**1,110,421**	1,065,674

(In thousands of dollars)

18. Capital structure (continued)

As at December 31, 2015, the Corporation was in compliance with covenants related to its short-term debt, bank term loan and debentures payable. The Corporation is in a temporary breach of a covenant related to Infrastructure Ontario financing and expects to receive a waiver following the reporting date. Details relating to covenants are disclosed in Note 11 and Note 12.

The Corporation is within the debt and equity requirements of the OEB. The Corporation's dividend policy is disclosed in Note 14.

19. Operating expenses

Operating expenses comprise:

	2015	2014
	$	$
Labour	**49,121**	49,747
Contract/consulting	**17,067**	15,710
Materials	**1,896**	1,651
Vehicle	**1,399**	1,579
Other	**30,735**	21,668
	100,218	90,355

20. Income taxes

(a) Income tax expense

PILs recognized in net income comprise the following:

	2015	2014
	$	$
Current tax recovery	**(3,526)**	(7,559)
Deferred tax expense	**6,916**	7,376
Income tax expense (recovery)	**3,390**	(183)

(In thousands of dollars)

20. Income taxes (continued)

(b) Reconciliation of effective tax rate

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

	2015	2014
	$	$
Income before taxes	**28,835**	13,691
Statutory Canadian federal and provincial income tax rates	**26.50%**	26.50%
Expected tax provision on income at statutory rates	**7,641**	3,628
Increase (decrease) in income taxes resulting from:		
Permanent differences	**67**	(5)
Adjustments in respect of prior years	**40**	(1,929)
Scientific Research & Experimental Development tax credit	**(1,122)**	(1,374)
Burden filing reserve reversal	**(2,800)**	-
Other	**(436)**	(503)
Total income tax expense (recovery)	**3,390**	(183)

Statutory Canadian federal and provincial income tax rates for the current year comprise 15% (2014 - 15%) for federal corporate tax and a rate of 11.5% (2013 - 11.5%) for corporate tax in Ontario. There was no change in the federal and provincial corporate tax rates in 2015 (no change in 2014).

(c) Deferred tax balances

Deferred tax assets/(liabilities) are attributable to the following:

	2015	2014
	$	$
Employee future benefits	**4,852**	4,601
Property, plant and equipment	**480**	3,154
Intangible assets	**1,102**	1,203
Non-capital loss	**5,040**	1,314
Tax credit carryovers	**765**	2,482
Other deductible temporary differences	**(5,012)**	1,485
	7,227	14,239

Management has a plan in place to utilize the above losses and draw down this asset.

(In thousands of dollars)

20. Income taxes (continued)

(c) Deferred tax balances (continued)

Movement in deferred tax balances during the year were as follows:

	2015	2014
	$	$
Balance at January 1	**14,239**	22,537
Recognized in net income	**(6,916)**	(7,376)
Recognized in OCI related to employee future benefits	**(96)**	(922)
Balance at December 31	**7,227**	14,239

21. Net change in non-cash operating working capital

	2015	2014
	$	$
Accounts receivable	**(9,979)**	(5,334)
Unbilled revenue	**17,925**	3,258
Due from related parties	**(6,930)**	(3,998)
Inventories	**(141)**	(129)
Prepaids and other assets	**(1,079)**	(233)
Customer deposits	**1,555**	1,079
Accounts payable and accrued liabilities	**11,791**	(1,442)
Due to related parties	**2,146**	1,167
Liability for subdivision development	**(448)**	(332)
Capital accruals in prior year	**9,603**	10,122
Capital accruals in current year	**(5,266)**	(9,603)
	19,177	(5,445)

22. Other revenue

	2015	2014
	$	$
Renewable generation	**16,699**	10,878
Other	**16,073**	15,175
	32,772	26,053

23. Contingencies, commitments and guarantees

(a) Contingencies- legal claims

The Corporation has been named as a defendant in several actions. No provision has been recorded in the financial statements for these potential liabilities as the Corporation expects that these claims are adequately covered by its insurance.

(b) Commitments

As at December 31, 2015, the Corporation has entered into agreements for capital projects and is committed to making payments of $15,067 in 2016.

(c) Guarantees

In the normal course of business, the Corporation enters into agreements that meet the definition of a guarantee as follows:

(i) The Corporation has provided indemnities under lease agreements for the use of various operating facilities. Under the terms of these agreements the Corporation agrees to indemnify the counterparties for various items including, but not limited to, all liabilities, loss, suits, and damages arising during, on or after the term of the agreement. The maximum amount of any potential future payment cannot be reasonably estimated.

(ii) Indemnity has been provided to all directors and/or officers of the Corporation for various items including, but not limited to, all costs to settle suits or actions due to association with the Corporation, subject to certain restrictions. The Corporation has purchased directors' and officers' liability insurance to mitigate the cost of any potential future suits or actions. The term of the indemnification is not explicitly defined, but is limited to the period over which the indemnified party served as a trustee, director or officer of the Corporation. The maximum amount of any potential future payment cannot be reasonably estimated.

(iii) In the normal course of business, the Corporation has entered into agreements that include indemnities in favor of third parties, such as purchase and sale agreements, confidentiality agreements, engagement letters with advisors and consultants, outsourcing agreements, leasing contracts, information technology agreements and service agreements. These indemnification agreements may require the Corporation to compensate counterparties for losses incurred by the counterparties as a result of breaches in representation and regulations or as a result of litigation claims or statutory sanctions that may be suffered by the counterparty as a consequence of the transaction. The terms of these indemnities are not explicitly defined and the maximum amount of any potential reimbursement cannot be reasonably estimated.

The nature of these indemnification agreements prevents the Corporation from making a reasonable estimate of the maximum exposure due to the difficulties in assessing the amount of liability which stems from the unpredictability of future events and the unlimited coverage offered to counterparties. Historically, the Corporation has not made any significant payments under such or similar indemnification agreements and therefore no amount has been accrued in the balance sheet with respect to these agreements.

24. Prior year's comparatives

Certain of prior year's figures have been reclassified to conform to the current year's presentation.

ATTACHMENT 10
BRAMPTON HYDRO 2016 AUDITED FINANCIAL STATEMENTS

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Hydro One Brampton Networks Inc.

IFRS Financial Statements

Year ended December 31, 2016 and 2015

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INDEPENDENT AUDITORS' REPORT

To the Shareholder of Hydro One Brampton Networks Inc.

We have audited the accompanying financial statements of Hydro One Brampton Networks Inc., which comprise the statement of financial position as at December 31, 2016, the statement of income and comprehensive income, statement of changes in shareholder's equity and cash flow for the year ended December 31, 2016, and notes, comprising a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with International Financial Reporting Standards, and for such internal control as management determines is necessary to enable the preparation of 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 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 financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the 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 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 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 financial statements present fairly, in all material respects, the financial position of Hydro One Brampton Networks Inc. as at December 31, 2016, and its financial performance and its cash flows for the year then ended in accordance with International Financial Reporting Standards.

KPMG LLP

April 17, 2017

Toronto, Canada

HYDRO ONE BRAMPTON NETWORKS INC.
Statement of Income and Other Comprehensive Income

Year ended December 31 (Canadian dollars in thousands)	**2016**	2015
Revenues		
Energy Sales	**525,050**	466,594
Distribution	**71,837**	66,967
Other	**4,632**	4,619
	601,519	538,180
Costs		
Purchased power (Note 20)	**520,487**	459,132
Operation, maintenance and administration (Notes 19 and 20)	**31,610**	27,862
Depreciation of property, plant and equipment and amortization of intangible assets (Notes 7 and 8)	**17,359**	18,246
	569,456	505,240
Financing costs (Notes 5 and 20)	**11,157**	11,418
Income before taxes	**20,906**	21,522
Income tax expense (Note 6)	**5,563**	5,451
Net income for the year	**15,343**	16,071
Net movement in regulatory balances, net of tax (Note 9)	**(1,642)**	(1,818)
Net income after net movement in regulatory balances	**13,701**	14,253
Other comprehensive income		
Item that will not be reclassified to income or loss		
Remeasurement of post-retirement benefits, net of tax (Note 15)	**833**	140
Total other comprehensive income	**833**	140
Total income and other comprehensive income for the year	**14,534**	14,393

See accompanying Notes to Financial Statements.

HYDRO ONE BRAMPTON NETWORKS INC.
Statements of Financial Position

(Canadian dollars in thousands)	**December 31, 2016**	December 31, 2015
Assets		
Non-current assets:		
Property, plant and equipment (Note 7)	**376,021**	362,029
Intangible assets (Note 8)	**20,698**	21,446
	396,719	383,475
Current assets:		
Cash	**55,215**	40,521
Accounts receivable (Note 14)	**88,711**	73,293
Materials and supplies	**1,343**	1,074
	145,269	114,888
Total assets	**541,988**	498,363
Regulatory balances (Note 9)	**11,590**	9,970
Total assets and regulatory balances	**553,578**	508,333

See accompanying notes to Financial Statements.

HYDRO ONE BRAMPTON NETWORKS INC.
Statements of Financial Position (cont'd)

(Canadian dollars in thousands)	**December 31, 2016**	December 31, 2015
Liabilities		
Non-current liabilities:		
Accounts payable and accrued liabilities (Note 16)	**123**	151
Deferred revenue (Note 17)	**38,570**	25,721
Deferred tax liabilities (Note 6)	**2,996**	901
Employee future benefits (Note 15)	**3,751**	4,324
	45,440	31,097
Long-term debt (Note 10)	**192,270**	192,239
	237,710	223,336
Current liabilities:		
Current tax liabilities	**1,241**	478
Accounts payable and accrued liabilities (Note 16)	**72,454**	72,321
Accrued interest	**18,931**	7,047
Deferred revenue (Note 17)	**1,510**	1,172
Employee future benefits (Note 15)	**127**	170
	94,263	81,188
Total liabilities	**331,973**	304,524
Shareholder's equity		
Share capital (Note 18)	**104,501**	104,501
Retained earnings	**105,944**	92,243
Accumulated other comprehensive income (Note 15)	**2,920**	2,087
Total shareholder's equity	**213,365**	198,831
Regulatory balances (Note 9)	**8,240**	4,978
Total liabilities, shareholder's equity and regulatory balances	**553,578**	508,333

See accompanying notes to Financial Statements.

On behalf of the Board of Directors:

Serge Imbrogno
Chair

Paul Tremblay
Director

HYDRO ONE BRAMPTON NETWORKS INC.
Statements of Changes in Shareholder's Equity

(Canadian dollars in thousands)	Share capital	Accumulated other comprehensive income	Retained earnings	Total
Balance at January 1, 2015	51,501	1,947	77,990	131,438
Issuance of common shares	53,000	-	-	53,000
Net income after net movement in regulatory balances	-	-	14,253	14,253
Other comprehensive income	-	140	-	140
Balance at December 31, 2015	104,501	2,087	92,243	198,831
Balance at January 1, 2016	104,501	2,087	92,243	198,831
Net income after net movement in regulatory balances	-	-	13,701	13,701
Other comprehensive income	-	833	-	833
Balance at December 31, 2016	**104,501**	**2,920**	**105,944**	**213,365**

See accompanying notes to Financial Statements.

HYDRO ONE BRAMPTON NETWORKS INC.
Statements of Cash Flows

Year ended December 31 (Canadian dollars in thousands)	**2016**	2015
Operating activities		
Net income after net movement in regulatory balances	**13,701**	14,253
Adjustments for non-cash items:		
Depreciation of PP&E and amortization of intangible assets (net of removal costs)	**17,520**	18,078
Amortization of debt costs	**31**	30
Amortization of deferred revenue (Note 17)	**(736)**	(605)
Post-retirement benefits (Note 15)	**217**	228
Net interest expense (Note 5)	**11,126**	12,030
PILs expense (Note 6)	**2,479**	332
	44,338	44,346
Changes in non-cash balances related to operations (Note 21)	**(10,613)**	(9,906)
PILs received (paid)	**(2,500)**	1,000
Regulatory balances (Note 9)	**1,642**	1,818
Net cash from operating activities	**32,867**	37,258
Investing activities		
Interest received (Note 5)	**326**	97
Property, plant and equipment (Note 7)	**(31,806)**	(44,919)
Intangible assets (Note 8)	**(466)**	(8,110)
Capital contributions received (Note 17)	**13,923**	12,376
Net cash used in investing activities	**(18,023)**	(40,556)
Financing activities		
Interest paid (Note 5)	**(150)**	(6,476)
Common shares issuance (Note 18)	**-**	53,000
Net cash raised (used) in financing activities	**(150)**	46,524
Net change in cash and cash equivalents	**14,694**	43,226
Cash and cash equivalents (bank indebtedness), January 1	**40,521**	(2,705)
Cash and cash equivalents, December 31	**55,215**	40,521

See accompanying notes to Financial Statements.

1. DESCRIPTION OF THE BUSINESS

Hydro One Brampton Networks Inc. (Hydro One Brampton or the Company) was incorporated on April 25, 2000 under the *Business Corporations Act* (Ontario). All issued and outstanding shares of Hydro One Brampton are held by Brampton Distribution Holdco Inc. which is wholly owned by the Province of Ontario (Province). The principal business of the Company is the ownership, operation and management of electricity distribution systems and facilities located at 175 Sandalwood Parkway West in Brampton, Ontario, L7A 1E8. The Company's business is regulated by the Ontario Energy Board (OEB).

2. BASIS OF PREPARATION

The annual financial statements of Hydro One Brampton as at December 31, 2016 and 2015 and for the year ended December 31, 2016 and 2015 have been prepared in accordance with International Financial Reporting Standards (IFRS). These Financial Statements have been prepared in accordance with the significant accounting policies described in Note 3. Certain prior year amounts have been reclassified to conform to current year groupings.

The Company has evaluated the events and transactions occurring subsequent to the date of the Statement of Financial Position date through to February 22, 2017, when the Company's Financial Statements were approved and authorized for issue by the Company's Board of Directors. This evaluation included the identification of events and transactions requiring recognition in the Financial Statements and/or disclosure in the Notes to the Financial Statements.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The significant accounting policies that have been applied in the preparation of these financial statements are detailed below:

Rate-setting

The Company's electricity distribution rates are subject to rate regulation by the OEB and are based on an approved revenue requirement that includes a rate of return of 9.3% (2015 - 9.3%). On December 10, 2015, the OEB approved Hydro One Brampton's 2016 rates on the basis of the OEB's Price Cap Incentive rate setting plan (Price Cap IR) option. The revised rates were implemented January 1, 2016. On December 8, 2016, the OEB approved Hydro One Brampton's 2017 rates on the basis of the OEB's Price Cap Incentive rate setting plan (Price Cap IR) option. The revised rates were implemented on January 1, 2017.

In January 2014, the IASB issued IFRS 14 "*Regulatory Deferral Accounts*" as an interim standard giving entities the option to continue with their legacy pre-IFRS accounting policies when adopting IFRS for the first time. Specifically, qualifying entities conducting rate-regulated activities have the option of continuing to recognize regulatory balances according to their previous national GAAP (i.e. CGAAP). As these regulatory balances provide readers with useful information about the Company's financial position, financial performance and cash flows, the Company opted to implement IFRS 14. IFRS 14 will remain in force until either repealed or replaced by permanent guidance on rate regulated accounting expected to result from the IASB's current Rate Regulated Activities Project. IFRS 14 is effective for annual periods beginning on or after January 1, 2016, but early adoption is permitted. The Company elected to early adopt IFRS 14 effective January 1, 2014 for the purpose of preparing its initial Financial Statements under IFRS.

The Company has determined that certain debit and credit balances arising from its rate-regulated activities qualify for the application of regulatory accounting treatment in accordance with IFRS 14. Under the Company's legacy rate-regulated accounting policies, which are continued under IFRS 14, the timing and recognition of certain expenses, losses revenues and gains may differ from that otherwise expected under IFRS. This has the effect of more appropriately reflecting the economic impact of the regulator's decisions regarding the Company's regulated operations. Amounts arising from such timing differences are recorded as regulatory debit and credit balances on the Company's Statements of Financial Position, and represent existing rights and obligations regarding future cash flows expected to be recovered from, or refunded to customers, based on expected and actual decisions and approvals by the OEB. Regulatory balances are recognized only if the OEB directs the relevant regulatory treatment or if future OEB direction is judged to be probable. In the event that the inclusion of the whole or a part of such balances is assessed to no longer be probable based on management's judgment, the balances will be derecognized with any resulting gain or loss being recorded in the Company's Statement of Income and Other Comprehensive Income in the period when the assessment is made.

Regulatory balances are segregated on the Statement of Financial Position and the net change in these balances is presented on the Statement of Income and Other Comprehensive Income as Net Movements in Regulatory Balances, net of income taxes. The netting of regulatory debit and credit balances is not permitted on the Statement of Financial Position. The measurement of regulatory balances is subject to certain estimates and assumptions by Management, including assumptions made in interpreting the OEB's regulations and decisions.

Revenue Recognition

Energy Sales and Distribution Revenue

Distribution revenues attributable to the sale and delivery of electricity are recognized as electricity is delivered to customers. Distribution revenues reflect actual consumption billed, actual customer consumption yet to be billed, and an estimate for any other unbilled consumption. Actual customer consumption yet to be billed is calculated using smart meter data and actual billing rates and an estimate for the price for energy. Unbilled revenues that relate to energy used by consumers from the last meter reading dates during the period to the end of the year are estimated based on historical actual consumption from smart meters.

Other Revenue

Other revenue includes amortization of customer contributions, government grants and incentives under Conservation and Demand Management (CDM) programs, revenue from billable customer demand activities and other general revenues. Certain items of property, plant and equipment are acquired or constructed with the assistance of contributions from customers or developers (customer contributions). These contributions are usually defined by OEB industry codes and may be received in the form of cash or as in-kind contribution. These customer contributions are recognized as deferred revenue and are amortized to revenue over the lives of the related assets. Government grants under CDM programs are recognized as income when there is reasonable assurance that the grant will be received and all related conditions will be met. Performance incentive payments under CDM programs are recognized by the Company when there is reasonable assurance that the program conditions have been satisfied and the incentive payment will be received. Other revenue related to billable activities is recognized as services are rendered.

Corporate Income Taxes

Under the *Electricity Act*, *1998,* Hydro One Brampton is required to make payments in lieu of corporate income taxes (PILs) to the Ontario Electricity Financial Corporation (OEFC). These payments are calculated in accordance with the rules for computing taxable income and other relevant amounts contained in the *Income Tax Act (Canada)* and the *Corporations Tax Act (Ontario)* as modified by the Electricity Act, 1998, and related regulations. The provision for PILs is calculated using the liability method.

IFRS 14 requires the recognition of regulatory balances and related deferred tax assets and liabilities representing those deferred tax amounts expected to be refunded to, or recovered from, customers through future electricity distribution rates. Any related gross-up reflecting the income tax benefits associated with reduced revenues resulting from the realization of deferred tax assets, is recorded within Regulatory Balances. Deferred taxes that are not included in the rate-setting process are charged or credited to the Statement of Income and Other Comprehensive Income.

Current Tax

Current tax assets and liabilities for the current and prior periods are measured at the amounts expected to be paid to, or recovered from, the OEFC. The tax rates and tax laws used to compute these amounts are those that are enacted or substantively enacted. Management periodically reevaluates positions taken in tax returns with respect to situations in which applicable tax regulations are subject to interpretation and establishes provisions, where appropriate, on the basis of amounts expected to be paid to the tax authorities. The amount of current tax payable or receivable is Management's best estimate of the tax amounts expected to be paid or received and reflect any uncertainty related to income taxes.

Deferred Tax

Deferred tax is recognized on temporary differences between the carrying amounts of assets and liabilities in the financial statements and the corresponding tax basis used in the computation of taxable profit. Deferred tax assets are recognized to the extent that it is probable that taxable profits will be available against which deductible temporary differences can be utilized.

Deferred tax is measured at the tax rates that are expected to apply in the period when the liability is settled or the asset is realized using the tax rates and tax laws that have been enacted or substantively enacted, at the reporting date.

Materials and Supplies

Materials and supplies represent consumables, minor spare parts and construction material held for internal construction and maintenance of property, plant and equipment assets (PP&E). These assets are carried at the lower of average cost or net realizable value. The Company classifies all major construction related spares and components of its electricity distribution infrastructure as property, plant and equipment but does not commence depreciation on this material until it is put into service as part of a component of PP&E.

Cash and Cash Equivalents

Cash and cash equivalents include cash in bank accounts and short-term investments with terms to maturity of 90 days or less from their date of acquisition. On the Statement of Cash Flows, cash and cash equivalents may represent bank indebtedness that is repayable on demand.

Accounts Receivable

The carrying amount of accounts receivable and unbilled revenue is reduced through an allowance for doubtful accounts, if applicable. When the Company considers that there are no realistic prospects of recovery of an account receivable, the relevant amount is determined to be impaired and is written off. If the amount of impairment loss subsequently decreases due to an event occurring after the impairment was recognized, then the previously recognized impairment loss is reversed through net income.

Property, Plant and Equipment

Property, plant and equipment is recorded at historical acquisition cost less accumulated depreciation. Cost includes expenditures that are directly attributable to the acquisition of the asset. The cost of self-constructed assets includes the cost of direct materials and direct labour, directly attributable overheads, and borrowing costs on qualifying assets. Significant parts of PP&E that have different useful lives are accounted for as separate items (major components) of PP&E.

PP&E consist of land, land rights and buildings, distribution assets, vehicles and other tangible assets. In addition, major spare parts and standby equipment are also accounted for as PP&E.

Some of the Company's distribution assets, particularly those located on unowned easements and rights-of-way, may have decommissioning or asset retirement obligations, constructive or otherwise. The majority of the Company's land rights (easements and rights-of-way) are subject to extension or renewal and are expected to be available for a perpetual duration. As the Company expects to use the majority of its installed assets into perpetuity, no removal date can be determined and consequently no reasonable estimate of the fair value of such asset retirement obligations can be made. If, at some future date, it becomes possible to estimate the fair value cost of removing the assets that the Company is legally or constructively required to remove, a related asset retirement obligation will be recognized at that time. The discounted amount is not material.

An item of PP&E is derecognized upon disposal or when no future economic benefits are expected from either use or disposal. Any gain or loss arising on asset derecognition (calculated as the difference between the net disposal proceeds and the carrying amount of the asset) is included in the Statement of Income and Other Comprehensive Income. The cost of replacing an item of PP&E, or a major part thereof, is recorded as an addition to the carrying amount of PP&E and the carrying amount of the replaced part is derecognized. The cost of the day-to-day servicing of PP&E assets is recorded in net income as incurred.

Construction in Progress

Construction in progress assets are generally assets that are undergoing active construction or development and which are not currently available for use. Such assets are therefore not depreciated. Borrowing costs directly attributable to the acquisition, construction or production of a qualifying asset are capitalized. A qualifying asset is one that necessarily takes a substantial period of time to get ready for its intended use. Management has assessed a substantial period of time to mean six months or more.

Intangible Assets

Intangible assets are measured at cost on an analogous basis as PP&E. Intangible assets are carried at cost less any accumulated amortization and any accumulated impairment losses.

The useful lives of intangible assets are assessed as either finite or indefinite. Intangible assets with finite lives are amortized over their estimated useful economic lives and are assessed for impairment whenever there is an indication that the carrying value may be impaired. Intangible assets with indefinite useful lives are not amortized, but are tested for impairment annually, either individually or at the cash generating unit (CGU) level.

Any gain or loss arising on asset derecognition (calculated as the difference between the net disposal proceeds and the carrying amount of the asset) is included in net income.

Depreciation and Amortization

The capital costs of PP&E and intangible assets are depreciated on a straight-line basis over their estimated remaining service lives. Remaining lives and methods of depreciation are reviewed by Management at each financial year end. Detailed reviews are performed periodically, generally as preparation for an OEB cost of service application and such reviews may involve inputs from an external depreciation consultant. Any changes arising from such a review are implemented on a remaining service life basis consistent with their inclusion in rates. The OEB approved new depreciation rates as part of the Company's 2015 cost of service rate decision.

The estimated service lives for the principal categories of PP&E and intangibles are, in aggregate, as shown in the table below:

	Years
Land rights	Indefinite
Buildings	25 to 50
Distribution assets:	
Distribution equipment	20 to 75
Transformer stations	10 to 40
Transformers and meters	15 to 40
Vehicles and other:	
Trucks and equipment	7 to 10
Office and computer equipment	5 to 10
Other	5 to 15
Intangible assets:	
Computer software	5
Capital contributions to Hydro One	40

The majority of land rights (including easements) are held in perpetuity and are not depreciated. Depreciation rates for finite life easements are based on contract life.

Where a disposition of a component of PP&E occurs through sale, a gain or loss is calculated based on net proceeds and is presented within depreciation expense. Depreciation expense also includes the costs incurred to remove PP&E where no decommissioning liability has been recognized.

Deferred Revenue

Contributions received towards the cost of property, plant and equipment are recorded as deferred revenue and amortized to revenue on a straight line basis over the estimated economic useful lives of the assets to which they relate.

In addition, amounts are received pursuant to agreements with developers for the estimated costs for the remediation of deficiencies to residential subdivisions (subdivision deficiencies) for which the related services have yet to be performed. These amounts are recorded initially as deferred revenue and are recognized as revenue in the fiscal year the related expenditures are incurred or services performed.

Impairment

Non-Financial Assets

The carrying costs of the Company’s PP&E and intangible assets are generally included in rate base where they earn an OEB-approved rate of return. In addition, the capital costs of the Company’s assets are generally recoverable in OEB-approved revenue requirements. As such, the Company’s assets would only indicate that an impairment trigger exists in the event that the OEB disallows recovery or if such disallowance is judged to be probable.

PP&E and intangible assets are reviewed at each reporting date to determine whether any indication exists of potential impairment. If such an indication exists, the relevant asset’s recoverable amount is tested for impairment.

Financial Assets

A financial asset is considered to be impaired if objective evidence indicates that there has been a negative effect on the recoverable amount (estimated future cash flows to accrue from that asset). If there is evidence that an impairment loss has been incurred, the amount of the loss is measured as the difference between the asset's carrying amount and the present value of estimated future cash flows discounted at original effective interest rate.

An impairment loss related to financial assets is reversed if, and to the extent there has been a change in the estimates used to determine the recoverable amount. The loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have existed had no impairment loss been recognized.

Reversals of impairment are recognized in finance costs.

Financial Instruments

All financial assets are classified as Loans and Receivables and all financial liabilities are classified as Other Liabilities. These financial instruments are recognized initially at fair value plus any directly attributable transaction costs. Subsequently, they are measured at amortized cost using the effective interest method less any impairment for the financial assets as described in note 3. The Company does not enter into derivative instruments.

Cash equivalents include short-term investments with maturities of three months or less when purchased.

Employee Future Benefits

Pension

Full-time employees participate in the Ontario Municipal Employees Retirement System Fund (OMERS), a multi-employer, contributory, defined benefit public sector pension fund. OMERS provides retirement pension payments based on a member's length of service and salary. Both participating employers and members are required to make plan contributions. The OMERS plan assets are pooled together to provide benefits to all plan participants and the plan assets are not segregated in separate accounts for each member entity. The OMERS plan has approximately 461,000 members, of whom approximately 208 are current employees of Hydro One Brampton. The Company's future contributions may be increased substantially if other entities withdraw from the plan.

The OMERS plan is accounted for as a defined contribution plan by the Company because it is not practicable to determine the present value of the Company's obligation, the fair value of plan assets or the related current service cost applicable to Hydro One Brampton employees. Hydro One Brampton recognizes its pension expense based on contributions to the OMERS plan, with a portion of these contributions being capitalized. They are capitalized when there is capital project work. The expensed portion is included in operation, maintenance and administration costs in the Statement of Income and Other Comprehensive Income.

Post-Retirement Benefits (OPRB)

The Company provides some or all of its retired employees with life insurance and medical and dental benefits beyond those provided by government sponsored plans. The costs of the Company's unfunded post-retirement benefit plan is recognized over the periods during which employees render service.

The obligations for this plan is actuarially determined using the projected unit credit method, which incorporates Management's best estimate of future salary levels, retirement ages of employees, health care costs, and other actuarial factors. Changes in actuarial assumptions and experience adjustments give rise to actuarial gains and losses which are recognized in OCI as they arise. The measurement date used to determine the present value of the benefit obligation is December 31 of the applicable year. The latest actuarial valuation was performed as at December 31, 2016.

All OPRB costs are attributed to labour and recognized in either net income or are capitalized as part of the cost of PP&E and intangible assets.

Provisions

A provision is recognized if, as a result of a past event, the Company has a present legal or constructive obligation that can be estimated reliably, and it is probable that an outflow of economic benefits will be required to settle the obligation.

Dividends

Common share dividends are declared at the sole discretion of the Company's Board of Directors and are recommended by Management based upon results of operations, financial condition, cash requirements and other relevant factors such as industry practice and shareholder expectations. Common share dividends are declared and paid within the same period.

Use of Judgments and Estimates

The preparation of the Company's financial statements requires Management to make judgments, estimates and assumptions that affect the reported amounts of revenues, expenses, assets and liabilities, the accompanying disclosures, and the disclosure of contingent liabilities. Uncertainty about these assumptions and estimates could result in outcomes that require a material adjustment to the carrying amount of assets or liabilities in future periods. Actual results could differ from these estimates including changes as a result of future decisions made by the OEB.

Key judgments and estimates affecting the financial statements are summarized below:

- Estimation of service lives for property, plant and equipment and intangible assets (Note 7 & 8)
- Recognition and measurement of regulatory balances (Note 9)
- Recognition of deferred tax assets - availability of future taxable income against which deductible temporary differences and loss carryforwards can be used (Note 6)
- Measurement of defined benefit obligations - key actuarial assumptions (Note 15)
- Measurement of unbilled revenue (Note 14)
- Asset impairments and asset retirement obligations
- Allowance for doubtful accounts (Note 14); and
- Recognition and measurement of environmental provisions

4. FUTURE ACCOUNTING PRONOUNCEMENTS

A number of new accounting standards, amendments and interpretations have been issued by the IASB and are not yet effective for the year ended December 31, 2016. As such they have not been applied in preparing these Financial Statements. The Company continues to analyze these standards and has initially determined that the following could have a significant impact on its financial statements.

IFRS	Date Issued	Description	Effective Date	Impact on Company
IFRS 15	May 2014	IFRS 15 Revenue from Contracts with Customers outlines a single comprehensive model for entities to use in accounting for revenues arising from contracts with customers. It supersedes current revenue recognition guidance including IAS 18 Revenues, IAS 11 Construction Contracts and related interpretations. The new revenue model applies to all contracts with customers except those that are within the scope of other IFRSs, such as leases, insurance contracts and financial instruments. IFRS 15 specifies how and when the entity should recognize revenue and additional disclosure requirements.	January 1, 2018	Under assessment
IFRS 9	July 2014	The final version of IFRS 9 Financial Instruments brings together the classification and measurement, impairment and hedge accounting to replace IAS 39 Financial Instruments: Recognition and Measurement. IFRS 9 is built on a logical, single classification and measurement approach for financial assets that reflects the business model in which they are managed and their cash flow characteristics. IFRS 9 has an expected credit loss model for a timely recognition of loan losses and is a single model that is applicable to all financial instruments subject to impairment accounting. It also includes an improved hedge accounting model to better link the economics of risk management with its accounting treatment.	January 1, 2018	Under assessment
IFRS 16	January 2016	IFRS 16 Leases replaces the previous leases Standard, IAS 17 Leases, and related Interpretations. IFRS 16 sets out the principles for the recognition, measurement, presentation and disclosure of leases. It eliminates the current dual accounting model for lessees, which distinguishes between on-balance sheet finance leases and off-balance sheet operating leases. Instead, there is a single, on-balance sheet accounting model that is similar to current finance lease accounting. A company can choose to apply IFRS 16 before January 1, 2019 but only if it also applies IFRS 15 Revenue from Contracts.	January 1, 2019	Under assessment

5. FINANCING COSTS

(Canadian dollars in thousands)	**2016**	2015
Financing costs:		
Interest expense:		
Interest on long-term debt	**11,884**	11,897
Amortization of deferred debt costs and debt premiums	**31**	30
Other interest expense	**150**	230
Less interest capitalized on construction and development in progress	**582**	642
Total financing costs	**11,483**	11,515
Finance income:		
Interest income:		
Less interest income on short term bank deposits	**326**	97
Total financing income	**326**	97
Net financing costs	**11,157**	11,418

6. INCOME TAX EXPENSE

A) Amount Recognized in Net Income

(Canadian dollars in thousands)	**2016**	2015
Current tax expense		
Current period	**3,351**	1,518
Adjustments for prior year(s)	**118**	495
	3,469	2,013
Deferred tax expense		
Origination and reversal of temporal differences	**(861)**	(1,246)
Prior period adjustments	**(129)**	(435)
	(990)	(1,681)
Total income tax expense	**2,479**	332
Income tax recorded in net movement in regulatory balances	**3,084**	5,119
Income tax expense and income tax recorded in net movement in regulatory balances	**5,563**	5,451

The total provision for PILs includes deferred income taxes using the Statement of Financial Position liability method of accounting.

B) Amount Recognized in Other Comprehensive Income

	2016			2015		
	Before tax	**Tax (expense) benefit**	**Net of tax**	Before tax	Tax (expense) benefit	Net of tax
Remeasurement of post-retirement benefit obligation	**2,920**	**-**	**2,920**	2,087	-	2,087
	2,920	**-**	**2,920**	2,087	-	2,087

(Canadian dollars in thousands)	**2016**	2015
Net income after net movement in regulatory balances before income tax expense and net movement in regulatory deferred tax balances	**16,180**	14,583
Federal and Ontario statutory tax rate	**26.5%**	26.5%
Income taxes at statutory rates	**4,287**	3,865
Increase (decrease) resulting from:		
Net temporary differences:		
Capital cost allowance in excess of depreciation and amortization	**(1,648)**	(3,383)
Capitalized interest deducted for tax purposes	**(154)**	(170)
Employee future benefits expense in excess of cash payments	**3**	6
Other	**(11)**	(51)
Net temporary differences	**(1,810)**	(3,598)
Net permanent differences	**2**	65
Current income tax	**2,479**	332
Total effective income tax rate	**15.32%**	2.28%

Deferred Tax Assets and Liabilities

(Canadian dollars in thousands)	**December 31, 2016**	December 31, 2015
Deferred income tax assets (liabilities)		
Post-retirement benefits in excess of cash payments	**1,801**	1,743
Capital cost allowance in excess of depreciation and amortization	**(4,974)**	(2,790)
Other	**177**	146
Total deferred tax assets (liabilities)	**(2,996)**	(901)

Movements in Deferred Tax Balances

(Canadian dollars in thousands)	Net balance January 1, 2016	Recognized in net income	**Net balance, December 31,2016**
Post-retirement benefits	1,743	58	**1,801**
PP&E and intangibles	(2,790)	(2,184)	**(4,974)**
Other	146	31	**177**
	(901)	(2,095)	**(2,996)**

(Canadian dollars in thousands)	Net balance January 1, 2015	Recognized in net income	Net balance, December 31,2015
Post-retirement benefits	1,684	59	1,743
PP&E and intangibles	751	(3,541)	(2,790)
Other	114	32	146
	2,549	(3,450)	(901)

7. PROPERTY, PLANT AND EQUIPMENT

(Canadian dollars in thousands)	Land, land rights & buildings	Distribution assets	Vehicles & other	Construction in progress	Total
Deemed cost					
At January 1, 2015	31,940	297,268	11,163	5,712	346,083
Additions	467	38,614	4,176	2,204	45,461
Retirements	-	(4,958)	(1,381)	-	(6,339)
At December 31, 2015	32,407	330,924	13,958	7,916	385,205
Additions	196	30,506	629	-	31,331
Retirements	-	(1,666)	(921)	(920)	(3,507)
At December 31, 2016	**32,603**	**359,764**	**13,666**	**6,996**	**413,029**
Accumulated depreciation					
At January 1, 2015	808	10,554	1,037	-	12,399
Depreciation	850	11,897	1,656	-	14,403
Retirements	-	(2,360)	(1,266)	-	(3,626)
At December 31, 2015	1,658	20,091	1,427	-	23,176
Depreciation	864	12,980	1,771	-	15,615
Retirements	-	(972)	(811)	-	(1,783)
At December 31, 2016	**2,522**	**32,099**	**2,387**	**-**	**37,008**
Carrying amounts (net book value):					
At January 1, 2015	31,132	286,714	10,126	5,712	333,684
At December 31, 2015	30,749	310,833	12,531	7,916	362,029
At December 31, 2016	**30,081**	**327,665**	**11,279**	**6,996**	**376,021**

Hydro One Brampton did not have any impairments in the periods presented above.

