Management's report on Internal Control over Financial Reporting

The consolidated financial statements and Management's Discussion and Analysis (MD&A) included in this Annual Report are the responsibility of the management of TransCanada PipeLines Limited (TCPL or the Company) and have been approved by the Board of Directors of the Company. The consolidated financial statements have been prepared by management in accordance with United States generally accepted accounting principles (GAAP) and include amounts that are based on estimates and judgments. The MD&A is based on the Company's financial results. It compares the Company's financial and operating performance in 2015 to that in 2014, and highlights significant changes between 2014 and 2013. The MD&A should be read in conjunction with the consolidated financial statements and accompanying notes. Financial information contained elsewhere in this Annual Report is consistent with the consolidated financial statements.

Management is responsible for establishing and maintaining adequate internal control over financial reporting for the Company. Management has designed and maintains a system of internal control over financial reporting, including a program of internal audits to carry out its responsibility. Management believes these controls provide reasonable assurance that financial records are reliable and form a proper basis for the preparation of financial statements. The internal control over financial reporting include management's communication to employees of policies that govern ethical business conduct.

Under the supervision and with the participation of the President and Chief Executive Officer and the Chief Financial Officer, management conducted an evaluation of the effectiveness of its internal control over financial reporting based on the framework in Internal Control (COSO) – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Management concluded, based on its evaluation, that internal control over financial reporting was effective as of December 31, 2015, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external reporting purposes.

The Board of Directors is responsible for reviewing and approving the financial statements and MD&A and ensuring that management fulfills its responsibilities for financial reporting and internal control. The Board of Directors carries out these responsibilities primarily through the Audit Committee, which consists of independent, non-management directors. The Audit Committee meets with management at least five times a year and meets independently with internal and external auditors and as a group to review any significant accounting, internal control and auditing matters in accordance with the terms of the Charter of the Audit Committee, which is set out in the Annual Information Form. The Audit Committee's responsibilities include overseeing management's performance in carrying out its financial reporting responsibilities and reviewing the Annual Report, including the consolidated financial statements and MD&A, before these documents are submitted to the Board of Directors for approval. The internal and independent external auditors have access to the Audit Committee without the requirement to obtain prior management approval.

The Audit Committee approves the terms of engagement of the independent external auditors and reviews the annual audit plan, the Auditors' Report and the results of the audit. It also recommends to the Board of Directors the firm of external auditors to be appointed by the shareholder.

The shareholder has appointed KPMG LLP as independent external auditors to express an opinion as to whether the consolidated financial statements present fairly, in all material respects, the Company's consolidated financial position, results of operations and cash flows in accordance with GAAP. The reports of KPMG LLP outline the scope of its examination and its opinion on the consolidated financial statements.

Russell K. Girling	**Donald R. Marchand**
President and Chief Executive Officer	Executive Vice-President and Chief Financial Officer

February 10, 2016

Independent Auditors' Report

TO THE SHAREHOLDER OF TRANSCANADA PIPELINES LIMITED

We have audited the accompanying consolidated financial statements of TransCanada PipeLines Limited, which comprise the Consolidated balance sheets as at December 31, 2015 and December 31, 2014, the Consolidated statements of income, comprehensive income, cash flows and equity for each of the years in the three-year period ended December 31, 2015, and Notes, comprising a summary of significant accounting policies and other explanatory information.

MANAGEMENT'S RESPONSIBILITY FOR THE CONSOLIDATED FINANCIAL STATEMENTS

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with U.S. generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

AUDITORS' RESPONSIBILITY

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

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

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

OPINION

In our opinion, the Consolidated financial statements present fairly, in all material respects, the consolidated financial position of TransCanada PipeLines Limited as at December 31, 2015 and December 31, 2014, and its consolidated results of operations and its consolidated cash flows for each of the years in the three-year period ended December 31, 2015 in accordance with U.S. generally accepted accounting principles.

KPMG LLP

Chartered Professional Accountants
Calgary, Canada
February 10, 2016

Consolidated statement of income

year ended December 31 (millions of Canadian $)	2015	2014	2013
Revenues			
Natural Gas Pipelines	**5,383**	4,913	4,497
Liquids Pipelines	**1,879**	1,547	1,124
Energy	**4,038**	3,725	3,176
	11,300	10,185	8,797
Income from Equity Investments (Note 8)	**440**	522	597
Operating and Other Expenses			
Plant operating costs and other	**3,250**	2,973	2,674
Commodity purchases resold	**2,237**	1,836	1,317
Property taxes	**517**	473	445
Depreciation and amortization	**1,765**	1,611	1,485
Asset impairment charges (Note 7)	**3,745**	—	—
	11,514	6,893	5,921
(Loss)/Gain on Assets Held for Sale/Sold (Notes 6 and 25)	**(125)**	117	—
Financial Charges			
Interest expense (Note 16)	**1,398**	1,235	1,046
Interest income and other	**(192)**	(128)	(72)
	1,206	1,107	974
(Loss)/Income before Income Taxes	**(1,105)**	2,824	2,499
Income Tax Expense/(Recovery) (Note 15)			
Current	**137**	146	43
Deferred	**(102)**	684	562
	35	830	605
Net (Loss)/Income	**(1,140)**	1,994	1,894
Net Income attributable to non-controlling interests (Note 18)	**6**	151	105
Net (Loss)/Income Attributable to Controlling Interests	**(1,146)**	1,843	1,789
Preferred share dividends	**—**	2	20
Net (Loss)/Income Attributable to Common Shares	**(1,146)**	1,841	1,769

The accompanying Notes to the consolidated financial statements are an integral part of these statements.

Consolidated statement of comprehensive income

year ended December 31 (millions of Canadian $)	2015	2014	2013
Net (Loss)/Income	**(1,140)**	1,994	1,894
Other Comprehensive Income/(Loss), Net of Income Taxes			
Foreign currency translation gains on net investment in foreign operations	**813**	517	383
Change in fair value of net investment hedges	**(372)**	(276)	(239)
Change in fair value of cash flow hedges	**(57)**	(69)	71
Reclassification to net income of gains and losses on cash flow hedges	**88**	(55)	41
Unrealized actuarial gains and losses on pension and other post-retirement benefit plans	**51**	(102)	67
Reclassification to net income of actuarial gains and losses and prior service costs on pension and other post-retirement benefit plans	**32**	18	23
Other comprehensive income/(loss) on equity investments	**47**	(204)	234
Other comprehensive income/(loss) (Note 21)	**602**	(171)	580
Comprehensive (Loss)/Income	**(538)**	1,823	2,474
Comprehensive income attributable to non-controlling interests	**312**	281	171
Comprehensive (Loss)/Income Attributable to Controlling Interests	**(850)**	1,542	2,303
Preferred share dividends	**—**	2	20
Comprehensive (Loss)/Income Attributable to Common Shares	**(850)**	1,540	2,283

The accompanying Notes to the consolidated financial statements are an integral part of these statements.

