CANADIAN UTILITIES LIMITED

An ATCO Company

CANADIAN UTILITIES LIMITED
CONSOLIDATED FINANCIAL STATEMENTS

FOR THE YEAR ENDED DECEMBER 31, 2015

February 24, 2016

Independent Auditor's Report

To the Share Owners of Canadian Utilities Limited

We have audited the accompanying consolidated financial statements of Canadian Utilities Limited and its subsidiaries, which comprise the consolidated balance sheets as at December 31, 2015 and December 31, 2014 and the consolidated statements of earnings, comprehensive income, changes in equity and cash flow for the years then ended, and the related notes, which comprise a summary of significant accounting policies and other explanatory information.

Management's responsibility for the consolidated financial statements

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

Auditor's responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Canadian Utilities Limited and its subsidiaries as at December 31, 2015 and December 31, 2014 and their financial performance and their cash flows for the years then ended in accordance with International Financial Reporting Standards.

PricewaterhouseCoopers LLP

Chartered Professional Accountants
Calgary, Alberta

PricewaterhouseCoopers LLP
111 5th Avenue SW, Suite 3100, Calgary, Alberta, Canada T2P 5L3
T: +1 403 509 7500, F: +1 403 781 1825, www.pwc.com/ca

CANADIAN UTILITIES LIMITED
CONSOLIDATED STATEMENT OF EARNINGS

(millions of Canadian Dollars except per share data)	Note	Year Ended December 31 2015	2014
Revenues	6	**3,264**	3,600
Costs and expenses			
Salaries, wages and benefits		**(463)**	(468)
Energy transmission and transportation		**(189)**	(168)
Plant and equipment maintenance		**(297)**	(271)
Fuel costs		**(244)**	(466)
Purchased power		**(78)**	(67)
Materials and consumables		**(18)**	(50)
Depreciation, amortization and impairment	12,13	**(642)**	(514)
Franchise fees		**(201)**	(218)
Property and other taxes		**(85)**	(93)
Other	7	**(229)**	(251)
		(2,446)	(2,566)
Gain on sales of operations and revaluation of joint venture	8,15	**30**	160
(Loss) earnings from investment in ATCO Structures & Logistics	14	**(6)**	18
Earnings from investment in joint ventures	15	**12**	15
Operating profit		**854**	1,227
Interest income		**10**	11
Interest expense	18	**(299)**	(308)
Net finance costs		**(289)**	(297)
Earnings before income taxes		**565**	930
Income taxes	9	**(205)**	(206)
Earnings for the year		**360**	724
Earnings attributable to:			
Equity owners of the Company		**352**	711
Equity preferred share owners of subsidiary company		**8**	13
		360	724
Earnings per Class A and Class B share	25	**$1.12**	2.52
Diluted earnings per Class A and Class B share	25	**$1.11**	2.52

See accompanying Notes to Consolidated Financial Statements.

CANADIAN UTILITIES LIMITED
CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

(millions of Canadian Dollars)	Note	Year Ended December 31 2015	2014
Earnings for the year		**360**	724
Other comprehensive income (loss), net of income taxes:			
Items that will not be reclassified to earnings:			
Re-measurement of retirement benefits (1)	29	**73**	(111)
Share of other comprehensive income (loss) of ATCO Structures & Logistics (2)	14	**1**	(1)
Share of other comprehensive loss of joint ventures (3)	15	**(2)**	(10)
		72	(122)
Items that are or may be reclassified subsequently to earnings:			
Cash flow hedges reclassified to earnings (4)		**(2)**	10
Foreign currency translation adjustment (2)		**49**	(6)
Share of other comprehensive income of ATCO Structures & Logistics (2)	14	**11**	3
Share of other comprehensive income of joint ventures (2)	15	**1**	1
		59	8
Other comprehensive income (loss)		**131**	(114)
Comprehensive income for the year		**491**	610
Comprehensive income attributable to:			
Equity owners of the Company		**483**	597
Equity preferred share owners of subsidiary company		**8**	13
		491	610

(1) Net of income taxes of $(42) million for the year ended December 31, 2015 (2014 - $37 million).

(2) Net of income taxes of nil.

(3) Net of income taxes of $1 million for the year ended December 31, 2015 (2014 - $3 million).

(4) Net of income taxes of nil for the year ended December 31, 2015 (2014 - $(1) million).

See accompanying Notes to Consolidated Financial Statements.

CANADIAN UTILITIES LIMITED
CONSOLIDATED BALANCE SHEET

(millions of Canadian Dollars)	Note	December 31 2015	2014
ASSETS			
Current assets			
Cash and cash equivalents		**520**	351
Accounts receivable		**433**	485
Finance lease receivables	10	**9**	20
Inventories	11	**44**	85
Prepaid expenses and other current assets		**51**	63
		1,057	1,004
Non-current assets			
Property, plant and equipment	12	**15,733**	14,608
Intangibles	13	**484**	396
Investment in ATCO Structures & Logistics	14	**202**	203
Investment in joint ventures	15	**175**	119
Finance lease receivables	10	**302**	290
Deferred income tax assets	9	**63**	24
Other assets		**53**	58
Total assets		**18,069**	16,702
LIABILITIES			
Current liabilities			
Bank indebtedness	16	**1**	4
Accounts payable and accrued liabilities		**726**	829
Asset retirement obligations and other provisions	17	**35**	30
Other current liabilities		**17**	19
Long-term debt	18	**5**	83
Non-recourse long-term debt	18	**15**	15
		799	980
Non-current liabilities			
Deferred income tax liabilities	9	**983**	740
Asset retirement obligations and other provisions	17	**152**	171
Retirement benefit obligations	29	**277**	411
Deferred revenues	19	**1,649**	1,512
Other liabilities	20	**45**	64
Long-term debt	18	**7,874**	7,105
Non-recourse long-term debt	18	**97**	112
Total liabilities		**11,876**	11,095
EQUITY			
Equity preferred shares	24	**1,483**	1,115
Equity preferred shares of subsidiary company	24	**187**	187
Class A and Class B share owners' equity			
Class A and Class B shares	25	**1,013**	909
Contributed surplus		**15**	16
Retained earnings		**3,467**	3,411
Accumulated other comprehensive income		**28**	(31)
		4,523	4,305
Total equity		**6,193**	5,607
Total liabilities and equity		**18,069**	16,702

See accompanying Notes to Consolidated Financial Statements.

[Original Signed by N.C. Southern]
DIRECTOR

[Original Signed by J.W. Simpson]
DIRECTOR

CANADIAN UTILITIES LIMITED
CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

(millions of Canadian Dollars)	Note	Class A and Class B Shares	Equity Preferred Shares [1]	Contributed Surplus	Retained Earnings	Accumulated Other Comprehensive Income	Total Equity
December 31, 2013		803	1,458	15	3,157	(39)	5,394
Earnings for the year		–	–	–	724	–	724
Other comprehensive loss		–	–	–	–	(114)	(114)
Losses on retirement benefits transferred to retained earnings	29	–	–	–	(122)	122	–
Shares issued, net of issue costs	25	104	–	–	–	–	104
Shares redeemed	24	–	(156)	–	(4)	–	(160)
Dividends	26	–	–	–	(344)	–	(344)
Share-based compensation	28	2	–	1	–	–	3
December 31, 2014		**909**	**1,302**	**16**	**3,411**	**(31)**	**5,607**
Earnings for the year		**–**	**–**	**–**	**360**	**–**	**360**
Other comprehensive income		**–**	**–**	**–**	**–**	**131**	**131**
Gains on retirement benefits transferred to retained earnings	29	**–**	**–**	**–**	**72**	**(72)**	**–**
Shares issued, net of issue costs	24,25	**99**	**368**	**–**	**–**	**–**	**467**
Dividends	26	**–**	**–**	**–**	**(376)**	**–**	**(376)**
Share-based compensation	28	**5**	**–**	**(1)**	**–**	**–**	**4**
December 31, 2015		**1,013**	**1,670**	**15**	**3,467**	**28**	**6,193**

(1) Includes equity preferred shares and equity preferred shares of subsidiary company.

See accompanying Notes to Consolidated Financial Statements.

CANADIAN UTILITIES LIMITED
CONSOLIDATED STATEMENT OF CASH FLOW

(millions of Canadian Dollars)	Note	Year Ended December 31 2015	2014
Operating activities			
Earnings for the year		**360**	724
Adjustments to reconcile earnings to cash flows from operating activities	30	**1,172**	919
Changes in non-cash working capital	30	**84**	(103)
Cash flows from operating activities		**1,616**	1,540
Investing activities			
Additions to property, plant and equipment		**(1,541)**	(2,105)
Proceeds on disposal of property, plant and equipment		**1**	19
Additions to intangibles		**(130)**	(93)
Acquisition of Thames Power Limited	8,15	**(25)**	–
Proceeds on sales of operations	8	**7**	204
Investment in joint venture	15	**(28)**	(35)
Changes in non-cash working capital	30	**(66)**	54
Other		**(24)**	(21)
Cash flows used in investing activities		**(1,806)**	(1,977)
Financing activities			
Issue of long-term debt	18	**650**	1,223
Repayment of long-term debt		**(4)**	(153)
Repayment of non-recourse long-term debt	18	**(15)**	(31)
Issue of equity preferred shares		**375**	–
Redemption of equity preferred shares by subsidiary company	24	**–**	(160)
Issue of Class A shares		**4**	3
Dividends paid on equity preferred shares	26	**(56)**	(50)
Dividends paid on equity preferred shares of subsidiary company	26	**(8)**	(13)
Dividends paid to Class A and Class B share owners	25,26	**(213)**	(177)
Interest paid		**(369)**	(343)
Other		**(11)**	(8)
Cash flows from financing activities		**353**	291
Increase (decrease) in cash position [1]		**163**	(146)
Foreign currency translation		**9**	(3)
Beginning of year		**347**	496
End of year		**519**	347

(1) Cash position consists of cash and cash equivalents less current bank indebtedness and includes $34 million (2014 - $34 million) which is not available for general use by the Company.

See accompanying Notes to Consolidated Financial Statements.

CANADIAN UTILITIES LIMITED
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

DECEMBER 31, 2015

(Tabular amounts in millions of Canadian Dollars, except as otherwise noted)

1. THE COMPANY AND ITS OPERATIONS

Canadian Utilities Limited was incorporated under the laws of Canada and is listed on the Toronto Stock Exchange. Its head office is at 700, 909 - 11th Avenue SW, Calgary, Alberta, T2R 1N6 and its registered office is 20th Floor, 10035 - 105 Street, Edmonton, Alberta T5J 2V6. The Company is controlled by ATCO Ltd. and its controlling share owner, the Southern family.

Canadian Utilities Limited is engaged in the following business activities:

- Electricity (power generation, distributed generation, and electricity distribution, transmission and infrastructure development); and
- Pipelines & Liquids (natural gas transmission, distribution and infrastructure development, natural gas liquids storage and processing, and industrial water solutions).

The consolidated financial statements include the accounts of Canadian Utilities Limited and its subsidiaries (the Company). The statements also include the accounts of a proportionate share of the Company's investments in joint operations and its equity-accounted investments in ATCO Structures & Logistics (24.5 per cent) and joint ventures.

2. BASIS OF PRESENTATION

STATEMENT OF COMPLIANCE

The consolidated financial statements are prepared according to International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board (IASB) and interpretations of the IFRS Interpretations Committee (IFRIC).

The Board of Directors (Board) authorized these consolidated financial statements for issue on February 24, 2016.

BASIS OF MEASUREMENT

The consolidated financial statements are prepared on a historic cost basis, except for derivative financial instruments, defined benefit pension and other employee retirement benefit liabilities and cash-settled share-based compensation liabilities as disclosed in the applicable accounting policies.

Certain comparative figures are reclassified to conform to the current presentation.

3. ACCOUNTING POLICIES

CHANGE IN ACCOUNTING POLICIES

Financial Instruments

The Company adopted IFRS 9 (2013) *Financial Instruments* effective January 1, 2015. This standard replaces IAS 39 *Financial Instruments: Recognition and Measurement* and previous versions of IFRS 9. It includes revised guidance on the classification and measurement of financial assets and liabilities and additional guidance on general hedge accounting.

Previously, the Company classified financial assets when they were first recognized as fair value through profit or loss, available for sale, held to maturity investments or loans and receivables. Under IFRS 9 (2013), the Company classifies financial assets under the same two measurement categories as financial liabilities; amortized cost or fair value through profit and loss. All of the Company's financial assets and financial liabilities will continue to be classified and measured at amortized cost with the exception of derivative financial instruments. The adoption of this standard has not resulted in any changes to comparative figures.

Previously, all derivative financial instruments, including derivatives embedded in other financial instruments or host contracts, were measured at fair value. Under IFRS 9 (2013), derivatives embedded in financial asset host contracts are no longer required to be separated. Instead, the contract is required to be classified in its entirety at either amortized cost or fair value. For those measured at fair value, the gain or loss that results from changes in fair value of the derivative is recognized in earnings immediately, unless the derivative is designated and effective as a hedging instrument, in which case the timing of recognition in earnings depends on the hedging relationship.

By early adopting hedge accounting under IFRS 9 (2013), the Company is able to better align its hedge accounting policy with its risk management objectives.

CONSOLIDATION

Subsidiaries are consolidated from the date control is obtained until the date control ends. Control exists where the Company has power over the investee, exposure or rights to variable returns from the investee and the ability to use its power over the investee to affect returns.

All intra-group balances and transactions are eliminated on consolidation.

JOINT ARRANGEMENTS

Joint operations are proportionately consolidated by including the Company's share of assets, liabilities, revenues, expenses and other comprehensive income (OCI) in the respective consolidated accounts.

Joint ventures are equity accounted. Under this method, the Company's interests in joint ventures are initially recognized at cost. The interests are subsequently adjusted to recognize the Company's share of post-acquisition profits or losses, movements in OCI and dividends or distributions received.

The Company's interests in joint ventures are tested for recoverability when events or circumstances indicate a possible impairment. An impairment loss is recognized in earnings when the carrying value of the Company's interest in an individual joint venture is higher than its recoverable amount. The recoverable amount is the higher of fair value less disposal costs and value in use. An impairment loss may be reversed if there is objective evidence that a change in the estimated recoverable amount of the investment is warranted.

BUSINESS COMBINATIONS

Business combinations are accounted for using the acquisition method. Assets acquired and liabilities assumed are measured at their fair value at the acquisition date. Acquisition costs are expensed in the period incurred.

RATE REGULATION

ATCO Electric and its subsidiaries, ATCO Electric Yukon, Northland Utilities (NWT) and Northland Utilities (Yellowknife), as well as ATCO Gas, ATCO Pipelines and ATCO Gas Australia are collectively referred to in the consolidated financial statements as utilities.

In the absence of a rate-regulated standard under IFRS that the Company is eligible to adopt, the utilities do not recognize assets and liabilities from rate-regulated activities as may be directed by regulatory decisions. Instead, the utilities recognize revenues in earnings when amounts are billed to customers consistent with the regulator-approved rate design (see revenue recognition accounting policy below).

Operating costs and expenses are recorded when incurred. Costs incurred in constructing an asset that meets the asset recognition criteria are included in the related property, plant and equipment or intangible asset.

SEGMENTED INFORMATION

The accounting policies applied by the segments are the same as those applied by the Company, except for those used in the calculation of adjusted earnings. Intersegment transactions are measured at the exchange amount, as agreed by the related parties.

REVENUE RECOGNITION

Revenues from the regulated distribution of natural gas in Canada and Australia and the regulated distribution of electricity in Canada include variable and fixed charges. Variable charges are recognized using meter readings on delivery of the commodity to customers and include an estimate of usage not yet billed. Fixed charges are based on the distribution service provided during the period.

Revenues for the use of regulated electricity transmission facilities are based on an annual tariff and are recognized evenly throughout the year.

Revenues from the regulated transmission of natural gas are recognized based on AUC-approved revenue requirement (cost of service).

Certain additions to property, plant and equipment, mainly in the utilities, are made with the assistance of non-refundable cash contributions from customers. These contributions are made when the estimated revenue is less than the cost of providing service or where the customer needs special equipment. Since these contributions will provide customers with on-going access to the supply of natural gas or electricity, they are classified as deferred revenues and are recognized in revenues over the life of the related asset.

Revenues from power generating plants are recognized on delivery of output or on availability of delivery as prescribed by contracts. In addition, incentives and penalties associated with the Power Purchase Arrangements (PPAs) are recognized in earnings on a straight-line basis as lease income. Accumulated incentives in excess of accumulated penalties are deferred. For an individual PPA, any surplus of the accumulated and estimated future incentives over the accumulated and estimated future penalties is amortized to revenues on a straight-line basis over the remaining term of the PPA. Conversely, any shortfall is expensed in the year the shortfall occurs.

Revenues from natural gas storage and processing capacity are recognized according to contracts. Revenues from the sale of natural gas liquids are recognized on delivery.

Revenues from the supply of contracted products and services are recorded using the percentage of completion method. The percentage of completion is based either on actual labour hours incurred as a proportion of the total estimated labour hours for the contract or on contract costs incurred as a proportion of the total estimated contract costs. Full provision is made for any anticipated loss. Other revenues are recognized when products are delivered or services provided. Billings in excess of earned revenue are classified as deferred revenues on the consolidated balance sheet.

SHORT-TERM EMPLOYEE BENEFITS

Short-term employee benefits are recognized as an expense in salaries, wages and benefits as employees render service. These benefits include wages, salaries, social security contributions, short-term compensated absences, incentives and non-monetary benefits, such as medical care. Costs for employee services incurred in constructing an asset that meet the asset recognition criteria are included in the related property, plant and equipment or intangible asset.

Termination benefits are recognized as an expense in salaries, wages and benefits at the earlier of when the Company can no longer withdraw the offer of those benefits and when the Company recognizes costs for a restructuring that includes the payment of termination benefits. In the case of an offer made to encourage voluntary redundancy, the termination benefits are measured based on the number of employees expected to accept the offer.

FRANCHISE FEES

Municipal governments charge franchise fees to the utilities in Canada for the exclusive right to provide service in their community. These costs are charged to customers through rates approved by the regulator. Franchise fee revenues and expenses are, therefore, recognized separately and are not recorded on a net basis.

INCOME TAXES

Income taxes are the sum of current and deferred taxes. Income tax is recognized in earnings, except to the extent it relates to items recorded in OCI or in equity.