During 2016 $4,005 thousand (2015 - $3,999 thousand) of future use assets were recognized in distribution assets.

Losses on de-recognition of PP&E are presented as an element of depreciation expense on the Statement of Income and Comprehensive Income. These losses amounted to $665 thousand (2015 - $2,534 thousand).

The Company capitalizes borrowing costs for all qualifying assets. Borrowing costs were capitalized on qualifying property, plant and equipment and intangible assets under construction or development at a rate of 6.16% (2015 - 6.16 %). Borrowing costs of $582 thousand were capitalized in 2016 (2015 - $642 thousand) as part of the costs of PP&E.

8. INTANGIBLE ASSETS

Canadian dollars in thousands	Contributed capital paid	Computer software	Total
Deemed Cost			
At January 1, 2015	13,505	1,875	15,380
Additions	7,705	541	8,246
At December 31, 2015	21,210	2,416	23,626
Additions	-	353	353
At December 31, 2016	**21,210**	**2,769**	**23,979**
Accumulated amortization			
At January 1, 2015	370	677	1,047
Amortization	467	666	1,133
At December 31, 2015	837	1,343	2,180
Amortization	410	691	1,101
At December 31, 2016	**1,247**	**2,034**	**3,281**
Carrying amount (net book value):			
At January 1, 2015	13,135	1,198	14,333
At December 31, 2015	20,373	1,073	21,446
At December 31, 2016	**19,963**	**735**	**20,698**

9. REGULATORY BALANCES

Regulatory balances arise as a result of the rate-making process. A continuity schedule of the carrying amount of regulatory balances is provided as follows.

(Canadian dollars in thousands)	January1, 2016	Additions	Carrying charges	Recovery	Other movements	December 31, 2016	Remaining recovery period
Regulatory debit balances:							
Accounting changes under CGAAP	3,223	-	-	(1,612)	-	1,611	1 year
Regulatory deferred tax asset	5,628	3,084	-	-	-	8,712	Note [1]
LRAM variance account	521	940	28	-	(901)	588	Note [1]
LV variance account	407	247	6	-	(411)	249	Note [1]
Renewable generation funding adder	127	19	-	-	-	146	Note [1]
Other	64	240	1	(21)	-	284	Note [1]
Total	9,970	4,530	35	(1,633)	(1,312)	11,590	

(Canadian dollars in thousands)	January 1, 2016	Additions	Carrying charges	Repayment	Other movements	December 31, 2016	Remaining recovery period
Regulatory credit balances:							
Retail settlement variance accounts	4,281	4,749	78	-	(4,241)	4,867	Note [1]
Regulatory balances approved for disposition	577	-	(9)	(305)	3,050	3,313	1 year
Other	120	60	1	-	(121)	60	Note [1]
Total	4,978	4,809	70	(305)	(1,312)	8,240	
Net change in regulatory balances	4,992	(279)	(35)	(1,328)	-	3,350	

(Canadian dollars in thousands)	December 31, 2016
Beginning balance, January 1	4,992
Ending balance, December 31	3,350
Net movement in regulatory balances, net of tax	**1,642**

[1] The Company expects to apply for disposition of these regulatory balances at a future date. These balances incur carrying charges at 1.10% per annum (2015 - 1.10%).

(Canadian dollars in thousands)	January1, 2015	Additions	Carrying charges	Recovery	Other movements	December 31, 2015	Remaining recovery period
Regulatory debit balances:							
Accounting changes under CGAAP	4,835	-	-	(1,612)	-	3,223	2 years
Regulatory deferred tax asset	509	5,119	-	-	-	5,628	Note [2]
LRAM variance account	142	376	3	-	-	521	Note [1]
Retail settlement variance accounts	3,456	-	-	-	(3,456)	-	Note [1]
LV variance account	155	249	3	-	-	407	Note [1]
Renewable generation funding adder	-	126	-	1	-	127	Note [1]
Other	69	11	-	(16)	-	64	Note [1]
Total	9,166	5,881	6	(1,627)	(3,456)	9,970	

(Canadian dollars in thousands)	January 1, 2015	Additions	Carrying charges	Repayment	Other movements	December 31, 2015	Remaining recovery period
Regulatory credit balances:							
Retail settlement variance accounts	-	7,722	15	-	(3,456)	4,281	Note [1]
Regulatory balances approved for disposition	2,290	-	11	(1,724)	-	577	2 years
Other	66	54	-	-	-	120	Note [1]
Total	2,356	7,776	26	(1,724)	(3,456)	4,978	
Net change in regulatory balances	6,810	(1,895)	(20)	97	-	4,992	

(Canadian dollars in thousands)	December 31, 2015
Beginning balance, January 1	6,810
Ending balance, December 31	4,992
Net movement in regulatory balances, net of tax	**1,818**

[2] The Company expects to apply for disposition of these regulatory balances at a future date. These balances incur carrying charges at 1.10% per annum (December 31, 2014 – 1.47%, January 1, 2014 – 1.47%).

In the absence of IFRS 14, carrying charges would not have been accreted on these regulatory balances, and financing costs would have been lower in 2016 by $35 thousand (2015 - $20 thousand).

The "Additions" column consists of additions to regulatory balances (for both debits and credits). The "Recovery" column refers to amounts collected through rate riders and other adjustments. The "Other movements" column consists of reclassification between regulatory debit and credit balances.

No impairments were recorded in 2016.

The Company is subject to regulatory risks, including the approval by the OEB of rates that permits a reasonable opportunity to recover the estimated costs of providing safe and reliable service on a timely basis and earn the approved rates of return. The OEB approves distribution rates based on projected electricity load and consumption levels. If actual load or consumption materially falls below projected levels, the income could be materially adversely affected. Also, the current revenue requirements for these businesses are based on cost assumptions that may not materialize. There is no assurance that the OEB would allow rate increases sufficient to offset unfavourable financial impacts from unanticipated changes in electricity demand or in costs.

The OEB's new Renewed Regulatory Framework for Electricity (RRFE) requires that the term of a cost of service rate application (distribution business) be a five-year period. There are risks associated with forecasting over a longer period. Changes in the industry may alter the investment needs or require changes to rate setting that could result in a significant impact on the Company's capability to execute its plan.

The load could also be negatively affected by successful CDM programs. The Company is also subject to risk of revenue loss from other factors, such as economic trends and weather. The risk exists that the OEB may not allow full recovery of such investments in the future. To the extent possible, the Company aims to mitigate this risk by ensuring prudent expenditures, seeking from the regulator clear policy direction on cost responsibility, and pre-approval of the need for capital expenditures.

While the Company expects that all expenditures would be fully recoverable after OEB review, any future regulatory decision to disallow or limit the recovery of such costs would lead to potential asset impairment and charges to results of operations, which could have a material adverse effect on the Company.

Regulatory debit balances

Accounting Changes under CGAAP

On July 17, 2012 the OEB issued a letter which required electricity distributors that had yet to adopt IFRS to implement changes to their regulatory capitalization and depreciation expense policies effective January 1, 2013. The OEB required these accounting changes to be implemented consistent with their regulatory accounting policies as set out for Modified IFRS as contained in the *Report of the Board, Transition to International Financial Reporting Standards*, EB-2008-0408, the Kinectrics Report, and the Revised 2012 *Accounting Procedures Handbook for Electricity Distributors* (APH). The regulatory policy changes required entities to adopt IFRS-based accounting treatments for costing and depreciating their PP&E and intangible assets, even while retaining CGAAP. A regulatory balance was provided for entities that did not have the ability to adjust rates due to their scheduled rebasing year. Based on the direction in the OEB's letter, to December 31, 2014 the Company had accumulated $4,836 thousand of adjustments in the regulatory balance. As part of its 2015 Cost of Service application, the OEB approved the Company's request for the disposition of the balance in this account.

In addition, in its letter dated June 25, 2013, the OEB required that a rate of return component be calculated on the balance in the regulatory account rather than the usual accretion of interest. In the OEB's decision on the Company's 2015 Cost of Service application, the OEB approved the recovery of the $4,835 thousand plus a return component of $1,046 thousand for a total recovery of $5,881 thousand over three years. In the absence of IFRS 14 depreciation expense would have been lower by $25 thousand (2015 - $56 thousand).

Regulatory Deferred Tax Asset (Liability)

Deferred taxes (i.e. PILS) are recognized on temporary differences between the carrying amount of assets and liabilities in the financial statements and the corresponding tax basis used in the computation of taxable profit. The Company has recognized balances which correspond to the taxes that flow through the rate-making process. In the absence of regulatory accounting, the Company's provision for income tax would have been recognized using the liability method and there would have been no regulatory balances established for taxes to be recovered through future rates. As a result, the 2016 provision for income tax would have been higher by $1,810 thousand (2015 - $3,598 thousand).

Lost Revenue Adjustment Mechanism (LRAM) Variance Account

The LRAM Variance account represents the difference between the results of actual approved impacts of authorized CDM activities related to the CDM programs which started in 2011 and the level of CDM program activities included in the Company's approved load forecast. In the absence of regulatory accounting, revenue would have been lower by $940 thousand in 2016 (2015 - $376 thousand). In December 2016, Hydro One Brampton received approval to recover $901 thousand of the December 31, 2015 balance of debit regulatory balance. Amounts are to be collected from customers over a one year period commencing January 1, 2017.

Low Voltage (LV) Variance Account

The Company records the variance arising from LV transactions which are not part of the electricity wholesale market. In December 2014, the OEB approved the disposition of the amounts accumulated in this account from January 1 to December 31, 2013, including accrued carrying charges, to be disposed over a 12-month period from January 1 to December 31, 2015 in the *Regulatory Balances Approved for Disposition* Account. The approved rates are applicable to electricity consumption for the respective year. Customer bills were issued in the subsequent year for all consumption up to and including December 31. Customer payments would then follow the normal timeline. In the absence of rate-regulated accounting, cost of purchased power would have been lower by $247 thousand in 2016 (2015 - $249 thousand lower). In December 2016, Hydro One Brampton received approval to recover $411 thousand of the December 31, 2015 balance of debit regulatory balance. Amounts are to be collected from customers over a one year period commencing January 1, 2017.

Renewable Generation Funding Adder

In December 2014 the OEB approved the disposition of the balance in this account accumulated from January 2011 to December 2013, including accrued carrying charges, to be disposed over a 12-month period from January 1 to December 31, 2015. The approved rates are applicable to electricity consumption for the respective year. Customer bills were issued in the subsequent year for all consumption up to and including December 31. Customer payments would then follow the normal timeline. In the absence of regulatory accounting, revenue would have been lower by $19 thousand in 2016 (2015 - $126 thousand).

Regulatory credit balances

Retail Settlement Variance Accounts

The Company has recognized RSVA's under the provisions of Article 490 of the OEB's Accounting Procedures Handbook. In December 2014, the OEB approved the disposition of the total RSVA balance accumulated from January 1 to December 31, 2013 to be disposed over a 24-month period from January 2014 to December 2015. The approved rates are applicable to electricity consumption for the respective year. Customer bills were issued in the subsequent year for all consumption up to and including December 31. Customer payments would then follow the normal timeline. In the absence of regulatory accounting, distribution revenues would have been higher by $4,749 thousand (2015 - $7,722 higher). In December 2016, Hydro One Brampton received approval to refund $4,241 thousand of the December 31, 2015 balance of credit regulatory balance. Amounts are to be repaid to customers over a one year period commencing January 1, 2017.

Regulatory Balances Approved for Disposition

In 2014, the OEB approved the Company's request to refund regulatory balances of $2,064 thousand over a 12-month period commencing January 1, 2015. The balances consisted of RSVA regulatory debit balances and refundable variances for previous rate riders since the Company's Cost of Service application in 2011.

In December 2016, Hydro One Brampton received approval to refund $3,050 thousand of the December 31, 2015 balance of credit regulatory balance. Amounts are to be repaid to customers over a one year period commencing January 1, 2017.

10. DEBT

(Canadian dollars in thousands)	**December 31, 2016**	December 31, 2015
Long-term debt:		
6.95% notes due June 1, 2032	**143,000**	143,000
4.41% notes due September 26, 2041	**20,000**	20,000
3.22% notes due January 13, 2022	**20,000**	20,000
4.19% notes due June 6, 2044	**10,000**	10,000
Total debt	**193,000**	193,000
Less: Unamortized balance of transaction costs	**730**	761
Long-term debt net of deferred transaction costs	**192,270**	192,239

The long-term debt is payable to Brampton Distribution Holdco Inc. and consists of four promissory notes, subject to redemption or repurchase in whole or in part, by the Company before maturity.

11. CARRYING AND FAIR VALUE OF FINANCIAL INSTRUMENTS

Fair Value Measurements

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. The fair value hierarchy establishes three levels to classify the inputs to valuation techniques used to measure fair value. These are described below:

- Level 1 inputs are quoted prices (unadjusted) in active markets for identical assets or liabilities.
- Level 2 inputs are quoted prices in markets that are not active, quoted prices for similar assets or liabilities in active markets, inputs other than quoted prices that are observable for the asset or liability (for example, interest rate and yield curves observable at commonly quoted intervals, forward pricing curves used to value currency and commodity contracts and volatility measurements used to value option contracts), or inputs that are derived principally from or corroborated by observable market data or other means.
- Level 3 inputs are unobservable (supported by little or no market activity).

The fair value hierarchy gives the highest priority to Level 1 inputs and the lowest priority to Level 3 inputs.

Valuation Technique and Assumptions for Measuring Fair Value

Long-term debt

Long-term debt is recorded at cost. The Company has not entered into any hedging relationships. The fair value 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 measurement of long-term debt is categorized as Level 2. The total fair value of the Company's long-term debt at December 31, 2016 was $250,214 thousand (2015 - $250,684 thousand) with a total carrying value of $193,000 thousand (2015 - $193,000).

There were no transfers between Level 1 and Level 2 in 2016 and 2015. There were no instruments categorized under Level 3 for years ended December 31, 2016 and December 31, 2015.

Other financial assets and liabilities

The carrying amounts of cash and cash equivalents, bank overdraft, accounts receivable, and accounts payable and accrued liabilities, approximate fair value due to the short maturity of these instruments.

12. FINANCIAL RISK MANAGEMENT

Hydro One Brampton is subject to interest rate risk, credit risk and liquidity risk that arises in the normal course of the Company's business.

Interest Rate Risk

Hydro One Brampton is exposed to fluctuations in interest rates as the regulated rate of return for the Company's distribution business is derived using a formulaic approach which is in part based on the forecast for long-term Government of Canada bond yields and the spread in 30 year "A" rated Canadian utility bonds, over the 30 year benchmark Government of Canada bond yield. The Company estimates that a 1% reduction in the deemed rate of return on equity would reduce its results of operations by approximately $1,600 thousand based on the 2015 cost of service application. In 2016, Hydro One Brampton's distribution rates were updated based on the OEB's third generation Incentive Regulation Mechanism (IRM) policies.

Credit Risk

Financial assets create credit risk that a counter-party will fail to discharge an obligation, causing a financial loss. The Company incurs credit risk in respect of accounts receivable transactions in the normal course of business. The maximum exposure to credit risk is represented by the carrying value of financial assets.

As at December 31, 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, the Company did not earn a significant amount of revenue from any individual customer. As at December 31, 2016 and December 31, 2015, there were no significant balances of accounts receivable due from any single customer.

Overdue accounts receivables are regularly monitored. Customers are assessed at each reporting date in order to determine impairment. Based on customer credit risk assessment, a certain percentage of the overdue receivables are recognized as an allowance for credit losses at each reporting period. The Company's maximum exposure to credit risk for accounts receivable is limited to the carrying amount on the Statement of Financial Position. In the year, the Company's allowance for accounts receivable remained relatively unchanged at $1,081 thousand as at December 31, 2016 (2015 - $1,184 thousand). Minor adjustments and write-offs were determined on the basis of a review of overdue accounts, taking into consideration historical experience. As of December 31, 2016, 1.6% of accounts receivable were due for more than 90 days (2015 - 1.8%).

Liquidity Risk

Liquidity risk refers to the Company's ability to meet its financial obligations as they come due by delivering cash or another financial asset. Short-term liquidity is provided through cash and cash equivalents, funds from operations, and an established revolving credit facility of $25,000 thousand (2015 - $50,000 thousand), if required. The short-term liquidity available to the Company should be sufficient to fund normal operating requirements. The Company monitors the level of expected cash inflows related to accounts receivable together with expected cash outflows on accounts payable.

The following are the remaining contractual maturities of the financial liabilities at the reporting dates:

Year ended December 31, 2016 (*Canadian dollars in thousands):*

Financial Liabilities	Due within 1 year $	Due within 2 years $	Due within 3 years $	Due within 4 years $	Due within 5 years $	Due after 5 years $
Current accounts payable and accrued liabilities	72,454	-	-	-	-	-
Non-current accounts payable and accrued liabilities	-	14	14	14	14	67
Current employee future benefits	127	-	-	-	-	-
Non-current employee future benefits	-	132	137	143	149	3,190
Interest on long-term debt	30,814	11,884	11,884	11,884	11,884	136,923
Long-term debt	-	-	-	-	-	193,000
	103,395	**12,030**	**12,035**	**12,041**	**12,047**	**333,180**

Year ended December 31, 2015 (*Canadian dollars in thousands):*

Financial Liabilities	Due within 1 year $	Due within 2 years $	Due within 3 years $	Due within 4 years $	Due within 5 years $	Due after 5 years $
Current accounts payable and accrued liabilities	72,321	-	-	-	-	-
Non-current accounts payable and accrued liabilities	-	16	16	16	16	87
Current employee future benefits	170	-	-	-	-	-
Non-current employee future benefits	-	177	184	191	199	3,573
Interest on long-term debt	18,931	11,884	11,884	11,884	11,884	148,806
Long-term debt	-	-	-	-	-	193,000
	91,422	**12,077**	**12,084**	**12,091**	**12,099**	**345,466**

13. CAPITAL MANAGEMENT

The Company considers its capital structure to consist of shareholder's equity, long-term debt, and cash and bank indebtedness. The Company's capital structure was as follows:

(Canadian dollars in thousands)	**December 31, 2016**	December 31, 2015
(Cash)	**(55,215)**	(40,521)
Long-term debt	**192,270**	192,239
	137,055	151,718
Share capital	**104,501**	104,501
Retained earnings	**105,944**	92,243
Accumulated other comprehensive income	**2,920**	2,087
	213,365	198,831
Total capital	**350,420**	350,549

14. ACCOUNTS RECEIVABLE

(Canadian dollars in thousands)	**December 31, 2016**	December 31, 2015
Current assets:		
Accounts receivable	**89,256**	73,574
Less: Allowance for doubtful accounts	**(1,081)**	(1,184)
Accounts receivable, net	**88,175**	72,390
Receivables due from related parties (Note 20)	**536**	903
Total accounts receivable	**88,711**	73,293

Which consists of:

(Canadian dollars in thousands)	**December 31, 2016**	December 31, 2015
Unbilled revenue	**52,206**	46,933
Customer receivables		
Current	**33,340**	23,150
30 - 60 days	**1,833**	2,430
61 - 90 days	**1,003**	673
Over 90 days	**1,410**	1,291
Less: Allowance for doubtful accounts	**(1,081)**	(1,184)
Total accounts receivable	**88,711**	73,293

15. EMPLOYEE FUTURE BENEFITS

Hydro One Brampton accounts for its participation in OMERS as a defined contribution plan. During 2016, the Company contributed $2,019 thousand to the plan (2015 - $1,910 thousand).

The Company also provides certain medical, dental and life insurance benefits to its retired employees and their dependents. The Company recognizes these post-retirement costs in the period in which the employees render services. Costs are determined by independent actuaries using the projected benefit method pro-rated on service and based on assumptions that reflect Management's best estimates.

The Company recognizes the unfunded status of its post-retirement plan (Plan) as a liability on its Statement of Financial Position. Actuarial gains and losses are recognized in accumulated other comprehensive income (AOCI). For the year ended December 31, 2016, the measurement date for the Plan was December 31.

Information about the Company's post-retirement benefit plan is as follows:

Year ended December 31 (Canadian dollars in thousands)	**2016**	2015
Change in defined benefit obligation		
Defined benefit obligation, beginning of year	**4,494**	4,406
Current service cost	**167**	170
Interest cost	**177**	173
Benefits paid	**(127)**	(115)
Net actuarial gain recognized in AOCI	**(833)**	(140)
Defined benefit obligation, end of year	**3,878**	4,494

The Company presents its benefit obligations on its Statement of Financial Position within the following line items:

(Canadian dollars in thousands)	**December 31, 2016**	December 31, 2015
Employee future benefits - non-current	**3,751**	4,324
Employee future benefits - current	**127**	170
Unfunded status	**3,878**	4,494

The following table provides the components of the net periodic benefit costs for the years ended December 31, 2016 and 2015:

Year ended December 31 (Canadian dollars in thousands)	**2016**	2015
Current service cost	**167**	170
Interest cost	**177**	173
Net periodic benefit cost	**344**	343

Assumptions

The measurement of the obligations of the Plan and costs of providing benefits under the Plan 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 incidence of mortality, 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 Plan is recognized in AOCI.

The following weighted average assumptions were used to determine the benefit obligations and benefit expense at December 31, 2016 and December 31, 2015. Assumptions used to determine current year-end benefit obligations are the assumptions used to estimate the subsequent year's net periodic benefit costs.

The significant actuarial assumptions used in measuring the defined benefit obligation are as follows:

	December 31, 2016	December 31, 2015
Discount rate for the expense	**4.00%**	4.00%
Discount rate for the defined benefit obligation	**3.75%**	4.00%
Rate of compensation scale escalation (without merit)	**3.00%**	3.00%
Rate of increase of long-term supplementary medical costs[1]	**7.61%**	7.82%
Rate of increase of prescription drugs[1]	**7.61%**	7.82%
Rate of increase of dental costs	**4.50%**	4.50%

[1] 7.61% in 2016, grading down to 4.50% per annum after 2031 (2015 - 7.82% per annum).

Sensitivity Analysis

The effect of 1% change in health care cost trends on the post-retirement benefits is as follows:

Year ended December 31 (Canadian dollars in thousands)	**2016**	2015
Effect of 1% increase in health care cost trends on:		
Defined benefit obligation	**153**	221
Service and interest costs	**29**	32
Effect of 1% decrease in health care cost trends on:		
Defined benefit obligation	**(134)**	(196)
Service and interest costs	**(27)**	(26)

16. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

(Canadian dollars in thousands)	**December 31, 2016**	December 31, 2015
Accounts payable - energy purchases	**42,665**	37,338
Customer deposits	**11,899**	10,860
Developers liability	**6,463**	10,562
CDM programs payable	**2,605**	4,656
Payroll payable	**1,719**	1,978
Debt retirement charge payable	**1,391**	2,043
Commodity taxes payable	**1,060**	940
Other payables and accrued liabilities	**4,652**	3,944
Total current accounts payable and accrued liabilities	**72,454**	72,321
Legal claims provision	**103**	110
Environmental liability	**20**	41
Total non-current accounts payable and accrued liabilities	**123**	151
Total accounts payable and accrued liabilities	**72,577**	72,472

17. DEFERRED REVENUE

(Canadian dollars in thousands)	**December 31, 2016**	December 31, 2015
Capital contributions, net of amortization	**38,925**	25,786
Subdivision deficiencies	**1,155**	1,107
Total deferred revenue	**40,080**	26,893
Less: current portion of capital contributions	**1,510**	1,172
Non-current portion of deferred revenue	**38,570**	25,721

The reconciliation between the opening and closing capital contribution balances is as follows:

(Canadian dollars in thousands)	**December 31, 2016**	December 31, 2015
Beginning balance, January 1	**25,786**	14,015
Receipt of capital contributions	**13,875**	12,376
Amortization	**(736)**	(605)
Ending balance, December 31	**38,925**	25,786

18. SHARE CAPITAL

Common Shares

The Company is authorized to issue an unlimited number of common shares. All issued and outstanding shares of Hydro One Brampton are held by Brampton Distribution Holdco Inc. No shares were issued as at December 31, 2016 (December 31, 2015 - 2,357 shares issued).

19. OPERATING, MAINTENANCE AND ADMINISTRATION

Operating, maintenance and administration expenses comprise of:

December 31 (thousands of Canadian dollars)	**2016**	2015
Labour	**16,393**	14,226
Supplies and external services	**10,528**	9,708
Vehicles	**1,203**	844
Materials	**356**	502
Other	**3,130**	2,582
	31,610	27,862

20. RELATED PARTY TRANSACTIONS

The Company had transactions with the following related parties and companies under Province's common control:

Name of the Company	Relationship	Country of Incorporation
Province of Ontario	Owner of Brampton Distribution Holdco Inc.	Canada
Brampton Distribution Holdco Inc.	Parent	Canada
Hydro One Inc. (Hydro One)	Under Province's Common Control	Canada
Hydro One Networks Inc.	Under Province's Common Control	Canada
Hydro One Remote Communities Inc.	Under Province's Common Control	Canada
Hydro One Telecom Inc.	Under Province's Common Control	Canada
IESO	Under Province's Common Control	Canada
Ontario Electricity Financial Corporation (OEFC)	Under Province's Common Control	Canada
Ontario Energy Board (OEB)	Under Province's Common Control	Canada

Transactions with the Province and entities under its common control

Hydro One Brampton is wholly owned by Brampton Distribution Holdco Inc. which is owned by the Province of Ontario. Hence, Brampton Distribution Holdco Inc., Hydro One and its subsidiaries, IESO, and OEB are related parties to Hydro One Brampton because they are also controlled or significantly influenced by the Province of Ontario. Transactions with these parties were in the normal course of operations and were measured at the exchange value which represented the amount of consideration established and agreed to by the parties.

Transactions between these parties and Hydro One Brampton were as follows:

In 2016, the Company purchased power from the IESO-administered spot market in the amount of $499,152 thousand (2015 - $415,233 thousand).

The IESO is responsible for funding some of the Company's CDM programs. The funding includes program costs, incentives and management fees and bonuses. In 2016, the Company received $8,053 thousand (2015 - $9,250 thousand) from the IESO in respect of the CDM programs and had a net accounts receivable of $337 thousand (2015 - $304 thousand).

Under the Ontario Energy Board Act, 1998, the OEB is required to recover all of its annual operating costs from gas and electricity distributors and electricity transmitters by way of fees. In 2016, Hydro One Brampton incurred $631 thousand (2015 - $424 thousand) in OEB fees.

The provision for PILs was paid or payable to the OEFC.

As at December 31, 2016, long-term debt of $193,000 thousand (2015 - $193,000 thousand) was due to Brampton Distribution Holdco Inc. Net financing charges for 2016 include interest expense on this debt in the amount of $11,884 thousand (2015 - $11,899 thousand). The total interest accrued and payable at the end of 2016 was $18,931 thousand (2015 - $7,047 thousand).

Hydro One and Subsidiaries

The Company made load guarantee contributions for the construction of transmission connection facilities of $nil (2015 - $7,705 thousand). In addition, certain transmission, connection, and administrative services were purchased from Hydro One Networks Inc. and Hydro One totaling $3,183 thousand (2015 - $3,421 thousand) and Hydro One Telecom Inc. totaling $187 thousand (2015 - $146 thousand). In 2016, the Company provided transmission and connection services to Hydro One Networks Inc. totaling $nil (2015 - $1,060 thousand). The Company recorded other rental revenues from Hydro One Networks Inc. of $17 thousand (2015 - $34 thousand) and from Hydro One Telecom Networks Inc. of $164 thousand (2015 - $159 thousand).

Net financing costs paid to Hydro One for 2016 include interest expense of $nil (2015 - $6,264 thousand). Additionally, interest expense payments on the inter-company demand facility were made in the amount of $nil (2015 - $107 thousand).

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

December 31 (Canadian dollars in thousands)	**2016**	2015
Due from related parties	**536**	903
Due to related parties[1]	**(65,260)**	(46,698)

[1] Included in due to related parties at December 31, 2016 are amounts owing to the IESO in respect of power purchases of $42,543 thousand (2015 - $37,345 thousand).

Sales to and purchases from related parties occur at normal market prices or at a proxy for fair value based on the requirements of the OEB's Affiliate Relationship Code. Outstanding balances at period end are unsecured, interest free and settled in cash.

Key management personnel are comprised of Hydro One Brampton's senior management team. The following compensation has been provided to key management personnel and members of the Board of Directors who have the authority and responsibility for planning, directing and controlling the activities of the entity, directly or indirectly:

Year ended December 31 (Canadian dollars in thousands)	**2016**	2015
Salaries and short term employee benefits	**755**	748
Retirement OMERS & OPRB contributions	**94**	97
Compensation paid for contract management personnel	**821**	766
Directors' Honorarium	**76**	3
Total	**1,746**	1,614

21. NET CHANGE IN NON-CASH BALANCES RELATED TO OPERATIONS

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

Year ended December 31 (Canadian dollars in thousands)	**2016**	2015
Accounts receivable	**(15,418)**	(9,696)
Income tax receivable	**-**	2,346
Materials and supplies	**(269)**	121
Deferred tax assets	**-**	2,549
Accounts payable and accrued liabilities	**2,223**	(6,273)
Income tax payable	**763**	478
Long-term accounts payable and accrued liabilities	**(7)**	(1,295)
Deferred tax liabilities	**2,095**	901
Other	**-**	963
Total	**(10,613)**	(9,906)

22. CONTINGENCIES

Legal Proceedings

The Company is involved in various lawsuits, claims and regulatory proceedings in the normal course of business. In the opinion of Management, the outcome of such matters, except as noted below, will not have a materially adverse effect on the Company's financial position, results of operations or cash flows.

23. COMMITMENTS

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 this security if the Company fails to make the payment required by a default notice issued by the IESO. In August 2016 Hydro One Brampton posted a letter of credit as security in the amount of $5,500 thousand (2015 - $5,500 thousand).

24. SUBSEQUENT EVENT

On January 31, 2017, Enersource Holdings Inc., PowerStream Holdings Inc. and Horizon Holdings Inc. amalgamated to form Alectra Inc. On March 2, 2017, Alectra Utilities Corporation, a subsidiary of Alectra Inc., will purchase the shares of Hydro One Brampton Networks Inc. for a purchase price of $607 million plus any closing adjustments. Alectra Inc. will serve almost a million customers in Mississauga, Brampton, Hamilton, St. Catharines, Markham, Vaughan, Aurora and Simcoe County. Alectra Inc. is owned by seven shareholders, the municipalities of Mississauga, Barrie, Hamilton, Markham, St. Catharines, Vaughan, and Borealis, a division of the Ontario Municipal Employees Retirement System. The transaction will enable a larger utility to use its collective resources to reduce upward pressure on distribution rates and deliver more efficient services and innovative technologies for customers, while providing significant benefits for communities and shareholders.

ATTACHMENT 11
BRAMPTON HYDRO 2015 AUDITED FINANCIAL STATEMENTS

Hydro One Brampton Networks Inc.

IFRS Financial Statements
Years ended December 31, 2015 and 2014

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Canada

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INDEPENDENT AUDITORS' REPORT

To the Shareholder of Hydro One Brampton Networks Inc.

We have audited the accompanying financial statements of Hydro One Brampton Networks Inc., which comprise the statements of financial position as at December 31, 2015, December 31, 2014 and January 1, 2014, the statements of income and comprehensive income, statements of changes in shareholder's equity and cash flows for the years ended December 31, 2015, and December 31, 2014, and notes, comprising a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with International Financial Reporting Standards, and for such internal control as management determines is necessary to enable the preparation of 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 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 financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the 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 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 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 financial statements present fairly, in all material respects, the financial position of Hydro One Brampton Networks Inc. as at December 31, 2015, December 31, 2014 and January 1, 2014, and its financial performance and its cash flows for the years ended December 31, 2015, and December 31, 2014 in accordance with International Financial Reporting Standards.

KPMG LLP

Chartered Professional Accountants, Licensed Public Accountants

March 24, 2016
Toronto, Canada

HYDRO ONE BRAMPTON NETWORKS INC.
Statement of income and other comprehensive income
For the years ended December 31, 2015 and 2014

Year ended December 31 (Canadian dollars in thousands)	**2015**	2014
Revenues		
Energy Sales	**466,594**	422,415
Distribution	**66,967**	59,611
Other	**4,619**	4,218
	538,180	486,244
Costs		
Purchased power (Note 21)	**459,132**	425,874
Operation, maintenance and administration (Notes 20 and 21)	**27,862**	26,669
Depreciation of property, plant and equipment and amortization of intangible assets (Notes 7 and 8)	**18,246**	15,166
	505,240	467,709
Financing costs (Notes 5 and 21)	**11,418**	11,021
Income before taxes	**21,522**	7,514
Income tax expense (Note 6)	**5,451**	2,310
Net income for the year	**16,071**	5,204
Net movement in regulatory balances, net of tax (Note 9)	**(1,818)**	8,497
Net income after net movement in regulatory balances	**14,253**	13,701
Other comprehensive income		
Item that will not be reclassified to income or loss		
Remeasurement of post-retirement benefits, net of tax	**140**	1,947
Total other comprehensive income	**140**	1,947
Total income and other comprehensive income for the year	**14,393**	15,648

See accompanying Notes to Financial Statements.

HYDRO ONE BRAMPTON NETWORKS INC.
Statements of financial position
As at December 31, 2015, December 31, 2014 and January 1, 2014

(Canadian dollars in thousands)	**December 31, 2015**	December 31, 2014	January 1, 2014
Assets			
Non-current assets:			
Property, plant and equipment (Note 7)	**362,029**	333,684	306,292
Intangible assets (Note 8)	**21,446**	14,333	15,151
Deferred tax assets (Note 6)	**-**	2,549	4,818
	383,475	350,566	326,261
Current assets:			
Cash	**40,521**	-	-
Accounts receivable (Note 14)	**73,293**	63,597	66,739
Income tax receivable	**-**	2,346	1,679
Materials and supplies	**1,074**	1,195	1,195
	114,888	67,138	69,613
Total assets	**498,363**	417,704	395,874
Regulatory balances (Note 9)	**9,970**	9,166	7,105
Total assets and regulatory balances	**508,333**	426,870	402,979

See accompanying notes to Financial Statements.

HYDRO ONE BRAMPTON NETWORKS INC.
Statements of financial position (continued)
As at December 31, 2015, December 31, 2014 and January 1, 2014

(Canadian dollars in thousands)	**December 31, 2015**	December 31, 2014	January 1, 2014
Liabilities			
Non-current liabilities:			
Accounts payable and accrued liabilities	**151**	114	3,275
Deferred revenue (Note 17)	**25,721**	14,500	988
Deferred tax liabilities (Note 6)	**901**	-	-
Employee future benefits (Note 15)	**4,324**	4,280	5,943
	31,097	18,894	10,206
Long-term debt (Note 10)	**192,239**	192,209	182,243
	223,336	211,103	192,449
Current liabilities:			
Bank indebtedness	**-**	2,705	8,114
Current tax liabilities	**478**	-	-
Accounts payable and accrued liabilities (Note 16)	**72,321**	77,183	67,957
Accrued interest	**7,047**	1,412	1,382
Deferred revenue (Note 17)	**1,172**	547	-
Employee future benefits (Note 15)	**170**	126	195
	81,188	81,973	77,648
Total liabilities	**304,524**	293,076	270,097
Shareholder's equity			
Share capital (Note 18)	**104,501**	51,501	51,501
Retained earnings	**92,243**	77,990	72,589
Accumulated other comprehensive income (Note 15)	**2,087**	1,947	-
Total shareholder's equity	**198,831**	131,438	124,090
Regulatory balances (Note 9)	**4,978**	2,356	8,792
Total liabilities, shareholder's equity and regulatory balances	**508,333**	426,870	402,979

See accompanying notes to Financial Statements.