Consolidated statement of cash flows

year ended December 31 (millions of Canadian $)	2015	2014	2013
Cash Generated from Operations			
Net (loss)/income	**(1,140)**	1,994	1,894
Depreciation and amortization	**1,765**	1,611	1,485
Asset impairment charges (Note 7)	**3,745**	—	—
Deferred income taxes (Note 15)	**(102)**	684	562
Income from equity investments (Note 8)	**(440)**	(522)	(597)
Distributed earnings received from equity investments (Note 8)	**576**	579	605
Employee post-retirement benefits expense, net of funding (Note 22)	**44**	37	50
Loss/(gain) on assets held for sale/sold (Notes 6 and 25)	**125**	(117)	—
Equity allowance for funds used during construction	**(165)**	(95)	(19)
Unrealized losses/(gains) on financial instruments	**58**	74	(35)
Other	**47**	22	32
Increase in operating working capital (Note 24)	**(359)**	(189)	(334)
Net cash provided by operations	**4,154**	4,078	3,643
Investing Activities			
Capital expenditures (Note 4)	**(3,918)**	(3,489)	(4,264)
Capital projects in development (Note 4)	**(511)**	(848)	(488)
Contributions to equity investments (Note 8)	**(493)**	(256)	(163)
Acquisitions, net of cash acquired (Note 25)	**(236)**	(241)	(216)
Proceeds from sale of assets, net of transaction costs (Note 25)	**—**	196	—
Distributions in excess of equity earnings (Note 8)	**226**	159	128
Deferred amounts and other	**324**	335	(117)
Net cash used in investing activities	**(4,608)**	(4,144)	(5,120)
Financing Activities			
Notes payable (repaid)/issued, net	**(1,382)**	544	(492)
Long-term debt issued, net of issue costs	**5,045**	1,403	4,253
Long-term debt repaid	**(2,105)**	(1,069)	(1,286)
Junior subordinated notes issued, net of issue costs	**917**	—	—
Advances to affiliates, net	**(189)**	(694)	(297)
Dividends on common shares	**(1,446)**	(1,345)	(1,286)
Dividends on preferred shares	**—**	(4)	(22)
Distributions paid to non-controlling interests	**(224)**	(174)	(146)
Common shares issued	**—**	1,115	899
Partnership units of subsidiary issued, net of issue costs	**55**	79	384
Preferred shares redeemed (Note 20)	**—**	(200)	(200)
Net cash provided by/(used in) financing activities	**671**	(345)	1,807
Effect of Foreign Exchange Rate Changes on Cash and Cash Equivalents	**112**	—	28
Increase/(Decrease) in Cash and Cash Equivalents	**329**	(411)	358
Cash and Cash Equivalents			
Beginning of year	**484**	895	537
Cash and Cash Equivalents			
End of year	**813**	484	895

The accompanying Notes to the consolidated financial statements are an integral part of these statements.

Consolidated balance sheet

at December 31 (millions of Canadian $)		2015	2014
ASSETS			
Current Assets			
Cash and cash equivalents		**813**	484
Accounts receivable (Note 28)		**1,401**	1,372
Due from affiliates (Note 28)		**2,476**	2,842
Inventories		**323**	292
Other (Note 5)		**1,353**	1,018
		6,366	6,008
Plant, Property and Equipment (Note 7)		**44,817**	41,774
Equity Investments (Note 8)		**6,214**	5,598
Regulatory Assets (Note 9)		**1,184**	1,297
Goodwill (Note 10)		**4,812**	4,034
Intangible and Other Assets (Note 11)		**3,185**	2,641
Restricted Investments		**351**	63
		66,929	61,415
LIABILITIES			
Current Liabilities			
Notes payable (Note 12)		**1,218**	2,467
Accounts payable and other (Note 13 and 28)		**3,014**	2,891
Due to affiliates (Note 28)		**311**	866
Accrued interest		**520**	425
Current portion of long-term debt (Note 16)		**2,547**	1,797
		7,610	8,446
Regulatory Liabilities (Note 9)		**1,159**	263
Other Long-Term Liabilities (Note 14)		**1,260**	1,052
Deferred Income Tax Liabilities (Note 15)		**5,144**	4,856
Long-Term Debt (Note 16)		**29,037**	22,960
Junior Subordinated Notes (Note 17)		**2,422**	1,160
		46,632	38,737
EQUITY			
Common shares, no par value (Note 19)		**16,320**	16,320
Issued and outstanding:	December 31, 2015 – 779 million shares		
	December 31, 2014 – 779 million shares		
Additional paid-in capital		**210**	404
Retained earnings		**2,989**	5,606
Accumulated other comprehensive loss (Note 21)		**(939)**	(1,235)
Controlling interests		**18,580**	21,095
Non-controlling interests (Note 18)		**1,717**	1,583
		20,297	22,678
		66,929	61,415

Commitments, Contingencies and Guarantees (Note 26)

Corporate Restructuring Costs (Note 27)

Subsequent Events (Note 29)

The accompanying Notes to the consolidated financial statements are an integral part of these statements.

On behalf of the Board:

Russell K. Girling
Director

Siim A. Vanaselja
Director

Consolidated statement of equity

year ended December 31 (millions of Canadian $)	2015	2014	2013
Common Shares			
Balance at beginning of year	**16,320**	15,205	14,306
Proceeds from shares issued (Note 19)	**—**	1,115	899
Balance at end of year	**16,320**	16,320	15,205
Preferred Shares			
Balance at beginning of year	**—**	194	389
Redemption of preferred shares	**—**	(194)	(195)
Balance at end of year	**—**	—	194
Additional Paid-In Capital			
Balance at beginning of year	**404**	431	400
Issuance of stock options, net of exercises	**13**	7	7
Dilution impact from TC PipeLines, LP units issued	**6**	9	29
Redemption of preferred shares	**—**	(6)	(5)
Impact of asset drop downs to TC PipeLines, LP (Note 25)	**(213)**	(37)	—
Balance at end of year	**210**	404	431
Retained Earnings			
Balance at beginning of year	**5,606**	5,125	4,657
Net (loss)/income attributable to controlling interests	**(1,146)**	1,843	1,789
Common share dividends	**(1,471)**	(1,360)	(1,301)
Preferred share dividends	**—**	(2)	(20)
Balance at end of year	**2,989**	5,606	5,125
Accumulated Other Comprehensive Loss			
Balance at beginning of year	**(1,235)**	(934)	(1,448)
Other comprehensive income/(loss) (Note 21)	**296**	(301)	514
Balance at end of year	**(939)**	(1,235)	(934)
Equity Attributable to Controlling Interests	**18,580**	21,095	20,021
Equity Attributable to Non-Controlling Interests			
Balance at beginning of year	**1,583**	1,417	1,036
Net (loss)/income attributable to non-controlling interests			
TC PipeLines, LP	**(13)**	136	93
Portland Natural Gas Transmission System	**19**	15	12
Other comprehensive income attributable to non-controlling interests	**306**	130	66
Issuance of TC PipeLines, LP units			
Proceeds, net of issue costs	**55**	79	384
Decrease in TCPL's ownership of TC PipeLines, LP	**(11)**	(14)	(47)
Distributions declared to non-controlling interests	**(222)**	(180)	(146)
Other	**—**	—	19
Balance at end of year	**1,717**	1,583	1,417
Total Equity	**20,297**	22,678	21,438

The accompanying Notes to the consolidated financial statements are an integral part of these statements.