Current tax is calculated on taxable earnings using rates enacted or substantively enacted at the balance sheet date in the jurisdictions in which the Company operates.

The liability method is used to determine deferred income tax on temporary differences between the financial statement carrying amounts of assets and liabilities and their respective tax bases. Deferred income tax is calculated using the enacted or substantively enacted tax rates that are expected to apply in the period when the liability is settled or the asset is realized. If expected tax rates change, deferred income taxes are adjusted to the new rates.

Deferred income tax assets and liabilities are not recognized if the temporary differences arise from the initial recognition of goodwill or of other assets and liabilities in a transaction, other than a business combination, that does not affect accounting or taxable earnings. The tax effect of temporary differences from investments in subsidiaries and joint arrangements are not accounted for where the Company is able to control the reversal of the temporary differences and it is probable that the temporary differences will not reverse in the foreseeable future. Deferred income tax assets are recognized only when it is probable that future taxable earnings will be available against which the temporary differences can be applied.

Current income tax assets and liabilities are offset where the Company has the legally enforceable right to offset and the Company intends to either settle on a net basis or realize the asset and settle the liability simultaneously.

Deferred income tax assets and liabilities are offset where the Company has a legally enforceable right to set off tax assets and liabilities, and when the deferred income tax assets and liabilities relate to income taxes levied by the same tax authority.

CASH AND CASH EQUIVALENTS

Cash and cash equivalents consist of cash at bank, bankers' acceptances, certificates of deposit issued or guaranteed by credit worthy financial institutions and federal government issued short-term investments with maturities generally of 90 days or less at purchase.

Cash and cash equivalents which are restricted under the terms of project financing agreements or are only available for use within the joint arrangements, unless partner approval has been obtained, are considered not available for general use within the Company.

INVENTORIES

Inventories are valued at the lower of cost or net realizable value. The cost of inventories that are interchangeable is assigned using the weighted average cost method. For inventories that are not interchangeable, cost is assigned using specific identification of their individual costs. Net realizable value is the estimated selling price in the ordinary course of business, less variable selling expenses.

The cost of inventories is comprised of all purchase, conversion and other costs to bring inventories to their present condition and location. Purchase costs consist of the purchase price, import duties, non-recoverable taxes, transport, handling and other costs directly attributable to the purchase of finished goods, materials or services. Conversion costs include direct material and labour costs and a systematic allocation of fixed and variable overheads incurred in converting materials into finished goods.

PROPERTY, PLANT AND EQUIPMENT

Property, plant and equipment are recorded at cost less accumulated depreciation and any recognized impairment losses. Cost includes expenditures that are directly attributable to the purchase or construction of the asset, such as materials, labour, borrowing costs incurred during construction, contracted services and asset retirement costs. Subsequent costs are included in the asset's carrying amount or recognized as a separate asset only when it is probable that future economic benefits will flow to the Company and the cost can be measured reliably.

Major overhaul costs are capitalized and depreciated on a straight-line basis over the period to the next major overhaul, which varies from three to eight years. The cost of repair and maintenance activities performed every two years or less which do not enhance or extend the useful life of the asset are expensed when incurred.

Borrowing costs attributable to a construction period of substantial duration are added to the cost of the asset. The effective interest method is used to calculate capitalized interest using specified rates for specific borrowings and a weighted average rate for general borrowings. Interest capitalization starts when borrowing costs and expenditures are incurred at the onset of construction and ends when construction is substantially complete.

The Company allocates the amount initially recognized in property, plant and equipment to its significant components and depreciates each component separately. Assets are depreciated mainly on a straight-line basis over their estimated useful lives. No depreciation is provided on land and construction work-in-progress.

The carrying amount of a replaced asset is derecognized when the cost of replacing the asset is capitalized. When an asset is derecognized, any resulting gain or loss is recorded in earnings.

Depreciation periods for the principal categories of property, plant and equipment are shown in the table below.

	Useful Life	Average Useful Life	Average Depreciation Rate
Utility transmission and distribution:			
Electricity transmission equipment	40 to 75 years	58 years	1.7%
Electricity distribution equipment	15 to 75 years	35 years	2.8%
Gas transmission equipment	3 to 81 years	44 years	2.3%
Gas distribution plant and equipment	3 to 120 years	39 years	2.6%
Power generation plant and equipment:			
Gas-fired	3 to 40 years	25 years	4.0%
Coal-fired	5 to 47 years	30 years	3.3%
Hydroelectric	50 years	50 years	2.2%
Buildings	1 to 55 years	48 years	2.1%
Other:			
Other plant, equipment and machinery	1 to 66 years	26 years	3.9%

Depreciation methods and the estimated residual values and useful lives of assets are reviewed on an annual basis. Any changes in these accounting estimates are recorded prospectively.

INTANGIBLES

Intangible assets are recorded at cost less accumulated amortization and any recognized impairment losses. The Company amortizes intangible assets on a straight-line basis over their useful lives. Useful life is not longer than 10 years for computer software and between 60 and 100 years for land rights based on the contractual life of the underlying agreements. Software work-in-progress is not amortized as the software is not available for use.

Amortization methods and useful lives of assets are reviewed annually. Any changes in these accounting estimates are recorded prospectively.

IMPAIRMENT OF PROPERTY, PLANT AND EQUIPMENT AND INTANGIBLES

Property, plant and equipment and intangible assets with finite lives are tested for recoverability when events or circumstances indicate a possible impairment. Impairment is assessed at the CGU level, which is the smallest identifiable group of assets that generates independent cash inflows. An impairment loss is recognized in earnings when the CGU's carrying value is higher than its recoverable amount. The recoverable amount is the greater of the CGU's fair value less disposal costs and its value in use. An impairment loss may be reversed in whole or in part if there is objective evidence that a change in the estimated recoverable amount is warranted. A reversal of an impairment loss shall not exceed the carrying amount that would have been determined (net of depreciation) had no impairment loss been recognized for the asset in prior years.

LEASES

A finance lease exists when the terms of the lease transfer substantially all the risks and rewards incidental to ownership of the leased asset to the lessee. Amounts due from lessees under finance leases are recorded as finance lease receivables. They are initially recognized at amounts equal to the present value of the minimum lease payments receivable. Payments that are part of the leasing arrangement are divided between a reduction in the finance lease receivable and finance lease income. Finance lease income is recognized so as to produce a constant rate of return on the Company's investment in the lease and is included in revenues.

Assets subject to operating leases are included in property, plant and equipment and are depreciated. Income from operating leases is recognized in earnings on a straight-line basis over the lease term.

When the Company has purchased goods or services as a lessee, and the lease is an operating lease, rental payments are expensed on a straight-line basis over the life of the lease.

For both finance and operating leases, contingent rents are recognized in earnings in the period in which they are incurred. Contingent rent is that portion of lease payments that is not fixed in amount but varies based on a future factor, such as the amount of use or production.

PROVISIONS AND CONTINGENCIES

The Company recognizes provisions when:

(i) there is a current legal or constructive obligation as a result of a past event,

(ii) a probable outflow of economic benefits will be required to settle the obligation; and

(iii) a reliable estimate of the obligation can be made.

If the effect is material, 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. If discounting is used, the increase in the provision due to the passage of time is recognized in interest expense.

A contingent liability is a possible obligation, and a contingent asset is a possible asset, that arises from past events and whose existence will be confirmed only by the occurrence or non-occurrence of one or more uncertain future events not wholly within the control of the Company. A contingent liability may also be a present obligation that arises from past events that is not recognized because it is not probable that an outflow of economic resources will be required to settle the obligation or the amount of the obligation cannot be measured reliably.

Neither contingent liabilities nor assets are recognized in the consolidated financial statements. However, a contingent liability is disclosed, unless the possibility of an outflow of resources is remote. A contingent asset is only disclosed where an inflow of economic benefits is probable.

Management evaluates the likelihood of contingent events based on the probability of exposure to potential loss. Actual results could differ from these estimates.

ASSET RETIREMENT OBLIGATIONS

Asset retirement obligations (AROs) are legal and constructive obligations connected with the retirement of tangible long-lived assets. These obligations are measured at management's best estimate of the expenditure required to settle the obligation and are discounted to present value when the effect is material. Cash flows for AROs are adjusted to take risks and uncertainties into account and are discounted using a pre-tax, risk-free discount rate.

Initially, an ARO is recorded in provisions, with a corresponding increase to property, plant and equipment. Subsequently, the carrying amount of the provision is accreted over the estimated time period until the obligation is to be settled; the accretion expense is recognized as interest expense. The asset is depreciated over its estimated useful life. Revaluations of the ARO at each reporting period take into account changes in estimated future cash flows and the discount rate.

FINANCIAL INSTRUMENTS

The Company classifies financial assets when they are first recognized as amortized cost or fair value through profit or loss. Classification is determined based on the Company's business model for managing financial assets and the contractual cash flow characteristics of the financial assets. Financial assets are measured at amortized cost if the financial asset is:

(i) held for the purpose of collecting contractual cash flows, and

(ii) the contractual cash flows of the financial asset solely represent payments of principle and interest.

All other financial assets are classified as fair value through profit or loss.

Financial liabilities are classified as amortized cost or fair value through profit or loss.

Amortized cost

Financial instruments classified as amortized cost are initially measured at fair value and subsequently measured at their amortized cost using the effective interest method.

Fair value through profit or loss

Financial instruments classified as fair value through profit or loss are initially measured at fair value with subsequent changes in fair value recognized in earnings.

Transaction costs

Transaction costs directly attributable to the purchase or issue of financial assets or financial liabilities that are not fair value through profit or loss are added to the fair value of such assets or liabilities when initially recognized. Transaction costs for long-term debt are amortized over the life of the respective financial liability using the effective interest method. The Company's long-term debt, non-recourse long-term debt and equity preferred shares are presented net of their respective transaction costs.

Offsetting financial instruments

Financial assets and financial liabilities are offset and the net amount is reported in the consolidated balance sheet:

(i) if there is a legally enforceable right to offset the recognized amounts, and

(ii) if the Company intends either to settle on a net basis or to realize the assets and settle the liabilities simultaneously.

Derecognition of financial instruments

Financial assets are derecognized:

(i) when the right to receive cash flows from the financial assets has expired or been transferred, and

(ii) the Company has transferred substantially all the risks and rewards of ownership.

Financial liabilities are derecognized when the obligation is discharged, cancelled, or expired.

Fair value hierarchy

The Company uses quoted market prices when available to estimate fair value. Models incorporating observable market data, along with transaction specific factors, are also used to estimate fair value. Financial assets and liabilities are classified in the fair value hierarchy according to the lowest level of input that is significant to the fair value measurement. Management's judgment as to the significance of a particular input may affect placement within the fair value hierarchy levels.

The hierarchy is as follows:

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

The Company applies settlement date accounting to the purchases and sales of financial assets. Settlement date accounting means recognizing an asset on the day it is received by the Company and recognizing the disposal of an asset on the day it is delivered by the Company. Any gain or loss on disposal is also recognized on that day.

IMPAIRMENT OF FINANCIAL INSTRUMENTS

At each reporting date, the Company assesses whether there is objective evidence that a financial asset or group of financial assets is impaired. If such evidence exists, an impairment loss is recognized in earnings.

Impairment losses on financial assets carried at amortized cost are calculated as the difference between the amortized cost and the present value of estimated future cash flows discounted at the financial asset's original effective interest rate. Impairment losses on financial assets carried at amortized cost may be reversed in whole or in part if there is objective evidence that a change in the estimated recoverable amount is warranted. The revised recoverable amount cannot exceed the carrying amount had no impairment charge been recognized in previous periods.

DERIVATIVE FINANCIAL INSTRUMENTS

Contracts settled net in cash or in another financial asset are classified as derivatives, unless they meet the Company's own use requirements.

All derivative financial instruments are measured at fair value. The gain or loss that results from changes in fair value of the derivative is recognized in earnings immediately, unless the derivative is designated and effective as a hedging instrument, in which case the timing of recognition in earnings depends on the hedging relationship.

Where the Company elects to apply hedge accounting, the Company documents the relationship between the derivative and the hedged item at inception of the hedge, based on the Company's risk management policies. A qualitative assessment of the effectiveness of the hedging relationship is performed at each reporting period if both the critical terms of the hedging relationship and the economic relationship between the hedged item and hedging instrument continue to remain the same or similar. If the mismatch in terms is significant, a quantitative assessment may be required. Ineffectiveness, if any, is measured at the end of each reporting period.

If the risk management hedge ratio used to form the economic relationship of the hedged item and hedging instrument changes, rebalancing of the hedging relationship is required. Under this circumstance, an adjustment to the quantities of the hedged item or hedging instrument would be allowed to realign the hedging relationship in accordance with the appropriate risk management hedge ratio. The Company can only discontinue hedge accounting prospectively if there is no longer an economic relationship between the hedged item and hedging instrument, the risk management objective changes, the derivative no longer is designated as a hedging instrument, or the underlying hedged item is derecognized.

Cash flow hedges

A cash flow hedge offsets the risk of volatility in the variable cash flows arising from a recognized asset or liability, a highly probable forecast transaction or a firm commitment in a foreign currency transaction. The effective portion of changes in fair value of the derivative is recognized in OCI, whereas the ineffective portion is recognized in earnings immediately. The cumulative gain or loss in accumulated other comprehensive income (AOCI) is transferred to earnings when the hedged item affects earnings. If a forecast transaction results in the recognition of a non-financial asset or liability, the amount in AOCI is added to the initial cost of the non-financial asset or liability.

If the Company discontinues hedge accounting, the cumulative gain or loss in AOCI is transferred to earnings at the same time as the hedged item affects earnings.

The amount in AOCI is immediately transferred to earnings if the hedged item is derecognized or it is probable that a forecast transaction will not occur in the originally specified time frame.

RETIREMENT BENEFITS

The Company accrues for its obligations under defined benefit pension and other post-employment benefit (OPEB) plans.

Pension plan assets at the balance sheet date are reported at market value. Accrued benefit obligations at the balance sheet date are determined using a discount rate that reflects market interest rates. The rates are equivalent to those on high quality corporate bonds that match the timing and amount of expected benefit payments.

The cost for defined benefit plans includes net interest expense. This expense is calculated by applying the discount rate to the net defined benefit asset or liability at the beginning of the year plus projected contributions and benefit payments during the year.

Gains and losses resulting from experience adjustments and changes in assumptions used to measure the accrued benefit obligations are recognized in OCI in the period in which they occur. Those gains and losses are then transferred directly to retained earnings.

Employer contributions to the defined contribution pension plans are expensed as employees render service.

For defined benefit pension plans and OPEB plans, service cost is recognized as an expense in salaries, wages and benefits, and net interest expense is recognized in interest expense. The cost of defined contribution pension plans is recognized as an expense in salaries, wages and benefits. Past service costs are recognized immediately in earnings in the period of a plan amendment or curtailment. The change in the present value of the defined benefit pension plans resulting from a curtailment is accounted for as a past service cost. When retirement benefit costs for employee services are incurred in constructing an asset and meet asset recognition criteria, they are included in the related property, plant and equipment or intangible asset.

SHARE-BASED COMPENSATION PLANS

The Company expenses stock options. The Company determines the fair value of the options on the date of grant. The fair value is recognized over the vesting period of the options granted by applying graded vesting, adjusted for estimated forfeitures. The fair value of the options is recorded in salaries, wages and benefits expense and contributed surplus. Contributed surplus is reduced as the options are exercised, and the amount initially recorded in contributed surplus is credited to Class A and Class B share capital.

Share Appreciation Rights (SARs) are cash-settled and are measured at fair value. The fair value is recognized over the vesting period of the SARs granted by applying graded vesting, adjusted for estimated forfeitures. The fair value of SARs is recorded in salaries, wages and benefits expense and accounts payable and accrued liabilities and other non-current liabilities. The liabilities are re-measured at each reporting period.

The mid-term incentive plan (MTIP) awards are equity-settled with shares purchased on the secondary market. They are measured at fair value based on the purchase price of the Company’s Class A non-voting shares at the date of grant. The awards are held by a trust until the shares are vested, at which time they are transferred to the employee. The fair value of the MTIP awards is recognized in salaries, wages and benefits expense over the vesting period, with a corresponding charge to contributed surplus.

RELATED PARTY TRANSACTIONS

Transactions with related parties in the normal course of business are measured at the exchange amount. Transfers or business combinations between entities under common control are measured at the carrying amount.

FOREIGN CURRENCY TRANSLATION

The consolidated financial statements are presented in Canadian dollars. Each entity within the Company determines its own functional currency based on the primary economic environment in which it operates. On consolidation, assets and liabilities of foreign operations are translated into Canadian dollars at the exchange rate at the balance sheet date. Revenues and expenses are translated at the average monthly exchange rates during the period. Gains or losses on translation are included in AOCI.

Transactions denominated in foreign currencies are translated at the exchange rate at the transaction date. Monetary assets and liabilities and non-monetary assets and liabilities measured at fair value denominated in a foreign currency are adjusted to reflect the exchange rate at the balance sheet date. Gains or losses on translation of these monetary and non-monetary items are recognized in earnings. Non-monetary items not measured at fair value are not retranslated after they are first recognized.

If the Company disposes of its entire interest in a foreign operation, or loses control, joint control, or significant influence over a foreign operation, the accumulated foreign currency translation gains or losses related to the foreign operation are recognized in earnings.

ACCOUNTING STANDARDS AND INTERPRETATIONS NOT YET ADOPTED

Certain new or amended standards or interpretations issued by the IASB or IFRIC do not need to be adopted in the current period. Standards issued, but not yet effective, which the Company anticipates may have a material effect on the consolidated financial statements or note disclosures are described below.

Standard	Description	Impact	Effective Date
IFRS 9 (2014) *Financial Instruments*	This final standard replaces IAS 39 *Financial Instruments: Recognition and Measurement* and previous versions of IFRS 9. It incorporates IFRS 9 (2013), with a further classification category for financial assets, and includes a new impairment model for financial instruments.	The Company has not yet determined the impact of the final standard.	Effective for annual periods on or after January 1, 2018. The Company will not early adopt this standard.
IFRS 15 *Revenue from Contracts with Customers*	This standard replaces previous guidance on revenue recognition. It provides a framework to determine when to recognize revenue and at what amount.	It applies to new contracts created on or after the effective date and to existing contracts not yet completed as of the effective date. The Company has not yet determined the impact of the final standard.	Effective for annual periods on or after January 1, 2018. The Company will not early adopt this standard.
IFRS 16 *Leases*	This standard replaces IAS 17 *Leases* and related interpretations. It introduces a new approach to lease accounting that requires a lessee to recognize assets and liabilities for the rights and obligations created by leases.	It brings most leases on-balance sheet for lessees, eliminating the distinction between operating and finance leases. However, lessor accounting remains similar to previous guidance and the distinction between operating and finance leases is retained. The Company has not yet determined the impact of the final standard.	Effective for annual periods on or after January 1, 2019. The Company will not early adopt this standard.