On behalf of the Board of Directors:

Serge Imbrogno
Chair

Paul Tremblay
Director

HYDRO ONE BRAMPTON NETWORKS INC.
Statements of Changes in Shareholder's Equity
As at December 31, 2015, December 31, 2014 and January 1, 2014

(Canadian dollars in thousands)	Share capital	Accumulated other comprehensive income	Retained earnings	Total
Balance at January 1, 2014	51,501	-	72,589	124,090
Net income after net movement in regulatory balances	-	-	13,701	13,701
Other comprehensive income	-	1,947	-	1,947
Dividends	-	-	(8,300)	(8,300)
Balance at December 31, 2014	51,501	1,947	77,990	131,438
Balance at January 1, 2015	51,501	1,947	77,990	131,438
Issuance of common shares	53,000	-	-	53,000
Net income after net movement in regulatory balances	-	-	14,253	14,253
Other comprehensive income	-	140	-	140
Balance at December 31, 2015	**104,501**	**2,087**	**92,243**	**198,831**

See accompanying notes to Financial Statements.

HYDRO ONE BRAMPTON NETWORKS INC.
Statements of Cash Flows
For the years ended December 31, 2015 and 2014

Year ended December 31 (Canadian dollars in thousands)	**2015**	2014
Operating activities		
Net income after net movement in regulatory balances	**14,253**	13,701
Adjustments for non-cash items:		
Depreciation of PP&E and amortization of intangible assets (net of removal costs)	**18,078**	16,148
Amortization of debt costs	**30**	27
Amortization of deferred revenue	**(605)**	(542)
Post-retirement benefits	**228**	215
Net interest expense	**12,030**	11,719
Income tax expense	**332**	2,722
	44,346	43,990
Changes in non-cash balances related to operations (Note 22)	**(9,906)**	8,703
Income taxes received (paid)	**1,000**	(525)
Regulatory balances	**1,818**	(8,497)
Net cash from operating activities	**37,258**	43,671
Investing activities		
Interest received	**97**	117
Property, plant and equipment	**(44,785)**	(42,509)
Intangible assets	**(8,244)**	(231)
Capital contributions received	**12,376**	14,557
Net cash used in investing activities	**(40,556)**	(28,066)
Financing activities		
Long-term debt issued	**-**	10,000
Transaction costs related to debt issue	**-**	(61)
Interest paid	**(6,476)**	(11,835)
Common shares issuance (Note 18)	**53,000**	-
Dividends paid (Note 19)	**-**	(8,300)
Net cash raised (used) in financing activities	**46,524**	(10,196)
Net change in cash and cash equivalents	**43,226**	5,409
Cash and cash equivalents, January 1	**(2,705)**	(8,114)
Cash (bank indebtedness), December 31	**40,521**	(2,705)

See accompanying notes to Financial Statements.

1. DESCRIPTION OF THE BUSINESS

Hydro One Brampton Networks Inc. (Hydro One Brampton or the Company) was incorporated on April 25, 2000 under the *Business Corporations Act* (Ontario). Hydro One Brampton was owned by Hydro One Inc. (Hydro One) until August 31, 2015. On August 31, 2015, Hydro One declared a dividend in kind of all of its issued and outstanding common shares of Hydro One Brampton. All issued and outstanding shares of Hydro One Brampton were transferred to Brampton Distribution Holdco Inc. which is wholly owned by the Province of Ontario (Province). The principal business of the Company is the ownership, operation and management of electricity distribution systems and facilities located at 175 Sandalwood Parkway West in Brampton, Ontario, L7A 1E8. The Company's business is regulated by the Ontario Energy Board (OEB).

2. BASIS OF PREPARATION

The annual financial statements of Hydro One Brampton for the year ended December 31, 2015 have been prepared in accordance with International Financial Reporting Standards (IFRS). These Financial Statements have been prepared in accordance with the significant accounting policies described in Note 3. IFRS 1, "First-time Adoption of IFRS" has been applied in preparing these financial statements. These are the Company's first financial statements prepared in accordance with IFRS. Previously, the Company's financial statements were prepared in accordance with Canadian Generally Accepted Accounting Principles (CGAAP) as defined by Part V of Handbook of the Chartered Professional Accountants of Canada. The accounting policies set out below have been applied consistently to all periods presented in these financial statements and in preparing the opening IFRS Statement of Financial Position as at January 1, 2014 ("the transition date"), for the purposes of the transition. (Note 25).

The Company has evaluated the events and transactions occurring subsequent to the date of the Statement of Financial Position date through to March 24, 2016, when the Company's Financial Statements were approved and authorized for issue by the Company's Board of Directors. This evaluation included the identification of events and transactions requiring recognition in the Financial Statements and/or disclosure in the Notes to the Financial Statements.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The significant accounting policies that have been applied in the preparation of these financial statements are detailed below:

Rate-setting

The Company's electricity distribution rates are subject to rate regulation by the OEB and are based on an approved revenue requirement that includes a rate of return of 9.3% (2014 – 9.66%). On December 18, 2014, the OEB approved Hydro One Brampton's 2015 rates on the basis of its cost of service application. The revised rates were implemented January 1, 2015. On December 10, 2015, the OEB approved Hydro One Brampton's 2016 rates on the basis of the OEB's Price Cap Incentive rate setting plan (Price Cap IR) option. The revised rates were implemented on January 1, 2016.

In January 2014, the IASB issued IFRS 14 "*Regulatory Deferral Accounts*" as an interim standard giving entities the option to continue with their legacy pre-IFRS accounting policies when adopting IFRS for the first time. Specifically, qualifying entities conducting rate-regulated activities have the option of continuing to recognize regulatory balances according to their previous national GAAP (i.e. CGAAP). As these regulatory balances provide readers with useful information about the Company's financial position, financial performance and cash flows, the Company opted to implement IFRS 14. IFRS 14 will remain in force until either repealed or replaced by permanent guidance on rate regulated accounting expected to result from the IASB's current Rate Regulated Activities Project. IFRS 14 is effective for annual periods beginning on or after January 1, 2016, but early adoption is permitted. The Company has elected to early adopt IFRS 14 effective January 1, 2014 for the purpose of preparing its initial Financial Statements under IFRS.

The Company has determined that certain debit and credit balances arising from its rate-regulated activities qualify for the application of regulatory accounting treatment in accordance with IFRS 14. Under the Company's legacy rate-regulated accounting policies, which are continued under IFRS 14, the timing and recognition of certain expenses, losses revenues and gains may differ from that otherwise expected under IFRS. This has the effect of more appropriately reflecting the economic impact of the regulator's decisions regarding the Company's regulated operations. Amounts arising from such timing differences are recorded as regulatory debit and credit balances on the Company's Statements of Financial Position, and represent existing rights and obligations regarding future cash flows expected to be recovered from, or refunded to customers, based on expected and actual decisions and approvals by the OEB. Regulatory balances are recognized only if the OEB directs the relevant regulatory treatment or if future OEB direction is judged to be probable. In the event that the inclusion of the whole or a part of such balances is assessed to no longer be probable based on management's judgment, the balances will be derecognized with any resulting gain or loss being recorded in the Company's Statement of Income and Other Comprehensive Income in the period when the assessment is made.

Regulatory balances are segregated on the Statement of Financial Position and the net change in these balances is presented on the Statement of Income and Other Comprehensive Income as Net Movements in Regulatory Balances, net of income taxes. The netting of regulatory debit and credit balances is not permitted on the Statement of Financial Position. The measurement of regulatory balances is subject to certain estimates and assumptions by Management, including assumptions made in interpreting the OEB's regulations and decisions.

Revenue Recognition

Energy Sales and Distribution Revenue

Distribution revenues attributable to the sale and delivery of electricity are recognized as electricity is delivered to customers. Distribution revenues reflect actual consumption billed, actual customer consumption yet to be billed, and an estimate for any other unbilled consumption. Actual customer consumption yet to be billed is calculated using smart meter data and actual billing rates and an estimate for the price for energy. Unbilled revenues that relate to energy used by consumers from the last meter reading dates during the period to the end of the year are estimated based on actual consumption from smart meters.

Other Revenue

Other revenue includes amortization of customer contributions, government grants and incentives under Conservation and Demand Management (CDM) programs, revenue from billable customer demand activities and other general revenues. Certain items of property, plant and equipment are acquired or constructed with the assistance of contributions from customers or developers (customer contributions). These contributions are usually defined by OEB industry codes and may be received in the form of cash or as in-kind contribution. These customer contributions are recognized as deferred revenue and are amortized to revenue over the lives of the related assets. Government grants under CDM programs are recognized as income when there is reasonable assurance that the grant will be received and all related conditions will be met. Performance incentive payments under CDM programs are recognized by the Company when there is reasonable assurance that the program conditions have been satisfied and the incentive payment will be received. Other revenue related to billable activities is recognized as services are rendered.

Corporate Income Taxes

Under the *Electricity Act*, *1998*, Hydro One Brampton is required to make payments in lieu of corporate income taxes (PILs) to the Ontario Electricity Financial Corporation (OEFC). These payments are calculated in accordance with the rules for computing taxable income and other relevant amounts contained in the *Income Tax Act (Canada)* and the *Corporations Tax Act (Ontario)* as modified by the Electricity Act, 1998, and related regulations. The provision for PILs is calculated using the liability method.

IFRS 14 requires the recognition of regulatory balances and related deferred tax assets and liabilities representing those deferred tax amounts expected to be refunded to, or recovered from, customers through future electricity distribution rates. Any related gross-up reflecting the income tax benefits associated with reduced revenues resulting from the realization of deferred tax assets, is recorded within Regulatory Balances. Deferred taxes that are not included in the rate-setting process are charged or credited to the Statements of Income and Other Comprehensive Income.

Current Tax

Current tax assets and liabilities for the current and prior periods are measured at the amounts expected to be paid to, or recovered from, the OEFC. The tax rates and tax laws used to compute these amounts are those that are enacted or substantively enacted. Management periodically reevaluates positions taken in tax returns with respect to situations in which applicable tax regulations are subject to interpretation and establishes provisions, where appropriate, on the basis of amounts expected to be paid to the tax authorities. The amount of current tax payable or receivable is Management's best estimate of the tax amounts expected to be paid or received and reflect any uncertainty related to income taxes.

Deferred Tax

Deferred tax is recognized on temporary differences between the carrying amounts of assets and liabilities in the financial statements and the corresponding tax basis used in the computation of taxable profit. Deferred tax assets are recognized to the extent that it is probable that taxable profits will be available against which deductible temporary differences can be utilized.

Deferred tax is measured at the tax rates that are expected to apply in the period when the liability is settled or the asset is realized using the tax rates and tax laws that have been enacted or substantively enacted, at the reporting date.

Materials and Supplies

Materials and supplies represent consumables, minor spare parts and construction material held for internal construction and maintenance of property, plant and equipment assets (PP&E). These assets are carried at the lower of average cost or net realizable value. The Company classifies all major construction related spares and components of its electricity distribution infrastructure as property, plant and equipment but does not commence depreciation on this material until it is put into service as part of a component of PP&E.

Cash and Cash Equivalents

Cash and cash equivalents include cash in bank accounts and short-term investments with terms to maturity of 90 days or less from their date of acquisition. On the Statement of Cash Flows, cash and cash equivalents may represent bank indebtedness that is repayable on demand.

Accounts Receivable

The carrying amount of accounts receivable and unbilled revenue is reduced through an allowance for doubtful accounts, if applicable. When the Company considers that there are no realistic prospects of recovery of an account receivable, the relevant amount is determined to be impaired and is written off. If the amount of impairment loss subsequently decreases due to an event occurring after the impairment was recognized, then the previously recognized impairment loss is reversed through net income.

Property, Plant and Equipment

Property, plant and equipment is recorded at historical acquisition cost less accumulated depreciation. Cost includes expenditures that are directly attributable to the acquisition of the asset. For property, plant and equipment used in rate-regulated activities, the Company elected to use the exemption available for assets subject to rate regulation such that the previous CGAAP carrying amount became the deemed acquisition cost under IFRS 1 at the date of transition (Note 25). The cost of self-constructed assets includes the cost of direct materials and direct labour, directly attributable overheads, and borrowing costs on qualifying assets. Significant parts of PP&E that have different useful lives are accounted for as separate items (major components) of PP&E.

PP&E consist of land, land rights and buildings, distribution assets, vehicles and other tangible assets. In addition, major spare parts and standby equipment are also accounted for as PP&E.

Some of the Company's distribution assets, particularly those located on unowned easements and rights-of-way, may have decommissioning or asset retirement obligations, constructive or otherwise. The majority of the Company's land rights (easements and rights-of-way) are subject to extension or renewal and are expected to be available for a perpetual duration. As the Company expects to use the majority of its installed assets into perpetuity, no removal date can be determined and consequently no reasonable estimate of the fair value of such asset retirement obligations can be made. If, at some future date, it becomes possible to estimate the fair value cost of removing the assets that the Company is legally or constructively required to remove, a related asset retirement obligation will be recognized at that time. The discounted amount is not material.

An item of PP&E is derecognized upon disposal or when no future economic benefits are expected from either use or disposal. Any gain or loss arising on asset derecognition (calculated as the difference between the net disposal proceeds and the carrying amount of the asset) is included in the Statement of Income and Other Comprehensive Income. The cost of replacing an item of PP&E, or a major part thereof, is recorded as an addition to the carrying amount of PP&E and the carrying amount of the replaced part is derecognized. The cost of the day-to-day servicing of PP&E assets is recorded in net income as incurred.

Construction in Progress

Construction in progress assets are generally assets that are undergoing active construction or development and which are not currently available for use. Such assets are therefore not depreciated. Borrowing costs directly attributable to the acquisition, construction or production of a qualifying asset are capitalized. A qualifying asset is one that necessarily takes a substantial period of time to get ready for its intended use. Management has assessed a substantial period of time to mean six months or more.

Intangible Assets

Intangible assets are measured at cost on an analogous basis as PP&E. The Company elected to use the exemption available for assets subject to rate regulation such that the previous CGAAP carrying amount became the deemed acquisition cost under IFRS 1 at the date of transition, January 1, 2014 (Note 25). Following initial recognition, intangible assets are carried at cost less any accumulated amortization and any accumulated impairment losses.

The useful lives of intangible assets are assessed as either finite or indefinite. Intangible assets with finite lives are amortized over their estimated useful economic lives and are assessed for impairment whenever there is an indication that the carrying value may be impaired. Intangible assets with indefinite useful lives are not amortized, but are tested for impairment annually, either individually or at the cash generating unit (CGU) level.

Any gain or loss arising on asset derecognition (calculated as the difference between the net disposal proceeds and the carrying amount of the asset) is included in net income.

Depreciation and Amortization

The capital costs of PP&E and intangible assets are depreciated on a straight-line basis over their estimated remaining service lives. Remaining lives and methods of depreciation are reviewed by Management at each financial year end. Detailed reviews are performed periodically, generally as preparation for an OEB cost of service application and such reviews may involve inputs from an external depreciation consultant. Any changes arising from such a review are implemented on a remaining service life basis consistent with their inclusion in rates. The OEB approved new depreciation rates as part of the Company's 2015 cost of service rate decision.

The estimated service lives for the principal categories of PP&E and intangibles are, in aggregate, as shown in the table below:

	Years
Land rights	Indefinite
Buildings	25 to 50
Distribution assets:	
Distribution equipment	20 to 75
Transformer stations	10 to 40
Transformers and meters	15 to 40
Vehicles and other:	
Trucks and equipment	7 to 10
Office and computer equipment	5 to 10
Other	5 to 15
Intangible assets:	
Computer software	5
Capital contributions to Hydro One	40

The majority of land rights (including easements) are held in perpetuity and are not depreciated. Depreciation rates for finite life easements are based on contract life.

Where a disposition of a component of PP&E occurs through sale, a gain or loss is calculated based on net proceeds and is presented within depreciation expense. Depreciation expense also includes the costs incurred to remove PP&E where no decommissioning liability has been recognized.

Deferred Revenue

Contributions received towards the cost of property, plant and equipment are recorded as deferred revenue and amortized to revenue on a straight line basis over the estimated economic useful lives of the assets to which they relate.

In addition, amounts are received pursuant to agreements with developers for the estimated costs for the remediation of deficiencies to residential subdivisions (subdivision deficiencies) for which the related services have yet to be performed. These amounts are recorded initially as deferred revenue and are recognized as revenue in the fiscal year the related expenditures are incurred or services performed.

Impairment

Non-Financial Assets

The carrying costs of the Company's PP&E and intangible assets are generally included in rate base where they earn an OEB-approved rate of return. In addition, the capital costs of the Company's assets are generally recoverable in OEB-approved revenue requirements. As such, the Company's assets would only indicate that an impairment trigger exists in the event that the OEB disallows recovery or if such disallowance is judged to be probable.

PP&E and intangible assets are reviewed at each reporting date to determine whether any indication exists of potential impairment. If such an indication exists, the relevant asset's recoverable amount is tested for impairment.

Financial Assets

A financial asset is considered to be impaired if objective evidence indicates that there has been a negative effect on the recoverable amount (estimated future cash flows to accrue from that asset). If there is evidence that an impairment loss has been incurred, the amount of the loss is measured as the difference between the asset's carrying amount and the present value of estimated future cash flows discounted at original effective interest rate.

An impairment loss related to financial assets is reversed if, and to the extent there has been a change in the estimates used to determine the recoverable amount. The loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have existed had no impairment loss been recognized.

Reversals of impairment are recognized in finance costs.

Financial Instruments

All financial assets are classified as Loans and Receivables and all financial liabilities are classified as Other Liabilities. These financial instruments are recognized initially at fair value plus any directly attributable transaction costs. Subsequently, they are measured at amortized cost using the effective interest method less any impairment for the financial assets as described in note 3(g). The Corporation does not enter into derivative instruments.

Cash equivalents include short-term investments with maturities of three months or less when purchased.

Employee Future Benefits

Pension

Full-time employees participate in the Ontario Municipal Employees Retirement System Fund (OMERS), a multi-employer, contributory, defined benefit public sector pension fund. OMERS provides retirement pension payments based on a member's length of service and salary. Both participating employers and members are required to make plan contributions. The OMERS plan assets are pooled together to provide benefits to all plan participants and the plan assets are not segregated in separate accounts for each member entity. The OMERS plan has approximately 451,000 members, of whom approximately 214 are current employees of Hydro One Brampton. The Company's future contributions may be increased substantially if other entities withdraw from the plan.

The OMERS plan is accounted for as a defined contribution plan by the Company because it is not practicable to determine the present value of the Company's obligation, the fair value of plan assets or the related current service cost applicable to Hydro One Brampton employees. Hydro One Brampton recognizes its pension expense based on contributions to the OMERS plan, with a portion of these contributions being capitalized. The expensed portion is included in operation, maintenance and administration costs in the Statements of Income and Other Comprehensive Income.

Post-Retirement Benefits (OPRB)

The Company provides some or all of its retired employees with life insurance and medical and dental benefits beyond those provided by government sponsored plans. The costs of the Company's unfunded post-retirement benefit plan is recognized over the periods during which employees render service.

The obligations for this plan is actuarially determined using the projected unit credit method, which incorporates Management's best estimate of future salary levels, retirement ages of employees, health care costs, and other actuarial factors. Changes in actuarial assumptions and experience adjustments give rise to actuarial gains and losses which are recognized in OCI as they arise. The measurement date used to determine the present value of the benefit obligation is December 31 of the applicable year. The latest actuarial valuation was performed as at December 31, 2015.

All OPRB costs are attributed to labour and recognized in either net income or are capitalized as part of the cost of PP&E and intangible assets.

Provisions

A provision is recognized if, as a result of a past event, the Company has a present legal or constructive obligation that can be estimated reliably, and it is probable that an outflow of economic benefits will be required to settle the obligation.

Dividends

Common share dividends are declared at the sole discretion of the Company's Board of Directors and are recommended by Management based upon results of operations, financial condition, cash requirements and other relevant factors such as industry practice and shareholder expectations. Common share dividends are declared and paid within the same period.

Use of Judgments and Estimates

The preparation of the Company's financial statements requires Management to make judgments, estimates and assumptions that affect the reported amounts of revenues, expenses, assets and liabilities, the accompanying disclosures, and the disclosure of contingent liabilities. Uncertainty about these assumptions and estimates could result in outcomes that require a material adjustment to the carrying amount of assets or liabilities in future periods. Actual results could differ from these estimates including changes as a result of future decisions made by the OEB.

Key judgments and estimates affecting the financial statements are summarized below:

- Estimation of service lives for property, plant and equipment and intangible assets (Note 7 & 8)
- Recognition and measurement of regulatory balances (Note 9)
- Recognition of deferred tax assets – availability of future taxable income against which deductible temporary differences and loss carryforwards can be used (Note 6)
- Measurement of defined benefit obligations – key actuarial assumptions (Note 15)
- Measurement of unbilled revenue
- Asset impairments and asset retirement obligations
- Allowance for doubtful accounts (Note 14); and
- Recognition and measurement of environmental provisions

4. FUTURE ACCOUNTING PRONOUNCEMENTS

A number of new accounting standards, amendments and interpretations have been issued by the IASB and are not yet effective for the year ended December 31, 2015. As such they have not been applied in preparing these Financial Statements. The Company continues to analyze these standards and has initially determined that the following could have a significant impact on its financial statements.

Revenues from Contracts with Customers

In May 2014, the IASB issued IFRS 15 Revenue from Contracts with Customers. The standard outlines a single comprehensive model for entities to use in accounting for revenues arising from contracts with customers. It supersedes current revenue recognition guidance including IAS 18 Revenues, IAS 11 Construction Contracts and related interpretations. The new revenue model applies to all contracts with customers except those that are within the scope of other IFRSs, such as leases, insurance contracts and financial instruments. IFRS 15 specifies how and when the entity should recognize revenue and additional disclosure requirements. The new standard is effective for annual periods beginning on or after January 1, 2018 and the Company is currently evaluating the impact of the new standard.

Financial Instruments

The IASB published the final version of IFRS 9 Financial Instruments in July 2014. The final version of IFRS 9 brings together the classification and measurement, impairment and hedge accounting to replace IAS 39 Financial Instruments: Recognition and Measurement. IFRS 9 is built on a logical, single classification and measurement approach for financial assets that reflects the business model in which they are managed and their cash flow characteristics. IFRS 9 has an expected credit loss model for a timely recognition of loan losses and is a single model that is applicable to all financial instruments subject to impairment accounting. It also includes an improved hedge accounting model to better link the economics of risk management with its accounting treatment. IFRS 9 is effective for annual periods beginning on or after January 1, 2018 and the Company is currently evaluating the impact of the new standard.

Leases

The IASB published IFRS 16 Leases in January 2016. It replaces the previous leases Standard, IAS 17 Leases, and related Interpretations. IFRS 16 sets out the principles for the recognition, measurement, presentation and disclosure of leases. It eliminates the current dual accounting model for lessees, which distinguishes between on-balance sheet finance leases and off-balance sheet operating leases. Instead, there is a single, on-balance sheet accounting model that is similar to current finance lease accounting. IFRS 16 is effective from 1 January 2019. A company can choose to apply IFRS 16 before that date but only if it also applies IFRS 15 Revenue from Contracts. The Company is currently evaluating the impact of the new standard.

5. FINANCING COSTS

(Canadian dollars in thousands)	**2015**	2014
Financing costs:		
Interest expense:		
Interest on long-term debt	**11,897**	11,705
Amortization of deferred debt costs and debt premiums	**30**	27
Other interest expense	**230**	131
Less interest capitalized on construction and development in progress	**(642)**	(725)
Total financing costs	**11,515**	11,138
Finance income:		
Interest income:		
Less interest income on short term bank deposits	**97**	117
Total financing income	**97**	117
Net financing costs	**11,418**	11,021

6. INCOME TAX EXPENSE

A) Amount Recognized in Net Income

(Canadian dollars in thousands)	**2015**	2014
Current tax expense		
Current period	**1,518**	37
Adjustments for prior year(s)	**495**	4
	2,013	41
Deferred tax expense		
Origination and reversal of temporal differences	**(1,246)**	2,682
Reduction in tax rate	**(435)**	(1)
	(1,681)	2,681
Total income tax expense	**332**	2,722
Income tax recorded in net movement in regulatory balances	**5,119**	(412)
Income tax expense and income tax recorded in net movement in regulatory balances	**5,451**	2,310

The total provision for PILs includes deferred income taxes using the Statement of Financial Position liability method of accounting.

B) Amount Recognized in Other Comprehensive Income

	2015			2014		
	Before tax	**Tax (expense) benefit**	**Net of tax**	Before tax	Tax (expense) benefit	Net of tax
Remeasurement of post-retirement benefit obligation	**2,087**	**-**	**2,087**	1,947	-	1,947
	2,087	**-**	**2,087**	1,947	-	1,947

(Canadian dollars in thousands)	**2015**	2014
Income before tax	**14,583**	16,424
Federal and Ontario statutory tax rate	**26.5%**	26.5%
Income taxes at statutory rates	**3,865**	4,352
Increase (decrease) resulting from:		
Net temporary differences:		
Capital cost allowance in excess of depreciation and amortization	**(3,383)**	(1,355)
Capitalized interest deducted for tax purposes	**(170)**	(192)
Employee future benefits expense in excess of cash payments	**6**	39
Other	**(51)**	(115)
Net temporary differences	**(3,598)**	(1,623)
Net permanent differences	**65**	(7)
Current income tax	**332**	2,722
Total effective income tax rate	**2.28%**	16.58%

Deferred Tax Assets and Liabilities

(Canadian dollars in thousands)	**December 31, 2015**	December 31, 2014	January 1, 2014
Deferred income tax assets (liabilities)			
Post-retirement benefits in excess of cash payments	**1,743**	1,684	1,627
Capital cost allowance in excess of depreciation and amortization	**(2,790)**	751	3,066
Other	**146**	114	125
Total deferred tax assets (liabilities)	**(901)**	2,549	4,818

Movements in Deferred Tax Balances

(Canadian dollars in thousands)	Net balance January 1, 2014	Recognized in net income	**Net balance, December 31,2014**
Post-retirement benefits	1,627	57	**1,684**
PP&E and intangibles	3,066	(2,315)	**751**
Other	125	(11)	**114**
	4,818	(2,269)	**2,549**

(Canadian dollars in thousands)	Net balance January 1, 2015	Recognized in net income	**Net balance, December 31,2015**
Post-retirement benefits	1,684	59	**1,743**
PP&E and intangibles	751	(3,541)	**(2,790)**
Other	114	32	**146**
	2,549	(3,450)	**(901)**

7. PROPERTY, PLANT AND EQUIPMENT

(Canadian dollars in thousands)	Land, land rights & buildings	Distribution assets	Vehicles & other	Construction in progress	Total
Deemed cost (net book value) at January 1, 2014	31,448	258,833	9,940	6,071	306,292
Additions	492	40,525	2,133	-	43,150
Retirements	-	(2,090)	(910)	(359)	(3,359)
Net book value at December 31, 2014	**31,940**	**297,268**	**11,163**	**5,712**	**346,083**
Additions	467	38,614	4,176	2,204	45,461
Retirements	-	(4,958)	(1,381)	-	(6,339)
At December 31, 2015	**32,407**	**330,924**	**13,958**	**7,916**	**385,205**
Accumulated depreciation:					
At January 1, 2014	-	-	-	-	-
Depreciation	808	11,750	1,890	-	14,448
Retirements	-	(1,196)	(853)	-	(2,049)
At December 31, 2014	**808**	**10,554**	**1,037**	-	**12,399**
Depreciation	850	11,897	1,656	-	14,403
Retirements	-	(2,360)	(1,266)	-	(3,626)
At December 31, 2015	**1,658**	**20,091**	**1,427**	-	**23,176**
Carrying amounts (net book value):					
At December 31, 2015	**30,749**	**310,833**	**12,531**	**7,916**	**362,029**
At December 31, 2014	**31,132**	**286,714**	**10,126**	**5,712**	**333,684**
At January 1, 2014	**31,448**	**258,833**	**9,940**	**6,071**	**306,292**

Hydro One Brampton did not have any impairments in the periods presented above.

During 2015 $3,999 thousand (December 31, 2014 $3,639 thousand, January 1, 2014 $3,834 thousand) of future use assets were recognized in PP&E.

Losses on derecognition of PP&E are presented as an element of depreciation expense on the Statement of Income and Comprehensive Income. These losses amounted to $2,534 thousand (2014 - $816 thousand).

The Company capitalizes borrowing costs for all qualifying assets. Borrowing costs were capitalized on qualifying property, plant and equipment and intangible assets under construction or development at a rate of 6.16% (December 31, 2014 - 6.16 %; January 1, 2014 - 6.07%). Borrowing costs of $642 thousand were capitalized in 2015 (2014 - $725 thousand) as part of the costs of PP&E.

8. INTANGIBLE ASSETS

Canadian dollars in thousands	Contributed capital paid	Computer software	Total
Deemed cost (net book value) at			
January 1, 2014	13,505	1,646	15,151
Additions	-	229	229
Retirements	-	-	-
Net book value at December 31, 2014	**13,505**	**1,875**	**15,380**
Additions	7,705	541	8,246
Retirements	-	-	-
At December 31, 2015	**21,210**	**2,416**	**23,626**
Accumulated amortization:			
at January 1, 2014	-	-	-
Additions	370	677	1,047
Retirements	-	-	-
At December 31, 2014	**370**	**677**	**1,047**
Additions	467	666	1,133
Retirements	**-**	**-**	**-**
At December 31, 2015	**837**	**1,343**	**2,180**
Carrying amount (net book value):			
At December 31, 2015	**20,373**	**1,073**	**21,446**
At December 31, 2014	**13,135**	**1,198**	**14,333**
At January 1, 2014	**13,505**	**1,646**	**15,151**

9. REGULATORY BALANCES

Regulatory balances arise as a result of the rate-making process. A continuity schedule of the carrying amount of regulatory balances is provided as follows.

(Canadian dollars in thousands)	January1, 2015	Additions	Carrying charges	Recovery	Other movements	December 31, 2015	Remaining recovery period
Regulatory debit balances:							
Accounting changes under CGAAP	4,835	-	-	(1,612)	-	3,223	2 years
Regulatory deferred tax asset	509	5,119	-	-	-	5,628	Note [1]
LRAM variance account	142	376	3	-	-	521	Note [1]
Retail settlement variance accounts	3,456	-	-	-	(3,456)	-	Note [1]
LV variance account	155	249	3	-	-	407	Note [1]
Renewable generation funding adder	-	126	-	1	-	127	Note [1]
Other	69	11	-	(16)	-	64	Note [1]
Total	9,166	5,881	6	(1,627)	(3,456)	9,970	

(Canadian dollars in thousands)	January 1, 2015	Additions	Carrying charges	Recovery	Other movements	December 31, 2015	Remaining recovery period
Regulatory credit balances:							
Retail settlement variance accounts	-	7,722	15	-	(3,456)	4,281	Note [1]
Regulatory balances approved for disposition	2,290	-	11	(1,724)	-	577	2 years
Other	66	54	-	-	-	120	Note [1]
Total	2,356	7,776	26	(1,724)	(3,456)	4,978	

[1] The Company expects to apply for disposition of these regulatory balances at a future date. These balances incur carrying charges at 1.10% per annum (December 31, 2014 – 1.47%, January 1, 2014 – 1.47%).

(Canadian dollars in thousands)	January 1, 2014	Additions	Carrying charges	Recovery	Other movements	December 31, 2014	Remaining recovery period
Regulatory debit balances:							
Accounting changes under CGAAP	2,684	2,151	-	-	-	4,835	3 years
Regulatory deferred tax asset	924	(412)	-	-	(3)	509	Note [1]
LRAM variance account	307	361	6	(532)	-	142	Note [1]
Retail settlement variance accounts	194	3,414	45	(197)	-	3,456	Note [1]
LV variance account	160	154	3	(162)	-	155	Note [1]
Smart meters	1,158	4	(25)	(1,137)	-	-	-
IFRS transition costs	961	-	13	(974)	-	-	-
Stranded meters	522	-	7	(529)	-	-	-
Other	195	11	2	(139)	-	69	Note [1]
Total	7,105	5,683	51	(3,670)	(3)	9,166	

(Canadian dollars in thousands)	January 1, 2014	Additions	Carrying charges	Recovery	Other movements	December 31, 2014	Remaining recovery period
Regulatory credit balances:							
Regulatory balances approved for disposition	8,399	86	91	(6,286)	-	2,290	1 year
Regulatory deferred tax liability	3	-	-	-	(3)	-	
Renewable generation funding adder	313	(347)	8	26	-	-	-
Other	77	64	2	(77)	-	66	Note [1]
Total	8,792	(197)	101	(6,337)	(3)	2,356	

[1] The Company expects to apply for disposition of these regulatory balances at a future date. These balances incur carrying charges at 1.10% per annum (December 31, 2014 – 1.47%, January 1, 2014 – 1.47%).

In the absence of IFRS 14, carrying charges would not have been accreted on these regulatory balances, and financing costs would have been lower in 2015 by $20 thousand (2014 – $50 thousand).

The “Additions” column consists of additions to regulatory balances (for both debits and credits). The “Recovery” column refers to amounts collected through rate riders and other adjustments. The “Other movements” column consists of reclassification between regulatory debit and credit balances.

No impairments were recorded in 2015 or 2014.

The Company is subject to regulatory risks, including the approval by the OEB of rates that permits a reasonable opportunity to recover the estimated costs of providing safe and reliable service on a timely basis and earn the approved rates of return. The OEB approves distribution rates based on projected electricity load and consumption levels. If actual load or consumption materially falls below projected levels, the income for could be materially adversely affected. Also, the current revenue requirements for these businesses are based on cost assumptions that may not materialize. There is no assurance that the OEB would allow rate increases sufficient to offset unfavourable financial impacts from unanticipated changes in electricity demand or in costs.

The OEB's new Renewed Regulatory Framework for Electricity (RRFE) requires that the term of a cost of service rate application (distribution business) be a five-year period. There are risks associated with forecasting over a longer period. Changes in the industry may alter the investment needs or require changes to rate setting that could result in a significant impact on the Company's capability to execute its plan.

The load could also be negatively affected by successful CDM programs. The Company is also subject to risk of revenue loss from other factors, such as economic trends and weather. The risk exists that the OEB may not allow full recovery of such investments in the future. To the extent possible, the Company aims to mitigate this risk by ensuring prudent expenditures, seeking from the regulator clear policy direction on cost responsibility, and pre-approval of the need for capital expenditures.

While the Company expects that all expenditures would be fully recoverable after OEB review, any future regulatory decision to disallow or limit the recovery of such costs would lead to potential asset impairment and charges to results of operations, which could have a material adverse effect on the Company.

Regulatory debit balances

Accounting Changes Under CGAAP

On July 17, 2012 the OEB issued a letter which required electricity distributors that had yet to adopt IFRS to implement changes to their regulatory capitalization and depreciation expense policies effective January 1, 2013. The OEB required these accounting changes to be implemented consistent with their regulatory accounting policies as set out for Modified IFRS as contained in the *Report of the Board, Transition to International Financial Reporting Standards,* EB-2008-0408, the Kinectrics Report, and the Revised 2012 *Accounting Procedures Handbook for Electricity Distributors* (APH). The regulatory policy changes required entities to adopt IFRS-based accounting treatments for costing and depreciating their PP&E and intangible assets, even while retaining CGAAP. A regulatory balance was provided for entities that did not have the ability to adjust rates due to their scheduled rebasing year. Based on the direction in the OEB's letter, to December 31, 2014 the Company had accumulated $4,836 thousand of adjustments in the regulatory balance. As part of its 2015 Cost of Service application, the OEB approved the Company's request for the disposition of the balance in this account.

In addition, in its letter dated June 25, 2013, the OEB required that a rate of return component be calculated on the balance in the regulatory account rather than the usual accretion of interest. In the OEB's decision on the Company's 2015 Cost of Service application, the OEB approved the recovery of the $4,835 thousand plus a return component of $1,046 thousand for a total recovery of $5,881 thousand over three years. In the absence of IFRS 14 depreciation expense would have been lower by $56 thousand (2014 – $1,551 thousand).

Regulatory Deferred Tax Asset (Liability)

Deferred taxes (i.e. PILS) are recognized on temporary differences between the carrying amount of assets and liabilities in the financial statements and the corresponding tax basis used in the computation of taxable profit. The Company has recognized balances which correspond to the taxes that flow through the rate-making process. In the absence of regulatory accounting, the Company's provision for income tax would have been recognized using the liability method and there would have been no regulatory balances established for taxes to be recovered through future rates. As a result, the 2015 provision for income tax would have been higher by $3,598 thousand (December 31, 2014 - $1,623 thousand, January 1, 2014 $1,750 thousand).