Notes to consolidated financial statements

1. DESCRIPTION OF TCPL'S BUSINESS

TransCanada PipeLines Limited (TCPL or the Company) is a leading North American energy infrastructure company which operates in three business segments, Natural Gas Pipelines, Liquids Pipelines and Energy, each of which offers different products and services. The Company is a wholly-owned subsidiary of TransCanada Corporation (TransCanada).

Natural Gas Pipelines

The Natural Gas Pipelines segment consists of the Company's investments in 67,300 km (41,900 miles) of regulated natural gas pipelines and 250 Bcf of regulated natural gas storage facilities. These assets are located in Canada, the United States (U.S.) and Mexico.

Liquids Pipelines

The Liquids Pipelines segment consists of 4,247 km (2,639 miles) of wholly-owned and operated crude oil pipeline systems which connect Alberta and U.S. crude oil supplies to U.S. refining markets in Illinois, Oklahoma and Texas.

Energy

The Energy segment primarily consists of the Company's investments in 19 electrical power generation plants and 2 non-regulated natural gas storage facilities. These include Canadian plants in Alberta, Ontario, Québec and New Brunswick and U.S. plants in New York, New England and Arizona.

2. ACCOUNTING POLICIES

The Company's consolidated financial statements have been prepared by management in accordance with U.S. generally accepted accounting principles (GAAP). Amounts are stated in Canadian dollars unless otherwise indicated.

Basis of Presentation

The consolidated financial statements include the accounts of TCPL and its subsidiaries. The Company consolidates its interest in entities over which it is able to exercise control. To the extent there are interests owned by other parties, these interests are included in Non-controlling interests. TCPL uses the equity method of accounting for joint ventures in which the Company is able to exercise joint control and for investments in which the Company is able to exercise significant influence. TCPL records its proportionate share of undivided interests in certain assets. Certain prior year amounts have been reclassified to conform to current year presentation.

Use of Estimates and Judgments

In preparing these financial statements, TCPL is required to make estimates and assumptions that affect both the amount and timing of recording assets, liabilities, revenues and expenses since the determination of these items may be dependent on future events. The Company uses the most current information available and exercises careful judgment in making these estimates and assumptions. Significant estimates and judgments used in the preparation of the consolidated financial statements include, but are not limited to:

- fair value and depreciation rates of plant, property and equipment (Note 7);
- carrying value of regulatory assets and liabilities (Note 9);
- fair value of goodwill (Note 10);
- amortization rates and fair value of intangible assets (Note 11);
- carrying value of asset retirement obligations (Note 14);
- provisions for income taxes (Note 15);
- assumptions used to measure retirement and other post-retirement obligations (Note 22);
- fair value of financial instruments (Note 23); and
- provision for commitments, contingencies and guarantees (Note 26).

Actual results could differ from those estimates.

Regulation

In Canada, regulated natural gas pipelines and liquids pipelines are subject to the authority of the National Energy Board (NEB). In the U.S., natural gas pipelines, liquids pipelines and regulated natural gas storage assets are subject to the authority of the Federal Energy Regulatory Commission (FERC). In Mexico, natural gas pipelines are subject to the authority of the Energy Regulatory Commission (CRE). The Company's Canadian, U.S. and Mexican natural gas transmission operations are regulated with respect to construction, operations and the determination of tolls. Rate-regulated accounting (RRA) standards may impact the timing of the recognition of certain revenues and expenses in TCPL's rate-regulated businesses which may differ from that otherwise expected in non-rate-regulated businesses to appropriately reflect the economic impact of the regulators' decisions regarding revenues and tolls. TCPL's businesses that apply RRA currently include Canadian, U.S. and Mexican natural gas pipelines, regulated U.S. natural gas storage and certain of its liquids pipelines projects. RRA is not applicable to the Keystone Pipeline System as the regulators' decisions regarding operations and tolls on that system generally do not have an impact on timing of recognition of revenues and expenses.

Revenue Recognition

Natural Gas Pipelines and Liquids Pipelines

Revenues from the Company's natural gas and liquids pipelines, with the exception of Canadian natural gas pipelines which are subject to RRA, are generated from contractual arrangements for committed capacity and from the transportation of natural gas or crude oil. Revenues earned from firm contracted capacity arrangements are recognized ratably over the contract period regardless of the amount of natural gas or crude oil that is transported. Transportation revenues for interruptible or volumetric-based services are recognized when physical deliveries of natural gas or crude oil are made.

Revenues from Canadian natural gas pipelines subject to RRA are recognized in accordance with decisions made by the NEB. The Company's Canadian natural gas pipeline rates are based on revenue requirements designed to recover the costs of providing natural gas transportation services, which include a return of and return on capital, as approved by the NEB. The Company's Canadian natural gas pipelines are not subject to risks related to variances in revenues and most costs. These variances are generally subject to deferral treatment and are recovered or refunded in future rates. The Company's Canadian natural gas pipelines are at times subject to incentive mechanisms, as negotiated with shippers and approved by the NEB. These mechanisms can result in the Company recognizing more or less revenue than required to recover the costs that are subject to incentives. Revenues are recognized on firm contracted capacity ratably over the contract period. Revenues from interruptible or volumetric-based services are recorded when physical delivery is made. Revenues recognized prior to an NEB decision on rates for that period reflect the NEB's last approved ROE assumptions. Adjustments to revenue are recorded when the NEB decision is received.

The Company's U.S. natural gas pipelines are subject to FERC regulations and, as a result, revenues collected may be subject to refund during a rate proceeding. Allowances for these potential refunds are recognized using management's best estimate based on the facts and circumstances of the proceeding. Any allowances that are recognized during the proceeding process are refunded or retained at the time a regulatory decision becomes final.

Revenues from the Company's regulated natural gas storage services are recognized ratably over the contract period for firm committed capacity regardless of the amount of natural gas that is stored and when gas is injected or withdrawn for interruptible or volumetric-based services. The Company does not take ownership of the gas or oil that it transports or stores for others.