4. SIGNIFICANT JUDGMENTS, ESTIMATES AND ASSUMPTIONS

Management makes estimates and judgments that could significantly affect how policies are applied, amounts in the consolidated financial statements are reported, and contingent assets and liabilities are disclosed. Most often these estimates and judgments concern matters that are inherently complex and uncertain. Judgments and estimates are reviewed on an on-going basis; changes to accounting estimates are recognized prospectively.

Significant judgments and estimates made by the Company are outlined below.

SIGNIFICANT ACCOUNTING JUDGMENTS

Joint arrangements

Judgment is required when assessing the classification of a joint arrangement as a joint operation or a joint venture. When making this assessment, the Company considers the structure of the arrangements, the legal form of any separate vehicles, the contractual terms of the arrangements, and other facts and circumstances.

Impairment of long-lived assets

Indicators of impairment are considered when evaluating whether or not an asset is impaired. Factors which could indicate an impairment exists include: significant underperformance relative to historical or projected operating results, significant changes in the way in which an asset is used or in the Company's overall business strategy, significant negative industry or economic trends, or adverse decisions by regulators. Events indicating an impairment may be clearly identifiable or based on an accumulation of individually insignificant events over a period of time. Measurement uncertainty is increased where the Company is not the operator of a facility. The Company continually monitors its operating facilities and the markets and business environment in which it operates. Judgments and assessments about conditions and events are made order to conclude whether a possible impairment exists.

Property, plant and equipment and intangibles

The Company makes judgments to: assess the nature of the costs to be capitalized and the time period over which they are capitalized in the purchase or construction of an asset; evaluate the appropriate level of componentization where an asset is made up of individual components for which different depreciation and amortization methods and useful lives are appropriate; distinguish major overhauls to be capitalized from repair and maintenance activities to be expensed; and determine the useful lives over which assets are depreciated and amortized.

Leases

The Company evaluates contract terms and conditions to determine whether they contain or are leases. Where a lease exists, the Company determines whether substantially all of the significant risks and rewards of ownership are transferred to the customer, in which case it is accounted for as a finance lease, or remain with the Company, in which case it is accounted for as an operating lease.

Income taxes

The Company makes judgments with respect to changes in tax legislation, regulations and interpretations thereof. Judgment is also applied to estimating probable outcomes, when temporary differences will reverse, and whether tax assets are realizable.

When tax legislation is subject to interpretation, management periodically evaluates positions taken in tax filings and records provisions where appropriate. The provisions are management's best estimates of the expenditures required to settle the present obligations at the balance sheet date, using a probability weighting of possible outcomes.

SIGNIFICANT ACCOUNTING ESTIMATES AND ASSUMPTIONS

Revenue recognition

An estimate of usage not yet billed is included in revenues from the regulated distribution of natural gas and electricity. The estimate is derived from unbilled gas and electricity distribution services supplied to customers. This estimate is from the date of the last meter reading and uses historical consumption patterns. Management applies judgment to the measure and value of the estimated consumption.

Useful lives of property, plant and equipment and intangibles

Useful lives are estimated based on current facts and past experience taking into account the anticipated physical life of the asset, existing long-term sales agreements and contracts, current and forecast demand, and the potential for technological obsolescence.

Impairment of long-lived assets

The Company continually monitors its long-lived assets and the markets and business environment in which it operates for indications of asset impairment. Where necessary, the Company estimates the recoverable amount for the CGU to determine if an impairment loss is to be recognized. These estimates are based on assumptions, such as the price for which the assets in the CGU could be obtained or future cash flows that will be produced by the CGU, discounted at an appropriate rate. Subsequent changes to these estimates or assumptions could significantly impact the carrying value of the assets in the CGU.

Retirement benefits

Costs for the defined benefit pension and OPEB plans are determined using the projected unit credit method and reflect management's best estimates of investment returns, long-term inflation rate, wage and salary increases, age at retirement, liability discount rates and expected health care costs. The Company consults with qualified actuaries when setting the assumptions used to estimate benefit obligations and the cost of providing retirement benefits during the period. Key assumptions used to determine benefit cost and obligation are shown in Note 29.

Income taxes

Management periodically evaluates positions taken in tax filings where tax legislation is subject to interpretation, and records provisions where appropriate. The provisions are management's best estimates of the expenditures required to settle the present obligations at the balance sheet date measured using a probability weighting of possible outcomes.

5. SEGMENTED INFORMATION

SEGMENT DESCRIPTIONS AND PRINCIPAL ACTIVITIES

The Company's operating segments are reported in the same way as internal reporting provided to the Chief Operating Decision Maker (CODM). The CODM consists of the Office of the Chair, comprised of the Chair and Chief Executive Officer, and five other senior executives.

In the fourth quarter of 2015, the Company reorganized its operating subsidiaries into the following segments: Electricity, Pipelines & Liquids and Corporate & Other. Comparative amounts for prior periods have been restated to reflect the realigned segments. Management has determined that the operating subsidiaries in the reportable segments below share similar economic characteristics, as such they have been aggregated.

Electricity	The Electricity segment is comprised of the generation, distribution and transmission businesses of ATCO Electric, ATCO Power and ATCO Power Australia. Together these businesses provide power generation, distributed generation, and electricity distribution, transmission and infrastructure development in northern and central east Alberta, the Yukon, the Northwest Territories and Australia.
Pipelines & Liquids	The Pipelines & Liquids segment is comprised of ATCO Gas, ATCO Pipelines, ATCO Gas Australia, ATCO Energy Solutions and ATCO Pipelines Mexico. These businesses offer natural gas transmission, distribution and infrastructure development, natural gas liquids storage and processing, and industrial water solutions throughout Alberta, the Lloydminster area of Saskatchewan and Western Australia.
Corporate & Other	The Corporate & Other segment is comprised of commercial real estate owned by the Company in Alberta, business development activities associated with ATCO Energy and the Company's expansion into Mexico and also included ATCO I-Tek until August 2014. ATCO I-Tek was sold by the Company in August 2014 to WIPRO Ltd. (see Note 8). ATCO I-Tek developed, operated and supported the Company's information systems and technologies. The billing services, payment processing, credit, collection, and call centre services formerly provided by ATCO I-Tek were retained by the Company.

SEGMENTED RESULTS

Results by operating segment for the years ended December 31, 2015 and 2014 are shown below.

YEAR ENDED DECEMBER 31

2015 2014 (Restated)	Electricity	Pipelines & Liquids	Corporate & Other	Intersegment Eliminations	Consolidated
Revenues - external	**1,759**	**1,487**	**18**	**–**	**3,264**
	1,802	1,700	98	–	3,600
Revenues - intersegment	**12**	**38**	**31**	**(81)**	**–**
	2	23	140	(165)	–
Revenues	**1,771**	**1,525**	**49**	**(81)**	**3,264**
	1,804	1,723	238	(165)	3,600
Operating expenses (1)	**(874)**	**(960)**	**(56)**	**86**	**(1,804)**
	(886)	(1,137)	(191)	162	(2,052)
Depreciation, amortization and impairment (2)	**(343)**	**(297)**	**(5)**	**3**	**(642)**
	(290)	(206)	(22)	4	(514)
Gain on sales of operations and revaluation of joint venture	**25**	**5**	**–**	**–**	**30**
	–	–	160	–	160
(Loss) Earnings from investment in ATCO Structures & Logistics (2)	**–**	**–**	**(6)**	**–**	**(6)**
	–	–	18	–	18
Earnings from investment in joint ventures (2)	**12**	**–**	**–**	**–**	**12**
	15	–	–	–	15
Net finance costs	**(158)**	**(137)**	**11**	**(5)**	**(289)**
	(153)	(151)	10	(3)	(297)
Earnings (loss) before income taxes	**433**	**136**	**(7)**	**3**	**565**
	490	229	213	(2)	930
Income taxes	**(153)**	**(58)**	**5**	**1**	**(205)**
	(125)	(62)	(19)	–	(206)
Earnings (loss) for the year	**280**	**78**	**(2)**	**4**	**360**
	365	167	194	(2)	724
Adjusted earnings	**322**	**189**	**(29)**	**1**	**483**
	369	196	10	–	575
Total assets (3)	**11,060**	**6,394**	**704**	**(89)**	**18,069**
	10,550	5,762	507	(117)	16,702
Total liabilities (3)	**7,434**	**4,551**	**148**	**(257)**	**11,876**
	6,992	4,040	152	(89)	11,095
Capital expenditures (4)	**935**	**824**	**9**	**–**	**1,768**
	1,622	620	32	–	2,274

(1) *Includes total costs and expenses, excluding depreciation, amortization and impairment expense.*

(2) *Includes impairment of property, plant and equipment (see Note 12) and investment in joint venture (see Note 15).*

(3) *Total assets and total liabilities do not reflect adjustments for rate-regulated activities included in adjusted earnings.*

(4) *Includes additions to property, plant and equipment and intangibles and $97 million (2014 - $76 million) of interest capitalized during construction for the year ended December 31, 2015.*

GEOGRAPHIC SEGMENTS

Revenues - external [1]

	2015	2014
Canada	**3,034**	3,336
Australia	**230**	264
Total	**3,264**	3,600

(1) Revenues are attributed based on the country in which the good or service originated.

Non-current assets

	Property, Plant and Equipment		Intangible Assets		Other Assets [2]		Total	
	2015	2014	2015	2014	2015	2014	2015	2014
Canada	**14,572**	13,583	**476**	390	**346**	326	**15,394**	14,299
Australia	**1,122**	1,016	**8**	6	**37**	36	**1,167**	1,058
Other	**39**	9	**–**	–	**44**	18	**83**	27
Total	**15,733**	14,608	**484**	396	**427**	380	**16,644**	15,384

(2) Excludes financial instruments and deferred income tax assets.

ADJUSTED EARNINGS

Adjusted earnings are earnings attributable to equity owners of the Company after adjusting for the timing of revenues and expenses for rate-regulated activities and dividends on equity preferred shares of the Company. Adjusted earnings also exclude one-time gains and losses, significant impairments and items that are not in the normal course of business or a result of day-to-day operations. Adjusted earnings are a key measure of segment earnings used by the CODM to assess segment performance and allocate resources. Other accounts in the consolidated financial statements have not been adjusted as they are not used by the CODM for those purposes.

The reconciliation of adjusted earnings and earnings for the 2015 and 2014 year is shown below.

2015 2014 (Restated)	Electricity	Pipelines & Liquids	Corporate & Other	Intersegment Eliminations	Consolidated
Adjusted earnings	**322**	**189**	**(29)**	**1**	**483**
	369	196	10	–	575
Restructuring costs	**(32)**	**(36)**	**(14)**	**–**	**(82)**
	–	–	–	–	–
Gain on sales of operations and revaluation of joint venture	**19**	**4**	**4**	**–**	**27**
	–	–	138	–	138
Impairments	**(26)**	**(66)**	**(15)**	**–**	**(107)**
	(14)	(14)	–	–	(28)
Rate-regulated activities	**(10)**	**(18)**	**–**	**3**	**(25)**
	(1)	(21)	–	(2)	(24)
Dividends on equity preferred shares of Canadian Utilities Limited	**3**	**1**	**52**	**–**	**56**
	3	1	46	–	50
Earnings attributable to equity owners of the Company	**276**	**74**	**(2)**	**4**	**352**
	357	162	194	(2)	711
Earnings attributable to equity preferred share owners of subsidiary company					**8**
					13
Earnings for the year					**360**
					724

Restructuring costs

In 2015, the Company recorded restructuring costs of $82 million, after-tax, that were not in the normal course of business. These costs were primarily related to staff reductions and associated severance costs and lease termination costs.

Gain on sales of operations and revaluation of joint venture

In 2015, the Company adjusted for the gain of $19 million, after-tax, on the revaluation of the Company's existing ownership in Thames Power Limited and for the gain of $4 million, after-tax, on sale of certain non-core natural gas gathering and processing assets (see Note 8). The Company also adjusted for its share of the gain of $4 million, after-tax, included in equity earnings from investment in ATCO Structures & Logistics as a result of the sale of its Emissions Management business (see Note 14).

In 2014, the Company adjusted for the realized gain on sale of its information technology services (see Note 8). The gain was $138 million, after tax.

Impairments

In 2015, the Company adjusted for significant impairments of $26 million, after-tax, relating to power generation assets, $7 million, after-tax, relating to certain gas processing facilities and $59 million after-tax, relating to the Tula Pipeline Project in Mexico (see Note 12). The Company also adjusted for its share of the impairment included in equity earnings from investment in ATCO Structures & Logistics, which amounted to $15 million, after-tax (see Note 14).

In 2014, the Company adjusted for a significant impairment of $14 million, after-tax, relating to certain natural gas gathering, processing and liquids extraction assets in Canada (see Note 12), as well as an impairment of $11 million, after-tax,relating to ATCO Power Australia’s Bulwer Island power station (see Note 10). The Company also adjusted for impairments of $3 million, after-tax, related to its joint venture power generation assets in the U.K. (see Note 15).

Rate-regulated activities

There is currently no specific guidance under IFRS for rate-regulated entities that the Company is eligible to adopt. Consequently, the Company does not recognize assets and liabilities arising from rate-regulated activities under IFRS.

The Company uses standards issued by the Financial Accounting Standards Board (FASB) in the United States as another source of generally accepted accounting principles (GAAP) to account for rate-regulated activities. The CODM believes that earnings presented in accordance with the FASB standards are a better representation of the operating results of the Company’s rate-regulated activities. Therefore, the Company presents adjusted earnings as part of segment disclosures on this basis.

Rate-regulated accounting differs from IFRS in the following ways:

	Rate-Regulated Accounting Treatment	IFRS Treatment
1.	The Company defers the recognition of cash received in advance of future expenditures.	The Company records revenues when amounts are billed to customers and recognizes costs when they are incurred.
2.	The Company recognizes revenues associated with recoverable costs in advance of future billings to customers.	The Company records costs when incurred, but does not recognize their recovery until changes to customer rates are reflected in future customer billings.
3.	The Company recognizes the earnings from a regulatory decision pertaining to current and prior periods when the decision is received.	The Company recognizes earnings when customer rates are changed and amounts are billed to customers.
4.	Intercompany profits on the manufacture or construction of facilities for a regulated public utility in the consolidated group are deemed to have been realized to the extent that the transfer price on such facilities is recognized for rate-making purposes by a regulator.	Intercompany profits are eliminated upon consolidation. The Company then recognizes those profits in earnings as amounts are billed to customers over the life of the related asset.

Timing adjustments for rate-regulated activities are as follows:

	2015	2014
Additional revenues billed in current period:		
Future removal and site restoration costs (1)	**35**	23
Retirement benefits (2)	**(1)**	1
Finance costs on major transmission capital projects (3)	**62**	46
Impact of colder temperatures on revenues (4)	**–**	7
Other	**6**	10
	102	87
Revenues to be billed in future periods:		
Deferred income taxes (5)	**(95)**	(86)
Deferred income taxes due to increase in provincial corporate tax rate (5)	**(67)**	–
Transmission access payments (6)	**(8)**	(7)
Transmission capital deferral (7)	**–**	(6)
Impact of warmer temperatures on revenues (4)	**(20)**	–
Impact of inflation on rate base for ATCO Gas Australia (8)	**(11)**	(8)
Other	**–**	(10)
	(201)	(117)
Regulatory decisions related to current and prior periods:		
Generic cost of capital decision (9)	**41**	–
Capital tracker decision (9)	**12**	–
ATCO Gas Australia access arrangement decision (9)	**19**	–
Evergreen decision(9)	**–**	4
Transmission access payment recoveries (9)	**10**	13
Transmission capital deferral refunds (9)	**(20)**	(10)
ATCO Gas Australia appeal decision	**–**	4
Refunds relating to temperature fluctuations (4)	**(3)**	(4)
Other	**16**	2
	75	9
Intercompany profits:		
Intercompany profits related to construction of property, plant and equipment and intangibles (10)	**(1)**	(3)
	(25)	(24)

Descriptions of the adjustments, and the timing of recovery or refund, are as follows:

	Description	Timing of Recovery or Refund
1.	Removal and site restoration costs billed to customers are based on the costs forecast to be incurred in future periods. Customers fund these expected costs over the estimated useful life of the related assets. Under rate-regulated accounting, billings to customers in excess of costs incurred in the current period are deferred.	The deferred revenues will be recognized in adjusted earnings when removal and site restoration costs are incurred.
2.	Contributions to defined benefit pension plans and other post-employment benefit plans are billed to customers when paid by the Company, whereas the costs of retirement benefits are accrued over the service life of the employees. Under rate-regulated accounting, contributions paid and billed to customers in excess of costs accrued in the current period are deferred.	The deferred revenues will be recognized in adjusted earnings as the variances between contributions and costs reverse over the life of the plans.
3.	Finance costs incurred by ATCO Electric during construction of major transmission capital projects are billed to customers when incurred. Under rate-regulated accounting, the finance costs billed to customers are deferred.	The deferred revenues will be recognized in adjusted earnings over the service life of the related assets.
4.	ATCO Gas' customer rates are based on a forecast of normal temperatures. Fluctuations in temperatures may result in more or less revenue being recovered from customers than forecast. Under rate-regulated accounting, revenues above or below the norm in the current period are deferred and refunded to or recovered from customers in future periods.	ATCO Gas may apply to the AUC for recoveries from or refunds to customers when the net revenue variances exceed $7 million at April 30th of any year for either of its North or South systems.
5.	Deferred income taxes are a non-cash expense resulting from temporary differences between the book value and the tax value of assets and liabilities. Income taxes are billed to customers when paid by the Company. Deferred income taxes are not billed to customers unless directed to do so by the regulator. Under rate-regulated accounting, revenues are recognized in the current period for the deferred income taxes to be billed to customers in future periods. In the second quarter of 2015, the Government of Alberta announced an increase in the provincial corporate tax rate from 10 per cent to 12 per cent effective July 1, 2015. As a result of this change, the Company increased income taxes and reduced earnings for the year ended December 31, 2015 by $70 million (see Note 9). Of the $70 million increase in income taxes, $67 million relates to deferred income taxes relating to the Alberta utilities.	The revenues will reverse when the temporary differences that gave rise to the deferred income taxes reverse in future periods.