Lost Revenue Adjustment Mechanism (LRAM) Variance Account

The LRAM Variance account represents the difference between the results of actual approved impacts of authorized CDM activities related to the CDM programs which started in 2011 and the level of CDM program activities included in the Company's approved load forecast. In the absence of regulatory accounting, revenue would have been lower by $376 thousand in 2015 (2014 - $361 thousand).

Low Voltage (LV) Variance Account

The Company records the variance arising from LV transactions which are not part of the electricity wholesale market. In December 2014, the OEB approved the disposition of the amounts accumulated in this account from January 1 to December 31, 2013, including accrued carrying charges, to be disposed over a 12-month period from January 1 to December 31, 2015 in the *Regulatory Balances Approved for Disposition* Account. In the absence of rate-regulated accounting, cost of purchased power would have been lower by $249 thousand in 2015 (2014 - $154 thousand higher).

Renewable Generation Funding Adder

In December 2014 the OEB approved the disposition of the balance in this account accumulated from January 2011 to December 2013, including accrued carrying charges, to be disposed over a 12-month period from January 1 to December 31, 2015. In the absence of regulatory accounting, revenue would have been lower by $126 thousand in 2015 (2014 – $347 thousand).

Regulatory credit balances

Retail Settlement Variance Accounts

The Company has recognized RSVA's under the provisions of Article 490 of the OEB's Accounting Procedures Handbook. In December 2014, the OEB approved the disposition of the total RSVA balance accumulated from January 1 to December 31, 2013 to be disposed over a 24-month period from January 2014 to December 2015. At December 2015 the Company had a credit as compared to a debit at December 31, 2014. In the absence of regulatory accounting, distribution revenues would have been higher by $7,722 thousand (2014 - $3,414 lower).

Regulatory Balances Approved for Disposition

In 2014, the OEB approved the Company's request to refund regulatory balances of $2,064 thousand over a 12-month period commencing January 1, 2015. The balances consisted of RSVA regulatory debit balances and refundable variances for previous rate riders since the Company's Cost of Service application in 2011.

10. DEBT

(Canadian dollars in thousands)	**December 31, 2015**	December 31, 2014	January 1, 2014
Long-term debt:			
6.95% notes due June 1, 2032	**143,000**	143,000	143,000
4.41% notes due September 26, 2041	**20,000**	20,000	20,000
3.22% notes due January 13, 2022	**20,000**	20,000	20,000
4.19% notes due June 6, 2044	**10,000**	10,000	-
Total debt	**193,000**	193,000	183,000
Unamortized balance of transaction costs	**761**	791	757
Long-term debt net of deferred transaction costs	**192,239**	192,209	182,243

On August 31, 2015, long-term debt, net of deferred transaction costs, of $192,239 thousand was transferred from Hydro One Inc. to Brampton Distribution Holdco Inc. The long-term debt consists of four promissory notes, subject to redemption or repurchase in whole or in part, by the Company before maturity.

11. CARRYING AND FAIR VALUE OF FINANCIAL INSTRUMENTS

Fair Value Measurements

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. The fair value hierarchy establishes three levels to classify the inputs to valuation techniques used to measure fair value. These are described below:

- Level 1 inputs are quoted prices (unadjusted) in active markets for identical assets or liabilities.
- Level 2 inputs are quoted prices in markets that are not active, quoted prices for similar assets or liabilities in active markets, inputs other than quoted prices that are observable for the asset or liability (for example, interest rate and yield curves observable at commonly quoted intervals, forward pricing curves used to value currency and commodity contracts and volatility measurements used to value option contracts), or inputs that are derived principally from or corroborated by observable market data or other means.
- Level 3 inputs are unobservable (supported by little or no market activity).

The fair value hierarchy gives the highest priority to Level 1 inputs and the lowest priority to Level 3 inputs.

Valuation Technique and Assumptions for Measuring Fair Value

Long-term debt

Long-term debt is generally recorded at cost. The Company has not entered into any hedging relationships. The fair value 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 measurement of long-term debt is categorized as Level 2. The total fair value of the Company's long-term debt at December 31, 2015 was $250,684 thousand (December 31, 2014 - $257,222 thousand, January 1, 2014 - $224,304 thousand) with a total carrying value of $193,000 thousand (December 31, 2014 - $193,000, January 1, 2014 - $183,000).

There were no transfers from Level 2 to Level 1 in 2015 and no transfers in either direction in 2014. There were no instruments categorized under Level 3 for years ended December 31, 2015, December 31, 2014 and January 1, 2014.

Other financial assets and liabilities

The carrying amounts of cash and cash equivalents, bank overdraft, accounts receivable, and accounts payable and accrued liabilities, approximate fair value due to the short maturity of these instruments.

12. FINANCIAL RISK MANAGEMENT

Hydro One Brampton is subject to interest rate risk, credit risk and liquidity risk that arises in the normal course of the Company's business.

Interest Rate Risk

Hydro One Brampton is exposed to fluctuations in interest rates as the regulated rate of return for the Company's distribution business is derived using a formulaic approach which is in part based on the forecast for long-term Government of Canada bond yields and the spread in 30 year "A" rated Canadian utility bonds, over the 30 year benchmark Government of Canada bond yield. The Company estimates that a 1% reduction in the deemed rate of return on equity would reduce its results of operations by approximately $1,600 thousand based on the 2015 cost of service application. In 2012, 2013 and 2014, Hydro One Brampton's distribution rates were updated based on the OEB's third generation Incentive Regulation Mechanism (IRM) policies.

Credit Risk

Financial assets create credit risk that a counter-party will fail to discharge an obligation, causing a financial loss. The Company incurs credit risk in respect of accounts receivable transactions in the normal course of business. The maximum exposure to credit risk is represented by the carrying value of financial assets.

As at December 31, 2015, 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, the Company did not earn a significant amount of revenue from any individual customer. As at December 31, 2015, December 31, 2014 and January 1, 2014 there were no significant balances of accounts receivable due from any single customer.

Overdue accounts receivables are regularly monitored. Customers are assessed at each reporting date in order to determine impairment. Based on customer credit risk assessment, a certain percentage of the overdue receivables are recognized as an allowance for credit losses at each reporting period. The Company's maximum exposure to credit risk for accounts receivable is limited to the carrying amount on the Statement of Financial Position. In the year, the Company's allowance for accounts receivable remained relatively unchanged at $1,184 thousand as at December 31, 2015 (December 31, 2014 - $1,015 thousand; January 1, 2014 - $906 thousand). Minor adjustments and write-offs were determined on the basis of a review of overdue accounts, taking into consideration historical experience. As of December 31, 2015, 1.8% of accounts receivable were deemed to be significantly aged (2014 – 1.5%).

Liquidity Risk

Liquidity risk refers to the Company's ability to meet its financial obligations as they come due by delivering cash or another financial asset. Short-term liquidity is provided through cash and cash equivalents, funds from operations, and an established revolving credit facility of $50,000 thousand, if required. The short-term liquidity available to the Company should be sufficient to fund normal operating requirements. The Company monitors the level of expected cash inflows related to accounts receivable together with expected cash outflows on accounts payable.

The following are the remaining contractual maturities of the financial liabilities at the reporting dates:

Year ended December 31, 2015 (*Canadian dollars in thousands):*

Financial Liabilities	Due within 1 year $	Due within 2 years $	Due within 3 years $	Due within 4 years $	Due within 5 years $	Due after 5 years $
Accounts payable and accrued liabilities	72,321	-	-	-	-	-
Interest on long-term debt	18,931	11,884	11,884	11,884	11,884	148,806
Long-term debt	-	-	-	-	-	193,000
	91,252	**11,884**	**11,884**	**11,884**	**11,884**	**341,806**

Year ended December 31, 2014 (*Canadian dollars in thousands):*

Financial Liabilities	Due within 1 year $	Due within 2 years $	Due within 3 years $	Due within 4 years $	Due within 5 years $	Due after 5 years $
Bank indebtedness	2,705	-	-	-	-	-
Accounts payable and accrued liabilities	77,183	-	-	-	-	-
Interest on long-term debt	13,295	11,884	11,884	11,884	11,884	161,012
Long-term debt	-	-	-	-	-	193,000
	93,183	**11,884**	**11,884**	**11,884**	**11,884**	**354,012**

As at January 1, 2014 (*Canadian dollars in thousands):*

Financial Liabilities	Due within 1 year $	Due within 2 years $	Due within 3 years $	Due within 4 years $	Due within 5 years $	Due after 5 years $
Bank indebtedness	8,114	-	-	-	-	-
Accounts payable and accrued liabilities	67,957	-	-	-	-	-
Interest on long-term debt	12,846	11,465	11,465	11,465	11,465	161,679
Long-term debt	-	-	-	-	-	183,000
	88,917	**11,465**	**11,465**	**11,465**	**11,465**	**344,679**

13. CAPITAL MANAGEMENT

The Company considers its capital structure to consist of shareholder's equity, long-term debt, and cash and bank indebtedness. The Company's capital structure was as follows:

(Canadian dollars in thousands)	**December 31, 2015**	December 31, 2014	January 1, 2014
(Cash) bank indebtedness	**(40,521)**	2,705	8,114
Long-term debt	**192,239**	192,209	182,243
	151,718	194,914	190,357
Share capital	**104,501**	51,501	51,501
Retained earnings	**92,243**	77,990	72,589
Accumulated other comprehensive income	**2,087**	1,947	-
	198,831	131,438	124,090
Total capital	**350,549**	326,352	314,447

14. ACCOUNTS RECEIVABLE

(Canadian dollars in thousands)	**December 31, 2015**	December 31, 2014	January 1, 2014
Current assets:			
Accounts receivable	**73,574**	60,976	65,065
Less: Allowance for doubtful accounts	**(1,184)**	(1,015)	(906)
Accounts receivable, net	**72,390**	59,961	64,159
Receivables due from related parties (Note 21)	**903**	3,636	2,580
Total accounts receivable	**73,293**	63,597	66,739

Which consists of:

(Canadian dollars in thousands)	**December 31, 2015**	December 31, 2014	January 1, 2014
Unbilled revenue	**46,933**	40,935	36,523
Customer receivables			
Current	**23,150**	20,658	28,293
30 - 60 days	**2,430**	1,493	1,416
61 - 90 days	**673**	597	559
Over 90 days	**1,291**	929	854
Less: Allowance for doubtful accounts	**(1,184)**	(1,015)	(906)
Total accounts receivable	**73,293**	63,597	66,739

15. EMPLOYEE FUTURE BENEFITS

Hydro One Brampton accounts for its participation in OMERS as a defined contribution plan. During 2015, the Company contributed $1,910 thousand to the plan (2014 - $1,848 thousand).

The Company also provides certain medical, dental and life insurance benefits to its retired employees and their dependents. The Company recognizes these post-retirement costs in the period in which the employees render services. Costs are determined by independent actuaries using the projected benefit method pro-rated on service and based on assumptions that reflect Management's best estimates.

The Company recognizes the unfunded status of its post-retirement plan (Plan) as a liability on its Statement of Financial Position. Actuarial gains and losses are recognized in accumulated other comprehensive income (AOCI). For the year ended December 31, 2015, the measurement date for the Plan was December 31.

Information about the Company's post-retirement benefit plan is as follows:

Year ended December 31 (Canadian dollars in thousands)	**2015**	2014
Change in defined benefit obligation		
Defined benefit obligation, beginning of year	**4,406**	6,138
Current service cost	**170**	274
Interest cost	**173**	272
Benefits paid	**(115)**	(72)
Net actuarial gain recognized in AOCI	**(140)**	(1,947)
Past service cost	**-**	(259)
Defined benefit obligation, December 31	**4,494**	4,406

The Company presents its benefit obligations on its Statement of Financial Position within the following line items:

(Canadian dollars in thousands)	**December 31, 2015**	December 31, 2014	January 1, 2014
Employee future benefits – non-current	**4,324**	4,280	5,943
Employee future benefits – current	**170**	126	195
Unfunded status	**4,494**	4,406	6,138

The following table provides the components of the net periodic benefit costs for the years ended December 31, 2015 and 2014:

Year ended December 31 (Canadian dollars in thousands)	**2015**	2014
Current service cost	**170**	274
Interest cost	**173**	272
Past service cost	**-**	(259)
Net periodic benefit cost	**343**	287

Assumptions

The measurement of the obligations of the Plan and costs of providing benefits under the Plan 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 incidence of mortality, 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 Plan is recognized in AOCI.

The following weighted average assumptions were used to determine the benefit obligations and benefit expense at December 31, 2015, December 31, 2014 and January 1, 2014. Assumptions used to determine current year-end benefit obligations are the assumptions used to estimate the subsequent year's net periodic benefit costs.

The significant actuarial assumptions used in measuring the defined benefit obligation are as follows:

	December 31, 2015	December 31, 2014	January 1, 2014
Discount rate for the expense	**4.00%**	4.50%	4.00%
Discount rate for the defined benefit obligation	**4.00%**	4.00%	4.50%
Rate of compensation scale escalation (without merit)	**3.00%**	3.00%	3.00%
Rate of increase of long-term supplementary medical costs[1]	**7.82%**	8.05%	8.26%
Rate of increase of prescription drugs[1]	**7.82%**	8.05%	8.26%
Rate of increase of dental costs	**4.50%**	4.50%	4.50%

[1] 7.82% in 2015, grading down to 4.50% per annum after 2031 (December 31, 2014 - 8.05% per annum, grading down to 4.50% per annum after 2031; January 1, 8.26% per annum, grading down to 4.50% per annum after 2031)

Sensitivity Analysis

The effect of 1% change in health care cost trends on the post-retirement benefits is as follows:

Year ended December 31 (Canadian dollars in thousands)	**2015**	**2014**
Effect of 1% increase in health care cost trends on:		
Defined benefit obligation	**221**	225
Service and interest costs	**32**	46
Effect of 1% decrease in health care cost trends on:		
Defined benefit obligation	**(196)**	(200)
Service and interest costs	**(26)**	(40)

16. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

(Canadian dollars in thousands)	**December 31, 2015**	December 31, 2014	January 1, 2014
Accounts payable – energy purchases	**42,558**	36,489	31,976
Customer deposits	**4,779**	4,602	4,558
Debt retirement charge payable	**2,043**	2,106	2,072
Commodity taxes payable	**940**	479	216
Payroll payable	**748**	981	1,583
Other payables and accrued liabilities	**21,253**	32,526	27,552
Total accounts payable and accrued liabilities	**72,321**	77,183	67,957

17. DEFERRED REVENUE

(Canadian dollars in thousands)	**December 31, 2015**	December 31, 2014	January 1, 2014
Capital contributions, net of amortization	**25,786**	14,015	-
Subdivision deficiencies	**1,107**	1,032	988
Total deferred revenue	**26,893**	15,047	988
Less: current portion of deferred revenue			
Capital contributions	**1,162**	539	-
Other	**10**	8	-
	1,172	547	-
Non-current portion of deferred revenue	**25,721**	14,500	988

The reconciliation between the opening and closing capital contribution balances is as follows:

(Canadian dollars in thousands)	**December 31, 2015**	December 31, 2014
Beginning balance, January 1	**14,015**	-
Receipt of capital contributions	**12,376**	14,557
Amortization	**(605)**	(542)
Balance at December 31	**25,786**	14,015

18. SHARE CAPITAL

Common Shares

The Company is authorized to issue an unlimited number of common shares. On August 31, 2015, Hydro One subscribed for 357 shares for an aggregate subscription price of $53,000,000. Also on August 31, 2015, subsequent to the subscription of common shares, Hydro One declared a dividend in kind of all of its issued and outstanding common shares of Hydro One Brampton. All issued and outstanding shares of Hydro One Brampton were transferred to Brampton Distribution Holdco Inc. 2,357 shares were issued as at December 31, 2015 (December 31, and January 1, 2014 - 2,000 shares were issued).

19. DIVIDENDS

Common dividends are declared at the sole discretion of the Hydro One Brampton Board of Directors, and are recommended by Management based on results of operations, financial condition, cash requirements and other relevant factors such as industry practice and shareholder expectations.

No common dividends were declared or paid during 2015 (2014 - $8,300 thousand).

20. OPERATING, MAINTENANCE AND ADMINISTRATION

Operating, maintenance and administration expenses comprise:

December 31 (thousands of Canadian dollars)	**2015**	**2014**
Labour	**14,226**	12,704
Supplies and external services	**9,708**	8,713
Vehicles	**844**	1,033
Materials	**502**	919
Other	**2,582**	3,300
	27,862	26,669

21. RELATED PARTY TRANSACTIONS

The Company had transactions with the following related parties and companies under Province's common control:

Name of the Company	Relationship	Country of Incorporation
Province of Ontario	Owner of Brampton Distribution Holdco Inc.	Canada
Brampton Distribution Holdco Inc.	Parent	Canada
Hydro One Inc. (Hydro One)	Under Province's Common Control	Canada
Hydro One Networks Inc.	Under Province's Common Control	Canada
Hydro One Remote Communities Inc.	Under Province's Common Control	Canada
Hydro One Telecom Link Limited	Under Province's Common Control	Canada
IESO	Under Province's Common Control	Canada
Ontario Electricity Financial Corporation (OEFC)	Under Province's Common Control	Canada
Ontario Energy Board (OEB)	Under Province's Common Control	Canada

Transactions with the Province and entities under its common control

Hydro One Brampton is wholly owned by Brampton Distribution Holdco Inc. who is owned by the Province of Ontario. Hence, Brampton Distribution Holdco Inc., Hydro One and its subsidiaries, IESO, and OEB are related parties to Hydro One Brampton because they are also controlled or significantly influenced by the Province of Ontario. Transactions with these parties were in the normal course of operations and were measured at the exchange value which represented the amount of consideration established and agreed to by the parties.

Transactions between these parties and Hydro One Brampton were as follows:

In 2015, the Company purchased power from the IESO-administered spot market in the amount of $415,233 thousand (2014 - $393,002 thousand).

The IESO is responsible for funding some of the Company's CDM programs. The funding includes program costs, incentives and management fees and bonuses. In 2015, the Company received $9,250 thousand (2014 - $4,523 thousand) from the IESO in respect of the CDM programs and had a net accounts receivable of $304 thousand (December 31, 2014 - $675 thousand; January 1, 2014 -$185 thousand).

Under the Ontario Energy Board Act, 1998, the OEB is required to recover all of its annual operating costs from gas and electricity distributors and electricity transmitters by way of fees. In 2015, Hydro One Brampton incurred $424 thousand (2014 - $397 thousand) in OEB fees.

The provision for PILs was paid or payable to the OEFC.

As at December 31, 2015, long-term debt of $193,000 thousand was due to Brampton Distribution Holdco Inc. The debt was transferred from Hydro One Inc. to Brampton Distribution Holdco Inc. on August 31, 2015. Net financing charges for 2015 include interest expense on this debt in the amount of $11,899 thousand. The total interest accrued and payable at the end of 2015 is $7,047 thousand (2014 - $1,412 thousand).

Hydro One and Subsidiaries

The Company made load guarantee contributions for the construction of transmission connection facilities of $7,705 thousand (2014 – nil). In addition, certain transmission, connection, and administrative services were purchased from Hydro One Networks and Hydro One totaling $3,421 thousand (2014 - $3,591 thousand). In 2015, the Company provided transmission and connection services to Hydro One Networks totaling $1,060 thousand (2014 - $856 thousand). The Company recorded other rental revenues from Hydro One Networks of $34 thousand (2014 - $59 thousand).

During 2015 the Company made no capital contributions nor purchases for computer software from Hydro One Networks (2014 – $84 thousand).

No common dividends were declared and paid to the Province, Brampton Distribution Holdco or Hydro One during 2015 (2014 - $8,300 thousand to Hydro One).

As at December 31, 2015, no long-term debt was due to Hydro One (December 31, 2014 - $193,000 thousand; January 1, - $183,000 thousand). Net financing costs paid to Hydro One for 2015 include interest expense of $6,264 thousand (2014 - $11,704 thousand). Additionally, interest expense payments on the inter-company demand facility was made in the amount of $107 thousand (2014 – $86 thousand).

Hydro One provided prudential support of $78,000 thousand to the IESO on behalf of the Company in the form of parental guarantees to August 31, 2015 (December 31, 2014 - $78,000 thousand; January 1, 2014 - $75,000 thousand).

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

December 31 (Canadian dollars in thousands)	**2015**	**2014**	**2013**
Due from related parties	**903**	3,636	2,580
Due to related parties[1]	**(46,698)**	(41,055)	(36,325)

[1] Included in due to related parties at December 31, 2015 are amounts owing to the IESO in respect of power purchases of $37,345 thousand (December 31, 2014 – $36,348 thousand and January 1, 2014 – $32,299 thousand).

Sales to and purchases from related parties occur at normal market prices or at a proxy for fair value based on the requirements of the OEB's Affiliate Relationship Code. Outstanding balances at period end are unsecured, interest free and settled in cash.

Key management personnel are comprised of Hydro One Brampton's senior management team. The following compensation has been provided to key management personnel and members of the Board of Directors who have the authority and responsibility for planning, directing and controlling the activities of the entity, directly or indirectly:

Year ended December 31 (Canadian dollars in thousands)	**2015**	**2014**
Salaries and short term employee benefits	**1,470**	378
Retirement OMERS & OPRB contributions	**97**	52
Compensation paid for contract management personnel	**766**	457
Other compensation	**-**	127
Directors Honorarium	**3**	6
	2,336	1,020

22. NET CHANGE IN NON-CASH BALANCES RELATED TO OPERATIONS

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

Year ended December 31 (Canadian dollars in thousands)	**2015**	2014
Accounts receivable	**(9,696)**	3,142
Income tax receivable	**2,346**	(667)
Materials and supplies	**121**	-
Deferred tax assets	**2,549**	2,269
Accounts payable and accrued liabilities	**(6,273)**	8,564
Income tax payable	**478**	-
Long-term accounts payable and accrued liabilities	**(1,295)**	(5,358)
Deferred tax liabilities	**901**	-
Other	**963**	753
Total	**(9,906)**	8,703

23. CONTINGENCIES

Legal Proceedings

The Company is involved in various lawsuits, claims and regulatory proceedings in the normal course of business. In the opinion of Management, the outcome of such matters, except as noted below, will not have a materially adverse effect on the Company's financial position, results of operations or cash flows.

24. COMMITMENTS

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 this security if the Company fails to make the payment required by a default notice issued by the IESO. In August 2015 Hydro One Brampton posted a letter of credit as security in the amount of $5,500 thousand (December 31, 2015 - $5,500 thousand). Prior to August 2015, prudential support was provided using parental guarantees through Hydro One Inc. (December 31, 2014 - $78,000 thousand; January 1, 2014 - $75,000 thousand).

25. TRANSITION TO IFRS

IFRS 1 Elective and Mandatory Exemptions

Hydro One Brampton adopted IFRS effective January 1, 2014 consistent with the date authorized by the Canadian Accounting Standards Board for rate regulated enterprises that selected the optional deferral in implementation. Based on this adoption date, the Company's IFRS transition date and date of the first IFRS opening Statement of Financial Position is January 1, 2014. An explanation of the significant adjustments made by the Company and how the transition to IFRS has affected the Company's financial position, financial performance and cash flows is set out in the following tables and accompanying notes.

IFRS 1 sets out the procedures that a company must follow when it adopts IFRS for the first time as the basis for preparing its Financial Statements. A company is required to establish its IFRS accounting policies immediately prior to its date of IFRS implementation. In the Company's case this is December 31, 2015. In general, these policies must be retrospectively applied to determine the IFRS opening Statement of Financial Position amounts at the date of transition. IFRS 1 provides a specific number of elective and mandatory exemptions to the general principle of retroactive restatement. These exemptions are described below with the Company's choices where applicable.

Mandatory Exemptions

Estimates

Hindsight was not used to create or revise estimates and accordingly, the estimates previously made by the Company under CGAAP are retained for the January 1, 2014 IFRS Statement of Financial Position.

Elective Exemptions

Regulatory Deferral Accounts IFRS 14

IFRS 1 offers an optional exemption for a first-time adopter to adopt IFRS 14 on initial adoption of IFRS. On January 30, 2014 the IASB published IFRS 14 allowing an entity with rate-regulated activities to continue to recognize amounts that qualify as regulatory balances in its financial statements in accordance with its previous national GAAP (CGAAP). This interim standard requires regulatory balances and movements therein to be presented as separate line items on the face of the financial statements, distinguished from assets, liabilities, income and expenses that are recognized in accordance with other IFRSs. An entity that recognizes regulatory balances in its financial statements is required to provide extensive disclosures to enable users of the financial statements to understand the features and nature of, and risks associated with, rate regulation; and the effect of rate regulation on the entity's financial position, performance and cash flows. The effect of the reclassifications would enhance comparability of IFRS 14 compliant financial statements with those of entities not applying IFRS 14. Hydro One Brampton has applied this exemption and has early adopted IFRS 14. As a result, the Company will continue to apply its previous CGAAP accounting policies for the recognition, measurement, impairment and derecognition of regulatory balances.

Carrying Amount of PP&E and Intangible Assets as Deemed Cost

IFRS 1 offers an optional exemption for a first-time adopter that has rate-regulated property, plant and equipment and intangible assets. This exemption allows the adopting entity to deem the net book value of its PP&E and intangible assets immediately prior to transition as its deemed acquisition cost at transition. Deemed acquisition cost includes original cost, less accumulated depreciation or amortization less unamortized capital contributions received. The deemed cost of acquisition may also include historical acquisition costs that would not qualify for capitalization under IFRS.

Hydro One Brampton has elected to use this exemption for its PP&E and intangible assets, all of which are rate-regulated. Therefore, the closing net book values of PP&E and intangible assets under CGAAP as at December 31, 2013 is the Company's deemed acquisition cost on the January 1, 2014, IFRS transition date. Pre-transition accumulated depreciation is no longer presented, although it is tracked as information for the OEB.

The impact of this change is to decrease both the cost and accumulated depreciation of PP&E by $278,717 thousand and to decrease both the cost and accumulated amortization of intangible assets by $4,851 thousand, as at January 1, 2014.

Decommissioning Liabilities Included in the Cost of PP&E

International Financial Reporting Interpretations Committee (IFRIC) Statement 1 ("Changes in Existing Decommissioning, Restoration, and Similar Liabilities") requires specified changes in decommissioning, restoration or similar liabilities be added to, or deducted from, the cost of the asset to which it relates retrospectively, with the adjusted depreciable amount of the asset being depreciated prospectively over its remaining useful life. IFRS 1 provides an exemption for changes that occurred before the date of transition date and permits the measurement of the decommissioning liability as at transition date in accordance with IAS 37 ("Provisions, Contingent Liabilities and Contingent Assets"). A first-time adopter need not apply IFRIC 1 retrospectively for decommissioning liabilities that arose prior to transition date.

Borrowing Cost (IAS 23, "Borrowing Cost")

Another first time adoption exemption allows an enterprise to choose an effective application date of January 1, 2009 for IAS 23 rather than conducting a full retrospective application of the standard. However, the Company did not apply this exemption as it instead elected to implement the first time adoption for rate-regulated activities enabling it to deem the December 31, 2013 net carrying amount of its property, plant and equipment and intangible assets under CGAAP as its acquisition cost on IFRS transition date, January 1, 2014.

Under CGAAP, the Company capitalized financing costs on PP&E under construction and intangible assets under development using OEB mandated industry interest rates for allowance for funds used during construction until transition date. Subsequent to the transition date, the Company will continue to capitalize financing costs on its internally constructed or developed assets consistent with the requirements of IAS 23.

Customer Contributions (IFRIC 18, "Transfers of Assets from Customers")

IFRS 1 allows first time adopters to adopt IFRIC 18 effective the later of July 1, 2009 or the date of transition to IFRS. Under IFRIC 18, the Company is required to recognize capital contributions as deferred revenues rather than as contra asset as allowed under CGAAP. In the absence of a finite term operating agreement with the contributing customer, such deferred revenues are recognized in results from operations as revenue on a straight-line basis over the service life of the related PP&E. When there is an operating or service agreement, the revenue is recognized over the term specified in the agreement.

As the Company elected the deemed cost exemption available under IFRS 1 for rate regulated PP&E, this exemption was not required for customer contributions received prior to the transition date. Subsequent to transition, capital contributions are recorded as deferred revenue and amortized to revenue straight-line over the estimated remaining service life of the related PP&E. The Company has applied IFRIC 18 prospectively beginning on the IFRS transition date.

Impact of Transition to IFRS

The reconciliation of Statement of Financial Position for the as at January 1, 2014 and December 31, 2014 from CGAAP to IFRS is provided below:

Reconciliation of financial position as at January 1, 2014 (Canadian dollars in thousands)	Notes	CGAAP	Presentation differences	Measurement & recognition differences	IFRS
Non-current assets:					
Property, plant and equipment	(b)	306,542	(250)	-	306,292
Intangible assets		15,151	-	-	15,151
Deferred tax assets	(a, c)	5,669	73	(924)	4,818
Regulatory assets	(d)	5,023	(5,023)	-	-
		332,385	(5,200)	(924)	326,261
Current assets:					
Accounts receivable		66,739	-	-	66,739
Income tax receivable		1,679	-	-	1,679
Deferred tax assets	(a)	73	(73)	-	-
Materials and supplies		1,195	-	-	1,195
Regulatory assets	(d)	1,158	(1,158)	-	-
		70,844	(1,231)	-	69,613
Total assets		**403,229**	**(6,431)**	**(924)**	**395,874**
Regulatory balances	(c, d)	**-**	**6,181**	**924**	**7,105**
Total assets and regulatory balances		**403,229**	**(250)**	**-**	**402,979**

Reconciliation of financial position as at January 1, 2014 (Canadian dollars in thousands)	Notes	CGAAP	Presentation differences	Measurement & recognition differences	IFRS
Non-current liabilities:					
Long-term debt		182,243	-	-	182,243
Employee future benefits	(c)	7,068	-	(1,125)	5,943
Regulatory liabilities	(d)	4,526	(4,526)	-	-
Accounts payable and accrued liabilities		3,275	-	-	3,275
Deferred revenue		988	-	-	988
		198,100	(4,526)	(1,125)	192,449
Current liabilities:					
Bank indebtedness		8,114	-	-	8,114
Accounts payable and accrued liabilities		67,957	-	-	67,957
Accrued interest		1,382	-	-	1,382
Regulatory liabilities	(d)	4,266	(4,266)	-	-
Employee future benefits other than pension		195	-	-	195
		81,914	(4,266)	-	77,648
Total liabilities		**280,014**	**(8,792)**	**(1,125)**	**270,097**
Shareholder's equity					
Share capital		51,501	-	-	51,501
Retained earnings	(b, c)	71,714	**(250)**	1,125	72,589
Total shareholder's equity		**123,215**	**(250)**	**1,125**	**124,090**
Regulatory balances	(d)	**-**	**8,792**	**-**	**8,792**
Total liabilities, shareholder's equity and regulatory balances		**403,229**	**(250)**	**-**	**402,979**

Reconciliation of financial position as at December 31, 2014 (Canadian dollars in thousands)	Notes	CGAAP	Presentation differences	Measurement & recognition differences	IFRS
Non-current assets:					
Property, plant and equipment	(b)	318,271	-	15,413	333,684
Intangible assets		14,333	-	-	14,333
Deferred tax assets	(a, c)	875	53	1,621	2,549
Regulatory assets	(d)	9,213	(9,213)	-	-
		342,692	(9,160)	17,034	350,566
Current assets:					
Accounts receivable	(b)	65,102	-	(1,505)	63,597
Income tax receivable		2,346	-	-	2,346
Deferred tax assets	(a)	53	(53)	-	-
Materials and supplies		1,195	-	-	1,195
Regulatory assets	(d)	6,330	(6,330)	-	-
		75,026	(6,383)	(1,505)	67,138
Total assets		**417,718**	**(15,543)**	**15,529**	**417,704**
Regulatory balances	(c, d)	**-**	**10,787**	**(1,621)**	**9,166**
Total assets and regulatory balances		**417,718**	**(4,756)**	**13,908**	**426,870**

Reconciliation of financial position as at December 31, 2014 (Canadian dollars in thousands)	Notes	CGAAP	Presentation differences	Measurement & recognition differences	IFRS
Non-current liabilities:					
Long-term debt		192,209	-	-	192,209
Employee future benefits other than pension	(c)	7,565	-	(3,285)	4,280
Regulatory liabilities	(d)	66	(66)	-	-
Deferred revenue	(b)	1,032	-	13,468	14,500
Accounts payable and accrued liabilities		114	-	-	114
		200,986	(66)	10,183	211,103
Current liabilities:					
Bank indebtedness		2,705	-	-	2,705
Accounts payable and accrued liabilities	(b)	76,646	-	537	77,183
Accrued interest		1,412	-	-	1,412
Deferred revenue	(b)	-	-	547	547
Regulatory liabilities	(d)	7,046	(7,046)	-	-
Employee future benefits other than pension		126	-	-	126
		87,935	(7,046)	1,084	81,973
Total liabilities		**288,921**	**(7,112)**	**11,267**	**293,076**
Shareholder's equity					
Share capital		51,501	-	-	51,501
Retained earnings	(b, c)	77,296	-	694	77,990
Accumulated other comprehensive income	(c)	-	-	1,947	1,947
Total shareholder's equity		**128,797**	**-**	**2,641**	**131,438**
Regulatory balances	(d)	**-**	**2,356**	**-**	**2,356**
Total liabilities, shareholder's equity and regulatory balances		**417,718**	**(4,756)**	**13,908**	**426,870**

The reconciliation of Statement of Income and Other Comprehensive Income for the year ended December 31, 2014 from CGAAP to IFRS is provided below:

Year ended December 31 (Canadian dollars in thousands)	Notes	CGAAP	Presentation differences	Measurement & recognition differences	IFRS
Revenues					
Energy	(d)	425,874	(3,459)	-	422,415
Distribution	(d)	64,085	(4,474)	-	59,611
Other	(b, d)	5,839	(2,163)	542	4,218
		495,798	(10,096)	542	486,244
Costs					
Purchased power		425,874	-	-	425,874
Operation, maintenance and administration	(c)	26,754	-	(85)	26,669
Depreciation of property, plant and equipment and amortization of intangible assets	(b)	15,461	(1,137)	842	15,166
		468,089	(1,137)	757	467,709
Financing costs		11,070	-	(49)	11,021
Income before taxes		16,639	(8,959)	(166)	7,514
Income taxes	(b, d)	2,757	2,630	(3,077)	2,310
Net income		**13,882**	**(11,589)**	**2,911**	**5,204**
Net movement in regulatory balances, net of tax	(d)	-	11,540	(3,043)	8,497
Net income after net movement in regulatory balances		**13,882**	**(49)**	**(132)**	**13,701**
Other comprehensive income, net of tax					
Item that will not be reclassified to income or loss					
Remeasurement of post-retirement benefit obligation	(c)	**-**	-	1,947	1,947
Total other comprehensive income for the year		**-**	**-**	**1,947**	**1,947**
Total income and other comprehensive income for the year		**13,882**	**(49)**	**1,815**	**15,648**

The reconciliation of Statement of Changes in Shareholder's Equity for the year ended December 31, 2014 from CGAAP to IFRS is provided below:

Year ended December 31 (Canadian dollars in thousands)	Notes	CGAAP	Presentation differences	Measurement & recognition differences	IFRS
Share capital		**51,501**	**-**	**-**	**51,501**
Retained earnings, January 1, 2014	(b, c)	71,714	-	875	72,589
Net income after net movement in regulatory balances	(c)	13,882	-	(181)	13,701
Other comprehensive income	(c)	-	-	1,947	1,947
Dividends		(8,300)	-	-	(8,300)
Retained earnings, December 31, 2014		**77,296**	**-**	**2,641**	**79,937**
Total equity		**128,797**	**-**	**2,641**	**131,438**

IFRS measurement, recognition and presentation adjustments

The following descriptions relate to the measurement, recognition and presentation adjustments included in the Statements of Financial Position and Statements of Income and Other Comprehensive Income and cash flows:

a) Current and Deferred Taxes (Presentation)

The conversion to IFRS does not result in an adjustment to the current tax amounts reported in prior periods under CGAAP. Changes made to deferred tax amounts previously reported under CGAAP are the result of certain amounts previously recorded in deferred tax assets and liabilities being reclassified to the deferred tax assets and liabilities within the regulatory balances account (discussed below).