Energy

Power

Revenues from the Company's Energy business are primarily derived from the sale of electricity and from the sale of unutilized natural gas fuel, which are recorded at the time of delivery. Revenues also include capacity payments and ancillary services, as well as gains and losses resulting from the use of commodity derivative contracts. The accounting for derivative contracts is described in the Derivative Instruments and Hedging Activities section of this note.

Natural Gas Storage

Revenues earned from providing non-regulated natural gas storage services are recognized in accordance with the terms of the natural gas storage contracts, which is generally over the term of the contract. Revenues earned on the sale of proprietary natural gas are recorded in the month of delivery. Derivative contracts for the purchase or sale of natural gas are recorded at fair value with changes in fair value recorded in Revenues.

Cash and Cash Equivalents

The Company's Cash and cash equivalents consist of cash and highly liquid short-term investments with original maturities of three months or less and are recorded at cost, which approximates fair value.

Inventories

Inventories primarily consist of materials and supplies, including spare parts and fuel, and natural gas inventory in storage, and are carried at the lower of weighted average cost or market.

Plant, Property and Equipment

Natural Gas Pipelines

Plant, property and equipment for natural gas pipelines are carried at cost. Depreciation is calculated on a straight-line basis once the assets are ready for their intended use. Pipeline and compression equipment are depreciated at annual rates ranging from one per cent to six per cent, and metering and other plant equipment are depreciated at various rates, reflecting their estimated useful lives. The cost of major overhauls of equipment is capitalized and depreciated over the estimated service lives of the overhauls. The cost of regulated natural gas pipelines includes an allowance for funds used during construction (AFUDC) consisting of a debt component and an equity component based on the rate of return on rate base approved by regulators. AFUDC is reflected as an increase in the cost of the assets in plant, property and equipment and the equity component of AFUDC is a non-cash expenditure with a corresponding credit recognized in Interest income and other expense in the Consolidated statement of income. Interest is capitalized during construction of non-regulated natural gas pipelines.

When regulated natural gas pipelines retire plant, property and equipment from service, the original book cost is removed from the gross plant amount and recorded as a reduction to accumulated depreciation. Costs incurred to remove a plant from service, net of any salvage proceeds, are also recorded in accumulated depreciation.

Liquids Pipelines

Plant, property and equipment for liquids pipelines are carried at cost. Depreciation is calculated on a straight-line basis once the assets are ready for their intended use. Pipeline and pumping equipment are depreciated at annual rates ranging from two per cent to 2.5 per cent, and other plant and equipment are depreciated at various rates. The cost of major overhauls of equipment is capitalized and depreciated over the estimated service lives of the overhauls. The cost of these assets includes interest capitalized during construction for non-regulated liquids pipelines and AFUDC for regulated pipelines. When liquids pipelines retire plant, property and equipment from service, the original book cost and related accumulated depreciation and amortization are derecognized and any gain or loss is recorded in earnings.

Energy

Power generation and natural gas storage plant, equipment and structures are recorded at cost and, once the assets are ready for their intended use, depreciated by major component on a straight-line basis over their estimated service lives at average annual rates ranging from two per cent to 20 per cent. Other equipment is depreciated at various rates. The cost of major overhauls of equipment is capitalized and depreciated over the estimated service lives of the overhauls. Interest is capitalized on facilities under construction. When these assets are retired from plant, property and equipment, the original book cost and related accumulated depreciation and amortization are derecognized and any gain or loss is recorded in earnings.

Corporate

Corporate Plant, property and equipment are recorded at cost and depreciated on a straight-line basis over their estimated useful lives at average annual rates ranging from three per cent to 20 per cent.

Capitalized Project Costs

The Company capitalizes project costs once advancement to a construction stage is probable or costs are otherwise likely to be recoverable. The Company also capitalizes interest for non-regulated projects in development and AFUDC for regulated projects. Capital projects in development are included in Intangible and other assets. These represent larger projects that generally require regulatory or other approvals before physical construction can begin. Once approvals are received, projects are moved to Plant, property and equipment under construction. When the asset is ready for its intended use and available for operations, capitalized project costs are depreciated in accordance with the Company's depreciation policies.

Project costs related to acquisitions are capitalized once the acquisition is probable.

Assets Held For Sale

The Company classifies assets as held for sale when management approves and commits to a formal plan to actively market a disposal group and expects the sale to close within the next twelve months. Upon classifying an asset as held for sale, the asset is recorded at the lower of its carrying amount or its estimated fair value, reduced for selling costs, and any losses are recognized in income. Depreciation expense is no longer recorded for any assets that are classified as held for sale.

Impairment of Long-Lived Assets

The Company reviews long-lived assets, such as Plant, property and equipment and Intangible assets for impairment whenever events or changes in circumstances indicate the carrying value may not be recoverable. If the total of the estimated undiscounted future cash flows or the estimated price to sell is less than the carrying value of an asset, an impairment loss is recognized for the excess of the carrying value over the fair value of the asset.

Acquisitions and Goodwill

The Company accounts for business acquisitions using the acquisition method of accounting and, accordingly, the assets and liabilities of the acquired entities are primarily measured at their estimated fair value at the date of acquisition. Goodwill is not amortized and is tested for impairment on an annual basis or more frequently if events or changes in circumstances indicate that the asset might be impaired. The annual review for goodwill impairment is performed at the reporting unit level which is one level below the Company's operating segments. The Company initially assesses qualitative factors to determine whether events or changes in circumstances indicate that goodwill might be impaired. If TCPL concludes that it is not more likely than not that the fair value of the reporting unit is greater than its carrying value, the first step of the two-step impairment test is performed by comparing the fair value of the reporting unit to its carrying value, which includes goodwill. If the fair value is less than carrying value, an impairment is indicated and a second step is performed to measure the amount of the impairment. In the second step, the implied fair value of goodwill is calculated by deducting the recognized amounts of all tangible and intangible net assets of the reporting unit from the fair value determined in the initial assessment. If the carrying value of goodwill exceeds the calculated implied fair value of goodwill, an impairment charge is recorded in an amount equal to the difference.

Power Purchase Arrangements

A power purchase agreement (PPA) is a long-term contract for the purchase or sale of power on a predetermined basis. Substantially all PPAs under which TCPL buys power are accounted for as operating leases. Initial payments for these PPAs were recognized in Intangible and other assets and amortized on a straight-line basis over the term of the contracts, which expire in 2017 and 2020. A portion of these PPAs has been subleased to third parties under terms and conditions similar to the PPAs. The subleases are accounted for as operating leases and TCPL records the margin earned from the subleases as a component of Revenues.

Restricted Investments

The Company has certain investments that are restricted as to their withdrawal and use. These restricted investments are classified as available for sale and are recorded at fair value on the Consolidated balance sheet.