6.	Transmission access payments billed to customers by ATCO Electric are based on the forecast payments to be incurred. Under rate-regulated accounting, differences between actual costs incurred and forecast costs billed to customers are deferred for collection from or refund to customers in future periods.	Recoveries from or refunds to customers of the differences between transmission access payments billed to customers and paid by ATCO Electric are expected to occur in the next 6 to 12 months.
7.	For major transmission capital projects, ATCO Electric's billings to customers include a return on forecast rate base. When actual capital costs vary from forecast capital costs, the return on rate base, and the resulting billings to the Alberta Electric System Operator (AESO), will be higher or lower than expected. Under rate-regulated accounting, differences between billings to the AESO and the return on actual rate base are deferred.	Recoveries from or refunds to the AESO of variances between forecast and actual returns on rate base are expected to occur in the following year.
8.	ATCO Gas Australia earns a return on rate base that excludes inflation. Inflation is accounted for by adjusting the rate base in subsequent periods by the actual rate of inflation; the impact of inflation is billed to customers through recovery of depreciation. Under rate-regulated accounting, an adjustment is made to recognize the inflation component of rate base when it is earned in the current period. Differences between the amounts earned and the amounts billed to customers are deferred.	The inflation-indexed portion of rate base will be recovered from customers over the life of the assets comprising rate base through the recovery of depreciation.
9.	The Canadian and Australian utilities recognize revenues from regulatory decisions when customer rates are changed and amounts are billed to customers. Under rate-regulated accounting, revenues from regulatory decisions that affect current and prior periods are recognized when the decision is received.	**Generic Cost of Capital Decision** The utilities recorded a reduction in adjusted earnings of $51 million in 2015 for an AUC decision which reduced the Return on Equity and deemed common equity ratios for 2013 to 2015. Of the $51 million recorded in 2015, $31 million related to 2013 and 2014. Under IFRS, earnings will be adjusted when the AUC approves revised customer rates and the amount payable to customers is refunded through future billings; $10 million has been refunded as at the end of the year 2015. **Capital Tracker Decision** ATCO Gas and the distribution operations of ATCO Electric recorded a reduction in adjusted earnings of $16 million in 2015 for the AUC Performance Based Regulation Capital Tracker decisions for 2013 to 2015. Of the $16 million recorded in 2015, $8 million related to 2013 and 2014. Although these decisions included approval of the Company's applied for Capital Tracker programs, the decisions resulted in lower Capital Tracker rates than previously approved primarily due to the AUC requiring the utilities to use the actual cost of debt in the rate determinations, which was lower than the forecast cost of debt that was previously being used.

	Under IFRS, earnings will be adjusted when the AUC approves revised customer rates and the amount payable to customers is refunded through future billings; $4 million has been refunded as at the end of the year 2015. **ATCO Gas Australia Access Arrangement Decision** In July 2015, the Economic Regulation Authority (ERA) released its final decision for ATCO Gas Australia's next Access Arrangement period (AA4) from July 2014 to December 2019. Among other things, the decision resulted in a reduced return on equity from 10.4 per cent to 7.28 per cent. The decision resulted in a decrease to adjusted earnings of $19 million in 2015. Of this amount, $7 million related to 2015 and $12 million related to 2014. Under IFRS, earnings will be adjusted when the Economic Regulation Authority of Western Australia approves revised customer rates and the amount payable to customers is refunded through future billings. **Evergreen Decision** The utilities recorded a reduction in adjusted earnings of $32 million in 2014 for an AUC decision which disallowed a portion of the information technology and customer care and billing costs (Evergreen decision) incurred in the period 2010 to 2014. In the fourth quarter of 2014, customer rates were adjusted and $28 million was refunded to customers. **Transmission Access Payment Recoveries** In 2014 and 2015, actual payments for transmission access paid by ATCO Electric exceeded forecast costs included in billings to customers. These excess costs are subsequently recovered from customers. **Transmission Capital Deferral Refunds** In 2014 and 2015, ATCO Electric refunded amounts to customers over-collected in 2011 and 2012 for major transmission capital projects.
10. Under rate-regulated accounting, intercompany profits from transactions with related parties and approved by the regulator for inclusion in rate base are not eliminated on consolidation; they are recognized as earnings in the current period.	Intercompany profits will be recognized as earnings under IFRS as rate base is depreciated and the depreciation is billed to customers over the life of the assets.

6. REVENUES

The components of revenues are as follows:

	2015	2014
Sale of goods	**445**	798
Rendering of services	**2,602**	2,592
Operating lease income	**186**	176
Finance lease income	**31**	34
	3,264	3,600

7. OTHER COSTS AND EXPENSES

Other costs and expenses are as follows:

	2015	2014
Goods and services (1)	**188**	219
Rent and utilities	**46**	43
Realized (gains) losses on derivatives	**(6)**	3
Unrealized losses (gains) on derivatives	**1**	(14)
	229	251

(1) Goods and services include professional fees, contractor costs, technology related expenses, advertising, and other general and administrative expenses.

8. SALES OF OPERATIONS AND REVALUATION OF JOINT VENTURE

REVALUATION OF EXISTING INTEREST IN JOINT VENTURE

On November 2, 2015, the Company increased its ownership in Thames Power Limited (TPL) from 50 per cent to 100 per cent. TPL owns a 51 per cent joint interest in Barking Power Limited, an entity that holds land assets in the U.K. Cash consideration for the purchase was $25 million. The transaction was accounted for as an asset acquisition and resulted in a revaluation gain of $25 million ($19 million after-tax) on the Company's existing ownership interest in TPL, and its related entities. This transaction was performed to strategically position the Company for future opportunities in the U.K. market.

TPL also has a 100 per cent ownership interest in Thames Power Services Limited, which has a defined benefit plan for employees. In 2015, trustees for the pension plan entered into a policy with Pension Insurance Corporation (PIC) and transferred the majority of plan assets to PIC in order to secure the benefits of the defined benefit plan. The pension plan assets and liabilities are included in the Company's retirement benefits obligations at December 31, 2015 (see Note 29). Individual policies are expected to be issued to members in 2016, at which time TPL will no longer have a legal obligation for benefits under the defined benefit plan.

SALE OF NATURAL GAS GATHERING AND PROCESSING ASSETS

On December 31, 2015, the Company sold certain non-core natural gas gathering and processing assets for proceeds of $7 million cash, resulting in a gain of $5 million ($4 million after-tax). Commencing December 31, 2015, the Company no longer recognizes these assets in its financial position, results of operations and cash flows in the consolidated financial statements. These assets were previously reported in the Pipelines & Liquids segment.

SALE OF INFORMATION TECHNOLOGY SERVICES

On August 15, 2014, the Company sold its 100 per cent ownership interest in ATCO I-Tek's information technology services as well as the assets of ATCO I-Tek Australia for proceeds of $204 million cash, resulting in a gain of $160 million ($138 million after-tax). This sale included current contracts and operational assets consisting of computer hardware and most software licenses. The Company retained the customer care and billing functions formerly provided by ATCO I-Tek as well as certain key enterprise-wide software licenses. Commencing August 15, 2014, the Company no longer recognizes ATCO I-Tek and ATCO I-Tek Australia's information technology services in its financial position, results of operations and cash flows in the consolidated financial statements. ATCO I-Tek and ATCO I-Tek Australia were previously reported in the Corporate & Other segment.

9. INCOME TAXES

CHANGE IN INCOME TAX RATE

In the second quarter of 2015, the Government of Alberta announced an increase in the provincial corporate tax rate from 10 per cent to 12 per cent effective July 1, 2015. As a result of this change, the Company made an adjustment of $70 million to current and deferred income taxes in 2015 as follows:

	Balance at December 31, 2014	Year Ended December 31, 2015	Total
Change in Alberta corporate tax rate included in:			
Current income taxes	–	1	1
Deferred income taxes	62	7	69
	62	8	70

INCOME TAX EXPENSE

The components of income tax expense are summarized below.

	2015	2014
Current income tax expense		
Canada	**23**	68
Australia	**11**	6
Adjustment in respect of prior years	**(1)**	(1)
	33	73
Deferred income tax expense		
Reversal of temporary differences	**102**	131
Amount relating to change in tax rates	**69**	–
Adjustment in respect of prior years	**1**	2
	172	133
	205	206

The reconciliation of statutory and effective income tax expense is as follows:

	2015		2014	
Earnings before income taxes	**565**	**%**	930	%
Income taxes, at statutory rates	**147**	**26.0**	233	25.0
Change in deferred income taxes resulting from increase in provincial corporate tax rate	**69**	**12.2**	–	–
International financing	**(10)**	**(1.8)**	(12)	(1.3)
Foreign tax rate variance	**1**	**0.2**	3	0.3
Equity earnings	**1**	**0.2**	(7)	(0.7)
Disposition of investment at capital gains rate	**–**	**–**	(18)	(1.9)
Tax cost of preferred share financings	**3**	**0.5**	2	0.2
Other	**(6)**	**(1.0)**	5	0.6
	205	**36.3**	206	22.2

As the tax rate change came into effect on July 1, 2015, the combined federal and Alberta statutory Canadian income tax rate for 2015 is 26.0 per cent (2014 - 25.0 per cent). Changes in income tax rates in foreign jurisdictions were not material.

INCOME TAX ASSETS AND LIABILITIES

Income tax assets and liabilities in the consolidated balance sheet at December 31 are summarized below.

	Balance Sheet Presentation	2015	2014
Income tax assets			
Current	Prepaid expenses and other current assets	**26**	17
Deferred	Deferred income tax assets	**63**	24
		89	41
Income tax liabilities			
Current	Other current liabilities	**12**	15
Deferred	Deferred income tax liabilities	**983**	740
		995	755

DEFERRED INCOME TAXES

The changes in deferred income tax assets and liabilities are as follows:

	Property, Plant and Equipment	Intangibles	Reserves	Tax Loss Carry Forwards and Tax Credits	Retirement Benefit Obligations	Other	Total
Deferred income tax assets							
December 31, 2013	(17)	(4)	35	11	3	–	28
Credit (charge) to earnings	6	–	(3)	(10)	–	3	(4)
Disposition	(1)	4	–	–	(3)	1	1
Other	–	–	–	–	–	(1)	(1)
December 31, 2014	**(12)**	**–**	**32**	**1**	**–**	**3**	**24**
Credit (charge) to earnings	**35**	**–**	**–**	**2**	**2**	**(1)**	**38**
Charge to other comprehensive income	**–**	**–**	**–**	**–**	**(1)**	**–**	**(1)**
Other	**1**	**–**	**1**	**(1)**	**–**	**1**	**2**
December 31, 2015	**24**	**–**	**33**	**2**	**1**	**3**	**63**
Deferred income tax liabilities							
December 31, 2013	759	45	(29)	(15)	(101)	(8)	651
Charge (credit) to earnings	109	37	(8)	(22)	(1)	14	129
Charge (credit) to other comprehensive income	–	–	1	–	(37)	(3)	(39)
Disposition	–	–	–	–	–	(2)	(2)
Other	–	–	–	3	–	(2)	1
December 31, 2014	**868**	**82**	**(36)**	**(34)**	**(139)**	**(1)**	**740**
Charge (credit) to earnings	**221**	**17**	**(1)**	**(58)**	**2**	**29**	**210**
Charge to other comprehensive income	**–**	**–**	**–**	**–**	**41**	**–**	**41**
Acquisition of TPL *(Note 8)*	**–**	**–**	**–**	**–**	**(9)**	**–**	**(9)**
Other	**(1)**	**–**	**–**	**1**	**(1)**	**2**	**1**
December 31, 2015	**1,088**	**99**	**(37)**	**(91)**	**(106)**	**30**	**983**

The Company expects approximately $9 million of its deferred income tax assets to reverse within the next twelve months (2014 - nil).

At the end of 2015, the Company had $376 million in tax losses and credits, which expire on the following dates:

	Non-Capital Losses
2029	1
2030	1
2031	18
2032	1
2033	49
2034	79
2035	203
Do not expire	24

The Company recorded deferred income tax assets of $93 million for losses and credits that expire. No deferred income tax assets were recorded for losses that do not expire.

The Company recorded deferred income tax assets of $2 million (2014 - nil) directly to equity.

The Company had $16 million (2014 - $34 million) of aggregate temporary differences for investments in subsidiaries, branches and joint ventures for which deferred income tax liabilities were not recognized.

10. LEASES

THE COMPANY AS LESSOR

The Company is party to certain arrangements that convey the right to use power generation and non-regulated electricity transmission assets. These arrangements are classified as finance leases, with the Company as the lessor. Certain assets under PPAs are classified as operating leases as the Company (as lessor) still retains substantially all the risks and rewards of ownership.

Finance leases

The total net investment in finance leases is shown below. Finance lease income is recognized in revenues.

	2015	2014
Net investment in finance leases		
Finance lease - gross investment	**635**	654
Unearned finance income	**(326)**	(346)
Unguaranteed residual value	**2**	2
	311	310
Current portion	**9**	20
Non-current portion	**302**	290
	311	310
Gross receivables from finance leases		
In one year or less	**42**	53
In more than one year, but not more than five years	**191**	159
In more than five years	**402**	442
	635	654
Net investment in finance leases		
In one year or less	**9**	20
In more than one year, but not more than five years	**55**	38
In more than five years	**247**	252
	311	310

During the year ended December 31, 2015, $4 million of contingent rent was recognized as income from these finance leases (2014 - $4 million).

Impairment

In June 2014, the Company recognized a pre-tax impairment of $12 million relating to ATCO Power Australia's 33 MW Bulwer Island power station (BIEP) (Electricity segment), which was included in depreciation, amortization and impairment expense. On April 2, 2014, BP announced it will cease refining operations at its oil refinery in Brisbane by mid-2015 and convert to an import terminal. BP was BIEP's only customer and no suitable economic replacement had been identified.

BIEP was jointly owned with Origin Energy and the plant was accounted for as a finance lease. As a result, BIEP's lease receivable had been impaired. The impairment calculation was based on pre-tax cash flow projections of the separation payments due from BP, salvage value of the plant and the expected remaining lease payments assuming a plant closure date of May 31, 2015. The plant subsequently closed on June 23, 2015, at which time the lease receivable was written down to nil. The expected future cash flows were discounted at a pre-tax rate of 12.4 per cent, which was the original effective interest rate of the lease receivable.

Operating leases

The aggregate future minimum lease payments receivable under non-cancellable operating leases were:

	2015	2014
Minimum lease payments receivable:		
In one year or less	**155**	157
In more than one year, but not more than five years	**640**	701
In more than five years	**82**	158
	877	1,016

During the year ended December 31, 2015, $30 million of contingent rent was recognized as income from these operating leases (2014 - $24 million).

THE COMPANY AS LESSEE

The Company's operating leases are mainly long-term leases for office premises and equipment.

Operating leases

During the year ended December 31, 2015, $41 million was recognized as an expense for these operating leases (2014 - $34 million). There were $2 million in sublease payments received for these operating leases (2014 - nil).

11. INVENTORIES

Inventories at December 31 were comprised of:

	2015	2014
Natural gas and fuel in storage	**20**	21
Raw materials and consumables	**23**	63
Work-in-progress	**1**	1
	44	85

For the year ended December 31, 2015, inventories recognized as an expense were $85 million (2014 - $113 million).

No inventories are pledged as security for liabilities.

12. PROPERTY, PLANT AND EQUIPMENT

The Company continues to make significant investment in utility infrastructure in Alberta, particularly in electricity transmission facilities.

A reconciliation of the changes in the carrying amount of property, plant and equipment is as follows:

	Utility Transmission & Distribution	Power Generation	Land and Buildings	Construction Work-in-Progress	Other	Total
Cost						
December 31, 2013	12,384	1,968	548	1,643	1,010	17,553
Additions	1,225	11	67	759	128	2,190
Disposals	(75)	(9)	(8)	(12)	(107)	(211)
Changes to asset retirement costs	–	10	–	–	32	42
Foreign exchange rate adjustment	(5)	–	(1)	–	(1)	(7)
December 31, 2014	**13,529**	**1,980**	**606**	**2,390**	**1,062**	**19,567**
Additions	**3,066**	**104**	**55**	**(1,638)**	**108**	**1,695**
Disposals	**(73)**	**(54)**	**(7)**	**(14)**	**(98)**	**(246)**
Changes to asset retirement costs	**8**	**4**	**–**	**–**	**(41)**	**(29)**
Foreign exchange rate adjustment	**71**	**–**	**1**	**9**	**3**	**84**
December 31, 2015	**16,601**	**2,034**	**655**	**747**	**1,034**	**21,071**
Accumulated depreciation						
December 31, 2013	2,894	1,153	117	–	484	4,648
Depreciation and impairment	313	64	18	–	79	474
Disposals	(69)	(9)	(3)	–	(80)	(161)
Foreign exchange rate adjustment	(2)	–	–	–	–	(2)
December 31, 2014	**3,136**	**1,208**	**132**	**–**	**483**	**4,959**
Depreciation and impairment	**357**	**106**	**10**	**85**	**53**	**611**
Disposals	**(73)**	**(53)**	**(5)**	**–**	**(98)**	**(229)**
Changes to asset retirement costs	**–**	**–**	**–**	**–**	**(12)**	**(12)**
Foreign exchange rate adjustment	**7**	**–**	**–**	**–**	**2**	**9**
December 31, 2015	**3,427**	**1,261**	**137**	**85**	**428**	**5,338**
Net book value						
December 31, 2014	10,393	772	474	2,390	579	14,608
December 31, 2015	**13,174**	**773**	**518**	**662**	**606**	**15,733**

The additions of property, plant and equipment included $97 million of interest capitalized (2014 - $76 million). Interest rates ranged from 2.76 per cent to 5.50 per cent (2014 - 4.28 per cent to 6.90 per cent).

Construction work-in-progress additions in 2015 are net of transfers of $2,893 million to other property, plant and equipment categories (2014 - $909 million).