IFRS does not permit deferred tax assets or liabilities to be recorded as current assets or liabilities. As a result, current deferred tax assets of $73 thousand at the transition date and $53 thousand as at December 31, 2014, were reclassified to/from current to non-current deferred taxes on the Statements of Financial Position. This reclassification was irrespective of the underlying assets or liabilities to which they relate, or the expected date of reversal of the temporary difference.

b) Customer Contributions (Presentation)

Under IFRIC 18, customer contributions made towards the Company's acquisition or construction of property, plant and equipment are recorded as deferred revenues to be amortized over the period of the estimated remaining service life of the related assets. Under CGAAP, these customer contributions were netted against the acquisition or construction costs of property, plant and equipment. These assets were depreciated on a net basis, after taking into account the contributed capital contra amount. The Company elected to deem the closing net carrying amounts under CGAAP as its deemed IFRS acquisition cost on the transition date. This deemed cost included any customer contributions recorded prior to January 1, 2014. Subsequent to transition, customer capital contributions are recorded as deferred revenue and amortized to revenue over the remaining service life of the related property, plant and equipment.

As at December 31, 2014, the impact was to increase property, plant and equipment by $15,541 thousand, current deferred revenue by $547 thousand and non-current deferred revenue by $13,468 thousand. For the year ended December 31, 2014, $542 thousand was amortised from deferred revenue to other revenue.

c) Employee Future Benefits (Measurement and Recognition)

Under CGAAP, the Company disclosed, but was not required to recognize, the net unfunded status of post-retirement benefit obligations on the Statements of Financial Position. Under IFRS, the Company recognized the unfunded status of post-retirement benefit obligations in retained earnings on the transition date to IFRS and to Other Comprehensive Income.

The impact for the Company at January 1, 2014 was to decrease the long-term employee future benefits payable and increase the retained earnings by $1,125 thousand each, and to decrease the deferred tax assets by $319 thousand with an offset increasing the regulatory assets balance by $319 thousand. As at December 31, 2014, the impact was to decrease the long-term employee future benefits payable by an additional $2,160 thousand, increase other comprehensive income by $1,947, decrease deferred tax assets by $1,621 thousand, decrease operation, maintenance and administration by $85 thousand, decrease property, plant and equipment by $128 thousand, increase net income by $85 thousand and increase regulatory assets balances by $1,621.

d) Regulatory Balances (Presentation)

IFRS 14 permits a rate-regulated entity to continue to apply its previous GAAP accounting policies for the recognition, measurement, impairment, and derecognition of regulatory balances. However, all regulatory balances and related deferred tax amounts are reclassified to a new and separate section of the Statement of Financial Position. As well, the net income effect of all changes in regulatory balances must be segregated in a new separate section of the Statements of Income and Other Comprehensive Income.

For the Company, the impact of IFRS 14 at January 1, 2014 was to transfer the deferred tax asset gross-up and deferred tax liabilities on regulatory balances to regulatory balances, and to transfer all other regulatory debit and credit balances to separate lines below what was formerly known as “Total assets” and “Total liabilities and shareholder’s equity”, respectively. The impact of this change as at January 1, 2014 was to reduce current regulatory assets by $1,158 thousand, non-current regulatory assets by $5,023 thousand, current regulatory liabilities by $4,266 thousand and noncurrent regulatory liabilities by $4,526 thousand, and increase regulatory debit balances by $6,181 thousand and regulatory credit balances by $8,792 thousand. Additionally, as at January 1, 2014 regulatory assets increased by $608 as a result of recognition of regulatory deferred tax movements generated by temporary differences in deferred taxes.

As at December 31, 2014, the impact was to reduce current regulatory assets by $6,330 thousand, non-current regulatory assets by $9,213 thousand, current regulatory liabilities by $7,046 thousand and noncurrent regulatory liabilities by $66 thousand, and increase regulatory debit balances by $10,787 thousand and regulatory credit balances by $2,356 thousand. Additionally, as at December 31, 2014 regulatory assets decreased by $2,434 as a result of recognition of regulatory deferred tax movements generated by temporary differences in deferred taxes.

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ATTACHMENT 12
GUELPH HYDRO 2016 AUDITED FINANCIAL STATEMENTS

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Financial Statements of

GUELPH HYDRO ELECTRIC SYSTEMS INC.

Year ended December 31, 2016
(Expressed in thousands of dollars)

KPMG LLP
115 King Street South
2nd Floor
Waterloo ON N2J 5A3
Canada
Tel 519 747-8800
Fax 519 747-8830

INDEPENDENT AUDITORS' REPORT

To the Shareholder of Guelph Hydro Electric Systems Inc.

We have audited the accompanying financial statements of Guelph Hydro Electric Systems Inc., which comprise the statement of financial position as at December 31, 2016, the statements comprehensive income, changes in equity and cash flows for the year then ended, and notes, comprising a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with International Financial Reporting Standards, and for such internal control as management determines is necessary to enable the preparation of 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 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 financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the 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 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 financial statements.

KPMG

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 financial statements present fairly, in all material respects, the financial position of Guelph Hydro Electric Systems Inc. as at December 31, 2016, and its financial performance and its cash flows for the year then ended in accordance with International Financial Reporting Standards.

KPMG LLP

Chartered Professional Accountants, Licensed Public Accountants

April 26, 2017
Waterloo, Canada

GUELPH HYDRO ELECTRIC SYSTEMS INC.

Balance Sheet

December 31, 2016, with comparative information for 2015
(Expressed in thousands of dollars)

	2016	2015
Assets		
Current assets:		
Cash	$ 23,935	$ 32,380
Accounts receivable (note 4)	22,096	21,508
Unbilled revenue	14,699	15,284
Income taxes recoverable	2,420	-
Inventory (note 5)	1,898	2,181
Other current assets	626	558
Due to related parties	1,579	-
Total current assets	67,253	71,911
Property, plant and equipment (note 6)	158,944	150,634
Intangible assets (note 7)	641	807
Deferred income taxes (note 8)	1,542	2,364
Total non-current assets	161,127	153,805
Total assets	$ 228,380	$ 225,716

GUELPH HYDRO ELECTRIC SYSTEMS INC.

Balance Sheet

December 31, 2016, with comparative information for 2015
(Expressed in thousands of dollars)

		2016		2015
Liabilities and Shareholder's Equity				
Current liabilities:				
Accounts payable and accrued liabilities	$	23,436	$	23,425
Income taxes payable		-		4,336
Deferred credits - budget billing		906		858
Customer deposits - current portion (note 9)		3,058		2,651
Due to related parties		-		500
Total current liabilities		27,400		31,770
Senior unsecured debentures (note 12)		94,283		94,245
Employee future benefits (note 11)		10,297		10,474
Customer deposits - long-term portion (note 9)		5,196		4,506
Deferred revenue		22,472		20,038
Total non-current liabilities		132,248		129,263
Total liabilities		159,648		161,033
Shareholder's equity:				
Share capital (note 18)		43,374		43,374
Accumulated other comprehensive loss		(555)		(933)
Retained earnings		25,913		22,242
		68,732		64,683
Commitments and contingencies (note 17)				
Guarantees (note 21)				
	$	228,380	$	225,716

The accompanying notes are an integral part of these financial statements.

On behalf of the Board:

_________________________ Director

_________________________ Director

GUELPH HYDRO ELECTRIC SYSTEMS INC.

Statement of Comprehensive Income

Year ended December 31, 2016, with comparative information for 2015
(Expressed in thousands of dollars)

	2016	2015
Electricity sales	$ 245,812	$ 242,665
Cost of electricity sold	214,504	201,196
	31,308	41,469
Other operating revenue (note 13)	4,668	3,760
Net operating revenue	35,976	45,229
Expenses:		
Operations and maintenance	12,921	12,118
General and administrative	9,716	10,186
	22,637	22,304
Earnings before the undernoted	13,339	22,925
Financial and other expenses (income):		
Interest on notes payable, less amounts capitalized	4,531	3,643
Interest income	(323)	(121)
Other	150	80
	4,358	3,602
Earnings from operations before income taxes	8,981	19,323
Income taxes (note 8):		
Provision for payments in lieu of corporate taxes	1,623	4,485
Deferred income taxes	687	394
	2,310	4,879
Net earnings from operations for the year	6,671	14,444
Other comprehensive income:		
Actuarial gains on employee future benefit plan	378	-
Total comprehensive income for the year	$ 7,049	$ 14,444

The accompanying notes are an integral part of these financial statements.

GUELPH HYDRO ELECTRIC SYSTEMS INC.

Statement of Changes in Equity
(In thousands of Canadian dollars)

Year ended December 31, 2016, with comparative information for 2015

	Share capital	Accumulated other comprehensive income (loss)	Retained earnings	Total
Balance at December 31, 2013	43,374	(933)	10,798	53,239
Dividends			(3,000)	(3,000)
Total comprehensive income for the year			14,444	14,444
Balance at December 31, 2015	43,374	(933)	22,242	64,683
Dividends			(3,000)	(3,000)
Total comprehensive income for the year		378	6,671	7,049
Balance, December 31, 2016	$ 43,374	$ (555)	$ 25,913	$ 68,732

The accompanying notes are an integral part of these financial statements.

GUELPH HYDRO ELECTRIC SYSTEMS INC.

Statement of Cash Flows

Year ended December 31, 2016, with comparative information for 2015
(Expressed in thousands of dollars)

	2016	2015
Cash flows from operating activities:		
Total Comprehensive income for the year	$ 7,049	$ 14,444
Adjustments for:		
Income tax expense	2,445	4,879
Depreciation and amortization	6,831	6,480
Amortization of deferred revenue	(632)	(562)
Interest income	(323)	(96)
Interest expense	4,681	3,723
Gain on disposal of property, plant and equipment	(48)	(31)
	20,003	28,837
Change in:		
Receivables	(588)	(3,620)
Unbilled revenue	585	(4,395)
Inventory	283	(349)
Other current assets	(68)	(6)
Accounts payable and accrued liabilities	11	538
Deferred credits - budget billing	48	(284)
Employee future benefits	(177)	434
	94	(7,682)
Income taxes (paid) refunded	(8,379)	1,556
Net cash from operating activities	11,718	22,711
Cash flows from investing activities:		
Purchase of property, plant and equipment	(14,733)	(15,517)
Purchase of intangible assets	(77)	(602)
Proceeds from disposal of property, plant and equipment	48	42
	(14,762)	(16,077)
Cash flows from financing activities:		
Issuance of long term debentures	-	29,607
Contributions in aid of construction	3,066	5,140
Net change in customer deposits	1,097	(1,294)
Dividends paid	(3,000)	(3,000)
Interest received	323	96
Interest paid	(4,808)	(3,502)
Change in amounts due to related parties	(2,079)	(211)
	(5,401)	26,836
Increase (decrease) in cash	(8,445)	33,470
Cash / (bank indebtedness), beginning of year	32,380	(1,090)
Cash, end of year	$ 23,935	$ 32,380

The accompanying notes are an integral part of these financial statements.

1. Reporting entity:

Guelph Hydro Electric Systems Inc. (the “Corporation” or “GHESI”) became a wholly-owned subsidiary of Guelph Municipal Holdings Inc. (“GMHI”) on September 6, 2015 when GMHI amalgamated with Guelph Hydro Inc. (“GHI”). GMHI is a wholly-owned subsidiary of the City of Guelph. GHESI was incorporated on October 31, 2000 under the laws of the Province of Ontario, Canada. The address of the Corporation’s registered office is 395 Southgate Drive, Guelph, Ontario.

The principal activity of the Corporation is to distribute electricity to the residents and businesses in the City of Guelph and the Village of Rockwood, under a license issued by the Ontario Energy Board (“OEB”). The Corporation is regulated by the OEB and adjustments to the Corporation’s distribution rates require OEB approval.

2. Basis of presentation:

(a) Statement of compliance:

The Corporation's financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as adopted by the International Accounting Standards Board ("IASB") and interpretations as issued by the International Financial Reporting Interpretations Committee ("IFRIC") of the IASB.

(b) Approval of the financial statements:

The financial statements were approved by the Board of Directors on April 26, 2017.

(c) Basis of measurement:

The financial statements have been prepared on the historical cost basis except for the following:

(i) Where held, financial instruments at fair value through profit or loss, including those held for trading, are measured at fair value.

(ii) Contributed assets are initially measured at fair value.

The methods used to measure fair values are discussed further in note 3 (c) and note 20.

(d) Functional and presentation currency:

These financial statements are presented in Canadian dollars, which is the Corporation's functional currency. All financial information presented in Canadian dollars has been rounded to the nearest thousand.

2. Basis of presentation (continued):

(e) Use of estimates and judgments:

The preparation of financial statements in conformity with IFRS requires management to make judgments, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses and disclosure of contingent assets and liabilities. Actual results may differ from those estimates.

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the year in which the estimates are revised and will affect any future period going forward

In particular, information about significant areas of estimation uncertainty and critical judgments in applying accounting policies that have the most significant effect on the amounts recognized in these financial statements is included in the following notes:

(i) Note 4 and note 20(a) - Receivables: allowance for impairment.
(ii) Note 6 - Property, plant and equipment: useful lives and the identification of significant components of property, plant and equipment.
(iii) Note 11 - Employee future benefits: measurement of the defined benefit obligation.
(iv) Note 19 - Financial instruments and risk management: valuation of long-term debt.

f) Rate regulation:

Effect of rate-setting regulations on the Corporation's activities and on these financial statements:

The Corporation is regulated by the OEB, under the authority granted by the *Ontario Energy Board Act (1988)*. Among other things, the OEB has the power and responsibility to approve or set rates for the transmission and distribution of electricity, providing continued rate protection for rural and remote electricity consumers, and ensuring that distribution companies fulfill obligations to connect and service customers. In its capacity to approve or set rates, the OEB has the authority to specify regulatory accounting treatments that may differ from IFRS for enterprises operating in a non-rate regulated environment.

On August 13, 2014, GHESI filed its 2015 electricity distribution rates application using the OEB's 4th Generation IRM as the basis for its application. The OEB rendered its Decision on December 4, 2014 which approved a distribution rate increase of 1.3% for all customers.

2. Basis of presentation (continued):

f) Rate Regulation (continued):

In addition to the distribution rate increase, the OEB approved GHESI's recovery of deferral and variance account balances in the amount of $6.9 million to be recovered over a one-year period. These recoveries relate to past difference between the costs charged by the IESO and Hydro One (including whole market, transmission connection and network, commodity, global adjustment, and low voltage charges) and OEB-approved non-distribution charges billed to GHESI's customers.

On April 24, 2015, GHESI filed a cost of service rate application for its 2016 electricity distribution rates application. The OEB rendered its Decision on November 26, 2015 which approved a distribution rate increase of 4.86% for all customers.

On August 15, 2016, GHESI filed its 2017 electricity distribution rates application using the OEB's 4th Generation IRM as the basis for its application. The OEB rendered its Decision on December 8, 2016 which approved a distribution rate increase of 1.6% for all customers.

The continuing restructuring of Ontario's electricity industry and other regulatory developments, including current and possible future consultation between the OEB and interested stakeholders, could affect the distribution rates that the Corporation may charge and the costs that the Corporation may recover, including the balance of its regulatory assets.

3. Significant accounting policies:

The accounting policies set out below have been applied consistently in all years presented in these financial statements.

(a) Cash and cash equivalents:

Cash equivalents include short-term investments with maturities of three months or less when purchased.

(b) Revenue recognition:

Revenue for the Corporation is recognized as electricity is delivered to customers and is recorded on the basis of regular meter readings and estimated customer usage since the last meter reading date to the end of the year. The related cost of power is recorded on the basis of power used.

The Corporation is licensed by the OEB to distribute electricity. As a licensed distributor, the Corporation is responsible for billing customers for electricity generated by third parties and the related costs of providing electricity service, such as transmission services and other services

3. Significant accounting policies (continued):

b) Revenue recognition (continued):

provided by third parties. The Corporation is required, pursuant to regulation, to remit such amounts to these third parties, irrespective of whether the Corporation ultimately collects these amounts from customers. The Corporation has determined that it is acting as a principal for electricity distribution and, therefore, has presented electricity revenue on a gross basis.

Customer billings for debt retirement charges are recorded on a net basis as the Corporation is acting as an agent for this revenue stream. The Corporation may file to recover uncollected debt retirement charges from Ontario Electricity Financial Corporation (“OEFC”) once each year.

Deferred revenue relating to contributions in aid of construction is amortized to income on a straight-line basis over the terms of the agreement with the customer or the economic useful life of the acquired or contributed asset, which represents the period of ongoing service to the customer.

All other revenues are recorded on a gross basis and are recognized when services are rendered.

(c) Inventory:

Inventory is valued at the lower of cost and net realizable value, with cost being determined on an average cost basis, and items considered major spare parts are recorded as capital assets.

(d) Property, plant and equipment:

Items of property, plant and equipment are measured at cost or deemed cost established on the transition date, or, where the item is transferred from customers, its fair value, less accumulated depreciation and accumulated impairment losses.

Cost includes expenditures that are directly attributable to the acquisition of the asset. The cost of self-constructed assets includes the cost of materials and direct labour, and any other costs directly attributable to bringing the asset to a working condition for its intended use.

Borrowing costs on qualifying assets are capitalized as part of the cost of the asset and are based on the Corporation’s average cost of borrowing.

When parts of an item of property, plant and equipment have different useful lives, they are accounted for as separate items (major components) of property, plant and equipment.

The cost of replacing a part of an item of property, plant and equipment is recognized in the net book value of the item if it is probable that the future economic benefits embodied within the part will flow to the Corporation and its cost can be measured reliably.

(Expressed in thousands of dollars)

3. Significant accounting policies (continued):

(d) Property, plant and equipment (continued)

In this event, the replaced part of property, plant and equipment is written off, and the related gain or loss is included in profit or loss. The costs of the day-to-day servicing of property, plant and equipment are recognized in profit or loss as incurred.

Depreciation is recognized in profit or loss on a straight-line basis over the estimated useful life of each part or component of an item of property, plant and equipment. Land is not depreciated. Construction-in-progress assets are not amortized until the project is complete and in service.

The estimated useful lives are as follows:

Buildings and fixtures	15 - 50 years
Distribution lines	40 – 70 years
Distribution transformers	35 – 55 years
Distribution meters	30 years
Smart meters	15 years
General office equipment	5 - 10 years
Computer equipment	5 years
Major tools	5 - 15 years
Data acquisition system	5 years
Trucks and rolling stock	5 - 10 years
Other capital assets	10 - 25 years

Depreciation methods, useful lives, and residual values are reviewed at each reporting date.

(e) Intangible assets:

(i) Computer software:

Computer software that is acquired or developed by the Corporation, including software that is not integral to the functionality of equipment purchased which has finite useful lives, is measured at cost less accumulated amortization and accumulated impairment losses.

(ii) Land rights:

Payments to obtain rights to access land ("land rights") are classified as intangible assets. These include payments made for easements, right of access and right of use over land for which the Corporation does not hold title. Land rights are measured at cost less accumulated amortization and accumulated impairment losses.

3. Significant accounting policies (continued):

(e) Intangible assets (continued):

(iii) Amortization:

Amortization is recognized in profit or loss on a straight-line basis over the estimated useful lives of intangible assets, other than goodwill, from the date that they are available for use.

The estimated useful lives for the current and comparative years are:

Computer software	5 years

Amortization methods and useful lives of all intangible assets are reviewed at each reporting date.

(f) Impairment:

(i) Financial assets:

A financial asset is assessed at each reporting date to determine whether there is any objective evidence that it is impaired. A financial asset is considered to be impaired if objective evidence indicates that one or more events have had a negative effect on the estimated future cash flows of that asset.

An impairment loss in respect of a financial asset measured at amortized cost is calculated as the difference between its current carrying amount (using prevailing interest rates), and the present value of the estimated future cash flows discounted at the original effective interest rate. Interest on the impaired assets continues to be recognized through the unwinding of the discount.

All impairment losses are recognized in profit or loss. An impairment loss is reversed if the reversal can be related objectively to an event occurring after the impairment loss was recognized. For financial assets measured at amortized cost the reversal is recognized in profit or loss.

(ii) Non-financial assets:

The carrying amounts of the Corporation's non-financial assets, other than inventories and deferred tax assets are reviewed at each reporting date to determine whether there is any indication of impairment. If any such indication exists, then the asset's recoverable amount is estimated.

3. Significant accounting policies (continued):

(f) Impairment (continued):

(iii) Non-financial assets (continued):

For the purpose of impairment testing, assets are grouped together into the smallest group of assets that generates cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets (the "cash-generating unit"). The Corporation has determined that it is a single cash-generating unit. The recoverable amount of an asset or cash-generating unit is the greater of its value in use and its fair value less costs to sell. In assessing value in use, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset.

An impairment loss is recognized if the carrying amount of an asset or its cash-generating unit exceeds its estimated recoverable amount. Impairment losses are recognized in profit or loss.

For assets other than goodwill, impairment recognized in prior periods is assessed at each reporting date for any indications that the loss has decreased or no longer exists. An impairment loss is reversed if there has been a change in the estimates used to determine the recoverable amount. An impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depreciation or amortization, if no impairment loss had been recognized.

(g) Provisions:

A provision is recognized if, as a result of a past event, the Corporation has a present legal or constructive obligation that can be estimated reliably, and it is probable that an outflow of economic benefits will be required to settle the obligation. Provisions are determined by discounting the expected future cash flows at a pre-tax rate that reflects current market assessments of the time value of money and the risks specific to the liability.

Decommissioning or dismantling:

When there is a legal or constructive obligation to remove and dispose of property, plant and equipment at the end of their useful life, a provision is recorded to cover such future removal and disposal costs.

3. Significant accounting policies (continued):

(h) Employee future benefits:

(i) Pension plan:

The Corporation provides a pension plan for all its full-time employees through Ontario Municipal Employees Retirement System (“OMERS”). OMERS is a multi-employer pension plan which operates as the Ontario Municipal Employees Retirement Fund (“the Fund”), and provides pensions for employees of Ontario municipalities, local boards and public utilities. The Fund is a contributory defined benefit pension plan, which is financed by equal contributions from participating employers and employees, and by the investment earnings of the Fund. To the extent that the Fund finds itself in an under-funded position, additional contribution rates may be assessed to participating employers and members. In this case, GHESI and its employees could face the prospect of higher contributions until the funded status of the Fund is restored. GHESI may only fully recover additional contribution amounts in distribution rates if increased contribution rates are factored into GHESI’s rebasing rates applications before the OEB.

(i) Post-employment benefits, other than pension:

The Corporation provides some of its retired employees with life insurance and medical benefits beyond those provided by government sponsored plans.

The cost of these benefits is expensed as earned by employees through employment service. The accrued benefit obligations and the current service costs are actuarially determined by applying the projected unit credit method and reflect management’s best estimate of certain underlying assumptions. Any actuarial gains (losses) will require a re-measurement of the net defined benefit liability or asset and will be recognized as other comprehensive income or loss in the year that it is known.

(i) Deferred revenue and assets transferred from customers:

Certain customers and developers are required to contribute towards the capital cost of construction in order to provide ongoing service. Cash contributions are initially recorded as current liabilities. Once the distribution system asset is completed or modified as outlined in the terms of the contract, the contribution amount is transferred to contributions in aid of construction.

When an asset is received as a capital contribution, the asset is initially recognized at its fair value, with the corresponding amount recognized as contributions in aid of construction.

3. Significant accounting policies (continued):

(i) Deferred revenue and assets transferred from customers (continued):

The contributions in aid of construction account, which represents the Corporation's obligation to continue to provide the customers access to the supply of electricity, is reported as deferred revenue, and is amortized to income on a straight-line basis over the terms of the agreement with the customer or the economic useful life of the acquired or contributed asset, which represents the period of ongoing service to the customer.

(j) Leased assets:

Leases in terms of which the Corporation assumes substantially all the risks and rewards of ownership are classified as finance leases. Upon initial recognition, the leased asset is measured at an amount equal to the lower of its fair value and the present value of the minimum lease payments. Subsequent to initial recognition, the asset is accounted for in accordance with the accounting policy applicable to that asset.

Other leases are operating leases and the leased assets are not recognized on the Corporation's balance sheet. Payments made under operating leases are recognized in profit or loss on a straight-line basis over the term of the lease.

(k) Finance income and finance costs:

Finance income is recognized as it accrues in profit or loss, using the effective interest method. Finance income comprises interest earned on cash and cash equivalents and on regulatory assets.

Finance costs comprise interest expense on borrowings, finance lease obligations, regulatory liabilities and unwinding of the discount on provisions and impairment losses on financial assets.

(l) Income taxes:

The income tax expense comprises current and deferred tax. Income tax expense is recognized in profit or loss except to the extent that it relates to items recognized directly in equity, in which case, it is recognized in equity.

Under the *Electricity Act, 1998*, the Corporation makes payments in lieu of corporate taxes to the OEFC. These payments are calculated in accordance with the rules for computing taxable income and taxable capital and other relevant amounts contained in the *Income Tax Act (Canada) and the Corporations Tax Act (Ontario)* as modified by the *Electricity Act, 1998*, and related regulations. Prior to October 1, 2001, the Corporation was not subject to income or capital taxes. Payments in lieu of taxes are referred to as income taxes.

Current tax is the tax payable on the taxable income for the year, using tax rates enacted or substantively enacted at the reporting date, and any adjustment to tax payable in respect of previous years.

(Expressed in thousands of dollars)

3. Significant accounting policies (continued):

(l) Income taxes (continued):

Deferred tax is recognized using the balance sheet method. Under this method, deferred income taxes reflect the net tax effects of temporary differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes, as well as for tax losses available to be carried forward to future years that are likely to be realized. Deferred tax assets and liabilities are measured using enacted or substantively enacted tax rates, at the reporting date, that are expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the year that includes the date of enactment or substantive enactment.

4. Accounts receivable:

	2016	2015
Revenue	$ 19,471	$ 18,981
Regulatory	842	868
Due from the City of Guelph	1,943	1,894
	22,256	21,743
Less allowance for doubtful accounts	(160)	(235)
	$ 22,096	$ 21,508

5. Inventory:

The amount of inventories consumed by the Corporation and recognized as an expense during 2016 was $252 (2015 - $243).

(Expressed in thousands of dollars)

6. Property, plant and equipment:

(a) Cost or deemed cost:

	Land and buildings	Distribution equipment	Other fixed assets	Construction -in- Progress	Total
Balance at January 1, 2015	$ 20,958	$ 131,008	$ 10,094	$ 4,675	$ 166,735
Additions	75	6,848	1,380	7,362	15,665
Transfers	-	4,675	-	(4,675)	-
Disposals/retirements	-	-	(112)	-	(112)
Balance at December 31, 2015	$ 21,033	$ 142,531	$ 11,362	$ 7,362	$ 182,288

	Land and buildings	Distribution equipment	Other fixed assets	Construction -in- Progress	Total
Balance at January 1, 2016	$ 21,033	$ 142,531	$ 11,362	$ 7,362	$ 182,288
Additions	213	7,915	1,407	5,362	14,897
Transfers	-	7,362	-	(7,362)	-
Disposals/retirements	-	-	(132)	-	(132)
Balance at December 31, 2016	$ 21,246	$ 157,808	$ 12,637	$ 5,362	$ 197,053

(b) Accumulated depreciation:

	Land and buildings	Distribution equipment	Other fixed assets	Construction -in- Progress	Total
Balance at January 1, 2015	$ 2,685	$ 17,513	$ 5,260	$ -	$ 25,458
Depreciation charge for the year	712	4,402	1,183	-	6,297
Disposals/retirements	-	-	(101)	-	(101)
Balance at December 31, 2015	$ 3,397	$ 21,915	$ 6,342	$ -	$ 31,654

	Land and buildings	Distribution equipment	Other fixed assets	Construction -in- Progress	Total
Balance at January 1, 2016	$ 3,397	$ 21,915	$ 6,342	$ -	$ 31,654
Depreciation charge for the year	718	4,725	1,144	-	6,587
Disposals/retirements	-	-	(132)	-	(132)
Balance at December 31, 2016	$ 4,115	$ 26,640	$ 7,354	$ -	$ 38,109

(Expressed in thousands of dollars)

6. Property, plant and equipment (continued):

(c) Carrying amounts:

	Land and buildings	Distribution equipment	Other fixed assets	Construction -in- Progress	Total
December 31, 2015	$ 17,636	$ 120,616	$ 5,020	$ 7,362	$ 150,634
December 31, 2016	17,131	131,168	5,283	5,362	158,944

(d) Borrowing costs:

During the year, borrowing costs of $165 (2015 - $148) were capitalized as part of the cost of property, plant and equipment.

(e) Allocation of depreciation and amortization:

The depreciation of property, plant and equipment and the amortization of intangible assets have been allocated to profit or loss as follows:

	Distribution expenses	Administration expenses	Total
December 31, 2015:			
Depreciation of property, plant and equipment	$ 6,199	$ 98	$ 6,297
Amortization of intangible assets	-	183	183
	$ 6,199	$ 281	$ 6,480
December 31, 2016:			
Depreciation of property, plant and equipment	$ 6,498	$ 89	$ 6,587
Amortization of intangible assets	-	244	244
	$ 6,498	$ 333	$ 6,831

(Expressed in thousands of dollars)

7. Intangible assets:

(a) Cost or deemed cost:

	Computer software
Balance at January 1, 2015	$ 614
Additions in 2015	602
Balance at December 31, 2015	1,216
Additions in 2016	78
Balance at December 31, 2016	$ 1,294

(b) Accumulated amortization:

	Computer software
Balance at January 1, 2015	$ 226
Amortization charges in 2015	183
Balance at December 31, 2015	409
Amortization charges in 2016	244
Balance at December 31, 2016	$ 653

(c) Carrying amounts:

	Computer software
Balance at December 31, 2015	$ 807
Balance at December 31, 2016	$ 641

(Expressed in thousands of dollars)

8. Income taxes:

The income tax expense varies from amounts which would be computed by applying the Corporation's combined statutory income tax rate as follows:

	2016	2015
Basic rate applied to profit before income tax	$ 2,380	$ 5,120
Decrease in income tax resulting from:		
Adjustment to prior year's taxes	(70)	(241)
Income tax expense	$ 2,310	$ 4,879
Effective rate applied to profit before income taxes	25.7%	25.3%

Significant components of the Corporation's deferred tax balances are as follows:

	2016	2015
Deferred tax assets (liabilities):		
Plant and equipment	$ (7,702)	$ (6,324)
Cumulative eligible capital	560	602
Employee benefits	2,865	2,776
Deferred revenue - contributed capital	5,955	5,310
Net deferred tax asset	$ 1,678	$ 2,364

As at December 31, 2016, a deferred tax asset of $1,678 (2015 - $2,364) has been recorded. The utilization of this tax asset is dependent on future taxable profits in excess of profits arising from the reversal of existing taxable temporary differences.

(Expressed in thousands of dollars)

9. Customer deposits:

Customer deposits represent cash deposits from electricity distribution customers and retailers, as well as construction deposits.

Deposits from electricity distribution customers are refundable to customers who demonstrate an acceptable level of credit risk as determined by the Corporation in accordance with policies set out by the OEB or upon termination of their electricity distribution service.

Construction deposits represent cash prepayments for the estimated cost of capital projects recoverable from customers and developers. Upon completion of the capital project, these deposits are transferred to contributions in aid of construction.

Customer deposits comprise:

	2016	2015
Customer deposits	$ 3,260	$ 2,504
Construction deposits	4,994	4,653
Total customer deposits	$ 8,254	$ 7,157

10. Pension agreement:

GHESI provides a pension plan for its employees through the Ontario Municipal Employees Retirement System (“OMERS”). OMERS is a multi-employer pension plan which operates as the Ontario Municipal Employee Retirement Fund (“the Fund”) and provides pensions for employees of Ontario municipalities, local boards, public utilities, and school boards. The Fund is a contributory defined benefit pension plan, which is financed by equal contributions from participating employers and employees, and by the investment earnings of the Fund. GHESI uses defined contribution plan accounting as it is only liable for contributions to the Plan. GHESI’s contribution for employees’ current service for the year ended December 31, 2016 was $1,161 (2015 - $1,096).

(Expressed in thousands of dollars)

11. Employee future benefits:

Components of employee future benefits recognized are as follows:

	2016	2015
Post-retirement benefits – accrued benefit liability as previously reported	$ 9,764	$ 9,814
Accrued sick leave benefit	533	660
	$ 10,297	$ 10,474

Post-retirement benefits:

The Corporation pays certain medical and life insurance benefits on behalf of some of its retired employees. The Corporation recognizes these post-retirement costs in the period in which employees' services are rendered. The accrued benefit liability at December 31, 2016 of $9,764 was based on an actuarial valuation completed in 2017 using a discount rate of 3.90%. The accrued benefit liability at December 31, 2015 of $9,814 was based on an actuarial valuation completed in 2015, using a discount rate of 4.05%.

Changes in the present value of the defined benefit unfunded obligation and the accrued benefit liability:

	2016	2015
Defined benefit obligation, beginning of year	$ 9,814	$ 9,359
Current service cost	285	273
Interest cost	393	374
Re-measurement of obligation	(513)	-
Benefits paid during the year	(215)	(192)
Accrued benefit liability, end of year	$ 9,764	$ 9,814

(Expressed in thousands of dollars)

11. Employee future benefits (continued):

Components of net benefit expense recognized are as follows:

	2016	2015
Current service cost	$ 285	$ 273
Interest cost	393	374
Net benefit costs	$ 678	$ 647

In 2016, $475 of the corporation's net benefit costs were charged as an operational expense and the remaining $203 was capitalized. In 2015, $647 of the corporation's net benefit costs were charged as an operational expense.

The significant actuarial assumptions used in the valuation are as follows (weighted average):

	2016	2015
Accrued benefit obligation:		
Discount rate	3.90%	4.05%
Benefit cost for the year:		
Withdrawal rate	1%	1%
Assumed health and dental care cost trend rates:		
Initial health and dental care cost trend rate	5%	5%
2018 and thereafter	6%	6%

The approximate effect on the accrued benefit obligation of the entire plan and the estimated net benefit expense of the entire plan if the health care trend rate assumption was increased or decreased by 1%, and all other assumptions were held constant, is as follows:

	Defined Benefit Obligation	Periodic Benefit Cost
1% increase in health care trend rate	$ 9,841	$ 755
1% decrease in health care trend rate	8,467	619

(Expressed in thousands of dollars)

11. Employee future benefits (continued):

Historical information

Amounts for the current and previous year, for the entire plan, are as follows:

	2016	2015
Defined benefit obligation	$ 9,764	$ 9,814
Experience adjustments	513	-

The main actuarial assumptions utilized for the valuation are as follows:

General inflation - future general inflation levels, as measured by the changes in the Consumer Price Index, were assumed at 2.0% in 2016, and thereafter (2015 - 2.0%).

Discount (interest) rate - the discount rate used to determine the present value of future liabilities and the expense for the year ended December 31, 2016, was 3.90% (2015 - 4.05%).

Salary levels - future general salary and wage levels were assumed to increase at 3.3% (2015 - 3.3%) per annum.

Medical costs - medical costs were assumed to increase 5% for 2016, 5% for 2017, and 6% thereafter.

Dental costs - dental costs were assumed to increase 5% for 2016, 5% for 2017, and 6% thereafter.

Accrued sick leave benefit:

The Corporation allows regular employees the equivalent of one and one-half days per month sick time credit to be applied in case of illnesses or accidents not covered by Workers' Compensation. A maximum of eighteen days sick time credit is accrued to each employee's credit each year and is reduced by the amount of sick time utilized each year. At the end of the year, the remaining credit, if any, is added to each employee's sick time credit accumulation. Employees can accumulate sick time credit up to a capped amount of 200 days with the following exception. Any employee on payroll at the date the cap went into effect (May 2, 2013), did not lose any credit for accumulated sick time exceeding 200 days. These employees had their sick time capped individually at the level of the sick time accumulation accrued when the cap came into effect. Any unused sick time credit is forfeited when employment ceases with the Corporation. As at December 31, 2016, the estimated value of the expected future payments to be made because of unused sick time credits amounts to $533 (2015 - $660).