As a result of the NEB’s Land Matters Consultation Initiative (LMCI), TCPL is required to collect funds to cover estimated future pipeline abandonment costs for all NEB regulated Canadian pipelines. Collected funds are placed in trusts that hold and invest the funds and are accounted for as Restricted investments. LMCI restricted investments may only be used to abandon the NEB regulated pipeline facilities; therefore, a corresponding regulatory liability is recorded on the Consolidated balance sheet. The Company also has other restricted investments that have been set aside to fund insurance claim losses to be paid by the Company's wholly-owned captive insurance subsidiary.

Income Taxes
The Company uses the asset and liability method of accounting for income taxes. This method requires the recognition of deferred income tax assets and liabilities for future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Deferred income tax assets and liabilities are measured using enacted tax rates at the balance sheet date that are anticipated to apply to taxable income in the years in which temporary differences are expected to be reversed or settled. Changes to these balances are recognized in income in the period during which they occur except for changes in balances related to the Canadian Mainline, NGTL System and Foothills, which are deferred until they are refunded or recovered in tolls, as permitted by the NEB.

Canadian income taxes are not provided on the unremitted earnings of foreign investments that the Company does not intend to repatriate in the foreseeable future.

Asset Retirement Obligations
The Company recognizes the fair value of a liability for asset retirement obligations (ARO) in the period in which it is incurred, when a legal obligation exists and a reasonable estimate of fair value can be made. The fair value is added to the carrying amount of the associated asset and the liability is accreted through charges to operating expenses.

The Company has recorded ARO related to the non-regulated natural gas storage operations and certain power generation facilities. The scope and timing of asset retirements related to natural gas pipelines, liquids pipelines and hydroelectric power plants is indeterminable. As a result, the Company has not recorded an amount for ARO related to these assets, with the exception of certain abandoned facilities.

Environmental Liabilities
The Company records liabilities on an undiscounted basis for environmental remediation efforts that are likely to occur and where the cost can be reasonably estimated. The estimates, including associated legal costs, are based on available information using existing technology and enacted laws and regulations. The estimates are subject to revision in future periods based on actual costs incurred or new circumstances. Amounts expected to be recovered from other parties, including insurers, are recorded as an asset separate from the associated liability.

Emission allowances or credits purchased for compliance are recorded on the Consolidated balance sheet at historical cost and expensed when they are utilized. Compliance costs are expensed when incurred. Allowances granted to or internally generated by TCPL are not attributed a value for accounting purposes. When required, TCPL accrues emission liabilities on the Consolidated balance sheet upon the generation or sale of power using the best estimate of the amount required to settle the obligation. Allowances and credits not used for compliance are sold and any gain or loss is recorded in Revenues.

Stock Options and Other Compensation Programs
The Company's Stock Option Plan permits options for the purchase of TransCanada common shares to be awarded to certain employees, including officers. Stock options granted are recorded using the fair value method. Under this method, compensation expense is measured at the grant date based on the fair value as calculated using a binomial model and is recognized on a straight-line basis over the vesting period, with an offset to Additional paid-in capital. TCPL records the compensation expense associated with these stock options.

The Company has medium-term incentive plans, under which payments are made to eligible employees. The expense related to these incentive plans is accounted for on an accrual basis. Under these plans, benefits vest when certain conditions are met, including the employees' continued employment during a specified period and achievement of specified corporate performance targets.

Employee Post-Retirement Benefits
The Company sponsors defined benefit pension plans (DB Plans), defined contribution plans (DC Plans), a savings plan and other post-retirement benefit plans. Contributions made by the Company to the DC Plans and savings plan are expensed in the period in which contributions are made. The cost of the DB Plans and other post-retirement benefits received by employees is actuarially determined using the projected benefit method pro-rated based on service and management's best estimate of expected plan investment performance, salary escalation, retirement age of employees and expected health care costs.

The DB Plans' assets are measured at fair value at December 31 of each year. The expected return on the DB Plans' assets is determined using market-related values based on a five-year moving average value for all of the DB Plans' assets. Past service costs are amortized over the expected average remaining service life of the employees. Adjustments arising from plan amendments are amortized on a straight-line basis over the average remaining service life of employees active at the date of amendment. The Company recognizes the overfunded or underfunded status of its DB Plans as an asset or liability, respectively, on its Consolidated balance sheet and recognizes changes in that funded status through Other comprehensive income/(loss) (OCI) in the year in which the change occurs. The excess of net actuarial gains or losses over 10 per cent of the greater of the benefit obligation and the market-related value of the DB Plans' assets, if any, is amortized out of Accumulated other comprehensive income/(loss) (AOCI) over the average remaining service life of the active employees. When the restructuring of a benefit plan gives rise to both a curtailment and a settlement, the curtailment is accounted for prior to the settlement.

For certain regulated operations, post-retirement benefit amounts are recoverable through tolls as benefits are funded. The Company records any unrecognized gains or losses or changes in actuarial assumptions related to these post-retirement benefit plans as either regulatory assets or liabilities. The regulatory assets or liabilities are amortized on a straight-line basis over the expected average remaining service life of active employees.

Foreign Currency Transactions and Translation

Foreign currency transactions are those transactions whose terms are denominated in a currency other than the currency of the primary economic environment in which the company or reporting subsidiary operates, referred to as the functional currency. Transactions denominated in foreign currencies are translated into the functional currency using the exchange rate prevailing at the date of the transaction. Monetary assets and liabilities denominated in foreign currencies are translated to the functional currency using the rate of exchange in effect at the balance sheet date whereas non-monetary assets and liabilities are translated at the historical rate of exchange in effect on the date of the transaction. Exchange gains and losses resulting from translation of monetary assets and liabilities are recorded in income except for exchange gains and losses of the foreign currency debt related to Canadian regulated natural gas pipelines, which are deferred until they are refunded or recovered in tolls, as permitted by the NEB.

Gains and losses arising from translation of foreign operations' functional currencies to the Company's Canadian dollar reporting currency are reflected in OCI. Asset and liability accounts are translated at the period-end exchange rates while revenues, expenses, gains and losses are translated at the exchange rates in effect at the time of the transaction. The Company's U.S. dollar-denominated debt has been designated as a hedge of the net investment in foreign subsidiaries and, as a result, the unrealized foreign exchange gains and losses on the U.S. dollar denominated debt are also reflected in OCI.

Derivative Instruments and Hedging Activities

All derivative instruments are recorded on the Consolidated balance sheet at fair value, unless they qualify for and are designated under a normal purchase and normal sales exemption, or are considered to meet other permitted exemptions.

The Company applies hedge accounting to arrangements that qualify and are designated for hedge accounting treatment, which includes fair value and cash flow hedges, and hedges of foreign currency exposures of net investments in foreign operations. Hedge accounting is discontinued prospectively if the hedging relationship ceases to be effective or the hedging or hedged items cease to exist as a result of maturity, expiry, sale, termination, cancellation or exercise.