Property, plant and equipment with a carrying value of $358 million were pledged as security for liabilities at December 31, 2015 (2014 - $337 million).

IMPAIRMENTS

Electricity Segment

Power Generation Assets

In December 2015, the Company recognized a pre-tax impairment of $35 million relating to the Battle River units 3 and 4 power generation assets in the Electricity segment. The impairment was included in depreciation, amortization and impairment expense. The Company determined that the net book value of these assets were not recoverable due to new environmental regulations which impacted emissions costs and ongoing soft market conditions in the Alberta power market. Management made assumptions about operating costs, forward Alberta power pool prices to forecast expected future cash flows. The cash flows were discounted at a pre-tax rate of 12 per cent. After recognizing this impairment, the recoverable amount of these assets was nil at December 31, 2015. This amount was determined using value in use.

Pipelines & Liquids Segment

Gas Gathering and Processing Assets

In December 2015, the Company recognized a pre-tax impairment of $9 million relating to certain gas processing facilities. The impairment was included in depreciation, amortization and impairment expense. The Company determined that the carrying value of these assets exceeded the recoverable amounts due to a significant and prolonged decline in commodity prices which reduced future cash flow forecasts. Management made assumptions about gas volumes, the price of natural gas, and operational capacity based on industry information and company forecasts of expected future cash flows. The cash flows were discounted at a pre-tax rate of 10 per cent. After recognizing this impairment, the recoverable amount of these assets was $9 million at December 31, 2015. This amount was determined using value in use.

In December 2014, the Company recognized a pre-tax impairment of $18 million based on a fair market value assessment of integrated gas system assets which are comprised of certain gas gathering and processing facilities and natural gas liquids extraction plants. The impairment was included in depreciation, amortization and impairment expense. The Company determined these assets were no longer economically viable due to declining gas production in the service area and deteriorating condition of these assets which would pose operational and financial risk. The impairment charge decreased the carrying amount of these assets to nil.

Mexico Tula Pipeline

In December 2015, the Company recognized a pre-tax impairment of $85 million relating to its Tula Pipeline Project in Mexico. The impairment was included in depreciation, amortization and impairment expense. The Company determined these construction work in progress assets were impaired as a result of significantly higher land access costs than originally forecast. The expected future cash flows were discounted at an after-tax rate of 9 per cent. After recognizing this impairment, the recoverable amount of these assets was $63 million at December 31, 2015. This amount was determined using a fair value less cost to sell model. If the discount rate was increased by 1 per cent the impairment would increase by $10 million.

13. INTANGIBLES

Intangible assets consist mainly of computer software not directly attributable to the operation of property, plant and equipment and land rights.

A reconciliation of the changes in the carrying amount of intangible assets is as follows:

	Computer Software	Land Rights	Other	Total
Cost				
December 31, 2013	430	197	33	660
Additions	52	32	–	84
Disposals	(36)	–	(6)	(42)
December 31, 2014	**446**	**229**	**27**	**702**
Additions	**51**	**73**	**7**	**131**
Disposals	**(4)**	–	**(2)**	**(6)**
Foreign exchange rate adjustment	–	–	**1**	**1**
December 31, 2015	**493**	**302**	**33**	**828**
Accumulated amortization				
December 31, 2013	250	30	10	290
Amortization	37	2	2	41
Disposals	(24)	–	(1)	(25)
December 31, 2014	**263**	**32**	**11**	**306**
Amortization	**39**	**3**	**1**	**43**
Disposals	**(4)**	–	**(2)**	**(6)**
Foreign exchange rate adjustment	–	–	**1**	**1**
December 31, 2015	**298**	**35**	**11**	**344**
Net book value				
December 31, 2014	183	197	16	396
December 31, 2015	**195**	**267**	**22**	**484**

14. INVESTMENT IN ATCO STRUCTURES & LOGISTICS

The Company has an ownership interest of 24.5 per cent in ATCO Structures & Logistics, which offers workforce housing, innovative modular facilities, construction, site support services, and logistics and operations management.

The summarized financial information for ATCO Structures & Logistics, which is accounted for using the equity method, is provided below.

	2015	2014
Balance sheet:		
Current assets	**446**	424
Non-current assets	**483**	534
Current liabilities	**(156)**	(157)
Non-current liabilities	**(123)**	(146)
Net assets	**650**	655

	2015	2014
Statement of earnings and comprehensive income:		
Revenues	**869**	962
(Loss) earnings for the year	**(22)**	75
Other comprehensive income	**47**	9
Comprehensive income for the year	**25**	84
Dividends received from ATCO Structures & Logistics	**7**	7

Reconciliation of the above summarized financial information to the carrying amount of the investment in ATCO Structures & Logistics recognized in the consolidated financial statements is as follows:

	2015	2014
Net assets	**650**	655
Proportion of the Company's ownership	**24.5%**	24.5%
	159	160
Fair value adjustment on acquisition	**43**	43
Carrying amount of the investment	**202**	203

SALE OF ATCO EMISSIONS MANAGEMENT

On December 31, 2015, ATCO Structures & Logistics completed the sale of its Emissions Management business. Included in the sale was all of Emissions Management's global operations in Canada, United States and Mexico and the transfer of current contracts and employees. Proceeds on the sale were $60 million, of which $10 million will be received in 2016, subject to a working capital adjustment true-up. The one-time after-tax gain was $18 million. The Company's 24.5 per cent share of the gain on sale contributed $4 million to equity earnings in the Corporate & Other segment.

IMPAIRMENT OF LODGE AND WORKFORCE HOUSING ASSETS

In 2015, ATCO Structures & Logistics recognized an after-tax impairment of $63 million relating to certain lodge and workforce housing assets. ATCO Structures & Logistics determined these assets were impaired due to a reduction in utilization, contracted rooms and rates charged as a result of continued and sustained decreases in key commodity prices as well as a significant reduction in the capital expenditure programs of key clients. The Company's 24.5 per cent share of the impairment decreased equity earnings by $15 million in the Corporate & Other segment.

15. JOINT ARRANGEMENTS

A joint arrangement is one in which two or more parties have joint control. The Company classifies its interests in joint arrangements as either joint operations or joint ventures depending on the Company's rights to the assets and obligations for the liabilities of the arrangements. Joint arrangements that are not structured as separate vehicles and give all parties direct rights to the assets and direct obligations for the liabilities under the arrangements are classified as joint operations. Joint arrangements that are structured as separate vehicles and provide all parties with rights to the net assets of the entities under the arrangements are classified as joint ventures.

JOINT OPERATIONS

Significant joint operations at December 31, 2015, are listed below.

Significant Joint Operations	Operating Jurisdiction	Ownership %	Principal Activity
Electricity:			
Sheerness Generating Plant	Canada	50.0	Electricity generation
Joffre Cogeneration Plant	Canada	40.0	Electricity generation
Cory Cogeneration Plant	Canada	50.0	Electricity generation
Muskeg River Cogeneration Plant	Canada	70.0	Electricity generation

JOINT VENTURES

The following joint ventures are considered the most significant; however, they are not individually material to the operations of the Company.

Significant Joint Ventures	Operating Jurisdiction	Ownership %	Principal Activity
Electricity:			
Brighton Beach Plant	Canada	50.0	Electricity generation
Osborne Cogeneration Plant	Australia	50.0	Electricity generation
Barking Power Limited	United Kingdom	51.0	Land assets
Pipelines & Liquids:			
Strathcona Storage Limited Partnership	Canada	60.0	Hydrocarbon storage

Aggregate information for the Company's interest in joint ventures is shown below.

	2015	2014
Earnings for the year	**12**	15
Other comprehensive loss	**(1)**	(9)
Comprehensive income for the year	**11**	6
Aggregate carrying amount of interests in joint ventures	**175**	119

STRATHCONA STORAGE LIMITED PARTNERSHIP

In 2015, the Company, contributed $28 million to the Strathcona Storage Limited Partnership, which is developing four salt caverns for hydrocarbon storage (2014 - $35 million).

BARKING POWER LIMITED

In October 2014, the Company, together with its partners, made the decision to close the 1,000 MW Barking generating plant in the U.K. ATCO Power had a 25.5 per cent ownership interest in this plant. On-going weakness in the U.K. economy and increased competition from renewable energy due to significant regulatory changes resulted in declining projected U.K. energy margins and continued losses for the Barking operations. As a result of the decision to close the plant, the Company recognized an impairment of $3 million in equity earnings in the Electricity segment in the fourth quarter of 2014. Subsequent to the closure of the plant, the only asset is land.

On November 2, 2015, the Company increased its ownership in TPL from 50 per cent to 100 per cent (see Note 8). TPL was previously accounted for as a joint venture and is now consolidated. TPL owns a 51 per cent joint interest in Barking Power Limited, which continues to be accounted for as a joint venture.

COMMITMENTS

The joint ventures have contractual obligations in the normal course of business. The Company's share of these contractual obligations and the future minimum undiscounted contractual maturities are as follows:

	2016	2017	2018	2019	2020	2021 and thereafter
Accounts payable and accrued liabilities	23	–	–	–	–	–
Non-recourse long-term debt	13	14	16	17	15	43
Interest expense	7	6	5	4	4	5
Operating and maintenance agreements	2	2	2	2	2	–
Capital expenditures	47	–	–	–	–	–
Derivatives	1	–	–	–	–	–
Other	1	3	1	–	–	8
	94	25	24	23	21	56

SIGNIFICANT RESTRICTIONS

The Company requires approval from its joint venture partners before any dividends or distributions can be paid.

16. BANK INDEBTEDNESS AND LINES OF CREDIT

The Company has the following lines of credit that enable it to obtain financing for general business purposes:

			2015			2014
	Total	Used	Available	Total	Used	Available
Long-term committed	**2,254**	**430**	**1,824**	2,227	494	1,733
Uncommitted	**303**	**124**	**179**	53	4	49
	2,557	**554**	**2,003**	2,280	498	1,782

Long-term committed credit facilities have maturities greater than one year. Uncommitted credit facilities have no set maturity and the lender can demand repayment at any time.

Of the $554 million used at December 31, 2015, $1 million was current bank indebtedness, $430 million was long-term debt and $123 million represented outstanding letters of credit (2014 - $4 million was current bank indebtedness, $404 million was long-term debt and $90 million represented outstanding letters of credit).

17. ASSET RETIREMENT OBLIGATIONS AND OTHER PROVISIONS

AROs represent the present value of the costs to be incurred to retire the Company's power generation plants and natural gas liquids extraction and processing plants. The other provision relates to restructuring costs.

The changes in AROs and other provisions are as follows:

	Asset Retirement Obligations	Other	Total
December 31, 2013	151	41	192
Additions	4	8	12
Utilized in the year	(2)	(40)	(42)
Reversals of unused amounts	–	(5)	(5)
Accretion expense	5	–	5
Revisions in discount rate	37	–	37
Foreign exchange rate adjustment	–	2	2
December 31, 2014	**195**	**6**	**201**
Additions	**8**	**30**	**38**
Utilized in the year	**(6)**	**(7)**	**(13)**
Reversals of unused amounts	**(16)**	**–**	**(16)**
Accretion expense	**3**	**–**	**3**
Revisions in discount rate	**(26)**	**–**	**(26)**
December 31, 2015	**158**	**29**	**187**
Current	**7**	**28**	**35**
Non-current	**151**	**1**	**152**
	158	**29**	**187**

ASSET RETIREMENT OBLIGATIONS

The Company estimates that the undiscounted amount of cash flows required to settle the AROs is approximately $578 million, which will be incurred between 2016 and 2111. The weighted average pre-tax, risk-free discount rate used to calculate the fair value of the AROs was 2.90 per cent (2014 - 2.12 per cent).

OTHER PROVISIONS

In order to maintain the Company's competitive position, a far reaching restructuring and transformation process was implemented in 2015. The Company has provided for staff and other costs directly attributable to restructuring, including lease termination, at December 31, 2015. The Company expects that restructuring costs will be incurred in the next year.

18. LONG-TERM DEBT AND NON-RECOURSE LONG-TERM DEBT

LONG-TERM DEBT

Long-term debt outstanding is shown in the table below.

	Effective Interest Rate	2015	2014
CU Inc. debentures - unsecured	5.046% (2014 - 5.146%)	**6,950**	6,300
(interest is the average effective interest rate weighted by principal amounts outstanding)			
CU Inc. other long-term obligation, due December 2017 - unsecured	2.700%	**3**	3
Canadian Utilities Limited debentures - unsecured 2012 3.122% due November 2022	3.187%	**200**	200
Less: Deferred financing charges		**(38)**	(35)
		7,115	6,468
ATCO Power Australia credit facility, payable in Australian dollars, at BBSY Rates, due February 2020, secured by a pledge of project assets and contracts, $84 million AUD (2014 - $87 million AUD) (1)	Floating (2)	**85**	83
ATCO Gas Australia Limited Partnership credit facility, payable in Australian dollars, at BBSY Rates, due December 2019, $250 million AUD (2014 - $250 million AUD) (1)	Floating (2)	**252**	237
ATCO Gas Australia Limited Partnership revolving credit facility, payable in Australian dollars, at BBSY Rates, due December 2019, $427 million AUD (2013 - $427 million AUD) (1)	Floating (2)	**430**	404
Less: Deferred financing charges		**(3)**	(4)
		7,879	7,188
Less: Amounts due within one year		**(5)**	(83)
		7,874	7,105

BBSY - Bank Bill Swap Benchmark Rate

(1) The above interest rates have additional margin fees at a weighted average rate of 1.1 per cent (2014 - 1.2 per cent). The margin fees are subject to escalation.

(2) Floating interest rates have been partially or completely hedged with interest rate swaps (see Note 22).

Debenture Issuances

During 2015, CU Inc. issued $400 million of 3.964 per cent debentures maturing on July 27, 2045, and $250 million of 4.211 per cent debentures maturing on October 29, 2055.

During 2014, CU Inc. issued $1 billion of 4.085 per cent debentures maturing on September 2, 2044, and $200 million of 4.094 per cent debentures maturing on October 19, 2054.

Pledged Assets

The ATCO Power Australia credit facility is secured by a mortgage on certain assets of the Karratha Power Plant and an assignment of certain contracts and agreements. The Karratha Power Plant is accounted for as a finance lease receivable. The credit facility is guaranteed by Canadian Utilities Limited.

NON-RECOURSE LONG-TERM DEBT

Project Financing	Effective Interest Rate	2015	2014
Joffre notes, at fixed rate of 8.59%, due to 2020	8.950%	**24**	29
Scotford notes, at fixed rate of 7.93%, due to 2022	8.240%	**19**	22
Muskeg River notes, at fixed rate of 7.56%, due to 2022	7.840%	**16**	18
Cory:			
Notes, at fixed rate of 7.586%, due to 2025	7.870%	**28**	31
Notes, at fixed rate of 7.601%, due to 2026	7.890%	**26**	28
Other long-term obligations, at rates of 8.16% to 12.65%, due to 2016		**1**	1
Less: Deferred financing charges		**(2)**	(2)
		112	127
Less: Amounts due within one year		**(15)**	(15)
		97	112

Pledged Assets

The non-recourse long-term debt is secured by charges on the projects' assets and by an assignment of the projects' bank accounts, outstanding contracts and agreements. The book value of the pledged assets at December 31, 2015, was $403 million (2014 - $407 million). The Cory project is accounted for as a finance lease receivable.

INTEREST EXPENSE

Interest expense is as follows:

	2015	2014
Long-term debt	**364**	349
Non-recourse long-term debt	**11**	12
Retirement benefits net interest expense	**9**	8
Amortization of deferred financing charges	**3**	3
Accretion of asset retirement obligations	**3**	5
Other	**6**	7
	396	384
Less: Interest capitalized *(Note 12)*	**(97)**	(76)
	299	308

19. DEFERRED REVENUES

Deferred revenues from customer contributions and other sources are:

	2015	2014
Customer contributions	**1,647**	1,508
Other	**2**	4
	1,649	1,512

CUSTOMER CONTRIBUTIONS

Customer contributions for extensions to plant are included in deferred revenues and recognized as revenue over the life of the related asset. Changes in deferred customer contribution revenues are summarized below.

	2015	2014
Beginning of year	**1,508**	1,377
Receipt of customer contributions	**197**	177
Amortization	**(59)**	(46)
Other	**1**	–
End of year	**1,647**	1,508

20. OTHER LIABILITIES

Other non-current liabilities are as follows:

	2015	2014
Unearned availability incentives	**23**	53
Derivative liabilities *(Note 23)*	**5**	–
Other	**17**	11
	45	64

21. CONTINGENCIES

Measurement inaccuracies occur from time to time on the utilities' metering facilities. These measurement adjustments are settled between the parties according to the Electricity and Gas Inspections Act (Canada) and related regulations. The AUC may disallow recovery of a measurement adjustment if it finds that controls and timely follow-up are inadequate.

Measurement inaccuracies occur from time to time on ATCO Gas Australia's metering facilities. These measurement adjustments are settled between the parties and the costs are recovered via the tariff based on a predetermined threshold contained in the current Access Arrangement. The Access Arrangement also contains a cost pass-through mechanism for recovery of any increases in gas commodity prices associated with these measurement adjustments. Recovery of a measurement adjustment may be disallowed if the adjustment exceeds a predetermined threshold; currently, levels are tracking below the threshold.

The Company is party to a number of other disputes and lawsuits in the normal course of business. The Company believes that the ultimate liability arising from these matters will have no material impact on the consolidated financial statements.

In 2004, ATCO Gas and ATCO Electric transferred their retail energy supply businesses to Direct Energy. The legal obligations of ATCO Gas and ATCO Electric for the retail functions transferred to Direct Energy, which include the supply of natural gas and electricity to customers as well as billing and customer care, remain if Direct Energy fails to perform. In certain circumstances, the functions will revert to ATCO Gas and/or ATCO Electric, with no refund of the transfer proceeds to Direct Energy.

Centrica plc., Direct Energy's parent company, provided a $300 million guarantee, supported by a $235 million letter of credit for Direct Energy's obligations to ATCO Gas and ATCO Electric under the transaction agreements. However, there can be no assurance that the coverage under these agreements will be adequate to defray all costs that could arise if the obligations are not met.

22. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

FINANCIAL RISKS

The Company is exposed to a variety of risks associated with the use of financial instruments. These risks are comprised of interest rate risk, foreign currency exchange rate risk, commodity price risk, credit risk and liquidity risk. The Company's Board is responsible for understanding the principal risks of the Company's business, achieving a proper balance between risks incurred and the potential return to share owners, and confirming there are controls in place to effectively monitor and manage those risks with a view to the long-term viability of the Company. The Board established the Audit & Risk Committee to review significant risks associated with future performance, growth and lost opportunities identified by management that could materially affect the Company's ability to achieve its strategic or operational targets. This committee is responsible for confirming that management has procedures in place to mitigate identified risks.

The Company may use various derivative instruments, including swaps and forward contracts, to manage the risks from fluctuating interest rates, exchange rates and commodity prices. All such instruments are used only to manage risk and not for trading purposes (see Note 23).

INTEREST RATE RISK

The Company's interest-bearing assets and liabilities include cash and cash equivalents, bank indebtedness, long-term debt and non-recourse long-term debt (see Note 18). The interest rate risk faced by the Company is largely a result of its cash and cash equivalents and variable rate long-term debt and non-recourse long-term debt.

Cash and cash equivalents include fixed rate instruments with maturities of generally 90 days or less that are reinvested as they mature. The Company is exposed to interest rate movements after these investments mature.

The Company has fixed interest rates, either directly or through interest rate swap agreements, on 99 per cent (2014 - 99 per cent) of total long-term debt and non-recourse long-term debt. Consequently, the exposure to fluctuations in market interest rates is limited. Interest rate swaps are designated as cash flow hedges; changes in the fair value of highly effective cash flow hedges are recorded in OCI. The effectiveness of the relationship between the hedged item and the interest rate swap is assessed throughout the hedging relationship. Sources of hedge ineffectiveness can occur as a result of i) credit risk, ii) change in hedge ratio, and iii) changes in the timing of payment. For the year ended December 31, 2015, there were no ineffective hedges.

The Company has converted certain variable rate long-term debt and non-recourse long-term debt to fixed rate debt through the following interest rate swap agreements:

Financing	Swap Fixed Interest Rate (1)	Variable Debt Interest Rate (2)	Maturity Date	Notional Principal 2015	Notional Principal 2014
ATCO Power Australia: 2015 - $84 million AUD (2014 - $87 million AUD)	3.660%	BBSY	February 2020	**85**	83
ATCO Gas Australia:					
2015 - $200 million AUD	3.604%	BBSY	December 2019	**202**	–
2015 - $155 million AUD	3.553%	BBSY	December 2019	**156**	–
2015 - $45 million AUD	3.423%	BBSY	December 2019	**45**	–
2015 - $200 million AUD	3.476%	BBSY	December 2019	**202**	–
2015 - $75 million AUD	3.601%	BBSY	December 2019	**75**	–
2015 - nil (2014 - $225 million AUD)	3.913%	BBSY	June 2015	**–**	213
2015 - nil (2014 - $225 million AUD)	3.913%	BBSY	June 2015	**–**	213
2015 - nil (2014 - $225 million AUD)	3.913%	BBSY	June 2015	**–**	213
Brighton Beach (2):	4.828%	90 day BA	June 2020	**3**	3
	5.034%	3 month CDOR	June 2020	**3**	3
				771	728

(1) The above swap fixed interest rates include any long-term debt margin fees; the margin fees are subject to escalation (Note 18).

(2) BBSY - Bank Bill Swap Benchmark Rates in Australia, BA - Bankers' Acceptance, CDOR - Canadian Dealer Offered Rate.

(3) The Brighton Beach swap was entered into by the Company; however, the non-recourse debt is held within the Company's investment in joint venture.

FOREIGN EXCHANGE RATE RISK

The Company's earnings from, and carrying values of, its foreign operations are exposed to fluctuating exchange rates. The Company offsets this foreign exchange impact in part by hedging and by financing with foreign-denominated debt.

The foreign exchange impact of a 10 cent increase in the value of the Australian dollar relative to the Canadian dollar on financial instruments of foreign operations would result in a decrease in OCI of $80 million. A decrease in the exchange rate would have the reverse effect. This sensitivity analysis is based on management's assessment that an average 10 cent increase or decrease in the Australian dollar relative to the Canadian dollar is a reasonable potential change over the next year.

ENERGY COMMODITY PRICE RISK

The Company's electricity generation business is exposed to commodity price movements, particularly to the market price of electricity and natural gas. At December 31, 2015, approximately 734 MW of power generating plant capacity out of a total capacity owned by ATCO Power of 2,286 MW is merchant capacity, which can be sold on the merchant electricity market.

Natural gas for contracted capacity is provided either under a long-term supply agreement or is the responsibility of the off-taker. Natural gas capacity not contracted is purchased on a daily basis at spot prices. The Company pays market prices for substitute energy when it is unable to supply energy from its contracted capacity.

The Company's risk management policy is to hedge approximately 90 per cent of forecasted merchant production to a maximum of five years forward. The Company has identified merchant electricity production and related natural gas consumption as the exposures to be hedged. The Company enters into natural gas purchase contracts and forward power sales contracts as the hedging instrument to manage the exposure to electricity and natural gas market price movements. The probability of the hedged item is high because the forecasted power generation and gas consumption is based on historical volumes; forecasted volumes are continually monitored and adjusted as required. Effectiveness is assessed prospectively at inception and throughout the hedging relationship either qualitatively or quantitatively to ensure a highly effective hedging relationship. Sources of ineffectiveness can occur as a result of i) credit risk, ii) change in hedge ratio, and iii) forecast adjustments leading to over-hedging. For the year ended December 31, 2015, there was no hedge ineffectiveness.

The Company is also exposed to seasonal summer/winter natural gas price spreads in its natural gas storage business.

CREDIT RISK

For cash and cash equivalents and accounts receivable, credit risk represents the carrying amount on the consolidated balance sheet. Cash and cash equivalents credit risk is reduced by investing in instruments issued by credit-worthy financial institutions and in short-term instruments issued by the federal government. Approximately 79 per cent of the cash equivalents at December 31, 2015 were invested in Government of Canada treasury bills and certificates of deposit issued by Canadian financial institutions.

Accounts receivable credit risk is reduced by a large and diversified customer base and credit security such as letters of credit. The utilities are also able to recover an estimate for doubtful accounts through approved customer rates and to request recovery through customer rates for any losses from retailers beyond the retailer security mandated by provincial regulations.

Derivative credit risk arises from the possibility that a counterparty to a contract fails to perform according to its terms and conditions. This risk is minimized by dealing with large, credit-worthy counterparties according to established credit approval policies.

Lease receivable credit risk arises from the possibility that a counterparty to a lease arrangement fails to make lease payments according to its terms and conditions. This risk is minimized by dealing with large, credit-worthy counterparties according to established credit approval policies.

The maximum exposure to credit risk is the carrying value of loans and receivables and derivative financial instruments. The Company does not have a concentration of credit risk with any counterparty, except for lease receivables, which by their nature are with a single counterparty. A significant portion of loans and receivables are from the Company’s operations in Alberta, except for the lease receivable for the Karratha plant in Australia.

At December 31, 2015, the Company held $54 million and $42 million in letters of credit and parental guarantees, respectively (2014 - $63 million and $70 million). The Company did not take possession of collateral it holds as security or call on other credit enhancements in the years ended December 31, 2015 and December 31, 2014.

The Company has also entered into guarantee arrangements with Centrica plc. (see Note 21).

Accounts receivable are non-interest bearing and are generally due in 30 to 90 days. Changes in the provision for impairment were as follows:

	2015	2014
Beginning of year	**1**	2
Receivables written off as uncollectible	**–**	(1)
End of year	**1**	1

The aging analysis of trade receivables that are past due but not impaired is as follows:

	2015	2014
30 to 90 days	**5**	4
Greater than 90 days	**1**	1
	6	5

No other impairments have been identified within accounts receivable.

LIQUIDITY RISK

Liquidity risk is the risk that the Company will not be able to meet its financial obligations. The Company considers it prudent to maintain sufficient liquidity to fund approximately one full year of cash requirements to preserve strong financial flexibility. Cash flow from operations provides a substantial portion of the Company's cash requirements. Additional cash requirements are met with the use of existing cash balances, bank borrowings and issuance of long-term debt, non-recourse long-term debt and preferred shares. Commercial paper borrowings and short-term bank loans are used under available credit lines to provide flexibility in the timing and amounts of long-term financing. The Company has a policy not to invest any of its cash balances in asset-backed securities.

The Company has contractual obligations in the normal course of business; future minimum undiscounted contractual maturities are as follows:

	2016	2017	2018	2019	2020	2021 and thereafter
Financial Liabilities						
Accounts payable and accrued liabilities	726	–	–	–	–	–
Long-term debt:						
Principal	5	158	5	1,168	164	6,420
Interest expense (1)	381	380	372	354	314	6,288
Non-recourse long-term debt:						
Principal	15	15	15	15	14	40
Interest expense (1)	11	7	6	5	4	7
Derivatives (2)	4	2	1	1	–	–
	1,142	562	399	1,543	496	12,755
Commitments						
Operating leases (3)	20	17	15	6	5	5
Purchase obligations:						
Coal purchase contracts (4)	63	69	72	74	77	252
Operating and maintenance agreements (5)	313	305	291	222	56	159
Capital expenditures (6)	76	–	–	–	–	–
Other (7)	52	–	–	1	–	–
	524	391	378	303	138	416
	1,666	953	777	1,846	634	13,171

(1) Interest payments on floating rate debt that has not been hedged have been estimated using rates in effect at December 31, 2015. Interest payments on debt that has been hedged have been estimated using hedged rates.

(2) Payments on outstanding derivatives have been estimated using rates in effect at December 31, 2015.

(3) Operating leases are comprised primarily of long-term leases for office premises and equipment.

(4) ATCO Power has long-term fixed price contracts to purchase coal for its coal-fired generating plants.

(5) Consists of ATCO Power's long-term service agreements with suppliers to provide operating and maintenance services at certain of their generating plants, ATCO Gas's transmission service from NOVA Gas Transmission Ltd. and the Company's information technology services contractual obligations.

(6) Consists of various contracts to purchase goods and services with respect to capital expenditures.

(7) Other includes $42 million committed to the Strathcona Storage Limited Partnership (see Note 15).

FAIR VALUE OF NON-DERIVATIVE FINANCIAL INSTRUMENTS

The fair value of cash and cash equivalents, accounts receivable, bank indebtedness and accounts payable and accrued liabilities approximate carrying value due to their short-term nature.

The fair values of the Company's non-derivative financial instruments measured at other than fair value are as follows:

		2015		2014
Recurring Measurements	**Carrying Value**	**Fair Value**	**Carrying Value**	**Fair Value**
Financial Assets				
Amortized Cost:				
Lease receivables [1]	**311**	**493**	310	504
Financial Liabilities				
Amortized Cost:				
Long-term debt [2]	**7,879**	**8,615**	7,188	8,202
Non-recourse long-term debt [2]	**112**	**137**	127	156

(1) Fair values are determined using a risk-adjusted, pre-tax interest rate to discount future cash receipts.

(2) Fair values are determined using quoted market prices for the same or similar issues. Where the market prices are not available, fair values are estimated using discounted cash flow analysis based on the Company's current borrowing rate for similar borrowing arrangements. Long-term debt and non-recourse long-term debt are classified in Level 2 of the fair value hierarchy.

OFFSETTING FINANCIAL ASSETS AND LIABILITIES

The following financial assets and financial liabilities are subject to offsetting, enforceable master netting arrangements and similar agreements:

			2015			2014
	Gross Amount	**Gross Amount Offset**	**Net Amount Recognized**	**Gross Amount**	**Gross Amount Offset**	**Net Amount Recognized**
Financial Assets						
Derivative assets	**9**	**(2)**	**7**	–	–	–
Accounts receivable	**60**	**(25)**	**35**	59	(22)	37
Financial Liabilities						
Derivative liabilities	**15**	**(7)**	**8**	–	–	–

23. DERIVATIVES

DERIVATIVE INSTRUMENTS

At December 31, 2015, the following derivative instruments were outstanding: interest rate swaps that hedge interest rate risk on the variable future cash flows for a portion of long-term debt and non-recourse long-term debt held in a joint venture, forward power contracts, and forward natural gas contracts.

The derivative assets and liabilities comprise the following:

	Derivative Assets (1)		Derivative Liabilities (2)	
	2015	**2014**	**2015**	**2014**
Current				
Interest rate swap agreements	–	–	–	1
Natural gas contracts	–	–	**4**	3
Forward power contracts	**5**	5	**1**	–
	5	5	**5**	4
Non-current				
Natural gas contracts	–	–	**3**	–
Forward power contracts	**3**	–	**2**	–
	3	–	**5**	–
	8	5	**10**	4

(1) Current derivative assets are included in prepaid expenses and other current assets. Non-current derivative assets are included in other assets.

(2) Current derivative liabilities are included in other current liabilities. Non-current derivative liabilities are included in other liabilities.

For the year ended December 31, 2015, gains after income taxes of $2 million (2014 - losses after income taxes of $10 million) were reclassified from AOCI and recognized in earnings. There was no hedge ineffectiveness in 2015 (2014 - a gain of $14 million was recognized due to hedge ineffectiveness). Over the next 12 months, the Company estimates that gains after income taxes of less than $1 million will be reclassified from AOCI to earnings.

FAIR VALUE OF DERIVATIVE FINANCIAL INSTRUMENTS

The fair values of the Company's derivative financial instruments are as follows:

2015		Subject to Hedge Accounting		Not Subject to Hedge Accounting	
Recurring Measurements	Interest Rate Swaps	Natural Gas (4)	Power (4)	Natural Gas (4)	Power (4)
Fair values (1)					
Assets	–	–	7	–	1
Liabilities	–	(6)	(2)	(1)	(1)
Notional values (2)					
Volumes (3)					
Purchases	–	19,479,000	–	6,767,000	556,080
Sales	–	–	2,722,233	1,761,000	65,720
Canadian dollars	771	–	–	–	–
Maturity	2019-2020	2020	2020	2018	2017
Fair value hierarchy level	Level 2	Level 2	Level 2	Level 2	Level 2

2014		Subject to Hedge Accounting		Not Subject to Hedge Accounting	
Recurring Measurements	Interest Rate Swaps	Natural Gas (4)	Power (4)	Natural Gas (4)	Power (4)
Fair values (1)					
Assets	–	–	5	–	–
Liabilities	(1)	(3)	–	–	–
Notional values (2)					
Volumes (3)					
Purchases	–	2,452,000	–	–	20,520
Sales	–	–	538,872	–	20,824
Canadian dollars	728	–	–	–	–
Maturity	2015-2020	2016	2019	–	2015
Fair value hierarchy level	Level 2	Level 2	Level 2	–	Level 2

(1) *Fair values for the interest rate swaps were estimated using interest rate yield curves at period-end. Fair values for commodity contracts were estimated using observable period-end forward curves, with inputs validated by publicly available market providers. The fair values were also determined using extrapolation formulas using readily observable inputs and implied volatility. These fair values approximate the amount that the Company would either pay or receive to settle the contracts at December 31, 2015.*

(2) *The notional principal is not recorded in the consolidated financial statements as it does not represent amounts that are exchanged by the counterparties.*

(3) *Notional amounts for the natural gas purchase contracts are the maximum volumes that can be purchased over the terms of the contracts. Notional amounts for the forward sale and purchase contracts are the commodity volumes committed in the contracts.*

(4) *Volumes for power and gas derivatives are in MWh and GJ, respectively.*

SENSITIVITY ANALYSIS

The analysis below illustrates the sensitivity in the fair value of outstanding derivatives to reasonably possible changes in Canadian and Australian interest rates, the forward price of natural gas, and the forward price of power in Alberta. Sensitivities are reflected in changes to earnings and OCI, after-tax.

Assumptions made in arriving at the sensitivity analysis are as follows:

- Changes in the fair value of derivatives are recorded in OCI if the instruments are highly effective cash flow hedges.
- Changes in the fair value of derivatives are recorded in earnings if the instruments are not designated as hedges, are fair value hedges, or are ineffective cash flow hedges.
- Changes in the forward price of natural gas affect the mark-to-market adjustment of the natural gas purchase contracts derivative asset.

A 25 basis point increase or decrease in Canadian or Australian interest rates would each increase or decrease OCI by less than $1 million and $5 million, respectively. A 10 per cent increase or decrease in the forward price of natural gas or power in Alberta would each increase or decrease OCI by $5 million and $12 million, respectively.

24. EQUITY PREFERRED SHARES

CU INC. EQUITY PREFERRED SHARES

Authorized and issued

Authorized: an unlimited number of Preferred Shares, issuable in series.

Issued:

			2015		2014	
	Stated Value *(dollars)*	Redemption Dates	Shares	Amount	Shares	Amount
Cumulative Redeemable Preferred Shares						
4.60% Series 1	25.00	See below	**4,600,000**	**115**	4,600,000	115
3.80% Series 4	25.00	See below	**3,000,000**	**75**	3,000,000	75
Issuance costs				**(3)**		(3)
				187		187

On June 1, 2014, CU Inc. redeemed all outstanding 6.70 per cent Cumulative Redeemable Preferred Shares Series 2 totaling $160 million. The redemption was financed with available cash reserves.

Fair values

The CU Inc. preferred shares have a fair value of $133 million at December 31, 2015 (2014 - $162 million) and are classified in Level 1 of the fair value hierarchy. The fair value was determined using quoted market prices of the same issues.

Redemption privileges

The Series 1 Preferred Shares became redeemable at the option of CU Inc. on June 1, 2012, at the stated value plus a 4 per cent premium per share for the next twelve months plus accrued and unpaid dividends. The redemption premium declines by 1 per cent in each succeeding twelve month period until June 1, 2016.

The Series 4 Preferred Shares may be redeemed by CU Inc. on June 1, 2016, and on June 1 of every fifth year thereafter, in whole or in part at the stated value plus all accrued and unpaid dividends. Holders may elect to convert any or all of their Series 4 Preferred Shares into an equal number of Cumulative Redeemable Preferred Shares Series 5 on June 1, 2016, and on June 1 of every fifth year thereafter. Holders of the Series 5 Preferred Shares will be entitled to receive, as and when declared by the Board of CU Inc., floating rate cumulative preferential cash dividends, payable quarterly at a rate equal to the then current 3-month Government of Canada Treasury Bill yield plus 1.36 per cent. On June 1, 2021, and on June 1 of every fifth year thereafter (Series 5 Conversion Date), holders of the Series 5 Preferred Shares may elect to convert any or all of their Series 5 Preferred Shares back into an equal number of Series 4 Preferred Shares. CU Inc. may redeem the Series 5 Preferred Shares in whole or in part at $25.00 on a Series 5 Conversion Date or at $25.50 on any other date.