(Expressed in thousands of dollars)

12. Long-term debt:

Series A senior unsecured debentures have a maturity date of December 6, 2030 and have an interest rate of 5.264% per annum. Interest is payable in equal semi-annual installments, in arrears, on June 6 and December 6 each year commencing June 6, 2014 until maturity. The debentures were issued on December 6, 2010. The debentures are represented by a single Global Debenture Certificate registered in the name of CDS & Co. In order to put the debentures in place, the Corporation incurred debt issuance costs in the amount of $500.

Series B senior unsecured debentures have a maturity date of September 25, 2045 and have an interest rate of 4.121% per annum. Interest is payable in equal semi-annual installments, in arrears, on March 25 and September 25 each year commencing March 25, 2016 until maturity. The debentures were issued on September 25, 2015. The debentures are represented by a single Global Debenture Certificate registered in the name of CDS & Co. In order to put the debentures in place, the Corporation incurred debt issuance costs in the amount of $393.

	2016	2015
Senior unsecured debentures, maturity 2030	$ 65,000	$ 65,000
Senior unsecured debentures, maturity 2045	30,000	30,000
Less: cost of debt issuance	(717)	(755)
Senior unsecured debentures, net proceeds	$ 94,283	$ 94,245

13. Other income:

Other income comprises:

	2016	2015
Late payment charges	$ 163	$ 152
Pole and other rental income	332	381
Collection and other service charges	447	376
Waterworks revenue	1,420	1,244
Storm water revenue	188	-
Intercompany services	577	749
Customer contributions	632	562
Shared Services	159	76
Conservation and Demand Management Performance Bonus	630	-
Miscellaneous	120	220
Total other income	$ 4,668	$ 3,760

(Expressed in thousands of dollars)

14. Employee benefits:

	2016	2015
Salaries, wages and benefits	$ 8,769	$ 8,659
Contributions to multi-employer plan	1,161	1,096
Expenses related to defined benefit plans	678	647
	$ 10,608	$ 10,402

15. Finance income and expense:

	2016	2015
Interest income on bank deposits	$ (323)	$ (121)
Finance income	(323)	(121)
Interest expense on long-term debt	4,696	3,794
Interest adjustment re: capitalized borrowing costs	(165)	(148)
Interest expense on deposits	31	32
Other	119	45
Net finance costs recognized in profit or loss	$ 4,358	$ 3,602

16. Related party transactions:

(a) Parent and ultimate controlling party:

The sole shareholder of the Corporation is Guelph Municipal Holdings Inc. ("GMHI"), effective September 8, 2014 when GMHI amalgamated with Guelph Hydro Inc. ("GHI"). GMHI is a wholly-owned subsidiary of the City of Guelph. The City produces financial statements that are available for public use.

(b) Key management personnel:

The key management personnel of the Corporation have been defined as members of its board of directors and executive management team members, and is summarized below.

	2016	2015
Directors' fees	$ 110	$ 108
Salaries and other short-term benefits	2,914	1,912
Post-employment benefits	57	48
	$ 3,081	$ 2,068

(Expressed in thousands of dollars)

16. Related party transactions (continued):

(c) Transactions with ultimate parent (the City):

The following summarizes the Corporation's related party transactions, recorded at the exchange amounts and balances with the City for the years ended December 31:

	2016	2015
Revenue:		
Energy sales (at commercial rates)	$ 9,047	$ 8,245
Waterworks revenue	1,419	1,243
Storm water revenue	188	-
Street light maintenance	-	353
Expenses:		
Subcontracting	5	7
Property taxes	355	327
Balances:		
Accounts receivable	1,943	1,894

(d) Transactions with subsidiaries of the City:

A listing of the various entities under the control of the City is set out on the City's website.

The Corporation had the following transactions with GMHI and its subsidiary, Envida Community Energy Inc.:

	2016	2015
Revenue:		
Energy sales (at commercial rates)	$ 50	$ 43
Multiple function support services	577	749
Street light maintenance	380	-
Expenses:		
Management services	278	656
Balances:		
Accounts receivable	1,580	1,185
Accounts payable and accrued charges	-	1,685

(Expressed in thousands of dollars)

17. Commitments and contingencies:

From time to time, the Corporation may be involved in various litigation matters arising in the ordinary course of its business. As at the end of 2016, there were no litigation matters facing the Corporation.

General Liability Insurance:

The Corporation is a member of the Municipal Electric Association Reciprocal Insurance Exchange (MEARIE). MEARIE is a pooling of public liability insurance risks of many of the electrical utilities in Ontario. All members of the pool are subjected to assessment for losses experienced by the pool for the years in which they were members on a pro-rata basis based on the total of their respective service revenues. As at December 31, 2015, no assessments have been made.

18. Share capital:

	2016	2015
Authorized:		
Unlimited number of common shares		
Issued:		
1,000 common shares	$ 43,374	$ 43,374

19. Financial instruments and risk management:

Cash and cash equivalents are measured at fair value. The carrying values of receivables, and accounts payable and accrued charges approximate fair value because of the short maturity of these instruments. The carrying value of the customer deposits approximates fair value because the amounts are payable on demand.

The fair value of the $65,000 senior unsecured debenture at December 31, 2016 was $73,612 (2015 - $73,068) and the fair value of the new $30,000 senior unsecured debenture at December 31, 2015 was $30,044. The fair value is calculated based on the present value of future principal and interest cash flows, discounted at the current rate of interest at the reporting date. The interest rate used to calculate fair value at December 31, 2016 was 4.012% (2015 - 4.140%) on the $65,000 debenture and was 4.112% (2015 – 4.190%) on the $30,000 debenture.

The Corporation’s activities provide for a variety of financial risks, particularly credit risk, market risk and liquidity risk.

19. Financial instruments and risk management (continued):

(a) Credit risk:

Financial assets carry credit risk that a counterparty will fail to discharge an obligation which could result in a financial loss. Financial assets held by the Corporation, such as accounts receivable, expose it to credit risk. The Corporation earns its revenue from a broad base of customers located in the City. No single customer accounts for revenue in excess of 10% of total revenue.

The carrying amount of accounts receivable is reduced through the use of an allowance for impairment and the amount of the related impairment loss is recognized in the income statement. Subsequent recoveries of receivables previously provisioned are credited to the income statement. The balance of the allowance for impairment at December 31, 2016 is $160 (2015 - $235). An impairment loss of $59 (2015 - $142) was recognized during the year. The Corporation's credit risk associated with accounts receivable is primarily related to payments from ratepayers. At December 31, 2016, approximately $232 (2015 - $327) was considered 60 days past due. The Corporation has over 55,000 customers, the majority of whom are residential customers. Credit risk is managed through collection of security deposits from customers in accordance with directions provided by the OEB. As at December 31, 2016, the Corporation held security deposits amounting to $4,993 (2015 - $4,653).

(b) Market risk:

Market risks primarily refer to the risk of loss resulting from changes in commodity prices, foreign exchange rates, and interest rates. The Corporation currently does not have any material commodity or foreign exchange risk. The Corporation is exposed to fluctuations in interest rates as the regulated rate of return for the Corporation's distribution business is derived using a complex formulaic approach which is in part based on the forecast for long-term Government of Canada bond yields. This rate of return is approved by the OEB as part of the approval of distribution rates.

The Corporation estimates that a 1% increase in interest rates at December 31, 2016 would have increased interest expense on the long-term debt by $950 (2015 - $950), assuming all other variables remained constant. A 1% decrease in the interest rate would have an equal but opposite effect.

(c) Liquidity risk:

The Corporation monitors its liquidity risk to ensure access to sufficient funds to meet operational and investing requirements. The Corporation's objective is to ensure that sufficient liquidity is on hand to meet obligations as they fall due while minimizing interest exposure.

20. Financial instruments and risk management (continued):

(c) Liquidity risk (continued):

As at December 31, 2016, the Corporation, through its parent company Guelph Municipal Holdings Inc. Centralized Banking Agreement, had access to a $20,000 credit facility. The Corporation monitors cash balances daily to ensure that a sufficient level of liquidity is on hand to meet financial commitments as they come due. As at December 31, 2016, no amounts had been drawn under this $20,000 credit facility (2015 - $20,000).

As part of the $20,000 credit facility, The Corporation has a bilateral facility for $5,000 (the "LC" facility) for the purpose of issuing letters of credit mainly to support the prudential requirements of the IESO, of which $4,000 has been drawn and posted with the IESO (2015 - $4,000).

The majority of accounts payable, as reported on the balance sheet, are due within 30 days.

(d) Capital disclosures:

The main objectives of the Corporation, when managing capital, are to ensure ongoing access to funding to maintain and improve the electricity distribution system, compliance with covenants related to its credit facilities, prudent management of its capital structure with regard for recoveries of financing charges permitted by the OEB on its regulated electricity distribution business, and to deliver the appropriate financial returns.

The Corporation's definition of capital includes shareholder's equity and long-term debt. As at December 31, 2016, shareholder's equity amounted to $68,732 (2015 - $64,683) and long-term debt amounted to $94,283 (2015 - $94,245).

21. Guarantees:

GHESI has a Connection and Cost Recovery Agreement with Hydro One Networks Inc. (Networks) for the supply of two additional breaker positions at the Campbell transformer station (cost $599), and the installation of a new metal clad switchgear to the two existing idle windings at Cedar TS (transformer station) with eight new feeder positions (cost $5,582). The costs of the connections are debts owed to Networks that will be forgiven provided that GHESI meets or exceeds the specific load requirement and the incremental transformation connection revenue received by Networks. GHESI expects to meet the conditions of the guarantee and does not anticipate any additional payments to Networks.

GHESI has another Connection and Cost Recovery Agreement with Networks for the line connection associated with the Arlen municipal transformer station. The $1,688 cost of the connection is a debt owed to Networks that will be forgiven provided that GHESI meets or exceeds the specific load requirement and the incremental transformer connection revenue received by Networks. GHESI expects to meet the conditions of the guarantee and does not anticipate an additional payment to Networks.

ATTACHMENT 13
GUELPH HYDRO 2015 AUDITED FINANCIAL STATEMENTS

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Financial Statements of

GUELPH HYDRO ELECTRIC SYSTEMS INC.

Year ended December 31, 2015
(Expressed in thousands of dollars)

KPMG LLP
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2nd Floor
Waterloo ON N2J 5A3

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INDEPENDENT AUDITORS' REPORT

To the shareholder of Guelph Hydro Electric Systems Inc.

We have audited the accompanying financial statements of Guelph Hydro Electric Systems Inc., which comprise the balance sheet as at December 31, 2015 and the statements of comprehensive income, changes in equity and cash flows for the year ended, and notes, comprising a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with International Financial Reporting Standards, and for such internal control as management determines is necessary to enable the preparation of 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 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 financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the 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 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 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 financial statements present fairly, in all material respects, the financial position of Guelph Hydro Electric Systems Inc. as at December 31, 2015, and its results of operations and its cash flows for the year ended in accordance with International Financial Reporting Standards.

KPMG LLP

Chartered Professional Accountants, Licensed Public Accountants

April 18, 2016
Waterloo, Canada

GUELPH HYDRO ELECTRIC SYSTEMS INC.

Balance Sheets

December 31, 2015, with comparative information for 2014
(Expressed in thousands of dollars)

	2015	2014
Assets		
Current assets:		
Cash	$ 32,380	$ -
Accounts receivable (note 4)	21,508	17,887
Unbilled revenue	15,284	10,889
Income taxes recoverable	-	1,706
Inventory (note 5)	2,181	1,832
Other current assets	558	552
Total current assets	71,911	32,866
Property, plant and equipment (note 6)	150,634	141,277
Intangible assets (note 7)	807	388
Deferred income taxes (note 8)	2,364	2,758
Total non-current assets	153,805	144,423
Total assets	225,716	$ 177,289

GUELPH HYDRO ELECTRIC SYSTEMS INC.

Balance Sheets

December 31, 2015, with comparative information for 2014
(Expressed in thousands of dollars)

	2015	2014

Liabilities and Shareholder's Equity

	2015	2014
Current liabilities:		
Bank indebtedness	$ -	$ 1,090
Accounts payable and accrued liabilities	23,425	22,556
Income taxes payable	4,336	-
Deferred credits - budget billing	858	1,142
Customer deposits - current portion (note 9)	2,651	5,577
Due to related parties	500	711
Total current liabilities	31,770	31,076
Senior unsecured debentures (note 12)	94,245	64,600
Employee future benefits (note 11)	10,474	10,039
Customer deposits - long-term portion (note 9)	4,506	2,874
Deferred revenue	20,038	15,460
Total non-current liabilities	129,263	92,973
Total liabilities	161,033	124,049
Shareholder's equity:		
Share capital (note 18)	43,374	43,374
Other comprehensive income (loss)	(933)	(933)
Retained earnings	22,242	10,799
	64,683	53,240
Commitments and contingencies (note 17)		
Guarantees (note 20)		
	$ 225,716	$ 177,289

The accompanying notes are an integral part of these consolidated financial statements.

On behalf of the Board:

____________________ Director

____________________ Director

GUELPH HYDRO ELECTRIC SYSTEMS INC.

Statements of Comprehensive Income

Year ended December 31, 2015, with comparative information for 2014
(Expressed in thousands of dollars)

	2015	2014
Electricity sales	$ 242,665	$ 212,562
Cost of electricity sold	201,196	190,844
	41,469	21,718
Other operating revenue (note 13)	3,760	4,718
Net operating revenue	45,229	26,436
Expenses:		
Operations and maintenance	12,118	11,861
General and administrative	10,186	9,373
	22,304	21,234
Earnings before the undernoted	22,925	5,202
Financial and other expenses (income):		
Interest on notes payable, less amounts capitalized	3,643	3,323
Interest income	(121)	(19)
Other	80	92
	3,602	3,396
Earnings from operations before income taxes	19,323	1,806
Income taxes (note 8):		
Provision for payments in lieu of corporate taxes	4,485	(403)
Deferred income taxes	394	767
	4,879	364
Net earnings from operations for the year	14,444	1,442
Other comprehensive income (loss):		
Actuarial losses on employee future benefit plan	-	(774)
Total comprehensive income for the year	$ 14,444	$ 668

The accompanying notes are an integral part of these financial statements.

GUELPH HYDRO ELECTRIC SYSTEMS INC.

Statements of Changes in Equity
(In thousands of Canadian dollars)

Year ended December 31, 2015, with comparative information for 2014

	Share capital	Other Comprehensive Income (loss)	Retained earnings	Total
Balance at December 31, 2013	43,374	(159)	12,355	55,570
Dividends			(3,000)	(3,000)
Total comprehensive income for the year		(774)	1,442	668
Balance at December 31, 2014	43,374	(933)	10,798	53,239
Dividends			(3,000)	(3,000)
Total comprehensive income for the year			14,444	14,444
Balance, December 31, 2015	$ 43,374	$ (933)	$ 22,242	$ 64,683

The accompanying notes are an integral part of these financial statements.

GUELPH HYDRO ELECTRIC SYSTEMS INC.

Statements of Cash Flows

Year ended December 31, 2015, with comparative information for 2014
(Expressed in thousands of dollars)

		2015		2014
Cash flows from operating activities:				
Total Comprehensive income for the year		14,444	$	668
Adjustments for:				
Income tax expense		4,879		85
Depreciation and amortization		6,480		6,041
Amortization of deferred revenue		(562)		(426)
Interest income		(96)		(19)
Interest expense		3,723		3,415
Loss on disposal of property, plant and equipment		(31)		22
		28,837		9,786
Change in:				
Receivables		(3,620)		1,614
Unbilled revenue		(4,395)		(906)
Inventory		(349)		(328)
Other current assets		(6)		2
Accounts payable and accrued liabilities		538		1,395
Deferred credits - budget billing		(284)		83
Employee future benefits		434		1,490
		(7,682)		3,350
Income taxes refunded		1,556		165
Net cash from operating activities		22,711		13,301
Cash flows from investing activities:				
Purchase of property, plant and equipment		(15,517)		(12,924)
Purchase of intangible assets		(602)		(167)
Proceeds from disposal of property, plant and equipment		42		90
		(16,077)		(13,001)
Cash flows from financing activities:				
Issuance of long term debentures		29,607		-
Contributions in aid of construction		5,140		2,372
Net change in customer deposits		(1,294)		2,135
Dividends paid		(3,000)		(3,000)
Interest received		96		19
Interest paid		(3,502)		(3,513)
Change in amounts due to related parties		(211)		(23)
		26,836		(2,010)
Increase (decrease) in cash		33,470		(1,710)
Cash / (bank indebtedness), beginning of year		(1,090)		620
Cash / (bank indebtedness), end of year	$	32,380	$	(1,090)

The accompanying notes are an integral part of these financial statements.

1. Reporting entity:

Guelph Hydro Electric Systems Inc. (the “Corporation” or “GHESI”) became a wholly-owned subsidiary of Guelph Municipal Holdings Inc. (“GMHI”) on September 6, 2014 when GMHI amalgamated with Guelph Hydro Inc. (“GHI”). GMHI is a wholly-owned subsidiary of the City of Guelph. GHESI was incorporated on October 31, 2000 under the laws of the Province of Ontario, Canada. The address of the Corporation’s registered office is 395 Southgate Drive, Guelph, Ontario.

The principal activity of the Corporation is to distribute electricity to the residents and businesses in the City of Guelph and the Village of Rockwood, under a license issued by the Ontario Energy Board (“OEB”). The Corporation is regulated by the OEB and adjustments to the Corporation’s distribution rates require OEB approval.

2. Basis of presentation:

(a) Statement of compliance:

The Corporation's financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as adopted by the International Accounting Standards Board ("IASB") and interpretations as issued by the International Financial Reporting Interpretations Committee ("IFRIC") of the IASB.

(b) Approval of the financial statements:

The financial statements were approved by the Board of Directors on April 18, 2016.

(c) Basis of measurement:

The financial statements have been prepared on the historical cost basis except for the following:

(i) Where held, financial instruments at fair value through profit or loss, including those held for trading, are measured at fair value.

(ii) Contributed assets are initially measured at fair value.

The methods used to measure fair values are discussed further in note 3 (c) and note 20.

(d) Functional and presentation currency:

These financial statements are presented in Canadian dollars, which is the Corporation's functional currency. All financial information presented in Canadian dollars has been rounded to the nearest thousand.

2. Basis of presentation (continued):

(e) Use of estimates and judgments:

The preparation of financial statements in conformity with IFRS requires management to make judgments, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses and disclosure of contingent assets and liabilities. Actual results may differ from those estimates.

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the year in which the estimates are revised and in any future periods affected.

In particular, information about significant areas of estimation uncertainty and critical judgments in applying accounting policies that have the most significant effect on the amounts recognized in these financial statements is included in the following notes:

(i) Note 4 and note 20(a) - Receivables: allowance for impairment.
(ii) Note 6 - Property, plant and equipment: useful lives and the identification of significant components of property, plant and equipment.
(iii) Note 11 - Employee future benefits: measurement of the defined benefit obligation.
(iv) Note 19 - Financial instruments and risk management: valuation of long-term debt.

f) Rate regulation:

Effect of rate-setting regulations on the Corporation's activities and on these financial statements:

The Corporation is regulated by the OEB, under the authority granted by the *Ontario Energy Board Act (1988)*. Among other things, the OEB has the power and responsibility to approve or set rates for the transmission and distribution of electricity, providing continued rate protection for rural and remote electricity consumers, and ensuring that distribution companies fulfill obligations to connect and service customers. In its capacity to approve or set rates, the OEB has the authority to specify regulatory accounting treatments that may differ from IFRS for enterprises operating in a non-rate regulated environment.

On July 24, 2012, GHESI filed its 2014 electricity distribution rates application using the OEB’s 3rd Generation Incentive Regulation Mechanism (“IRM”) as the basis for its application. The OEB rendered its Decision on December 6, 2012, which approved a distribution rate increase of 1.08 per cent for all customers.

On August 16, 2013, GHESI filed its 2014 electricity distribution rates application using the OEB’s 4th Generation IRM as the basis for its application. The OEB rendered its Decision on December 5, 2014 which approved a distribution rate increase of 1.4 per cent for all customers.

2. Basis of presentation (continued):

f) Rate Regulation (continued):

On August 13, 2014, GHESI filed its 2015 electricity distribution rates application using the OEB's 4th Generation IRM as the basis for its application. The OEB rendered its Decision on December 4, 2014 which approved a distribution rate increase of 1.3 per cent for all customers.

In addition to the distribution rate increase, the OEB approved GHESI's recovery of deferral and variance account balances in the amount of $6.9 million to be recovered over a one-year period. These recoveries relate to past difference between the costs charged by the IESO and Hydro One (including whole market, transmission connection and network, commodity, global adjustment, and low voltage charges) and OEB-approved non-distribution charges billed to GHESI's customers.

On April 24, 2015, GHESI filed a cost of service rate application for its 2016 electricity distribution rates application. The OEB rendered its Decision on November 26, 2015 which approved a distribution rate increase of 4.86 per cent for all customers.

The continuing restructuring of Ontario's electricity industry and other regulatory developments, including current and possible future consultation between the OEB and interested stakeholders, could affect the distribution rates that the Corporation may charge and the costs that the Corporation may recover, including the balance of its regulatory assets.

3. Significant accounting policies:

The accounting policies set out below have been applied consistently in all years presented in these financial statements.

(a) Cash and cash equivalents:

Cash equivalents include short-term investments with maturities of three months or less when purchased.

(b) Revenue recognition:

Revenue for the Corporation is recognized as electricity is delivered to customers and is recorded on the basis of regular meter readings and estimated customer usage since the last meter reading date to the end of the year. The related cost of power is recorded on the basis of power used.

The Corporation is licensed by the OEB to distribute electricity. As a licensed distributor, the Corporation is responsible for billing customers for electricity generated by third parties and the related costs of providing electricity service, such as transmission services and other services provided by third parties. The Corporation is required, pursuant to regulation, to remit such amounts to these third parties, irrespective of whether the Corporation ultimately collects these

3. Significant accounting policies (continued):

b) Revenue recognition (continued):

amounts from customers. The Corporation has determined that it is acting as a principal for the electricity distribution and, therefore, has presented electricity revenue on a gross basis.

Customer billings for debt retirement charges are recorded on a net basis as the Corporation is acting as an agent for this revenue stream. The Corporation may file to recover uncollected debt retirement charges from Ontario Electricity Financial Corporation ("OEFC") once each year.

Deferred revenue relating to contributions in aid of construction is amortized to income on a straight-line basis over the terms of the agreement with the customer or the economic useful life of the acquired or contributed asset, which represents the period of ongoing service to the customer.

All other revenues are recorded on a gross basis and are recognized when services are rendered.

(c) Inventory:

Inventory is valued at the lower of cost and net realizable value, with cost being determined on an average cost basis, and items considered major spare parts are recorded as capital assets.

(d) Property, plant and equipment:

Items of property, plant and equipment are measured at cost or deemed cost established on the transition date, or, where the item is transferred from customers, its fair value, less accumulated depreciation and accumulated impairment losses.

Cost includes expenditures that are directly attributable to the acquisition of the asset. The cost of self-constructed assets includes the cost of materials and direct labour, and any other costs directly attributable to bringing the asset to a working condition for its intended use.

Borrowing costs on qualifying assets are capitalized as part of the cost of the asset and are based on the Corporation's average cost of borrowing.

When parts of an item of property, plant and equipment have different useful lives, they are accounted for as separate items (major components) of property, plant and equipment.

The cost of replacing a part of an item of property, plant and equipment is recognized in the net book value of the item if it is probable that the future economic benefits embodied within the part will flow to the Corporation and its cost can be measured reliably. In this event, the replaced part of property, plant and equipment is written off, and the related gain or loss is included in profit or loss. The costs of the day-to-day servicing of property, plant and equipment are recognized in profit or loss as incurred.

(Expressed in thousands of dollars)

3. Significant accounting policies (continued):

d) Property, plant and equipment (continued):

Depreciation is recognized in profit or loss on a straight-line basis over the estimated useful life of each part or component of an item of property, plant and equipment. Land is not depreciated. Construction-in-progress assets are not amortized until the project is complete and in service.

The estimated useful lives are as follows:

Buildings and fixtures	15 - 50 years
Distribution lines	40 – 70 years
Distribution transformers	35 – 55 years
Distribution meters	30 years
Smart meters	15 years
General office equipment	5 - 10 years
Computer equipment	5 years
Major tools	5 - 15 years
Data acquisition system	5 years
Trucks and rolling stock	5 - 10 years
Other capital assets	10 - 25 years

Depreciation methods, useful lives, and residual values are reviewed at each reporting date.

(e) Intangible assets:

(i) Computer software:

Computer software that is acquired or developed by the Corporation, including software that is not integral to the functionality of equipment purchased which has finite useful lives, is measured at cost less accumulated amortization and accumulated impairment losses.

(ii) Land rights:

Payments to obtain rights to access land ("land rights") are classified as intangible assets. These include payments made for easements, right of access and right of use over land for which the Corporation does not hold title. Land rights are measured at cost less accumulated amortization and accumulated impairment losses.

(iii) Amortization:

Amortization is recognized in profit or loss on a straight-line basis over the estimated useful lives of intangible assets, other than goodwill, from the date that they are available for use.

3. Significant accounting policies (continued):

(e) Intangible assets (continued):

(iii) Amortization (continued):

The estimated useful lives for the current and comparative years are:

Computer software	5 years

Amortization methods and useful lives of all intangible assets are reviewed at each reporting date.

(f) Impairment:

(i) Financial assets:

A financial asset is assessed at each reporting date to determine whether there is any objective evidence that it is impaired. A financial asset is considered to be impaired if objective evidence indicates that one or more events have had a negative effect on the estimated future cash flows of that asset.

An impairment loss in respect of a financial asset measured at amortized cost is calculated as the difference between its current carrying amount (using prevailing interest rates), and the present value of the estimated future cash flows discounted at the original effective interest rate. Interest on the impaired assets continues to be recognized through the unwinding of the discount.

All impairment losses are recognized in profit or loss. An impairment loss is reversed if the reversal can be related objectively to an event occurring after the impairment loss was recognized. For financial assets measured at amortized cost the reversal is recognized in profit or loss.

(ii) Non-financial assets:

The carrying amounts of the Corporation's non-financial assets, other than inventories and deferred tax assets are reviewed at each reporting date to determine whether there is any indication of impairment. If any such indication exists, then the asset's recoverable amount is estimated.

For the purpose of impairment testing, assets are grouped together into the smallest group of assets that generates cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets (the "cash-generating unit"). The Corporation has determined that it is a single cash-generating unit. The recoverable amount of an asset or cash-generating unit is the greater of its value in use and its fair

3. Significant accounting policies (continued):

f) Impairment (continued):

ii) Non-financial assets (continued):

value less costs to sell. In assessing value in use, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset.

An impairment loss is recognized if the carrying amount of an asset or its cash-generating unit exceeds its estimated recoverable amount. Impairment losses are recognized in profit or loss.

For assets other than goodwill, impairment recognized in prior periods is assessed at each reporting date for any indications that the loss has decreased or no longer exists. An impairment loss is reversed if there has been a change in the estimates used to determine the recoverable amount. An impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depreciation or amortization, if no impairment loss had been recognized.

(g) Provisions:

A provision is recognized if, as a result of a past event, the Corporation has a present legal or constructive obligation that can be estimated reliably, and it is probable that an outflow of economic benefits will be required to settle the obligation. Provisions are determined by discounting the expected future cash flows at a pre-tax rate that reflects current market assessments of the time value of money and the risks specific to the liability.

Decommissioning or dismantling:

When there is a legal or constructive obligation to remove and dispose of property, plant and equipment at the end of their useful life, a provision is recorded to cover such future removal and disposal costs.

(h) Employee future benefits:

(i) Pension plan:

The Corporation provides a pension plan for all its full-time employees through Ontario Municipal Employees Retirement System (“OMERS”). OMERS is a multi-employer pension plan which operates as the Ontario Municipal Employees Retirement Fund (“the Fund”), and provides pensions for employees of Ontario municipalities, local boards and public utilities. The Fund is a contributory defined benefit pension plan, which is financed by equal contributions from participating employers and employees, and by the investment

3. Significant accounting policies (continued):

(h) Employee future benefits (continued):

(i) Pension plan (continued):

earnings of the Fund. To the extent that the Fund finds itself in an under-funded position, additional contribution rates may be assessed to participating employers and members. In this case, GHESI and its employees could face the prospect of higher contributions until the funded status of the Fund is restored. GHESI is only likely to recover additional contribution amounts in distribution rates if increased contribution rates are factored into GHESI's rebasing rates applications before the OEB.

(ii) Post-employment benefits, other than pension:

The Corporation provides some of its retired employees with life insurance and medical benefits beyond those provided by government sponsored plans.

The cost of these benefits is expensed as earned by employees through employment service. The accrued benefit obligations and the current service costs are actuarially determined by applying the projected unit credit method and reflect management's best estimate of certain underlying assumptions. Any actuarial gains (losses) will require a re-measurement of the net defined benefit liability or asset and will be recognized as other comprehensive income or loss in the year that it is known.

(i) Deferred revenue and assets transferred from customers:

Certain customers and developers are required to contribute towards the capital cost of construction in order to provide ongoing service. Cash contributions are initially recorded as current liabilities. Once the distribution system asset is completed or modified as outlined in the terms of the contract, the contribution amount is transferred to contributions in aid of construction.

When an asset is received as a capital contribution, the asset is initially recognized at its fair value, with the corresponding amount recognized as contributions in aid of construction.

The contributions in aid of construction account, which represents the Corporation's obligation to continue to provide the customers access to the supply of electricity, is reported as deferred revenue, and is amortized to income on a straight-line basis over the terms of the agreement with the customer or the economic useful life of the acquired or contributed asset, which represents the period of ongoing service to the customer.

3. Significant accounting policies (continued):

(j) Leased assets:

Leases in terms of which the Corporation assumes substantially all the risks and rewards of ownership are classified as finance leases. Upon initial recognition, the leased asset is measured at an amount equal to the lower of its fair value and the present value of the minimum lease payments. Subsequent to initial recognition, the asset is accounted for in accordance with the accounting policy applicable to that asset.

Other leases are operating leases and the leased assets are not recognized on the Corporation's balance sheet. Payments made under operating leases are recognized in profit or loss on a straight-line basis over the term of the lease.

(k) Finance income and finance costs:

Finance income is recognized as it accrues in profit or loss, using the effective interest method. Finance income comprises interest earned on cash and cash equivalents and on regulatory assets.

Finance costs comprise interest expense on borrowings, finance lease obligations, regulatory liabilities and unwinding of the discount on provisions and impairment losses on financial assets.

(l) Income taxes:

The income tax expense comprises current and deferred tax. Income tax expense is recognized in profit or loss except to the extent that it relates to items recognized directly in equity, in which case, it is recognized in equity.

Under the *Electricity Act, 1998*, the Corporation makes payments in lieu of corporate taxes to the OEFC. These payments are calculated in accordance with the rules for computing taxable income and taxable capital and other relevant amounts contained in the *Income Tax Act (Canada) and the Corporations Tax Act (Ontario)* as modified by the *Electricity Act, 1998*, and related regulations. Prior to October 1, 2001, the Corporation was not subject to income or capital taxes. Payments in lieu of taxes are referred to as income taxes.

Current tax is the tax payable on the taxable income for the year, using tax rates enacted or substantively enacted at the reporting date, and any adjustment to tax payable in respect of previous years.

Deferred tax is recognized using the balance sheet method. Under this method, deferred income taxes reflect the net tax effects of temporary differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes, as well as for tax losses available to be carried forward to future years that are likely to be realized. Deferred tax assets

(Expressed in thousands of dollars)

3. Significant accounting policies (continued):

(l) Income taxes (continued):

and liabilities are measured using enacted or substantively enacted tax rates, at the reporting date, that are expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the year that includes the date of enactment or substantive enactment.

4. Accounts receivable:

	2015	2014
Revenue	$ 18,981	$ 15,603
Regulatory	867	1,047
Due from the City of Guelph	1,894	1,612
	21,742	18,262
Less allowance for doubtful accounts	(235)	(375)
	$ 21,507	$ 17,887

5. Inventory:

The amount of inventories consumed by the Corporation and recognized as an expense during 2015 was $243 (2014 - $211).

6. Property, plant and equipment:

(a) Cost or deemed cost:

	Land and buildings	Distribution equipment	Other fixed assets	Construction -in- Progress	Total
Balance at January 1, 2014	$ 20,474	$ 122,624	$ 7,739	$ 2,981	$ 153,818
Additions	484	5,403	2,487	4,675	13,049
Transfers	-	2,981	-	(2,981)	-
Disposals/retirements	-	-	(132)	-	(132)
Balance at December 31, 2014	$ 20,958	$ 131,008	$ 10,094	$ 4,675	$ 166,735

(Expressed in thousands of dollars)

6. Property, plant and equipment (continued):

	Land and buildings	Distribution equipment	Other fixed assets	Construction -in- Progress	Total
Balance at January 1, 2015	$ 20,958	$ 131,008	$ 10,094	$ 4,675	$ 166,735
Additions	75	6,848	1,380	7,362	15,665
Transfers	-	4,675	-	(4,675)	-
Disposals/retirements	-	-	(112)	-	(112)
Balance at December 31, 2015	$ 21,033	$ 142,531	$ 11,362	$ 7,362	$ 182,288

(b) Accumulated depreciation:

	Land and buildings	Distribution equipment	Other fixed assets	Construction -in- Progress	Total
Balance at January 1, 2014	$ 1,985	$ 13,897	$ 3,661	$ -	$ 19,543
Depreciation charge for the year	700	3,616	1,619	-	5,935
Disposals/retirements	-	-	(20)	-	(20)
Balance at December 31, 2014	$ 2,685	$ 17,513	$ 5,260	$ -	$ 25,458

	Land and buildings	Distribution equipment	Other fixed assets	Construction -in- Progress	Total
Balance at January 1, 2015	$ 2,685	$ 17,513	$ 5,260	$ -	$ 25,458
Depreciation charge for the year	712	4,402	1,183	-	6,297
Disposals/retirements	-	-	(101)	-	(101)
Balance at December 31, 2015	$ 3,397	$ 21,915	$ 6,342	$ -	$ 31,654

(c) Carrying amounts:

	Land and buildings	Distribution equipment	Other fixed assets	Construction -in- Progress	Total
December 31, 2014	$ 18,273	$ 113,495	$ 4,834	$ 4,675	$ 141,277
December 31, 2015	17,636	120,616	5,020	7,362	150,634

(d) Borrowing costs:

During the year, borrowing costs of $148 (2014 - $123) were capitalized as part of the cost of property, plant and equipment.

(Expressed in thousands of dollars)

6. Property, plant and equipment (continued):

(e) Allocation of depreciation and amortization:

The depreciation of property, plant and equipment and the amortization of intangible assets have been allocated to profit or loss as follows:

	Cost of electricity sold	Distribution expenses	Administration expenses	Total
December 31, 2014:				
Depreciation of property, plant and equipment	$ -	$ 5,778	$ 157	$ 5,935
Amortization of intangible assets	-	-	106	106
	$ -	$ 5,778	$ 263	$ 6,041
December 31, 2015:				
Depreciation of property, plant and equipment	$ -	$ 6,199	$ 98	$ 6,297
Amortization of intangible assets	-	-	183	183
	$ -	$ 6,199	$ 281	$ 6,480

(Expressed in thousands of dollars)

7. Intangible assets:

(a) Cost or deemed cost:

	Computer software	Land rights	Total
Balance at January 1, 2014	447	-	447
Additions in 2014	167	-	167
Balance at December 31, 2014	614	-	614
Additions in 2015	602	-	602
Balance at December 31, 2015	$ 1,216	$ -	$ 1,216

(b) Accumulated amortization:

	Computer software	Land rights	Total
Balance at January 1, 2014	120	-	120
Amortization charges in 2014	106	-	106
Balance at December 31, 2014	226	-	226
Amortization charges in 2015	183	-	183
Balance at December 31, 2015	$ 409	-	$ 409

(c) Carrying amounts:

	Computer software	Land rights	Total
Balance at December 31, 2014	$ 388	$ -	$ 388
Balance at December 31, 2015	$ 807	$ -	$ 807

(Expressed in thousands of dollars)

8. Income taxes:

The income tax expense varies from amounts which would be computed by applying the Corporation's combined statutory income tax rate as follows:

	2015	2014
Basic rate applied to profit before income tax	$ 5,120	$ 479
Increase (decrease) in income tax resulting from:		
Adjustment to prior year's taxes	(241)	(115)
Income tax expense	$ 4,879	$ 364
Effective rate applied to profit before income taxes	25.3%	20.2%

Significant components of the Corporation's deferred tax balances are as follows:

	2015	2014
Deferred tax assets (liabilities):		
Plant and equipment	$ (6,324)	$ (4,647)
Cumulative eligible capital	602	648
Employee benefits	2,776	2,660
Deferred revenue - contributed capital	5,310	4,097
Net deferred tax asset	$ 2,364	$ 2,758

As at December 31, 2015, a deferred tax asset of $2,364 (2014 - $2,758) has been recorded. The utilization of this tax asset is dependent on future taxable profits in excess of profits arising from the reversal of existing taxable temporary differences.