In a fair value hedging relationship, the carrying value of the hedged item is adjusted for changes in fair value attributable to the hedged risk and these changes are recognized in Net income. Changes in the fair value of the hedged item, to the extent that the hedging relationship is effective, are offset by changes in the fair value of the hedging item, which are also recorded in Net income. Changes in the fair value of foreign exchange and interest rate fair value hedges are recorded in Interest income and other expense and Interest expense, respectively. If hedge accounting is discontinued, the carrying value of the hedged item is no longer adjusted and the cumulative fair value adjustments to the carrying value of the hedged item are amortized to Net income over the remaining term of the original hedging relationship.

In a cash flow hedging relationship, the effective portion of the change in the fair value of the hedging derivative is initially recognized in OCI, while any ineffective portion is recognized in Net income in the same financial statement category as the underlying transaction. When hedge accounting is discontinued, the amounts recognized previously in AOCI are reclassified to Revenues, Interest expense and Interest income and other, as appropriate, during the periods when the variability in cash flows of the hedged item affects Net income or as the original hedged item settles. Gains and losses on derivatives are reclassified immediately to Net income from AOCI when the hedged item is sold or terminated early, or when it becomes probable that the anticipated transaction will not occur.

In hedging the foreign currency exposure of a net investment in a foreign operation, the effective portion of foreign exchange gains and losses on the hedging instruments is recognized in OCI and the ineffective portion is recognized in Net income. The amounts recognized previously in AOCI are reclassified to Net income in the event the Company reduces its net investment in a foreign operation.

In some cases, derivatives do not meet the specific criteria for hedge accounting treatment. In these instances, the changes in fair value are recorded in Net income in the period of change.

The recognition of gains and losses on derivatives for Canadian natural gas regulated pipelines exposures is determined through the regulatory process. Gains and losses arising from changes in the fair value of derivatives accounted for as part of RRA, including those that qualify for hedge accounting treatment, can be recovered through the tolls charged by the Company. As a result, these gains and losses are deferred as Regulatory assets or Regulatory liabilities and are refunded to or collected from the ratepayers, in subsequent years when the derivative settles.

Derivatives embedded in other financial instruments or contracts (host instrument) are recorded as separate derivatives. Embedded derivatives are measured at fair value if their economic characteristics are not clearly and closely related to those of the host instrument, their terms are the same as those of a stand-alone derivative and the total contract is not held for trading or accounted for at fair value. When changes in the fair value of embedded derivatives are measured separately, they are included in Net income.

Long-Term Debt Transaction Costs

The Company records Long-term debt transaction costs as other assets and amortizes these costs using the effective interest method for all costs except those related to the Canadian natural gas regulated pipelines, which continue to be amortized on a straight-line basis in accordance with the provisions of regulatory tolling mechanisms.

Guarantees

Upon issuance, the Company records the fair value of certain guarantees entered into by the Company or partially owned entities for which contingent payments may be made. The fair value of these guarantees is estimated by discounting the cash flows that would be incurred by the Company if letters of credit were used in place of the guarantees as appropriate in the circumstances. Guarantees are recorded as an increase to Equity investments, Plant, property and equipment, or a charge to Net income, and a corresponding liability is recorded in Other long-term liabilities.

3. ACCOUNTING CHANGES

Changes in Accounting Policies for 2015

Derivatives and Hedging

In August 2015, the Financial Accounting Standards Board (FASB) issued new guidance on the application of the normal purchases and normal sales scope exception to certain electricity contracts within nodal energy markets. The amendments in this update apply to entities that enter into contracts for the purchase or sale of electricity on a forward basis and arrange for transmission through or delivery to a location within a nodal energy market whereby one of the contracting parties incurs charges (or credits) for the transmission of that electricity based in part on locational marginal pricing differences payable to (or receivable from) an independent system operator. This new guidance was effective upon issuance, was applied prospectively and did not have a material impact on the Company's consolidated financial statements.

Balance Sheet Classification of Deferred Taxes

In November 2015, the FASB issued new guidance which requires that deferred tax assets and liabilities be classified as non-current on the balance sheet. The new guidance is effective January 1, 2017, however, since early application is permitted, the Company elected to retrospectively apply this guidance effective January 1, 2015. Application of this new guidance will simplify the Company’s process in determining deferred tax amounts and simplify their presentation. The application of this amendment resulted in a reclassification of Deferred tax assets previously recorded in Other current assets, and Deferred tax liabilities previously recorded in Accounts payable and other to non-current Deferred income tax assets and liabilities. Prior year amounts have been reclassified to conform to current year presentation.

Reporting discontinued operations

In April 2014, the FASB issued amended guidance on the reporting of discontinued operations. The criteria of what will qualify as a discontinued operation has changed and there are expanded disclosures required. This new guidance was applied prospectively from January 1, 2015 and there was no impact on the Company's consolidated financial statements as a result of applying this new standard.

Future Accounting Changes

Revenue from contracts with customers

In 2014, the FASB issued new guidance on revenue from contracts with customers. This guidance supersedes the current revenue recognition requirements and most industry-specific guidance. This new guidance requires that an entity recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the company expects to be entitled in exchange for those goods or services. In July 2015, the FASB deferred the effective date of this new standard to January 1, 2018, with early adoption not permitted before January 1, 2017. There are two methods in which the amendment can be applied: (1) retrospectively to each prior reporting period presented, or (2) retrospectively with the cumulative effect recognized at the date of initial application.

The Company is currently evaluating the impact of the adoption of this guidance and has not yet determined the effect on its consolidated financial statements.

Extraordinary and unusual income statement items

In January 2015, the FASB issued new guidance on extraordinary and unusual income statement items. This update eliminates from GAAP the concept of extraordinary items. This new guidance is effective from January 1, 2016 and will be applied prospectively. The Company does not expect the adoption of this new standard to have a material impact on its consolidated financial statements.

Consolidation

In February 2015, the FASB issued new guidance on consolidation analysis. This update requires that entities reevaluate whether they should consolidate certain legal entities and eliminates the presumption that a general partner should consolidate a limited partnership. This new guidance is effective from January 1, 2016 and will be applied retrospectively. The Company is currently evaluating the impact of the adoption of this guidance and has not yet determined the effect on its consolidated financial statements.

Imputation of interest

In April 2015, the FASB issued new guidance on simplifying the accounting for debt issuance costs. The amendments in this update require that debt issuance costs be presented in the balance sheet as a direct deduction from the carrying amount of the debt liability consistent with debt discounts or premiums. This new guidance is effective January 1, 2016 and will be applied retrospectively. The application of this amendment will result in a reclassification of debt issuance costs currently recorded in Intangible and other assets to an offset of their respective debt liabilities.

Inventory

In July 2015, the FASB issued new guidance on simplifying the measurement of inventory. The amendments in this update specify that an entity should measure inventory within the scope of this update at the lower of cost and net realizable value. Net realizable value is the estimated selling price in the ordinary course of business, less reasonably predictable costs of completion, disposal and transportation. This new guidance is effective January 1, 2017 and will be applied prospectively. The Company does not expect the adoption of this new standard to have a material impact on its consolidated financial statements.