CANADIAN UTILITIES LIMITED EQUITY PREFERRED SHARES

Authorized and issued

Authorized: an unlimited number of Series Second Preferred Shares, issuable in series.

Issued:

	Stated Value *(dollars)*	Redemption Dates	2015 Shares	2015 Amount	2014 Shares	2014 Amount
Cumulative Redeemable Second Preferred Shares						
4.00% Series Y	25.00	See below	**13,000,000**	**325**	13,000,000	325
4.90% Series AA	25.00	See below	**6,000,000**	**150**	6,000,000	150
4.90% Series BB	25.00	See below	**6,000,000**	**150**	6,000,000	150
4.50% Series CC	25.00	See below	**7,000,000**	**175**	7,000,000	175
4.50% Series DD	25.00	See below	**9,000,000**	**225**	9,000,000	225
5.25% Series EE	25.00	See below	**5,000,000**	**125**	–	–
4.50% Series FF	25.00	See below	**10,000,000**	**250**	–	–
Perpetual Cumulative Second Preferred Shares						
4.00% Series V	25.00	October 3, 2017	**4,400,000**	**110**	4,400,000	110
Issuance costs				**(27)**		(20)
				1,483		1,115
Total CU Inc. and Canadian Utilities Limited equity preferred shares				**1,670**		1,302

On August 7, 2015, the Company issued $125 million Cumulative Redeemable Second Preferred Shares Series EE at $25.00 per share under its base shelf prospectus. Holders are entitled to receive fixed cumulative preferential cash dividends, payable quarterly as and when declared by the Board of Directors, at an annual rate of $1.3125 per share, or 5.25 per cent.

On September 24, 2015, the Company issued $250 million Cumulative Redeemable Second Preferred Shares Series FF at $25.00 per share under its base shelf prospectus. Holders are entitled to receive fixed cumulative preferential cash dividends, payable quarterly for an initial period of five years, as and when declared by the Board of Directors, at an annual rate of $1.125 per share, or 4.50 per cent. Thereafter, the dividend rate will reset every five years to the then 5-Year Government of Canada Bond yield plus 3.69 per cent, and in any event, no less than 4.50 per cent.

Issuance costs of $7 million, net of income taxes, were recorded in equity (as a reduction of equity preferred shares) in the year ended December 31, 2015.

Fair values

The Canadian Utilities Limited Preferred Shares have a fair value of $1,351 million at December 31, 2015 (2014 - $1,113 million). All of the shares are classified in Level 1 of the fair value hierarchy with the exception of the Series V Preferred Shares which are classified in Level 2. The fair value was determined using quoted market prices of the same or similar issues.

Redemption privileges

The Series Y Preferred Shares may be redeemed by the Company on June 1, 2017, and on June 1 of every fifth year thereafter, in whole or in part at the stated value plus all accrued and unpaid dividends. Holders may elect to convert any or all of their Series Y Preferred Shares into an equal number of Cumulative Redeemable Second Preferred Shares Series Z on June 1, 2017, and on June 1 of every fifth year thereafter. Holders of the Series Z Preferred Shares will be entitled to receive floating rate cumulative preferential cash dividends, as and when declared by the Board, payable quarterly at a rate equal to the then current 3-month Government of Canada Treasury Bill yield plus 2.40 per cent. On June 1, 2022, and on June 1 of every fifth year thereafter (Series Z Conversion Date), holders of the Series Z Preferred Shares may elect to convert any or all of their Series Z Preferred Shares back into an equal number of Series Y Preferred Shares. The Company may redeem the Series Z Preferred Shares in whole or in part at $25.00 on a Series Z Conversion Date or at $25.50 on any other date.

The Series AA and Series BB Preferred Shares are redeemable in whole or in part at the option of the Company starting September 1, 2017, at the stated value plus a 4 per cent premium per share for the next twelve months plus accrued and unpaid dividends. The redemption premium declines by 1 per cent in each succeeding twelve month period until September 1, 2021.

The Series CC Preferred Shares are redeemable in whole or in part at the option of the Company starting June 1, 2018, at the stated value plus a 4 per cent premium per share for the next twelve months plus accrued and unpaid dividends. The redemption premium declines by 1 per cent in each succeeding twelve month period until June 1, 2022.

The Series DD Preferred Shares are redeemable in whole or in part at the option of the Company starting September 1, 2018, at the stated value plus a 4 per cent premium per share for the next twelve months plus accrued and unpaid dividends. The redemption premium declines by 1 per cent in each succeeding twelve month period until September 1, 2022.

The Series EE Preferred Shares are redeemable in whole or in part at the option of the Company starting September 1, 2020, at the stated value plus a 4 per cent premium per share for the next twelve months plus accrued and unpaid dividends. The redemption premium declines by 1 per cent in each succeeding twelve month period until September 1, 2024.

The Series FF Preferred Shares may be redeemed by the Company on December 1, 2020, and on December 1 of every fifth year thereafter, in whole or in part at the stated value plus all accrued and unpaid dividends. Holders may elect to convert any or all of their Series FF Preferred Shares into an equal number of Cumulative Redeemable Second Preferred Shares Series GG on December 1, 2020, and on December 1 of every fifth year thereafter. Holders of the Series GG Preferred Shares will be entitled to receive quarterly floating rate cumulative preferential cash dividends, as and when declared by the Board of Directors, equal to the then current 3-month Government of Canada Treasury Bill yield plus 3.69 per cent. On December 1, 2025, and on December 1, of every fifth year thereafter, the Company may redeem the Series GG Preferred Shares in whole or in part at the stated value. On any other date, the Company may redeem the Series GG Preferred Shares in whole or in part by the payment of $25.50 for each share to be redeemed.

The Series V Perpetual Cumulative Second Preferred Shares are redeemable on the date specified above at the option of the Company at the stated value plus accrued and unpaid dividends.

25. CLASS A AND CLASS B SHARES AND EARNINGS PER SHARE

A reconciliation of the number and dollar amount of outstanding Class A non-voting and Class B common shares at December 31, 2015 is shown below.

AUTHORIZED AND ISSUED

	Class A Non-Voting		Class B Common		Total	
	Shares	Amount	Shares	Amount	Shares	Amount
Authorized:	Unlimited		Unlimited			
Issued and outstanding:						
December 31, 2013	185,736,837	677	75,292,998	142	261,029,835	819
Shares issued	2,699,207	104	–	–	2,699,207	104
Stock options exercised	178,400	3	–	–	178,400	3
Converted: Class B to Class A	106,463	–	(106,463)	–	–	–
December 31, 2014	**188,720,907**	**784**	**75,186,535**	**142**	**263,907,442**	**926**
Shares issued	**2,792,302**	**99**	**–**	**–**	**2,792,302**	**99**
Stock options exercised	**195,800**	**6**	**–**	**–**	**195,800**	**6**
Converted: Class B to Class A	**122,000**	**–**	**(122,000)**	**–**	**–**	**–**
December 31, 2015	**191,831,009**	**889**	**75,064,535**	**142**	**266,895,544**	**1,031**

There were 489,949 Class A non-voting shares held in the MTIP trust at December 31, 2015, with a carrying amount of $18 million (2014 - 511,554 shares with a carrying amount of $17 million). The carrying amount of the Class A and B share capital, net of shares held in trust, was $1,013 million at December 31, 2015 (2014 - $909 million).

There were 855,200 options to purchase Class A non-voting shares outstanding at December 31, 2015, under the Company's stock option plan. From January 1, 2016 to February 23, 2016, no stock options were granted, 16,400 stock options were exercised, 1,400 stock options were cancelled and 121,408 Class B common shares were converted to Class A non-voting shares.

Class A non-voting and Class B common shares have no par value.

EARNINGS PER SHARE

Earnings per Class A non-voting and Class B common share are calculated by dividing the earnings attributable to Class A and Class B shares by the weighted average shares outstanding. Diluted earnings per share are calculated using the treasury stock method, which reflects the potential exercise of stock options and MTIPs on the weighted average Class A non-voting and Class B common shares outstanding.

The earnings and average number of shares used to calculate earnings per share are as follows:

	2015	2014
Average shares		
Weighted average shares outstanding	**264,651,701**	262,013,208
Effect of dilutive stock options	**186,177**	293,197
Effect of MTIPs	**511,444**	511,544
Weighted average dilutive shares outstanding	**265,349,322**	262,817,949
Earnings for earnings per share calculation		
Earnings for the period	**360**	724
Dividends on equity preferred shares of the Company	**(56)**	(50)
Dividends on equity preferred shares of subsidiary company	**(8)**	(13)
	296	661
Earnings and diluted earnings per Class A and Class B share		
Earnings per Class A and Class B share	**$1.12**	$2.52
Diluted earnings per Class A and Class B share	**$1.11**	$2.52

SHARE OWNER RIGHTS

Class A and Class B share owners are entitled to share equally, on a share for share basis, in all dividends the Company declares on either of such classes of shares as well as in the Company's remaining property on dissolution. Class B share owners are entitled to vote and to exchange at any time each share held for one Class A share.

If a take-over bid is made for the Class B shares and if it would result in the offeror owning more than 50 per cent of the outstanding Class B shares (excluding any Class B shares acquired upon conversion of Class A shares), the Class A share owners are entitled, for the duration of the take-over bid, to exchange their Class A shares for Class B shares and to tender the newly acquired Class B shares to the take-over bid. Such right of exchange and tender is conditional on completion of the applicable take-over bid.

In addition, Class A share owners are entitled to exchange their shares for Class B shares if ATCO Ltd., the Company's controlling share owner, ceases to own or control, directly or indirectly, more than 10,000,000 of the issued and outstanding Class B shares. In either case, each Class A share is exchangeable for one Class B share, subject to changes in the exchange ratio for certain events such as a stock split or rights offering.

DIVIDEND REINVESTMENT PLAN

The Company has a dividend reinvestment plan (DRIP) for eligible Class A non-voting and Class B common share owners who are enrolled in the program. The DRIP allows eligible Class A non-voting and Class B common share owners of the Company to reinvest all or a specified portion of their dividends in additional Class A non-voting shares.

The Class A non-voting shares are issued from treasury at a two per cent discount to the volume weighted average price of the Class A non-voting shares traded on the Toronto Stock Exchange during the last five qualifying trading days preceding the dividend payment date.

During the year ended December 31, 2015, 2,792,302 Class A non-voting shares were issued under the DRIP (2014 - 2,699,207), using re-invested dividends of $99 million (2014 - $104 million). The shares issued by the Company were priced at an average of $35.42 per share (2014 - $38.60 per share).

26. DIVIDENDS

Cash dividends declared and paid per share are as follows:

(dollars per share)	**2015**	**2014**
Equity preferred shares		
4.00% Perpetual Cumulative Second Preferred Shares, Series V	**1.00000**	1.00000
4.00% Cumulative Redeemable Second Preferred Shares, Series Y	**1.00000**	1.00000
4.90% Cumulative Redeemable Second Preferred Shares, Series AA	**1.22500**	1.22500
4.90% Cumulative Redeemable Second Preferred Shares, Series BB	**1.22500**	1.22500
4.50% Cumulative Redeemable Second Preferred Shares, Series CC	**1.12500**	1.12500
4.50% Cumulative Redeemable Second Preferred Shares, Series DD	**1.12500**	1.12500
5.25% Cumulative Redeemable Second Preferred Shares, Series EE	**0.41712**	–
4.50% Cumulative Redeemable Second Preferred Shares, Series FF	**0.20959**	–
Class A and Class B shares	**1.18000**	1.07000

The Company's policy is to pay dividends quarterly on its Class A and Class B shares. Increases in the quarterly dividend are addressed by the Board in the first quarter of each year. The payment of any dividend is at the discretion of the Board and depends on the financial condition of the Company and other factors.

27. CAPITAL DISCLOSURES

The Company's objectives when managing capital are to:

1. Safeguard the Company's ability to continue as a going concern so it can continue to provide returns to share owners and benefits for other stakeholders.
2. Maintain strong investment-grade credit ratings in order to provide efficient and cost-effective access to funds required for operations and growth.
3. Remain within the capital structure approved by the AUC for the utilities.

The Company considers both its regulated and non-regulated operations, as well as changes in economic conditions and risks impacting its operations, in managing its capital structure. The Company may adjust the dividends paid to share owners, issue or purchase Class A and Class B shares, and issue or redeem preferred shares, long-term debt and non-recourse long-term debt. Financing decisions are based on assessments by management in line with the Company's objectives, with a goal of managing the financial risk to the Company as a whole.

While the Alberta utilities have as their objective to be capitalized according to the AUC-approved capital structure, the Company as a whole is not restricted in the same manner. The Company sets its capital structure relative to risk and to meet financial and operational objectives, while factoring in the decisions of the regulator.

The Company also manages capital to comply with the customary covenants on its long-term debt. A common financial covenant for a large portion of the Company's debentures and credit facilities is that total debt divided by total capitalization must be less than 75 per cent. The Company defines total debt as the sum of bank indebtedness, long-term debt and non-recourse long-term debt (including their respective current portions). It defines total capitalization as the sum of Class A and Class B shares, contributed surplus, retained earnings, AOCI, equity preferred shares, and total debt. Management maintains the debt capitalization ratio well below 75 per cent to sustain access to cost-effective financing.

Debt capitalization does not have standardized meaning under IFRS and might not be comparable to similar measures presented by other companies. Also, the definitions of total debt and total capitalization vary slightly in the Company's debt-related agreements.

The Company's capitalization is as follows:

	2015	2014
Bank indebtedness	**1**	4
Long-term debt	**7,879**	7,188
Non-recourse long-term debt	**112**	127
Total debt	**7,992**	7,319
Class A and Class B shares	**1,013**	909
Contributed surplus	**15**	16
Retained earnings	**3,467**	3,411
Accumulated other comprehensive income	**28**	(31)
Equity preferred shares	**1,670**	1,302
Total equity	**6,193**	5,607
Total capitalization	**14,185**	12,926
Debt capitalization	**56%**	57%

For the year ended December 31, 2015, the Company complied with externally imposed requirements on its capital, including covenants related to debentures and credit facilities. The Company will continue to assess its capital structure and objectives in light of any future decisions received from the AUC.

28. SHARE-BASED COMPENSATION PLANS

STOCK OPTION PLAN

Of the 12,800,000 Class A non-voting shares authorized for grant of options under Canadian Utilities Limited's stock option plan, 5,461,400 Class A non-voting shares were available for issuance at December 31, 2015. Options may be granted to officers and key employees of Canadian Utilities Limited and its subsidiaries at an exercise price equal to the weighted average of the trading price of the shares on the Toronto Stock Exchange for the five trading days immediately preceding the date of grant. The options have a term of 10 years and vest over the first 5 years.

Information about the options outstanding and exercisable is given below.

	2015		2014	
	Options	Weighted Average Exercise Price	Options	Weighted Average Exercise Price
Outstanding options, beginning of year	**968,000**	**$27.41**	1,061,500	$24.62
Granted	**102,250**	**40.17**	100,500	39.43
Exercised	**(195,800)**	**22.16**	(178,400)	17.17
Forfeited	**(19,250)**	**37.13**	(15,600)	32.12
Outstanding options, end of year	**855,200**	**$29.92**	968,000	$27.41
Options exercisable, end of year	**579,650**	**$25.93**	685,250	$23.95

Options			Outstanding		Exercisable
Range of Exercise Prices	Number Outstanding	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price	Number Exercisable	Weighted Average Exercise Price
$21.78 - $23.92	410,000	2.2	$23.04	410,000	$23.04
$24.74 - $29.97	67,300	5.6	25.27	51,800	24.90
$33.18 - $37.43	91,750	6.4	33.48	55,250	33.33
$38.64 - $40.78	286,150	8.2	39.72	62,600	39.18
$21.78 - $40.78	855,200	4.9	$29.92	579,650	$25.93

Compensation expense related to stock options was less than $1 million in each of 2015 and 2014, with a corresponding increase to contributed surplus.

SHARE APPRECIATION RIGHTS

Directors, officers and key employees of the Company may be granted SARs that are based on Class A non-voting shares of Canadian Utilities Limited or Class I Non-Voting Shares of ATCO Ltd. The vesting provisions and exercise period are determined at the time of grant and cannot exceed 10 years.

The base value of the SAR is equal to the weighted average of the trading price of the Class A non-voting shares and the Class I Non-Voting Shares, respectively, on the Toronto Stock Exchange for the five trading days immediately preceding the date of grant. The holder is entitled on exercise to receive a cash payment equal to any increase in the market price of the Class A non-voting shares and the Class I Non-Voting Shares, respectively, over the base value of the SAR exercised.

Information about the SARs outstanding and exercisable is summarized below.

		2015		2014
	SARs	Weighted Average Exercise Price	SARs	Weighted Average Exercise Price
Outstanding SARs, beginning of year	**818,200**	**$28.42**	778,700	$26.78
Granted	**102,250**	**40.17**	100,500	39.43
Exercised	**(79,400)**	**22.89**	(45,400)	23.37
Forfeited	**(19,250)**	**37.13**	(15,600)	32.12
Outstanding SARs, end of year	**821,800**	**$30.21**	818,200	$28.42
SARs exercisable, end of year	**546,250**	**$26.13**	535,450	$24.52

SARs			Outstanding		Exercisable
Range of Exercise Prices	Number Outstanding	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price	Number Exercisable	Weighted Average Exercise Price
$21.17 - $27.05	438,900	2.7	$23.33	428,400	$23.29
$29.97 - $34.80	90,250	6.4	33.02	53,350	33.20
$35.69 - $39.45	201,050	7.7	39.16	63,700	39.10
$40.61 - $40.78	91,600	9.2	40.78	800	40.61
$22.17 - $40.78	821,800	5.1	$30.21	546,250	$26.13

In 2015 compensation expense related to SARs was a credit of $4 million (2014 was compensation expense of $3 million). The total carrying value of liabilities arising from SARs at December 31, 2015 was $3 million (2014 - $9 million). The total intrinsic value of all vested SARs at December 31, 2015 was $4 million (2014 - $9 million).