(Expressed in thousands of dollars)

9. Customer deposits:

Customer deposits represent cash deposits from electricity distribution customers and retailers, as well as construction deposits.

Deposits from electricity distribution customers are refundable to customers who demonstrate an acceptable level of credit risk as determined by the Corporation in accordance with policies set out by the OEB or upon termination of their electricity distribution service.

Construction deposits represent cash prepayments for the estimated cost of capital projects recoverable from customers and developers. Upon completion of the capital project, these deposits are transferred to contributions in aid of construction.

Customer deposits comprise:

	2015	2014
Customer deposits	$ 2,504	$ 4,040
Construction deposits	$ 4,653	4,411
Total customer deposits	$ 7,157	$ 8,451

10. Pension agreement:

GHESI provides a pension plan for its employees through the Ontario Municipal Employees Retirement System (“OMERS”). OMERS is a multi-employer pension plan which operates as the Ontario Municipal Employee Retirement Fund (“the Fund”) and provides pensions for employees of Ontario municipalities, local boards, public utilities, and school boards. The Fund is a contributory defined benefit pension plan, which is financed by equal contributions from participating employers and employees, and by the investment earnings of the Fund. GHESI uses defined contribution plan accounting as it is only liable for contributions to the Plan. GHESI’s contribution for employees’ current service for the year ended December 31, 2015 was $1,096 (2014 - $1,054).

(Expressed in thousands of dollars)

11. Employee future benefits:

Components of employee future benefits recognized are as follows:

	2015	2014
Post-retirement benefits – accrued benefit liability as previously reported	$ 9,814	$ 9,359
Accrued sick leave benefit	660	681
	$ 10,474	$ 10,040

Post-retirement benefits:

The Corporation pays certain medical and life insurance benefits on behalf of some of its retired employees. The Corporation recognizes these post-retirement costs in the period in which employees' services are rendered. The accrued benefit liability at December 31, 2015 of $9,814 was based on an actuarial valuation completed in 2014 and rolled forward using updated membership data and a discount rate of 4.05%. The accrued benefit liability at December 31, 2014 of $9,359 was based on an actuarial valuation completed in 2014, using a discount rate of 4.05%.

Changes in the present value of the defined benefit unfunded obligation and the accrued benefit liability:

	2015	2014
Defined benefit obligation, beginning of year	$ 9,359	$ 7,929
Current service cost	273	211
Interest cost	374	387
Re-measurement of obligation	-	1,053
Benefits paid during the year	(192)	(221)
Accrued benefit liability, end of year	$ 9,814	$ 9,359

(Expressed in thousands of dollars)

11. Employee future benefits (continued):

Components of net benefit expense recognized are as follows:

	2015	2014
Current service cost	$ 273	$ 211
Interest cost	374	387
Net benefit expense recognized	$ 647	$ 598

The full amount of the Corporation's net benefit expense was charged to operations in 2014 and 2015.

The significant actuarial assumptions used in the valuation are as follows (weighted average):

	2015	2014
Accrued benefit obligation:		
Discount rate	4.05%	4.05%
Benefit cost for the year:		
Withdrawal rate	1%	1%
Assumed health care cost trend rates:		
Initial health care cost trend rate	5%	5%

The approximate effect on the accrued benefit obligation of the entire plan and the estimated net benefit expense of the entire plan if the health care trend rate assumption was increased or decreased by 1%, and all other assumptions were held constant, is as follows:

	Defined Benefit Obligation	Periodic Benefit Cost
1% increase in health care trend rate	$ 11,542	$ 787
1% decrease in health care trend rate	8,348	538

(Expressed in thousands of dollars)

11. Employee future benefits (continued):

Historical information

Amounts for the current and previous year, for the entire plan, are as follows:

	2015	2014
Defined benefit obligation	$ 9,814	$ 9,359
Experience adjustments	-	1,053

The main actuarial assumptions utilized for the valuation are as follows:

General inflation - future general inflation levels, as measured by the changes in the Consumer Price Index, were assumed at 2.0% in 2015, and thereafter (2014 - 2.0%).

Discount (interest) rate - the discount rate used to determine the present value of future liabilities and the expense for the year ended December 31, 2015, was 4.05% (2014 - 4.05%).

Salary levels - future general salary and wage levels were assumed to increase at 3.3% (2014 - 3.3%) per annum.

Medical costs - medical costs were assumed to increase 5% for 2014, 5% for 2015, 5% for 2016, and 5% thereafter.

Dental costs - dental costs were assumed to increase 5% for 2014, 5% for 2015, 5% for 2016, and 5% thereafter.

Accrued sick leave benefit:

The Corporation allows regular employees the equivalent of one and one-half days per month sick time credit to be applied in case of illnesses or accidents not covered by Workers' Compensation. A maximum of eighteen days sick time credit is accrued to each employee's credit each year and is reduced by the amount of sick time utilized each year. At the end of the year, the remaining credit, if any, is added to each employee's sick time credit accumulation. Any unused sick time credit is forfeited when employment ceases with the Corporation. As at December 31, 2015, the estimated valued of the expected future payment to be made as a result of the unused sick time credits amounts to $660 (2014 - $681).

(Expressed in thousands of dollars)

12. Long-term debt:

A senior unsecured debentures have a maturity date of December 6, 2030 and have an interest rate of 5.264% per annum. Interest is payable in equal semi-annual installments, in arrears, on June 6 and December 6 each year commencing June 6, 2014 until maturity. The debentures were issued on December 6, 2013. The debentures are represented by a single Global Debenture Certificate registered in the name of CDS & Co. In order to put the debentures in place, the Corporation incurred debt issuance costs in the amount of $500.

A senior unsecured debentures have a maturity date of September 25, 2045 and have an interest rate of 4.121% per annum. Interest is payable in equal semi-annual installments, in arrears, on March 25 and September 25 each year commencing March 25, 2016 until maturity. The debentures were issued on September 25, 2015. The debentures are represented by a single Global Debenture Certificate registered in the name of CDS & Co. In order to put the debentures in place, the Corporation incurred debt issuance costs in the amount of $393.

	2015	2014
Senior unsecured debentures, maturity 2030	$ 65,000	$ 65,000
Senior unsecured debentures, maturity 2045	30,000	-
Less: cost of debt issuance	(755)	(400)
Senior unsecured debentures, net proceeds	$ 94,245	$ 64,600

13. Other income:

Other income comprises:

	2015	2014
Late payment charges	$ 152	$ 116
Pole and other rental income	432	343
Collection and other service charges	410	436
Waterworks revenue	1,244	1,172
Intercompany services	749	734
Customer contributions	562	426
Conservation and Demand Management Performance Bonus	-	1,255
Miscellaneous	211	236
Total other income	$ 3,760	$ 4,718

(Expressed in thousands of dollars)

14. Employee benefits:

		2015		2014
Salaries, wages and benefits	$	8,659	$	8,182
Contributions to multi-employer plan		1,096		1,054
Expenses related to defined benefit plans		647		598
	$	10,402	$	9,834

15. Finance income and expense:

		2015		2014
Interest income on bank deposits	$	(121)	$	(19)
Finance income		(121)		(19)
Interest expense on long-term debt		3,794		3,446
Interest adjustment re: capitalized borrowing costs		(148)		(123)
Interest expense on deposits		32		37
Other		45		55
Net finance costs recognized in profit or loss	$	3,602	$	3,396

(Expressed in thousands of dollars)

16. Related party transactions:

(a) Parent and ultimate controlling party:

The sole shareholder of the Corporation is Guelph Municipal Holdings Inc. ("GMHI"), effective September 8, 2014 when GMHI amalgamated with Guelph Hydro Inc. ("GHI"). GMHI is a wholly-owned subsidiary of the City of Guelph. The City produces financial statements that are available for public use.

(b) Key management personnel:

The key management personnel of the Corporation have been defined as members of its board of directors and executive management team members, and is summarized below.

	2015	2014
Directors' fees	$ 108	$ 115
Salaries and other short-term benefits	1,912	2,024
Post-employment benefits	48	64
	$ 2,068	$ 2,203

(c) Transactions with ultimate parent (the City):

The following summarizes the Corporation's related party transactions, recorded at the exchange amounts and balances with the City for the years ended December 31:

	2015	2014
Revenue:		
Energy sales (at commercial rates)	$ 8,245	$ 8,238
Waterworks revenue	1,243	1,172
Street light maintenance	353	303
Expenses:		
Subcontracting	7	16
Property taxes	327	325
Balances:		
Accounts receivable	1,894	1612
Accounts payable and accrued charges	-	-

(Expressed in thousands of dollars)

16. Related party transactions (continued):

(d) Transactions with subsidiaries of the City:

A listing of the various entities under the control of the City is set out on the City's website.

The Corporation had the following transactions with GMHI and its subsidiary, Envida Community Energy Inc.:

	2015	2014
Revenue:		
Energy sales (at commercial rates)	$ 43	$ 30
Multiple function support services	749	734
Expenses:		
Planning services through Board of Directors	-	93
Management services	656	648
Balances:		
Accounts receivable	1,185	853
Accounts payable and accrued charges	1,685	2,654

17. Commitments and contingencies:

From time to time, the Corporation is involved in various litigation matters arising in the ordinary course of its business. The Corporation has no reason to believe that the disposition of any such current matter could reasonably be expected to have a materially adverse impact on the Corporation’s financial position, results of operations or its ability to carry on any of its business activities.

General Liability Insurance:

The Corporation is a member of the Municipal Electric Association Reciprocal Insurance Exchange (MEARIE). MEARIE is a pooling of public liability insurance risks of many of the electrical utilities in Ontario. All members of the pool are subjected to assessment for losses experienced by the pool for the years in which they were members on a pro-rata basis based on the total of their respective service revenues. As at December 31, 2015, no assessments have been made.

(Expressed in thousands of dollars)

18. Share capital:

		2015		2014
Authorized:				
Unlimited number of common shares				
Issued:				
1,000 common shares	$	43,374	$	43,374

19. Financial instruments and risk management:

Cash and cash equivalents are measured at fair value. The carrying values of receivables, and accounts payable and accrued charges approximate fair value because of the short maturity of these instruments. The carrying value of the customer deposits approximates fair value because the amounts are payable on demand.

The fair value of the $65,000 senior unsecured debenture at December 31, 2015 was $73,068 (2014 - $75,008) and the fair value of the new $30,000 senior unsecured debenture at December 31, 2015 was $29,648. The fair value is calculated based on the present value of future principal and interest cash flows, discounted at the current rate of interest at the reporting date. The interest rate used to calculate fair value at December 31, 2015 was 4.140% (2014 - 3.985%) on the $65,000 debenture and was 4.190% on the $30,000 debenture.

The Corporation's activities provide for a variety of financial risks, particularly credit risk, market risk and liquidity risk.

(a) Credit risk:

Financial assets carry credit risk that a counterparty will fail to discharge an obligation which could result in a financial loss. Financial assets held by the Corporation, such as accounts receivable, expose it to credit risk. The Corporation earns its revenue from a broad base of customers located in the City. No single customer accounts for revenue in excess of 10% of total revenue.

19. Financial instruments and risk management (continued):

The carrying amount of accounts receivable is reduced through the use of an allowance for impairment and the amount of the related impairment loss is recognized in the income statement. Subsequent recoveries of receivables previously provisioned are credited to the income statement. The balance of the allowance for impairment at December 31, 2015 is $235 (2014 - $375). An impairment loss of $142 (2014 - $135) was recognized during the year. The Corporation's credit risk associated with accounts receivable is primarily related to payments from ratepayers. At December 31, 2015, approximately $327 (2014 - $478) was considered 60 days past due. The Corporation has over 53 thousand customers, the majority of whom are residential customers. Credit risk is managed through collection of security deposits from customers in accordance with directions provided by the OEB. As at December 31, 2015, the Corporation held security deposits amounting to $4,653 (2014 - $4,411).

(b) Market risk:

Market risks primarily refer to the risk of loss resulting from changes in commodity prices, foreign exchange rates, and interest rates. The Corporation currently does not have any material commodity or foreign exchange risk. The Corporation is exposed to fluctuations in interest rates as the regulated rate of return for the Corporation's distribution business is derived using a complex formulaic approach which is in part based on the forecast for long-term Government of Canada bond yields. This rate of return is approved by the OEB as part of the approval of distribution rates.

The Corporation estimates that a 1% increase in interest rates at December 31, 2015 would have increased interest expense on the long-term debt by $950 (2014 - $650), assuming all other variables remained constant. A 1% decrease in the interest rate would have an equal but opposite effect.

(c) Liquidity risk:

The Corporation monitors its liquidity risk to ensure access to sufficient funds to meet operational and investing requirements. The Corporation's objective is to ensure that sufficient liquidity is on hand to meet obligations as they fall due while minimizing interest exposure. As at December 31, 2015, the Corporation, through its parent company Guelph Municipal Holdings Inc. Centralized Banking Agreement, had access to a $20,000 credit facility. The Corporation monitors cash balances daily to ensure that a sufficient level of liquidity is on hand to meet financial commitments as they come due. As at December 31, 2015, no amounts had been drawn under this $20,000 credit facility (2014 - $10,000).

As part of the $20,000 credit facility, The Corporation has a bilateral facility for $5,000 (the "LC" facility) for the purpose of issuing letters of credit mainly to support the prudential requirements of the IESO, of which $4,000 has been drawn and posted with the IESO (2014 - $4,000).

The majority of accounts payable, as reported on the balance sheet, are due within 30 days.

20. Financial instruments and risk management (continued):

(d) Capital disclosures:

The main objectives of the Corporation, when managing capital, are to ensure ongoing access to funding to maintain and improve the electricity distribution system, compliance with covenants related to its credit facilities, prudent management of its capital structure with regard for recoveries of financing charges permitted by the OEB on its regulated electricity distribution business, and to deliver the appropriate financial returns.

The Corporation's definition of capital includes shareholder's equity and long-term debt. As at December 31, 2015, shareholder's equity amounted to $64,668 (2014 - $53,240) and long-term debt amounted to $94,245 (2014 - $64,600).

21. Guarantees:

GHESI has a Connection and Cost Recovery Agreement with Hydro One Networks Inc. (Networks) for the supply of two additional breaker positions at the Campbell transformer station (cost $599), and the installation of a new metal clad switchgear to the two existing idle windings at Cedar TS (transformer station) with eight new feeder positions (cost $5,582). The costs of the connections are debts owed to Networks that will be forgiven provided that GHESI meets or exceeds the specific load requirement and the incremental transformation connection revenue received by Networks. GHESI expects to meet the conditions of the guarantee and does not anticipate any additional payments to Networks.

GHESI has another Connection and Cost Recovery Agreement with Networks for the line connection associated with the Arlen municipal transformer station. The $1,688 cost of the connection is a debt owed to Networks that will be forgiven provided that GHESI meets or exceeds the specific load requirement and the incremental transformer connection revenue received by Networks. GHESI expects to meet the conditions of the guarantee and does not anticipate an additional payment to Networks.

ATTACHMENT 14
ALECTRA PRO FORMA FINANCIAL STATEMENTS

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Alectra (post consolidation)
Pro Forma Statement of Comprehensive Income
First Full Year Following Completion of Transaction

($000s)	
Revenue	
Energy Revenue	3,622,332
Distribution revenue	581,073
Other income from operations	33,268
	4,236,674
Expenses	
Cost of Power	3,622,332
Operating Expenses	252,826
Depreciation and amortization	138,123
	4,013,282
Income from operations	223,392
Interest Expense	71,518
Income before payments in lieu of taxes	151,874
Payments in lieu of taxes	22,971
Net Income	128,902

Alectra (post consolidation)
Pro Forma Statement of Financial Position
First Full Year Following Completion of Transaction

($000s)

ASSETS	
Current Assets	
Cash & cash equivalents	92,974
Accounts receivable	515,383
Inventory	19,153
Prepaid expenses	11,480
Amounts due from related parties	8,426
Other current assets	554
	647,970
Non-Current Assets	
Property, plant and equipment	3,254,692
Regulatory assets	19,402
Intangible assets	128,030
Goodwill	753,760
Investments	15,172
Deferred tax asset	19,668
	4,190,724
Total Assets	**4,838,694**
LIABILITIES	
Current Liabilities	
Accounts payable and accrued liabilities	479,989
Due to related parties	53,032
Customer deposits liability	76,598
Other current liabilities	3,122
Current portion of long term borrowings	40,000
Deferred tax liability - current	18,150
	670,891
Long-term Liabilities	
Long-term borrowings	1,933,421
Employee future benefits	85,601
Deferred revenues	335,953
Capital lease	14,817
Regulatory liabilities	3,119
Other non-current liabilities	11,061
	2,383,973
Total Liabilities	**3,054,864**
SHAREHOLDER'S EQUITY	
Share capital	569,779
Contributed surplus	655,518
Retained earnings	558,533
Total Shareholder's Equity	1,783,830
Total Liabilities and Shareholder's Equity	**4,838,694**

Alectra (post consolidation)
Pro Forma Statement of Cash Flows
First Full Year Following Completion of Transaction

($000s)	
Operating activities	
Net income	128,902
Items not affecting cash:	
Depreciation and amortization	138,123
Net change on other assets and liabilities	22,615
	289,641
Investing activities	
Capital expenditures	(264,036)
	(264,036)
Financing activities	
Net change in deferred revenue	2,109
Net change in other non-current liabilities	3,132
Net change in long-term borrowings	(41,412)
Dividends paid	(77,341)
	(113,512)
Increase (decrease) in cash and equivalents	**(87,908)**
Cash and equivalents, beginning of year	180,881
Cash and equivalents, end of year	**92,974**

ATTACHMENT 15
FORM OF AMENDED DISTRIBUTION LICENCE

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Ontario

Electricity Distribution Licence

ED-2016-0360

Alectra Utilities Corporation

Valid Until

December 7, 2036

Original signed by

Kirsten Walli
Board Secretary
Ontario Energy Board
Date of Issuance: December 8, 2016
Effective Date: March 1, 2017
Date of Last Amendment: ■

Ontario Energy Board	Commission de l'énergie de l'Ontario
P.O. Box 2319	C.P. 2319
2300 Yonge Street	2300, rue Yonge
27th Floor	27e étage
Toronto, ON M4P 1E4	Toronto ON M4P 1E4

LIST OF AMENDMENTS

OEB File No. Date of Amendment:
■, 2018

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1 **Definitions**

In this Licence:

"**Accounting Procedures Handbook**" means the handbook, approved by the Board which specifies the accounting records, accounting principles and accounting separation standards to be followed by the Licensee;

"**Act**" means the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, Schedule B;

"**Affiliate Relationships Code for Electricity Distributors and Transmitters**" means the code, approved by the Board which, among other things, establishes the standards and conditions for the interaction between electricity distributors or transmitters and their respective affiliated companies;

"**Conservation and Demand Management**" and "**CDM**" means distribution activities and programs to reduce electricity consumption and peak provincial electricity demand;

"**Conservation and Demand Management Code for Electricity Distributors**" means the code approved by the Board which, among other things, establishes the rules and obligations surrounding Board approved programs to help distributors meet their CDM Targets;

"**distribution services**" means services related to the distribution of electricity and the services the Board has required distributors to carry out, including the sales of electricity to consumers under section 29 of the Act, for which a charge or rate has been established in the Rate Order;

"**Distribution System Code**" means the code approved by the Board which, among other things, establishes the obligations of the distributor with respect to the services and terms of service to be offered to customers and retailers and provides minimum, technical operating standards of distribution systems;

"**Electricity Act**" means the *Electricity Act, 1998*, S.O. 1998, c. 15, Schedule A;

"**IESO**" means the Independent Electricity System Operator;

"**Licensee**" means Alectra Utilities Corporation;

"**Market Rules**" means the rules made under section 32 of the Electricity Act;

"**Net Annual Peak Demand Energy Savings Target**" means the reduction in a distributor's peak electricity demand persisting at the end of the four-year period (i.e. December 31, 2014) that coincides with the provincial peak electricity demand that is associated with the implementation of CDM Programs;

"**Net Cumulative Energy Savings Target**" means the total amount of reduction in electricity consumption associated with the implementation of CDM Programs between 2011-2014;

"**OPA**" means the Ontario Power Authority;

"**Performance Standards**" means the performance targets for the distribution and connection activities of the Licensee as established by the Board in accordance with section 83 of the Act;

"**Provincial Brand**" means any mark or logo that the Province has used or is using, created or to be created by or on behalf of the Province, and which will be identified to the Board by the Ministry as a provincial mark or logo for its conservation programs;

"**Rate Order**" means an Order or Orders of the Board establishing rates the Licensee is permitted to charge;

"**regulation**" means a regulation made under the Act or the Electricity Act;

"**Retail Settlement Code**" means the code approved by the Board which, among other things, establishes a distributor's obligations and responsibilities associated with financial settlement among retailers and consumers and provides for tracking and facilitating consumer transfers among competitive retailers;

"**service area**" with respect to a distributor, means the area in which the distributor is authorized by its licence to distribute electricity;

"**Standard Supply Service Code**" means the code approved by the Board which, among other things, establishes the minimum conditions that a distributor must meet in carrying out its obligations to sell electricity under section 29 of the Electricity Act;

"**wholesaler**" means a person that purchases electricity or ancillary services in the IESO administered markets or directly from a generator or, a person who sells electricity or ancillary services through the IESO-administered markets or directly to another person other than a consumer.

2 Interpretation

2.1 In this Licence, words and phrases shall have the meaning ascribed to them in the Act or the Electricity Act. Words or phrases importing the singular shall include the plural and vice versa. Headings are for convenience only and shall not affect the interpretation of the Licence. Any reference to a document or a provision of a document includes an amendment or supplement to, or a replacement of, that document or that provision of that document. In the computation of time under this Licence, where there is a reference to a number of days between two events, they shall be counted by excluding the day on which the first event happens and including the day on which the second event happens and where the time for doing an act expires on a holiday, the act may be done on the next day that is not a holiday.

3 Authorization

3.1 The Licensee is authorized, under Part V of the Act and subject to the terms and conditions set out in this Licence:

a) to own and operate a distribution system in the service area described in Schedule 1 of this Licence;

b) to retail electricity for the purposes of fulfilling its obligation under section 29 of the Electricity Act in the manner specified in Schedule 2 of this Licence; and

a) to act as a wholesaler for the purposes of fulfilling its obligations under the Retail Settlement Code or under section 29 of the Electricity Act.

4 Obligation to Comply with Legislation, Regulations and Market Rules

4.1 The Licensee shall comply with all applicable provisions of the Act and the Electricity Act and regulations under these Acts, except where the Licensee has been exempted from such compliance by regulation.

4.2 The Licensee shall comply with all applicable Market Rules.

5 Obligation to Comply with Codes

5.1 The Licensee shall at all times comply with the following Codes (collectively the “Codes”) approved by the Board, except where the Licensee has been specifically exempted from such compliance by the Board. Any exemptions granted to the licensee are set out in Schedule 3 of this Licence. The following Codes apply to this Licence:

a) the Affiliate Relationships Code for Electricity Distributors and Transmitters;

b) the Distribution System Code;

c) the Retail Settlement Code; and

d) the Standard Supply Service Code.

5.2 The Licensee shall:

a) make a copy of the Codes available for inspection by members of the public at its head office and regional offices during normal business hours; and

b) provide a copy of the Codes to any person who requests it. The Licensee may impose a fair and reasonable charge for the cost of providing copies.

6 Obligation to Provide Non-discriminatory Access

6.1 The Licensee shall, upon the request of a consumer, generator or retailer, provide such consumer, generator or retailer with access to the Licensee’s distribution system and shall convey electricity on behalf of such consumer, generator or retailer in accordance with the terms of this Licence.

7 Obligation to Connect

7.1 The Licensee shall connect a building to its distribution system if:

a) the building lies along any of the lines of the distributor’s distribution system; and

b) the owner, occupant or other person in charge of the building requests the connection in writing.

7.2 The Licensee shall make an offer to connect a building to its distribution system if:

a) the building is within the Licensee's service area as described in Schedule 1; and

b) the owner, occupant or other person in charge of the building requests the connection in writing.

7.3 The terms of such connection or offer to connect shall be fair and reasonable and made in accordance with the Distribution System Code, and the Licensee's Rate Order as approved by the Board.

7.4 The Licensee shall not refuse to connect or refuse to make an offer to connect unless it is permitted to do so by the Act or a regulation or any Codes to which the Licensee is obligated to comply with as a condition of this Licence.

8 Obligation to Sell Electricity

8.1 The Licensee shall fulfill its obligation under section 29 of the Electricity Act to sell electricity in accordance with the requirements established in the Standard Supply Service Code, the Retail Settlement Code and the Licensee's Rate Order as approved by the Board.

9 Obligation to Maintain System Integrity

9.1 The Licensee shall maintain its distribution system in accordance with the standards established in the Distribution System Code and Market Rules, and have regard to any other recognized industry operating or planning standards adopted by the Board.

10 Market Power Mitigation Rebates

10.1 The Licensee shall comply with the pass through of Ontario Power Generation rebate conditions set out in Appendix A of this Licence.

11 Distribution Rates

11.1 The Licensee shall not charge for connection to the distribution system, the distribution of electricity or the retailing of electricity to meet its obligation under section 29 of the Electricity Act except in accordance with a Rate Order of the Board.

12 Separation of Business Activities

12.1 The Licensee shall keep financial records associated with distributing electricity separate from its financial records associated with transmitting electricity or other activities in accordance with the Accounting Procedures Handbook and as otherwise required by the Board.

13 Expansion of Distribution System

13.1 The Licensee shall not construct, expand or reinforce an electricity distribution system or make an interconnection except in accordance with the Act and Regulations, the Distribution System Code and applicable provisions of the Market Rules.

13.2 In order to ensure and maintain system integrity or reliable and adequate capacity and supply of electricity, the Board may order the Licensee to expand or reinforce its distribution system in accordance with Market Rules and the Distribution System Code, or in such a manner as the Board may determine.

14 Provision of Information to the Board

14.1 The Licensee shall maintain records of and provide, in the manner and form determined by the Board, such information as the Board may require from time to time.

14.2 Without limiting the generality of paragraph 14.1, the Licensee shall notify the Board of any material change in circumstances that adversely affects or is likely to adversely affect the business, operations or assets of the Licensee as soon as practicable, but in any event no more than twenty (20) days past the date upon which such change occurs.

15 Restrictions on Provision of Information

15.1 The Licensee shall not use information regarding a consumer, retailer, wholesaler or generator obtained for one purpose for any other purpose without the written consent of the consumer, retailer, wholesaler or generator.

15.2 The Licensee shall not disclose information regarding a consumer, retailer, wholesaler or generator to any other party without the written consent of the consumer, retailer, wholesaler or generator, except where such information is required to be disclosed:

a) to comply with any legislative or regulatory requirements, including the conditions of this Licence;

b) for billing, settlement or market operations purposes;

c) for law enforcement purposes; or

d) to a debt collection agency for the processing of past due accounts of the consumer, retailer, wholesaler or generator.

15.3 The Licensee may disclose information regarding consumers, retailers, wholesalers or generators where the information has been sufficiently aggregated such that their particular information cannot reasonably be identified.

15.4 The Licensee shall inform consumers, retailers, wholesalers and generators of the conditions under which their information may be released to a third party without their consent.

15.5 If the Licensee discloses information under this section, the Licensee shall ensure that the information provided will not be used for any other purpose except the purpose for which it was disclosed.

16 Customer Complaint and Dispute Resolution

16.1 The Licensee shall:

a) have a process for resolving disputes with customers that deals with disputes in a fair, reasonable and timely manner;

b) publish information which will make its customers aware of and help them to use its dispute resolution process;

c) make a copy of the dispute resolution process available for inspection by members of the public at each of the Licensee's premises during normal business hours;

d) give or send free of charge a copy of the process to any person who reasonably requests it; and

e) subscribe to and refer unresolved complaints to an independent third party complaints resolution service provider selected by the Board. This condition will become effective on a date to be determined by the Board. The Board will provide reasonable notice to the Licensee of the date this condition becomes effective.

17 Term of Licence

17.1 This Licence shall take effect on March 1, 2017 and expire on December 7, 2036. The term of this Licence may be extended by the Board.

18 Fees and Assessments

18.1 The Licensee shall pay all fees charged and amounts assessed by the Board.

19 Communication

19.1 The Licensee shall designate a person that will act as a primary contact with the Board on matters related to this Licence. The Licensee shall notify the Board promptly should the contact details change.

19.2 All official communication relating to this Licence shall be in writing.

19.3 All written communication is to be regarded as having been given by the sender and received by the addressee:

a) when delivered in person to the addressee by hand, by registered mail or by courier;

b) ten (10) business days after the date of posting if the communication is sent by regular mail; and

c) when received by facsimile transmission by the addressee, according to the sender's transmission report.

20 Copies of the Licence

20.1 The Licensee shall:

a) make a copy of this Licence available for inspection by members of the public at its head office and regional offices during normal business hours; and

b) provide a copy of this Licence to any person who requests it. The Licensee may impose a fair and reasonable charge for the cost of providing copies.

21 Conservation and Demand Management

21.1 2011-2014 Conservation and Demand Management Framework

21.1.1 The Licensee shall achieve reductions in electricity consumption and reductions in peak provincial electricity demand through the delivery of CDM programs. The Licensee shall:

21.1.2 The Licensee shall achieve reductions in electricity consumption and reductions in peak provincial electricity demand through the delivery of CDM programs. The Licensee shall:

a) Meet its 2014 Net Annual Peak Demand Savings Target of 45.610 MW, and its 20112014 Net Cumulative Energy Savings Target of 189.540 GWh (collectively the "CDM Targets") for the Hydro One Brampton Networks Inc. Rate Zone as described in Schedule 1, over a four-year period beginning January 1, 2011.

b) Meet its 2014 Net Annual Peak Demand Savings Target of 92,980 MW, and its 20112014 Net Cumulative Energy Savings Target of 147.220 GWh (collectively the "CDM Targets") to the Enersource Hydro Mississauga Inc. Rate Zone, as described in Schedule 1, over a four year period beginning January 1, 2011.

c) Meet its 2014 Net Annual Peak Demand Savings Target of 60.360 MW, and its 20112014 Net Cumulative Energy Savings Target of 281.420 GWh (collectively the "CDM Targets") for the Horizon Utilities Corporation Rate Zone, as described in Schedule 1, over a four-year period beginning January 1, 2011.

d) Meet its 2014 Net Annual Peak Demand Savings Target of 95.570 MW, and its 2011-2014 Net Cumulative Energy Savings Target of 407.340 GWh (collectively the "CDM Targets") for the PowerStream Inc. Rate Zone, over a four-year period beginning January 1, 2011.

e) Meet its 2014 Net Annual Peak Demand Savings Target of 16.710 MW, and its 2011-2014 Net Cumulative Energy Servings Target of 79.530 GWh (collectively, the "CDM Targets") for the Guelph Rate Zone, over a four year period beginning January 1, 2014.

21.1.3 The Licensee shall meet its CDM Targets through:

a) the delivery of Board approved CDM Programs delivered in the Licensee's service area ("Board-Approved CDM Programs");

b) the delivery of CDM Programs that are made available by the OPA to distributors in the Licensee's service area under contract with the OPA ("OPA-Contracted Province-Wide CDM Programs"); or

c) a combination of a) and b).

21.1.4 The Licensee shall make its best efforts to deliver a mix of CDM Programs to all consumer types in the Licensee's service area.

21.1.5 The Licensee shall comply with the rules mandated by the Board's Conservation and Demand Management Code for Electricity Distributors.

21.1.6 The Licensee shall utilize the common Provincial brand, once available, with all Board-Approved CDM Programs, OPA-Contracted Province-Wide Programs, and in conjunction with or co-branded with the Licensee's own brand or marks.

21.2 2015-2020 Conservation and Demand Management Framework

21.2.1 The Licensee shall, between January 1, 2015 and December 31, 2020, make CDM programs, available to customers in its licensed service area and shall, as far as is appropriate and reasonable having regard to the composition of its customer base, do so in relation to each customer segment in its service area ("CDM Requirement").

21.2.2 The CDM programs referred to in item 21.2.1 above shall be designed to achieve reductions in electricity consumption.

21.2.3 The Licensee shall meet its CDM Requirement by:

a) making Province-Wide Distributor CDM Programs, funded by the Ontario Power Authority (the "OPA"), available to customers in its licensed service area;

b) making Local Distributor CDM Programs, funded by the OPA, available to customers in its licensed service area; or

c) a combination of a) and b).

21.2.4 The Licensee shall, as far as possible having regard to any confidentiality or privacy constraints, make the details and results of Local Distributor CDM Programs available to other licensed electricity distributors upon request.

21.2.5 The Licensee shall, as far as possible having regard to any confidentiality or privacy constraints, make the details and results of Local Distributor CDM Programs available to any other person upon request.

21.2.6 The Licensee shall report to the OPA the results of the CDM programs in accordance with the requirements of the licensee's "CDM-related" contract with the OPA.

22 Pole Attachments

22.1 The Licensee shall provide access to its distribution poles to all Canadian carriers, as defined by the Telecommunications Act, and to all cable companies that operate in the Province of Ontario. For each attachment, with the exception of wireless attachments, the Licensee shall charge the rate approved by the Board and included in the Licensee's tariff.

22.2 The Licensee shall:

a) annually report the net revenue, and the calculations used to determine that net revenue, earned from allowing wireless attachments to its poles. Net revenues will be accumulated in a deferral account approved by the Board;

b) credit that net revenue against its revenue requirement subject to Board approval in rate proceedings; and

c) provide access for wireless attachments to its poles on commercial terms normally found in a competitive market.

23 Winter Disconnection, Reconnection and Load Control Devices

23.1 Subject to paragraph 23.4, the Licensee shall not, during a Disconnection Ban Period:

a) disconnect an occupied residential property solely on the grounds of non-payment;

b) issue a disconnection notice in respect of an occupied residential property solely on the grounds of non-payment; or

c) install a load control device in respect of an occupied residential property solely on the grounds of non-payment.

Nothing in this paragraph shall preclude the Licensee from (i) disconnecting an occupied residential property during a Disconnection Ban Period in accordance with all applicable regulatory requirements, including the required disconnection notice, or (ii) installing a load control device in respect of an occupied residential property during a Disconnection Ban Period, in each case if at the unsolicited request of the customer given in writing for that Disconnection Ban Period.

23.2 Subject to paragraph 23.4,

(a) for the 2017/2018 Disconnection Ban Period, if the Licensee had disconnected a residential property on or before November 2, 2017 solely on the grounds of non-payment, the Licensee shall reconnect that property, if an occupied residential property, as soon as possible, and shall do the same in respect of any such property that may be disconnected by Licensee between that date and the commencement of the Disconnection Ban Period. The Licensee shall waive any reconnection charge that might otherwise apply in respect of that reconnection; and

(b) for each subsequent Disconnection Ban Period, the Licensee shall ensure that any

residential property that had been disconnected solely on the grounds of non-payment is, if an occupied residential property, reconnected as at the commencement of the Disconnection Ban Period. The Licensee shall waive any reconnection charge that might otherwise apply in respect of that reconnection.

Nothing in this paragraph shall require the Licensee to reconnect an occupied residential property in respect of a Disconnection Ban Period if the customer gives unsolicited notice to the Licensee

not to do so in writing for that Disconnection Ban Period and has not rescinded that notice.