Business Combinations

In September 2015, the FASB issued guidance which replaces the requirement that an acquirer in a business combination account for measurement period adjustments retrospectively with a requirement that an acquirer recognize adjustments to the provisional amounts that are identified during the measurement period in the reporting period in which the adjustment amounts are determined. The amended guidance requires that the acquirer record, in the same period’s financial statements as the adjustment was determined, the effect on earnings of changes in depreciation, amortization, or other income effects, if any, as a result of the change to the provisional amounts, calculated as if the accounting had been completed at the acquisition date. The new guidance is effective January 1, 2016 and will be applied prospectively. The Company does not expect the adoption of this new standard to have a material impact on its consolidated financial statements.

4. SEGMENTED INFORMATION

year ended December 31, 2015 (millions of Canadian $)	**Natural Gas Pipelines**	**Liquids Pipelines**	**Energy**	**Corporate**	**Total**
Revenues	**5,383**	**1,879**	**4,038**	**—**	**11,300**
Income from equity investments	**179**	**—**	**261**	**—**	**440**
Plant operating costs and other	**(1,736)**	**(478)**	**(766)**	**(270)**	**(3,250)**
Commodity purchases resold	**—**	**—**	**(2,237)**	**—**	**(2,237)**
Property taxes	**(349)**	**(79)**	**(89)**	**—**	**(517)**
Depreciation and amortization	**(1,132)**	**(266)**	**(336)**	**(31)**	**(1,765)**
Asset impairment charges	**—**	**(3,686)**	**(59)**	**—**	**(3,745)**
Loss on assets held for sale	**(125)**	**—**	**—**	**—**	**(125)**
Segmented earnings/(losses)	**2,220**	**(2,630)**	**812**	**(301)**	**101**
Interest expense					**(1,398)**
Interest income and other					**192**
Loss before income taxes					**(1,105)**
Income tax expense					**(35)**
Net loss					**(1,140)**
Net income attributable to non-controlling interests					**(6)**
Net loss attributable to controlling interests					**(1,146)**
Preferred share dividends					**—**
Net loss attributable to common shares					**(1,146)**
Capital spending					
Capital expenditures	**2,466**	**1,012**	**376**	**64**	**3,918**
Capital projects in development	**233**	**278**	**—**	**—**	**511**
	2,699	**1,290**	**376**	**64**	**4,429**

year ended December 31, 2014 (millions of Canadian $)	Natural Gas Pipelines	Liquids Pipelines	Energy	Corporate	Total
Revenues	4,913	1,547	3,725	—	10,185
Income from equity investments	163	—	359	—	522
Plant operating costs and other	(1,501)	(426)	(919)	(127)	(2,973)
Commodity purchases resold	—	—	(1,836)	—	(1,836)
Property taxes	(334)	(62)	(77)	—	(473)
Depreciation and amortization	(1,063)	(216)	(309)	(23)	(1,611)
Gain on assets sold	9	—	108	—	117
Segmented earnings/(losses)	2,187	843	1,051	(150)	3,931
Interest expense					(1,235)
Interest income and other					128
Income before income taxes					2,824
Income tax expense					(830)
Net income					1,994
Net income attributable to non-controlling interests					(151)
Net income attributable to controlling interests					1,843
Preferred share dividends					(2)
Net income attributable to common shares					1,841
Capital spending					
Capital expenditures	1,768	1,469	206	46	3,489
Capital projects in development	368	480	—	—	848
	2,136	1,949	206	46	4,337

year ended December 31, 2013 (millions of Canadian $)	**Natural Gas Pipelines**	**Liquids Pipelines**	**Energy**	**Corporate**	**Total**
Revenues	4,497	1,124	3,176	—	8,797
Income from equity investments	145	—	452	—	597
Plant operating costs and other	(1,405)	(328)	(833)	(108)	(2,674)
Commodity purchases resold	—	—	(1,317)	—	(1,317)
Property taxes	(329)	(44)	(72)	—	(445)
Depreciation and amortization	(1,027)	(149)	(293)	(16)	(1,485)
Segmented earnings/(losses)	1,881	603	1,113	(124)	3,473
Interest expense					(1,046)
Interest income and other					72
Income before income taxes					2,499
Income tax expense					(605)
Net income					1,894
Net income attributable to non-controlling interests					(105)
Net income attributable to controlling interests					1,789
Preferred share dividends					(20)
Net income attributable to common shares					1,769
Capital spending					
Capital expenditures	1,776	2,286	152	50	4,264
Capital projects in development	245	243	—	—	488
	2,021	2,529	152	50	4,752

at December 31 (millions of Canadian $)	2015	2014
Total Assets		
Natural Gas Pipelines	**31,072**	27,103
Liquids Pipelines	**16,046**	16,116
Energy	**15,558**	14,197
Corporate	**4,253**	3,999
	66,929	61,415

Geographic Information

year ended December 31 (millions of Canadian $)	2015	2014	2013
Revenues			
Canada – domestic	**3,877**	3,956	4,659
Canada – export	**1,292**	1,314	997
United States	**5,872**	4,718	3,029
Mexico	**259**	197	112
	11,300	10,185	8,797

at December 31 (millions of Canadian $)	2015	2014
Plant, Property and Equipment		
Canada	**19,287**	19,191
United States	**21,899**	20,098
Mexico	**3,631**	2,485
	44,817	41,774

5. OTHER CURRENT ASSETS

at December 31 (millions of Canadian $)	2015	2014
Cash held as collateral	**585**	423
Fair value of derivative contracts (Note 23)	**442**	409
Regulatory assets (Note 9)	**85**	16
Assets held for sale (Note 6)	**20**	—
Other	**221**	170
	1,353	1,018

6. ASSETS HELD FOR SALE

On December 18, 2015, the Company entered into an agreement to sell TC Offshore LLC (TCO) to a third party and expects the sale to close in early 2016. As a result, at December 31, 2015, the related assets and liabilities were held for sale in the Natural Gas Pipelines segment and were recorded at their fair values less costs to sell. This resulted in a loss of $125 million pre-tax in 2015 which is included in (Loss)/gain on assets held for sale/sold in the Consolidated statement of income. TCO is a FERC regulated entity that operates as part of ANR. TCO does not represent a major line of business or geographical area of the Company, and therefore is not considered to be a discontinued operation as of December 31, 2015.

at December 31 (millions of Canadian $)	2015
Assets Held for Sale	
Accounts receivable	**4**
Inventories	**1**
Other current assets	**1**
Plant, property and equipment	**14**
Total Assets Held for Sale (included in Other current assets, Note 5)	**20**
Liabilities Related to Assets Held for Sale	
Accounts payable and other	**38**
Other long-term liabilities	**1**
Total Liabilities Related to Assets Held for Sale (included in Accounts payable and other, Note 13)	**39**