The Company uses the Black-Scholes option pricing model to estimate the weighted average fair value of the stock options and SARs granted. The following weighted average assumptions were used:

	2015		2014	
	Options	SARs	Options	SARs
Class A share price	**$40.17**	**$40.17**	$39.43	$39.43
Risk-free interest rate	**0.83%**	**0.83%**	1.6%	1.4%
Share price volatility (1)	**19.12%**	**18.22%**	17.6%	18.0%
Estimated annual Class A share dividend	**3.0%**	**3.0%**	2.7%	2.6%
Expected holding period prior to exercise	**6.9 years**	**6.1 years**	6.8 years	6.0 years

(1) The share price volatility is based on historical data and reflects the assumption that historical volatility over a period similar to the life of the option or SAR is indicative of future trends, which may not necessarily be indicative of exercise patterns that may occur.

MID-TERM INCENTIVE PLAN

Officers and key employees of the Company may be awarded MTIPs which are equity-settled with Class I Non-Voting Shares of ATCO Ltd purchased on the secondary market. The awards vest after two to three years. In 2015, the Company, through a trustee, purchased $6 million of shares to be distributed to employees on vesting of awards (2014 - $6 million).

Information about the MTIPs outstanding is summarized below.

	2015		2014	
	MTIPs	Weighted Average Grant Date Fair Value	MTIPs	Weighted Average Grant Date Fair Value
Outstanding MTIPs, beginning of year	**511,554**	**$37.41**	508,651	$33.03
Granted	**185,150**	**40.12**	164,800	40.09
Vested	**(159,850)**	**33.48**	(140,170)	25.74
Forfeited	**(90,400)**	**39.63**	(47,992)	34.50
Change in unallocated shares (1)	**43,495**	**–**	26,265	–
Outstanding MTIPs, end of year	**489,949**	**$39.64**	511,554	$37.41

(1) Unallocated shares are Class A non-voting shares held by the trustee which have not been awarded to officers or key employees.

MTIPs			Outstanding
Range of Prices	Number Outstanding	Weighted Average Remaining Contractual Life	Grant Date Fair Value
$29.97 - $36.78	50,750	2.4	$35.74
$37.78 - $39.39	124,300	0.3	38.71
$40.00 - $41.86	242,600	1.7	40.93
Unallocated shares	72,299	–	–
$33.38 - $40.46	489,949	1.4	$39.64

Compensation expense related to MTIP grants amounted to $4 million for 2015 (2014 - $4 million) with a corresponding increase to contributed surplus.

The MTIP trust is considered a special purpose entity and is consolidated in the Company's financial statements. The Class A non-voting shares, while held in trust, are accounted for as a reduction of share capital.

29. RETIREMENT BENEFITS

The Company maintains registered defined benefit and defined contribution pension plans for most of its employees. It also provides other post-employment benefits, principally health, dental and life insurance, for retirees and their dependents. The defined benefit pension plans provide for pensions based on employees' length of service and final average earnings. As of 1997, new employees automatically participate in the defined contribution pension plan.

The Company also maintains non-registered, non-funded defined benefit pension plans for certain officers and key employees.

The majority of benefit payments are made from trustee-administered funds; however, there are a number of unfunded plans where the Company makes the benefit payments. Plan assets held in trusts are governed by provincial and federal legislation and regulations, as is the relationship between the Company and the trustee. The Pension Committee of the Board is responsible for governance of the funded plans and policy decisions related to benefit design, liability management, and funding and investment, including selection of investment managers and investment options for the plans.

BENEFIT PLAN ASSETS, OBLIGATIONS AND FUNDED STATUS

The changes in Company's pension and OPEB plan assets and obligations are as follows:

	2015		2014	
	Pension Benefit Plans	OPEB Plans	Pension Benefit Plans	OPEB Plans
Market value of plan assets				
Beginning of year	**2,452**	–	2,161	–
Interest income	**96**	–	103	–
Employee contributions	**2**	–	2	–
Employer contributions	**42**	–	44	–
Benefit payments	**(92)**	–	(81)	–
Acquisition of TPL *(Note 8)*	**69**	–	–	–
Return on plan assets, excluding amounts included in interest income	**84**	–	223	–
Foreign exchange rate adjustment	**1**	–	–	–
Other	**(4)**	–	–	–
End of year	**2,650**	–	2,452	–
Accrued benefit obligations				
Beginning of year	**2,746**	**117**	2,340	96
Current service cost	**35**	**3**	34	2
Interest cost	**109**	**4**	114	5
Employee contributions	**2**	–	2	–
Benefit payments from plan assets (1)	**(92)**	–	(81)	–
Benefit payments by employer	**(6)**	**(3)**	(5)	(3)
Curtailment gain (2)	**(22)**	**(1)**	(11)	(1)
Acquisition of TPL *(Note 8)*	**69**	–	–	–
Actuarial (gains) losses	**(27)**	**(8)**	353	18
Foreign exchange rate adjustment	**1**	–	–	–
End of year (2)	**2,815**	**112**	2,746	117
Funded status				
Net retirement benefit obligations	**165**	**112**	294	117

(1) In 2015, the Company recorded a curtailment gain of $23 million related to significant employee reductions. The gain is reported in salaries, wages and benefits expenses. (2014 - The sale of the Company's ownership interest in ATCO I-Tek's information technology services resulted in a curtailment gain of $12 million (see Note 8)).

(2) The non-registered, non-funded defined benefit pension plans accrued benefit obligations increased to $132 million at December 31, 2015 (2014 - $128 million) due to experience adjustments partially offset by an increase in the liability discount rate.

BENEFIT PLAN COST

The components of benefit plan cost are as follows:

	2015		2014	
	Pension Benefit Plans	OPEB Plans	Pension Benefit Plans	OPEB Plans
Current service cost	**35**	**3**	34	2
Interest cost	**109**	**4**	114	5
Interest income	**(96)**	**–**	(103)	–
Curtailment gain	**(22)**	**(1)**	(11)	(1)
Defined benefit plans cost	**26**	**6**	34	6
Defined contribution plans cost	**34**	**–**	32	–
Total cost	**60**	**6**	66	6
Less: Capitalized	**37**	**3**	32	3
Net cost recognized	**23**	**3**	34	3

RE-MEASUREMENT OF RETIREMENT BENEFITS

Re-measurements of the pension and OPEB plans are as follows:

	2015		2014	
	Pension Benefit Plans	OPEB Plans	Pension Benefit Plans	OPEB Plans
Gains (losses) on plan assets from:				
Return on plan assets, excluding amounts included in net interest expense	**84**	**–**	223	–
Other	**(4)**	**–**	–	–
	80	**–**	223	–
Gains (losses) on plan obligations from:				
Changes in demographic assumptions (1)	**–**	**5**	(24)	(2)
Changes in financial assumptions	**37**	**2**	(336)	(15)
Experience adjustments	**(10)**	**1**	7	(1)
	27	**8**	(353)	(18)
Gains (losses) recognized in other comprehensive income (2)	**107**	**8**	(130)	(18)

(1) In 2014, the Company adopted the Private Sector Canadian Pensioners Mortality table published by the Canadian Institute of Actuaries as the basis for assumption regarding future life expectancy.

(2) Gains (losses) net of income taxes was $73 million for the year ended December 31, 2015 (2014 - $(111) million).

PLAN ASSETS

The market values of the Company's defined benefit pension plan assets at December 31 are as follows:

				2015				2014
Plan asset mix	**Quoted**	**Un-quoted**	**Total**	**%**	**Quoted**	**Un-quoted**	**Total**	**%**
Equity securities								
Public								
Canada	**241**	–	**241**		249	–	249	
United States	**357**	–	**357**		294	–	294	
International	**178**	–	**178**		154	–	154	
Private	–	**20**	**20**		–	25	25	
	776	**20**	**796**	**30**	697	25	722	30
Fixed income securities								
Government bonds	**770**	–	**770**		827	–	827	
Corporate bonds and debentures	**563**	–	**563**		573	–	573	
Securitizations	**53**	–	**53**		–	–	–	
Mortgages	–	**46**	**46**		–	40	40	
	1,386	**46**	**1,432**	**54**	1,400	40	1,440	59
Real estate								
Land and building (1)	–	**66**	**66**		–	69	69	
Real estate funds	–	**180**	**180**		–	139	139	
	–	**246**	**246**	**9**	–	208	208	8
Cash and other assets								
Cash	**66**	–	**66**		38	–	38	
Short-term notes and money market funds	**26**	–	**26**		37	–	37	
Qualifying insurance policy	–	**76**	**76**		–	–	–	
Accrued interest and dividends receivable	**8**	–	**8**		7	–	7	
	100	**76**	**176**	**7**	82	–	82	3
	2,262	**388**	**2,650**	**100**	2,179	273	2,452	100

(1) The land and building are occupied by the Company.

At December 31, 2015, plan assets include Class A non-voting and Class B common shares of Canadian Utilities Limited having a market value of $30 million (2014 - $38 million) and Class I Non-Voting Shares of ATCO Ltd. having a market value of $34 million (2014 - $46 million). There is no segregated CU Inc. debt as of December 31, 2015 (2014 - $19 million).

FUNDING

Employees contribute a percentage of their salary to registered pension plans. The Company contributes its share of contributions for the defined contribution pension plans. The Company also provides the balance of the funding necessary to ensure that benefits will be fully provided for the defined benefit pension plans.

In 2014, an actuarial valuation for funding purposes as of December 31, 2013 was completed for the registered defined benefit pension plans. Based on this valuation, employer contributions for 2015 were $42 million (2014 - $44 million). In 2016 the Company expects to complete a new actuarial valuation for funding purposes as of December 31, 2015; estimated employer contributions for 2016 are $33 million.

Employer contributions to the defined contribution plan were $34 million in 2015 (2014 - $32 million).

WEIGHTED AVERAGE ASSUMPTIONS

The significant assumptions used to determine the benefit plan cost and accrued benefit obligation were as follows:

	2015		2014	
	Pension Benefit Plans	OPEB Plans	Pension Benefit Plans	OPEB Plans
Benefit plan cost				
Discount rate for the year	**4.00%**	**4.00%**	4.90%	4.90%
Average compensation increase for the year	**3.25%**	**n/a**	3.25%	n/a
Accrued benefit obligations				
Discount rate at December 31	**4.10%**	**4.10%**	4.00%	4.00%
Long-term inflation rate	**2.00%**	**n/a**	2.00%	n/a
Health care cost trend rate:				
Drug costs (1)	**n/a**	**5.70%**	n/a	5.83%
Other medical costs	**n/a**	**4.50%**	n/a	4.50%
Dental costs	**n/a**	**4.00%**	n/a	4.00%

(1) The Company uses a graded drug cost trend rate which assumes a rate of 4.50 per cent in 2024.

The weighted average duration of the defined benefit obligation is 14.3 years.

RISKS

The Company is exposed to a number of risks related to its defined benefit pension plans and OPEB plans. The most significant risks are described below.

Investment risk

The Company makes investment decisions for its funded plans using an asset-liability matching framework. Within this framework, the Company's objective over time is to increase the proportion of plan assets in fixed income securities with maturities that match the expected benefit payments as they fall due. However, due to the long-term nature of the benefit obligations, the strength of the Company, and the belief that equities offer the best returns over the long-term with an acceptable level of risk, the Company continues to invest in equity securities. This investment is an important element of the Company's long-term strategy to manage the plans efficiently. The equity securities are in a diversified portfolio of high-quality businesses. The Company has not changed the processes used to manage its risks from previous periods.

Interest rate risk

A decrease in long-term interest rates will increase accrued benefit obligations, which will be partially offset by an increase in the value of the plans' bond holdings. Other things remaining the same, a further decrease in long-term interest rates will cause the funded status to deteriorate, while increases in interest rates will result in gains.

Compensation risk

The present value of the accrued benefit obligations is calculated using the estimated future compensation of plan participants. Should future compensation be higher than estimated, benefit obligations will increase.

Inflation risk

Accrued benefit obligations are linked to inflation, and higher inflation will lead to increased obligations.
For the defined benefit pension plans, inflation risk is mitigated because the indexing of benefit payments is capped at an annual increase of 3.0 per cent.

The majority of plan assets are also affected by inflation. As inflation rises, long-term interest rates will likely rise, pushing up bond yields and reducing the value of existing fixed rate bonds. The relationship between equities and inflation is not as clear, but generally speaking, high inflation has a negative impact on equity valuations. Overall, rising inflation will likely reduce a plan surplus or increase a deficit.

Life expectancy

Should pensioners live longer than assumed, benefit obligations and liabilities will be larger than expected.

SENSITIVITIES

The 2015 sensitivities of key assumptions used in measuring the Company's pension and OPEB plans is as follows:

		Accrued Benefit Obligation		Net Benefit Plan Cost	
Assumption	**Percent Change**	**Increase in Assumption**	**Decrease in Assumption**	**Increase in Assumption**	**Decrease in Assumption**
Discount rate	1%	(379)	476	(11)	10
Future compensation rate	1%	34	(33)	1	(1)
Long-term inflation rate [(1)]	1%	417	(342)	12	(10)
Health care cost trend rate	1%	13	(10)	–	–
Life expectancy	10%	74	(67)	2	(2)

(1) The long-term inflation rate for pension plans reflects the fact that pension plan benefit payments have historically been indexed annually to increases in the Canadian Consumer Price Index to a maximum increase of 3.0 per cent per annum.

The above sensitivities have been calculated independently of each other. Actual experience may result in changes in a number of assumptions simultaneously.

30. CONSOLIDATED STATEMENT OF CASH FLOWS

Adjustments to reconcile earnings to cash flows from operating activities are summarized below.

	2015	**2014**
Adjustments to reconcile earnings to cash flows from operating activities		
Depreciation, amortization and impairment	**642**	514
Gain on sales of operations and revaluation of joint venture	**(30)**	(160)
Earnings from investment in ATCO Structures & Logistics, net of dividends received	**13**	(11)
Earnings from investment in joint ventures, net of dividends and distributions received	**8**	6
Income taxes	**205**	206
Unearned availability incentives	**(30)**	(3)
Contributions by customers for extensions to plant *(Note 19)*	**197**	177
Amortization of customer contributions *(Note 19)*	**(59)**	(46)
Net finance costs	**289**	297
Income taxes paid	**(46)**	(66)
Other	**(17)**	5
	1,172	919

The changes in non-cash working capital are summarized below.

	2015	2014
Operating activities		
Accounts receivable	**50**	(20)
Inventories	**–**	(1)
Prepaid expenses and other current assets	**23**	(24)
Accounts payable and accrued liabilities	**(8)**	(20)
Provisions and other current liabilities	**19**	(38)
	84	(103)
Investing activities		
Inventories	**29**	6
Prepaid expenses	**–**	2
Accounts payable and accrued liabilities	**(95)**	46
	(66)	54

31. SUBSIDIARIES

Principal operating subsidiaries, all of which are wholly owned, are listed below.

Principal Operating Subsidiaries	Principal Place of Business	Principal Activity
CU Inc.	Canada	Holding company
ATCO Electric	Canada	Distributed generation, electricity distribution, transmission and infrastructure development
ATCO Gas	Canada	Natural gas distribution and infrastructure development
ATCO Pipelines	Canada	Natural gas transmission and infrastructure development
ATCO Power	Canada	Electricity generation and distributed generation
ATCO Energy Solutions	Canada	Natural gas liquids storage and processing, and industrial water solutions
ATCO Gas Australia	Australia	Natural gas distribution
ATCO Power Australia	Australia	Electricity generation
ATCO I-Tek [1]	Canada	Information systems and technologies

(1) ATCO I-Tek was sold by the Company in August 2014 (see Note 8).

32. RELATED PARTY TRANSACTIONS

TRANSACTIONS WITH PARENT AND AFFILIATE COMPANIES

Transaction	Recorded As	2015	2014
Computer operations and systems development services	Revenues	**–**	8
Administrative expenses, rent expense and licensing fees	Other expenses	**14**	14
Trailer supply and noise management services	Property, plant and equipment	**2**	1

JOINT VENTURE TRANSACTIONS

In transactions with the Company's joint ventures, the Company recognized revenues of $5 million (2014 - $1 million) relating to management fees and surface and mineral rights.

GROUP PENSION PLAN TRANSACTIONS

In transactions with the Company's group pension plans, the Company paid occupancy costs of $8 million (2014 - $8 million) relating to property owned by the pension plans.

RELATED PARTY BALANCES

At December 31, 2015, accounts receivable due from related parties amounted to $7 million (2014 - $4 million) and accounts payable due to related parties amounted to $5 million (2014 - $2 million). Receivables and payables with related parties are generally due within 30 days or less from the date of the transaction. The amounts outstanding are unsecured, bear no interest and will be settled in cash. No provisions are held against receivables from related parties.

DIVIDEND REINVESTMENT PLAN

The Company issued 1,479,752 Class A non-voting shares to ATCO Ltd. under the DRIP in 2015 (2014 - 1,675,441 shares), using re-invested dividends of $52 million (2014 - $65 million). The shares were priced at an average of $35.37 per share (2014 - $38.60 per share).

OTHER RELATED PARTY TRANSACTIONS

The Company sold property and equipment of nil (2014 - $4 million) to an entity related through common control and incurred $1 million (2014 - $1 million) in advertising, promotion and other expenses from an entity related through common control.

KEY MANAGEMENT COMPENSATION

Information on management compensation is shown below.

	2015	2014
Salaries and short-term employee benefits	**7**	11
Retirement benefits	**1**	1
Share-based compensation	**(3)**	5
	5	17

Key management personnel comprise members of executive management and the Board, a total of 21 individuals (2014 - 23 individuals).

33. SUBSEQUENT EVENTS

On January 7, 2016, the Company declared quarterly eligible dividends of $0.25000 on the Series Y Preferred Shares, $0.30625 on the Series AA Preferred Shares, $0.30625 on the Series BB Preferred Shares, $0.28125 on the Series CC Preferred Shares, $0.28125 on the Series DD Preferred Shares, $0.328125 on the Series EE Preferred Shares and $0.28125 on the Series FF Preferred Shares.

On January 7, 2016, the Company declared a quarterly dividend of $0.32500 per Class A non-voting share and Class B common share.

In January 2016, the Company sold its 51.3 per cent ownership in the Edmonton Ethane Extraction Plant for proceeds of $21 million cash, resulting in a gain of $18 million ($13 million after-tax).