23.3 Subject to paragraph 23.4,

(a) for the 2017/2018 Disconnection Ban Period, if the Licensee had installed a load control device in respect of an occupied residential property on or before November 2, 2017 either for non-payment or at the customer’s request, the Licensee shall remove that device and restore full service to the property as soon as possible, and shall do the same in respect of any load control device installed in respect of any such property between that date and the commencement of the Disconnection Ban Period. The Licensee shall waive any charge that might otherwise apply in respect of such removal; and

(b) for each subsequent Disconnection Ban Period, the Licensee shall ensure that any load control device installed in respect of an occupied residential property either for non-payment or at the customer’s request is removed and full service is restored to the property as at the commencement of the Disconnection Ban Period. The Licensee shall waive any charge that might otherwise apply in respect of such removal.

Nothing in this paragraph shall (i) require the Licensee to remove a load control device in respect of a Disconnection Ban Period if the customer gives unsolicited notice to the Licensee not to do so in writing for that Disconnection Ban Period and has not rescinded that notice; or (ii) prevent the Licensee from installing or maintaining a load control device if the customer makes an unsolicited request in writing for the Licensee to do so for that Disconnection Ban Period and has not rescinded that request.

23.4 Nothing in paragraphs 23.1 to 23.3 shall:

a) prevent the Licensee from taking such action in respect of an occupied residential property as may be required to comply with any applicable and generally acceptable safety requirements or standards; or

b) require the Licensee to act in a manner contrary to any applicable and generally accepted safety requirements or standards.

23.5 The Licensee shall waive any collection of account charge that could otherwise be charged in relation to an occupied residential property during a Disconnection Ban Period.

23.6 For the purposes of paragraphs 23.1 to 23.5:

“Disconnection Ban Period” means the period commencing at 12:00 am on November 15th in one year and ending at 11:59 pm on April 30th in the following year;

“load control device” has the meaning given to it in the Distribution System Code; and “occupied residential property” means an account with the Licensee:

a) that falls within the residential rate classification as specified in the Licensee’s Rate Order; and

b) that is:

i. inhabited; or

ii. in an uninhabited condition as a result of the property having been disconnected by the Licensee or of a load control device having been installed in respect of the property outside of a Disconnection Ban Period.

23.7 Paragraphs 23.1 to 23.5 apply despite any provision of the Distribution System Code to the contrary.

SCHEDULE 1 DEFINITION OF DISTRIBUTION SERVICE AREA

This Schedule specifies the area in which the Licensee is authorized to distribute and sell electricity in accordance with paragraph 8.1 of this Licence.

The Licensee's service area is comprised of the distribution service areas of the former Enersource Hydro Mississauga Inc. (ED-2003-0017); Horizon Utilities Corporation (ED-2006-0031); Hydro One Brampton Networks Inc. (ED-2003-0038); and PowerStream Inc. (ED-2004-0420) as they existed at the date of the completion of their consolidation, as approved by the OEB in its Decision and Order in OEB File No. EB-2016-0025, and the distribution service area of the former Guelph Hydro Electric Systems Inc. (ED-2002-0565), as it existed at the date of the completion of the consolidation approved by the OEB in its Decision and Order in OEB File No. EB-2018-0014. The service areas of these predecessor distributors are referred to as Rate Zones for the purposes of this Licence and for the purposes of the Rate Orders assigned to LDC Co as part of the OEB's Decision and Order in EB-2016-0025 and the EB-2018-0014.

The Brampton Rate Zone:

1. The City of Brampton as at December 31, 1990 excluding:

   - the property with the municipal address of 7751 Winston Churchill Blvd;
   - lands located 45m south of the center-line of Castlemore Rd and 37.5m west of the centerline of Highway 50;
   - lands located 50m west of the centre-line of Mavis Road and 128m north of the City of Mississauga Boundary; and
   - lands located 70m west of the centre-line of Mavis Road and 75m north of the City of Mississauga Boundary.

2. Lots 1-78 inclusive and Parts 1-8 inclusive on the City of Brampton Draft Plan No. 21T-

99002C. **The Enersource Rate Zone:**

1. The City of Mississauga as of December 31, 1990, excluding:

   - the lands located on Winston Churchill Blvd, between Hwy 401 and Meadowpine Blvd with the civic address number 7575; and

   - the triangular piece of lands located between Dundas Street West to Ninth Line to Highway 403, generally between (250 metres north of) Burnhamthorpe Road to the north and Dundas Street West to the south.

2 The following lands located within the City of Brampton:

   - lands located 50m west of the centre-line of Mavis Road and 128m north of the City of Mississauga Boundary; and

   - lands located 70m west of the centre-line of Mavis Road and 75m north of the City of Mississauga Boundary.

The Horizon Rate Zone:

1. The former Police Village of Ancaster in the former Town of Ancaster as of December 31, 1973, now in the City of Hamilton and described as:

Alectra Utilities Corporation
Electricity Distribution Licence ED-2016-0360

- NW corner of Concession 1, Lot 42 and Old Railway Line
- Directly NNE to middle of Concession I, Lot 46
- North to Dundas boundary, along boundary NE to Hamilton boundary, along Dundas/Hamilton boundary
- SW across Filman Road to include 1245 Filman, travel SW parallel with Hwy 2 to the escarpment
- S along escarpment (include Ancaster heights survey)
- S to W border of Concession II, Lot 49 to Railway Right of Way (behind Mohawk Road)
- SW to Cayuga Drive, W to Railway Right of Way
- West along Right of Way to far west boundary of Concession III, Lot 47
- South between Lot 46 and 47 to include 38 Chancery Drive West
- West, parallel with Golf Links Road to back lot of 23 Cameron Drive in Concession III, Lot 44
- Follow back of Cameron Drive back lot to 35 Cameron, go south parallel to end of 209 Rosemary Drive, East to the back of 206 Rosemary Drive
- North along back lots to 104 Rosemary, East to back lot of 103 Rosemary
- North along back lots of St. Margarets Road to Hwy 2
- Direct line SW, crossing over Fiddlers Green to middle of Concession III, Lot 41 North back lot of Rembrandt Court to Jerseyville Road W
- SW along Jersey ville through back lots of Blair, Terrence Park and Oakhill to back lot lien of 211/220 Colleen Crescent

- SW along Jersey ville through back lots of Blair, Terrence Park and Oakhill to back lot lien of 211/220 Colleen Crescent

- NE to division of back lot along border of Concession III, Lots 41 & 42
- SW along border to lot line of 145 Terrence Park, across Terrence Park to include back lots of 51 and 55
- SE over Terrence Park between houses 94 and 90
- N along the rear lots of Terrence Park and McGregor Crescent
- NE between houses 69 & 65 McGregor, across McGregor between houses 74 and 62

- Continue rear lots East between houses 54 and 50 McGregor
- North in direct line to Sulphur Springs Road
- West 100 metres, directly NW to Concession II, Lot 42 to Old Railway Line

2. The former Town of Dundas as of December 31, 1980, now in the City of Hamilton.

1. The former Police Village of Lynden in the former Town of Ancaster as of December 31, 1973, now in the City of Hamilton.

2. The former Village of Waterdown in the former Township of Flamborough as of December 31, 1980, now in the City of Hamilton.

3. The expansion area as set out in By-law No. 96-17-H in the former Township of Flamborough as of December 31, 1980, now in the City of Hamilton and defined as :

   - East Boundary: Concession 3 East – Centreline of Kerns Road extending north along east boundary of 60' Interprovincial Pipeline easement continuing north along boundary line between Town of Flamborough and City of Burlington.
   - North Boundary: Concession 5 East – Centreline of the 50' wide Sun Canadian Pipeline Company easement – extending across Hwy. No. 6, along boundary line between properties 25.50.200.430.56400 and 25.30.200.430.56800/25.30.200.430.56600.
   - West Boundary: Boundary line between Lots 19 and 20 on Concession 1, Concession 2, Concession 3, and Concession 4 proceeding northerly to north boundary as described above.
   - South Boundary: Flamborough/Burlington/Dundas boundaries where the electrical distribution systems of Ontario Hydro and Burlington Hydro are already separated.
   - Includes to the East: The boundaries of the Town of Lynden as defined in 1. above.

6. The City of Hamilton as of December 31, 2000.

4. The former City of Stoney Creek as of December 31, 2000, now in the City of Hamilton.

5. Plan 62 R-15706, Part of Lot 3, Block 1, Concession 1, former Geographic Township of Binbrook, in the former Township of Glanbrook, now in the City of Hamilton, comprising Part 1 to Part 11 inclusive.

6. Land located “in the former Township of Binbrook, in the former Township of Glanbrook, as of December 31, 1973, now in the City of Hamilton and described as Block 1, Block 2 and Street ‘A’ part of a plan of “The Brooks of Rymal/20 Phase 1", being a subdivision of Part of Lots 1 and 2 - Block 4, Concession 1".

7. The former Township of Binbrook in the former Township of Glanbrook as of December 31, 1973, now in the City of Hamilton and described as Part of Township Lots Six (6) and Seven (7), Block Five (5) in the First Concession of the Geographic Township of Binbrook and known as Summit

Park Phase 1 on Plan 62M. These lands are bounded to the north by Rymal Road east, to the east by Fletcher Road, to the west by Dakota Boulevard and to the south by a Hydro One Networks Inc. high voltage transmission line right of way.

11. The former Township of Binbrook in the former Township of Glanbrook as of December 31, 1973, now in the City of Hamilton and described as Part of Township Lots Six (6) and Seven (7), Block Five (5) in the First Concession of the Geographic Township of Binbrook and known as Summit Park Phase 2, on Plan 62M.

12. The City of St. Catharines as at December 31, 1990.

13. The former Township of Binbrook in the former Township of Glanbrook as of December 31, 1973, now in the City of Hamilton and described as Part of Township Lot Seven (7), Block Five (5) in the First Concession of the Geographic Township of Binbrook and known as Summit Park Phase 3, on Plan 62M.

14. The former Township of Binbrook in the former Township of Glanbrook as of December 31, 1973, now in the City of Hamilton and described as Part of Township Lot Seven (7), Block Five (5) in the First Concession of the Geographic Township of Binbrook and known as Summit Park Phase 4, on Plan 62M.

15. The former Township of Binbrook in the former Township of Glanbrook as of December 31, 1973, now in the City of Hamilton and described as Part of Township Lot Six (6), Block Five (5) in the First Concession of the Geographic Township of Binbrook and known as The Gardens at Summit Park on Plan 62M.

16. The former Township of Binbrook in the former Township of Glanbrook as of December 31, 1973, now in the City of Hamilton and described as Part of Township Lot Five (5), Block Four (4) in the First Concession of the Geographic Township of Binbrook and known as Summit Park Phase Six.

17. Lands located in the former Township of Binbrook in the former Township of Glanbrook as of December 31, 1973, now in the City of Hamilton and described as Part of Township Lot Five (5), Block Five (5) in the First Concession of the Geographic Township of Binbrook, Block 139 and known as The Summit Park Phase 5 on the registered Plan 62M except for the following address (which is excluded):

    - 31 Trinity Church Road in the City of Hamilton.

18. Lands located in the former Township of Binbrook in the former Township of Glanbrook as of December 31, 1973, now in the City of Hamilton and described as Part of Township Lot Two (2), Blocks Three (3), Four (4), Five (5), Nine (9), Ten (10) and Eleven (11).

19. The former Township of Binbrook in the former Township of Glanbrook as of December 31, 1973, now in the city of Hamilton and described as Part of Township Lots Four (4) and Five (5), Block Four (4) of the First Concession of the Geographic Township of Binbrook, City of Hamilton and known as Summit Park Phase Seven.

20. The following properties on Rymal Road East in the City of Hamilton – 2062, 2064, 2066, 2068, 2070, 2070B, 2080.

21. Lands described by Plans 62M-1154, Blocks 1 and 2, 62R-18589 Parts 8 and 9, and 62R-18707 Parts 1, 2, 3 and 4.

22. Part of Lots Four (4) and Five (5), Block Four (4) of Concession 1 of the Geographic Township of Binbrook, City of Hamilton and known as Summit Park Phase Eight.

8. 2100 Rymal Road East, Hannon, Ontario in the City of Hamilton and designated as Lot 3, Block 3, Concession 1, Binbrook, Ontario

The PowerStream Rate Zone:

1. The Town of Markham as of January 1, 1979.

2. The service area is co-terminus with the City of Vaughan municipal boundary pursuant to the Regional Municipality of York Act, R.S.O. 1990, R.18, with the exception of an area two lots north of King-Vaughan Rd. abutting 7th Concession of the Town of King, as detailed in the parcel lot descriptions noted in Appendix B.

3. The Town of Richmond Hill as of January 1, 1979, with the exception of the boundary along Bathurst St, two lots north of King-Vaughan Rd. to Bloomington Rd., noted in Appendix B.

4. The Town of Aurora as of January 1, 1979, with the exception of the boundary along Bathurst St, seven lots north of Bloomington Rd. to two lots north of St. John's Sideroad, noted in Appendix B.

5. Lands located 45m south of the center-line of Castlemore Rd and 37.5m west of the center-line of Highway 50 in the City of Brampton.

6. City of Barrie Service Area:

   Within the municipal boundary of the City of Barrie as detailed firstly in Schedules A and B to the Barrie-Innisfil Annexation Act, 1981, secondly in the Schedule to the Barrie-Vespra Annexation Act, 1984 and thirdly as shown on Reference Map Document Number 4884 included on page 4 of “Schedule 1 Definition of Distribution Service Area” dated March 10, 2004, filed as supplementary material with the Board.

7. Community of Bradford West Gwillimbury Service Area:

   Within the Community of Bradford-West Gwillimbury as detailed firstly as the "Expansion Service Area" in Schedule 'B' and 'C' to the Corporation of the Town of Bradford-West Gwillimbury By-law 95-048 dated September 11, 1995, and shown in attached Reference Map, Document Number 4993, and further described in attached Map 1. The boundary is defined by Crooked Creek between Middletown Road (10th Sideroad) to the West and the concession line between lot 12 and lot 13 to the East, south of Holland Street West and north of 6th Line in the Town of Bradford-West Gwillimbury.

8. Community of Thornton Service Area:

   Within the Community of Thornton as detailed firstly in the Thornton Settlement Area in accordance with Schedule “A” of the Official Plan of the Township of Essa as approved by the County of Simcoe, April 22, 2003 and secondly as shown on Reference Map Document Number 5009 included on page 6 of “Schedule 1 Definition of Distribution Service Area” dated March 10, 2004, filed as supplementary material with the Board, excluding the following municipal addresses:

- #'s 6, 8, 10, 12, 19, 21, 23, 25, 27, 28, 29, 30, 31, 32, 33, 34 and 35 Earl's Court;
- # 4520 Robert Street (or County Road 21 Pt.16 Concession11);
- all residential lots fronting onto Jamieson Court from Thornton Ave to the cul-de-sac dead end;
- #'s 218, 219, 220, 221, 222, 223, 224, 225, 226, 227, 228, 229, 230, 231, and 232 Thornton Avenue;
- all residential lots fronting onto Lennox Court from Spence Avenue to the cul-de-sac dead end;
- all residential lots fronting onto Spencer Avenue except # 221 Spencer Avenue from Thornton Avenue to North Ridge Road;
- all residential lots fronting onto North Ridge Road except #'s 204 and 205 from Camilla Crescent to Spencer Avenue.

9. Community of Alliston Service Area:

Within the Community of Alliston as detailed firstly as the "Alliston Urban Area Expansion" in Schedule 'A' to the Corporation of the Town of the Amalgamated Municipalities of Alliston, Beeton, Tecumseth & Tottenham By-law 91-169 dated October 15, 1991 (entiltled "H.E.C. Service Area Expansion By-Law") and secondly as shown on Reference Map Document Number 5720 included on page 7 of "Schedule 1 Definition of Distribution Service Area" dated March 10, 2004, filed as supplementary material with the Board, excluding the consumer located at 4700 Tottenham Road. 2011 – to include lands as described in Proposed Draft Plan of Subdivision of Belterra Estates, to include Part of Lots 12 &13, Concession 14 and Parts of Lots 12 & 13, Concession 15, file number NT-T03002 under the Corporate Township of Tecumseh. In effect it will include lands east of the current border to include the new subdivision by Cable Bridge Enterprises Inc. (Belterra Estates).

10. Community of Beeton Service Area:

Within the Community of Beeton as detailed firstly as the "Beeton Urban Area Expansion" in Schedule 'A' to the Corporation of the Town of the Amalgamated Municipalities of Alliston, Beeton, Tecumseth & Tottenham By-law 91-169 dated October 15, 1991 (entiltled "H.E.C. Service Area Expansion By-Law") and secondly as shown on Reference Map Document Number 4982 included on page 8 of "Schedule 1 Definition of Distribution Service Area" dated March 10, 2004, filed as supplementary material with the Board.

11. Community of Tottenham Service Area:

Within the Community of Tottenham as detailed firstly as the "Tottenham Urban Area Expansion" in Schedule 'A' to the Corporation of the Town of the Amalgamated Municipalities of Alliston, Beeton, Tecumseth & Tottenham By-law 91-169 dated October 15, 1991 (entiltled "H.E.C. Service Area Expansion By-Law") and secondly as shown on Reference Map Document Number 5013 included on page 9 of "Schedule 1 Definition of Distribution Service Area" dated March 10, 2004, filed as supplementary material with the Board. It is noted that the "Beeton Creek" referenced in this schedule is technically a tributary to the actual Beeton Creek. The location of this tributary creek is shown on the Reference Map and it is to the east of the former Village of Tottenham.

12. Community of Penetanguishene Service Area:

Within the Community of Penetanguishene as detailed firstly as the “Boundary Expansion Agreement” or “Annexation Transfer Agreement” dated December 31, 1998 between the former Ontario Hydro and the Penetanguishene Hydro-Electric Commission and secondly as shown on Reference Map Document Number 5001 included on page 10 of “Schedule 1 Definition of Distribution Service Area” dated March 10, 2004, filed as supplementary material with the Board.

The Guelph Rate Zone:

1. The City of Guelph as at April 1, 1993.

2. The Police Village of Rockwood as of May 30, 1903, now part of the Township of Guelph/Eramosa.

3. Customers located in the following areas of the Township of Puslinch:
    - Lot 15, Concession 5
    - Lot 16 Concession 7
    - Lot 16 Concession 8
    - Lots 2, 3, 4, 5 and 6 Concession 9
    - Lots14 and 15 Concession 9

4. Customers located in the following areas of the Township of Guelph/Eramosa:
    - Lot 6 Concession 1, Township of Guelph
    - Lot 6 Concession 4, Township of Eramosa
    - Lot 4 Concession 5, Township of Eramosa
    - Lot 1 Concession 1, Township of Guelph
    - Lots 1 to 5 Concession 5, Township of Guelph
    - Lot 3 Concession 4, Township of Eramosa

5. Except customer on Lot 3 Concession 5 of the Township of Guelph, with the following civic address: 675 Speedvale Ave.

6. The Pump House on Part Lot 15, Concession 9 in the Township of Puslinch with the civic address: 2194 Victoria Road S., Guelph, ON N1L 1N9.

7. Rockwood Public School on Part of the Southwest half of Lot 3, Concession 4 in the Township of Eramosa.

SCHEDULE 2 PROVISION OF STANDARD SUPPLY SERVICE

This Schedule specifies the manner in which the Licensee is authorized to retail electricity for the purposes of fulfilling its obligation under section 29 of the Electricity Act.

1. The Licensee is authorized to retail electricity directly to consumers within its service area in accordance with paragraph 8.1 of this Licence, any applicable exemptions to this Licence, and at the rates set out in the Rate Orders.

SCHEDULE 3 LIST OF CODE EXEMPTIONS

This Schedule specifies any specific Code requirements from which the Licensee has been exempted.

With respect to the Enersource Rate Zone:

1. The Licensee is exempt from the requirement of section 2.6.1A of the Distribution System Code to issue a bill to each non-seasonal residential customer and each General Service <50kW customer in the Enersource Rate Zone on a monthly basis. This monthly billing exemption expires on December 31, 2018.

With respect to the Horizon Rate Zone:

1. The Licensee is exempt from the requirement of section 2.6.1A of the Distribution System Code to issue a bill to each non-seasonal residential customer and each General Service <50kW customer in the Horizon Utilities Rate Zone on a monthly basis. This monthly billing exemption expires on June 30, 2017.

APPENDIX A MARKET POWER MITIGATION REBATES

1. Definitions and Interpretations

In this Licence

"embedded distributor" means a distributor who is not a market participant and to whom a host distributor distributes electricity;

"embedded generator" means a generator who is not a market participant and whose generation facility is connected to a distribution system of a distributor, but does not include a generator who consumes more electricity than it generates;

"host distributor" means a distributor who is a market participant and who distributes electricity to another distributor who is not a market participant.

In this Licence, a reference to the payment of a rebate amount by the IESO includes interim payments made by the IESO.

2. Information Given to IESO

a Prior to the payment of a rebate amount by the IESO to a distributor, the distributor shall provide the IESO, in the form specified by the IESO and before the expiry of the period specified by the IESO, with information in respect of the volumes of electricity withdrawn by the distributor from the IESO-controlled grid during the rebate period and distributed by the distributor in the distributor's service area to:

i consumers served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and

ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998.*

b Prior to the payment of a rebate amount by the IESO to a distributor which relates to electricity consumed in the service area of an embedded distributor, the embedded distributor shall provide the host distributor, in the form specified by the IESO and before the expiry of the period specified in the Retail Settlement Code, with the volumes of electricity distributed during the rebate period by the embedded distributor's host distributor to the embedded distributor net of any electricity distributed to the embedded distributor which is attributable to embedded generation and distributed by the embedded distributor in the embedded distributor's service area to:

i consumers served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and

ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998*.

c Prior to the payment of a rebate amount by the IESO to a distributor which relates to electricity consumed in the service area of an embedded distributor, the host distributor shall provide the IESO, in the form specified by the IESO and before the expiry of the period specified by the

IESO, with the information provided to the host distributor by the embedded distributor in accordance with section 2.

The IESO may issue instructions or directions providing for any information to be given under this section. The IESO shall rely on the information provided to it by distributors and there shall be no opportunity to correct any such information or provide any additional information and all amounts paid shall be final and binding and not subject to any adjustment.

For the purposes of attributing electricity distributed to an embedded distributor to embedded generation, the volume of electricity distributed by a host distributor to an embedded distributor shall be deemed to consist of electricity withdrawn from the IESO-controlled grid or supplied to the host distributor by an embedded generator in the same proportion as the total volume of electricity withdrawn from the IESO-controlled grid by the distributor in the rebate period bears to the total volume of electricity supplied to the distributor by embedded generators during the rebate period.

3. Pass Through of Rebate

A distributor shall promptly pass through, with the next regular bill or settlement statement after the rebate amount is received, any rebate received from the IESO, together with interest at the Prime Rate, calculated and accrued daily, on such amount from the date of receipt, to:

a retailers who serve one or more consumers in the distributor's service area where a service transaction request as defined in the Retail Settlement Code has been implemented;

b consumers who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998* and who are not served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and

c embedded distributors to whom the distributor distributes electricity.

The amounts paid out to the recipients listed above shall be based on energy consumed and calculated in accordance with the rules set out in the Retail Settlement Code. These payments may be made by way of set off at the option of the distributor.

If requested in writing by OPGI, the distributor shall ensure that all rebates are identified as coming from OPGI in the following form on or with each applicable bill or settlement statement:

"ONTARIO POWER GENERATION INC. rebate"

Any rebate amount which cannot be distributed as provided above or which is returned by a retailer to the distributor in accordance with its licence shall be promptly returned to the host distributor or IESO as applicable, together with interest at the Prime Rate, calculated and accrued daily, on such amount from the date of receipt.

Nothing shall preclude an agreement whereby a consumer assigns the benefit of a rebate payment to a retailer or another party.

Pending pass-through or return to the IESO of any rebate received, the distributor shall hold the funds received in trust for the beneficiaries thereof in a segregated account.

ONTARIO POWER GENERATION INC. REBATES

For the payments that relate to the period from May 1, 2006 to April 30, 2009, the rules set out below shall apply.

1. Definitions and Interpretations

In this Licence

"embedded distributor" means a distributor who is not a market participant and to whom a host distributor distributes electricity;

"embedded generator" means a generator who is not a market participant and whose generation facility is connected to a distribution system of a distributor, but does not include a generator who consumes more electricity than it generates;

"host distributor" means a distributor who is a market participant and who distributes electricity to another distributor who is not a market participant.

In this Licence, a reference to the payment of a rebate amount by the IESO includes interim payments made by the IESO.

2. Information Given to IESO

a Prior to the payment of a rebate amount by the IESO to a distributor, the distributor shall provide the IESO, in the form specified by the IESO and before the expiry of the period specified by the IESO, with information in respect of the volumes of electricity withdrawn by the distributor from the IESO-controlled grid during the rebate period and distributed by the distributor in the distributor's service area to:

i consumers served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented and the consumer is not receiving the prices established under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998*; and

ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998*.

b Prior to the payment of a rebate amount by the IESO to a distributor which relates to electricity consumed in the service area of an embedded distributor, the embedded distributor shall provide the host distributor, in the form specified by the IESO and before the expiry of the period specified in the Retail Settlement Code, with the volumes of electricity distributed during the rebate period by the embedded distributor's host distributor to the embedded distributor net of any electricity distributed to the embedded distributor which is attributable to embedded generation and distributed by the embedded distributor in the embedded distributor's service area to:

i consumers served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and

ii consumers other than consumers referred to in clause (i) who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998*.

c Prior to the payment of a rebate amount by the IESO to a distributor which relates to electricity consumed in the service area of an embedded distributor, the host distributor shall provide the IESO, in the form specified by the IESO and before the expiry of the period specified by the IESO, with the information provided to the host distributor by the embedded distributor in accordance with section 2.

The IESO may issue instructions or directions providing for any information to be given under this section. The IESO shall rely on the information provided to it by distributors and there shall be no opportunity to correct any such information or provide any additional information and all amounts paid shall be final and binding and not subject to any adjustment.

For the purposes of attributing electricity distributed to an embedded distributor to embedded generation, the volume of electricity distributed by a host distributor to an embedded distributor shall be deemed to consist of electricity withdrawn from the IESO-controlled grid or supplied to the host distributor by an embedded generator in the same proportion as the total volume of electricity withdrawn from the IESO-controlled grid by the distributor in the rebate period bears to the total volume of electricity supplied to the distributor by embedded generators during the rebate period.

3. Pass Through of Rebate

A distributor shall promptly pass through, with the next regular bill or settlement statement after the rebate amount is received, any rebate received from the IESO, together with interest at the Prime Rate, calculated and accrued daily, on such amount from the date of receipt, to:

a retailers who serve one or more consumers in the distributor's service area where a service transaction request as defined in the Retail Settlement Code has been implemented and the consumer is not receiving the prices established under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998*;

b consumers who are not receiving the fixed price under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998* and who are not served by a retailer where a service transaction request as defined in the Retail Settlement Code has been implemented; and

c embedded distributors to whom the distributor distributes electricity.

The amounts paid out to the recipients listed above shall be based on energy consumed and calculated in accordance with the rules set out in the Retail Settlement Code. These payments may be made by way of set off at the option of the distributor.

If requested in writing by OPGI, the distributor shall ensure that all rebates are identified as coming from OPGI in the following form on or with each applicable bill or settlement statement:

"ONTARIO POWER GENERATION INC. rebate"

Any rebate amount which cannot be distributed as provided above or which is returned by a retailer to the distributor in accordance with its licence shall be promptly returned to the host distributor or IESO as applicable, together with interest at the Prime Rate, calculated and accrued daily, on such amount from the date of receipt.

Nothing shall preclude an agreement whereby a consumer assigns the benefit of a rebate payment to a retailer or another party.

Pending pass-through or return to the IESO of any rebate received, the distributor shall hold the funds received in trust for the beneficiaries thereof in a segregated account.

APPENDIX B LAND DESCRIPTIONS

No.	Area	Legal Description	No.	Area	Legal Description
1	Vaughan	PT LOT 2, CON 7, PTS 6 & 8, 65R24532; KING ; T/W R216549; S/T EASE OVER PT 6, 65R24532 AS IN A24558A AND RENEWED BY R610943.	17	Richmond Hill	PT LT 5 CON 2 KING PT 22 65R531 ; KING
2	Vaughan	PT E 1/2 LT 2 CON 7 KING; PT LT 3 CON 7 KING AS IN R707971; S/T & T/W B35507B ; S/T A24558A KING	18	Richmond Hill	PT LT 5 CON 2 KING PT 22 65R531 ; KING
3	Vaughan	PT LT 2 CON 6 KING AS IN A55205A EXCEPT PTS 1 & 2 65R18259 ; KING	19	Richmond Hill	PT LT 2 CON 2 KING; PT LT 3 CON 2 KING AS IN B16975B, B19261B & A29730A EXCEPT PTS 4 & 5 65R14738 & PTS 8 & 9 65R531 ; KING
4	Vaughan	PT LT 2 CON 6 KING AS IN A55205A EXCEPT PTS 1 & 2 65R18259 ; KING	20	Richmond Hill	LOT 5, CONCESSION 2, KING
5	Vaughan	PT E 1/2 LT 2 CON 7 KING; PT LT 3 CON 7 KING AS IN R707971; S/T & T/W B35507B ; S/T A24558A KING	21	Richmond Hill	PT LT 3 CON 2 KING PT 2 65R5820 ; KING
6	Vaughan	PT E 1/2 LT 2 CON 7 KING; PT LT 3 CON 7 KING AS IN R707971; S/T & T/W B35507B ; S/T A24558A KING	22	Richmond Hill	PT LT 5 CON 2 KING PT 2 65R599 ; KING
7	Vaughan	PT LT 3 CON 6 KING AS IN R184760 ; KING	23	Richmond Hill	PT LT 5 CON 2 KING PT 2 65R599 ; KING
8	Vaughan	PT LT 3 CON 6 KING AS IN R184760 ; KING	24	Vaughan	LOT 2, CONCESSION 2, KING TWNSHP
9	Richmond Hill	PT LT 5 CON 2 KING PT 2 65R599 ; KING	25	Vaughan	PT LT 5 CON 2 KING PT 2 65R599 ; KING
10	Richmond Hill	PT LT 3 CON 2 KING PT 2 65R5820 ; KING	26	Richmond Hill	PT LT 5 CON 2 KING PT 2 65R599 ; KING
11	Richmond Hill	LOT 7, CONCESSION 2, KING	27	Vaughan	PT LT 5 CON 2 KING PT 2 65R599 ; KING
12	Richmond Hill	PT LT 5 CON 2 KING PT 22 65R531 ; KING	28	Aurora	PT LT 14 CON 2 KING AS IN R180958 EXCEPT PT 13 EXPROP PL R233113 ; KING ; SUBJECT TO EXECUTION 95-05877, IF ENFORCEABLE. ; SUBJECT TO EXECUTION 95-06771, IF ENFORCEABLE. ; SUBJECT TO EXECUTION 96-02878, IF ENFORCEABLE. ;
13	Richmond Hill	PT LT 5 CON 2 KING PT 22 65R531 ; KING	29	Aurora	PT LT 14 CON 2 KING AS IN KI25920 EXCEPT PT 11 EXPROP PL R233113 ; KING ; SUBJECT TO EXECUTION 96-06008, IF ENFORCEABLE. ;
14	Richmond Hill	PT LT 5 CON 2 KING PT 2 65R599 ; KING	30	Aurora	PT LT 14 CON 2 KING PT 1 65R2712 ; KING
15	Richmond Hill	PT LT 2 CON 2 KING; PT LT 3 CON 2 KING AS IN B16975B, B19261B & A29730A EXCEPT PTS 4 & 5 65R14738 & PTS 8 & 9 65R531 ; KING	31	Aurora	PT LT 14 CON 2 KING PT 1 65R2712 ; KING
16	Richmond Hill	PT LT 5 CON 2 KING PT 2 65R599 ; KING	32	Aurora	PT LT 15 CON 2 KING PT 2 65R8504 ; KING

No.	Area	Legal Description	No.	Area	Legal Description
33	Aurora	PT LT 15 CON 2 KING PT 1 65R8504 ; KING	51	Aurora	PT LT 22 CON 2 KING; PT LT 23 CON 2 KING PT 1, 65R6742 ; KING
34	Aurora	PT LT 15 CON 2 KING AS IN B47985B EXCEPT PT 8 EXPROP PL R233113 ; KING	52	Aurora	PT LT 22 CON 2 KING; PT LT 23 CON 2 KING PT 1, 65R6742 ; KING
35	Aurora	PT SE1/4 LT 16 CON 2 KING PTS 2 & 3 65R10629; T/W R439940 ; KING	53	Aurora	PT LT 24 CON 2 KING AS IN R629682 T/W R137178 ; KING
36	Aurora	PT SE1/4 LT 16 CON 2 KING PTS 2 & 3 65R10629; T/W R439940 ; KING	54	Aurora	PT LT 24 CON 2 KING AS IN R629682 T/W R137178 ; KING
37	Aurora	PT NE1/4 LT 16 CON 2 KING PT 2 65R15552 ; KING	55	Aurora	PT LT 24, CON 2, (KING) IN R662420 EXCEPT PTS 1 & 2, PL 65R29165, KING
38	Aurora	PT NE1/4 LT 16 CON 2 KING; PT LT 17 CON 2 KING; PT LT 18 CON 2 KING PTS 1, 3 65R15552 ; KING	56	Aurora	LOT 16, CONCESSION 2, KING
39	Aurora	PT NE1/4 LT 16 CON 2 KING; PT LT 17 CON 2 KING; PT LT 18 CON 2 KING PTS 1, 3 65R15552 ; KING	57	Aurora	PT LT 15 CON 2 KING AS IN R166067 EXCEPT R242869 ; KING
40	Aurora	PT LT 18 CON 2 KING PT 1 65R5395 ; KING	58	Aurora	PT LT 15 CON 2 KING AS IN R400615 ; KING
41	Aurora	PT LT 18 CON 2 KING AS IN R602840 ; KING	59	Aurora	PT SE1/4 LT 16 CON 2 KING PT 1 65R3379; T/W R145038 ; KING
42	Aurora	LOT 18, CONCESION 2, KING TWSHP	60	Aurora	PT LT 14 CON 2 KING AS IN B50839B EXCEPT PTS 10 & 12 EXPROP PL R233113; PT LT 15 CON 2 KING AS IN B27240B EXCEPT PT 2 65R9307; T/W R406638 ; KING
43	Aurora	PT LT 18 CON 2 KING PT 1 65R13476 ; KING	61	Aurora	PT LT 14 CON 2 KING AS IN B50839B EXCEPT PTS 10 & 12 EXPROP PL R233113; PT LT 15 CON 2 KING AS IN B27240B EXCEPT PT 2 65R9307; T/W R406638 ; KING
44	Aurora	PT LT 18 CON 2 KING PT 1 65R13476 ; KING	62	Aurora	PT LT 15 CON 2 KING PTS 2, 3 & 4 65R17617; S/T R660937; T/W R660070. ; KING
45	Aurora	PT LT 18 CON 2 KING PT 1 65R609 EXCEPT PT 8 EXPROP PL R233114 ; KING	63	Aurora	PT LT 15 CON 2 KING PT 5 65R17617; T/W R660938 ; KING
46	Aurora	LOT 19, KING TWSHP	64	Aurora	NE1/4 LT 16 CON 2 KING PTS 1,2 65R3343; SE1/4 LT 16 CON 2 KING PTS 3,4 65R3343 ; KING
47	Aurora	LOT 19, KING TWSHP	65	Aurora	PT LT 13 CON 2 KING AS IN R306307 S/T INTEREST IN KI22671, S/T DEBTS IN R306307 ; KING
48	Aurora	PT LT 20 CON 2 KING PT 1 65R1245 EXCEPT PT 11, EXPROP PL R233114 ; KING	66	Aurora	PT SE1/4 LT 16 CON 2 KING PT 1, 65R20034; KING
49	Aurora	PT LT 21 CON 2 KING; PT LT 22 CON 2 KING AS IN B2661B EXCEPT PT 4 B33711B; DESCRIPTION MAY NOT BE ACCEPTABLE IN THE FUTURE AS IN B2661B ; KING	67	Aurora	PT SE1/4 LT 16 CON 2 KING PT 3, 65R20034; T/W R720871 ; KING ; SUBJECT TO EXECUTION 96-00974, IF ENFORCEABLE
50	Aurora	PT LT 22 CON 2 KING; PT LT 23 CON 2 KING PT 1, 65R6742 ; KING	68	Aurora	LOT 21, CONCESSION 2, KING TWNSHP