7. PLANT, PROPERTY AND EQUIPMENT

at December 31 (millions of Canadian $)	2015 Cost	2015 Accumulated Depreciation	2015 Net Book Value	2014 Cost	2014 Accumulated Depreciation	2014 Net Book Value
Natural Gas Pipelines						
Canadian Mainline						
Pipeline	**9,164**	**5,966**	**3,198**	9,045	5,712	3,333
Compression	**3,433**	**2,220**	**1,213**	3,423	2,100	1,323
Metering and other	**499**	**192**	**307**	458	180	278
	13,096	**8,378**	**4,718**	12,926	7,992	4,934
Under construction	**257**	**—**	**257**	135	—	135
	13,353	**8,378**	**4,975**	13,061	7,992	5,069
NGTL System						
Pipeline	**8,456**	**3,820**	**4,636**	8,185	3,619	4,566
Compression	**2,188**	**1,404**	**784**	2,055	1,318	737
Metering and other	**1,096**	**489**	**607**	1,032	446	586
	11,740	**5,713**	**6,027**	11,272	5,383	5,889
Under construction	**969**	**—**	**969**	413	—	413
	12,709	**5,713**	**6,996**	11,685	5,383	6,302
ANR[1]						
Pipeline	**1,449**	**350**	**1,099**	1,217	227	990
Compression	**1,101**	**187**	**914**	780	140	640
Metering and other	**977**	**252**	**725**	737	231	506
	3,527	**789**	**2,738**	2,734	598	2,136
Under construction	**304**	**—**	**304**	127	—	127
	3,831	**789**	**3,042**	2,861	598	2,263
Mexico						
Pipeline	**1,296**	**162**	**1,134**	1,053	104	949
Compression	**183**	**14**	**169**	151	6	145
Metering and other	**388**	**27**	**361**	314	20	294
	1,867	**203**	**1,664**	1,518	130	1,388
Under construction	**1,959**	**—**	**1,959**	1,098	—	1,098
	3,826	**203**	**3,623**	2,616	130	2,486
Other Natural Gas Pipelines						
GTN	**2,278**	**765**	**1,513**	1,842	588	1,254
Great Lakes	**2,157**	**1,155**	**1,002**	1,807	939	868
Foothills	**1,606**	**1,162**	**444**	1,671	1,180	491
Other[2]	**2,223**	**572**	**1,651**	1,800	363	1,437
	8,264	**3,654**	**4,610**	7,120	3,070	4,050
Under construction	**71**	**—**	**71**	34	—	34
	8,335	**3,654**	**4,681**	7,154	3,070	4,084
	42,054	**18,737**	**23,317**	37,377	17,173	20,204

Liquids Pipelines						
Keystone						
Pipeline	**9,288**	**718**	**8,570**	7,931	463	7,468
Pumping equipment	**1,092**	**108**	**984**	964	80	884
Tanks and other	**3,034**	**228**	**2,806**	2,282	144	2,138
	13,414	**1,054**	**12,360**	11,177	687	10,490
Under construction	**1,826**	**—**	**1,826**	4,438	—	4,438
	15,240	**1,054**	**14,186**	15,615	687	14,928
Energy						
Natural Gas – Ravenswood	**2,607**	**654**	**1,953**	2,140	476	1,664
Natural Gas – Other[3,4]	**3,361**	**1,164**	**2,197**	3,214	971	2,243
Hydro, Wind and Solar[5]	**2,417**	**476**	**1,941**	2,194	359	1,835
Natural Gas Storage and Other	**740**	**132**	**608**	717	118	599
	9,125	**2,426**	**6,699**	8,265	1,924	6,341
Under construction	**430**	**—**	**430**	149	—	149
	9,555	**2,426**	**7,129**	8,414	1,924	6,490
Corporate	**267**	**82**	**185**	232	80	152
	67,116	**22,299**	**44,817**	61,638	19,864	41,774

1 TCO is excluded from the ANR net book value at December 31, 2015 as it has been classified as an asset held for sale. Refer to Note 6 for further information.

2 Includes Bison, Portland Natural Gas Transmission System (PNGTS), North Baja, Tuscarora and Ventures LP.

3 Includes facilities with long-term PPAs that are accounted for as operating leases. The cost and accumulated depreciation of these facilities were $813 million and $142 million, respectively, at December 31, 2015 (2014 – $695 million and $103 million, respectively). Revenues of $93 million were recognized in 2015 (2014 – $81 million; 2013 – $78 million) through the sale of electricity under the related PPAs.

4 Includes Halton Hills, Coolidge, Bécancour, Ocean State Power, Mackay River and other natural gas-fired facilities.

5 Includes the acquisitions of four solar power facilities in 2014.

Keystone XL Impairment

At December 31, 2015, the Company evaluated its investment in Keystone XL and related projects, including the Keystone Hardisty Terminal (KHT), for impairment in connection with the November 6, 2015 denial of the U.S. Presidential permit. As a result of the analysis, the Company recognized a non-cash impairment charge of $3,686 million ($2,891 million after-tax) based on the excess of the carrying value over the estimated fair value of $621 million of these assets. The impairment charge includes $77 million ($56 million after-tax) for certain cancellation fees that will be incurred in the future if the project is ultimately abandoned.

at December 31, 2015	**Estimated**	**Impairment charge**	
(millions of Canadian $)	**Fair Value**	**Pre-tax**	**After-tax**
Plant and equipment	**463**	**1,460**	**1,391**
Terminals, including KHT	**158**	**274**	**219**
Intangible assets	**—**	**1,150**	**737**
Capitalized interest	**—**	**725**	**488**
Future cancellation costs	**—**	**77**	**56**
	621	**3,686**	**2,891**

The estimated fair value of $463 million related to plant and equipment was based on the price that would be received on sale of the plant and equipment in its current condition. An independent third party valuation was utilized in the assessment of the fair value of these assets. Key assumptions used in the determination of selling price included an estimated two year disposal period and the current weak energy market conditions. The valuation considered a variety of potential selling prices that were based on the various markets that could be used in order to dispose of these assets.

The estimated $158 million fair value of the terminal assets, including KHT, was determined using a discounted cash flow approach as a measure of fair value. The expected cash flows were discounted using a risk-adjusted discount rate to determine the fair value.

The valuation techniques above required the use of unobservable inputs. As a result, the fair value is classified within Level 3 of the fair value hierarchy. Refer to Note 23 for further information on the fair value hierarchy.

Energy Turbine Impairment

Following the evaluation of specific capital project opportunities in 2015, it was determined that the carrying value of certain Energy turbine equipment was not fully recoverable. These turbines had been previously purchased for a power development project that did not proceed. As a result, at December 31, 2015, the Company recognized a non-cash impairment charge of $59 million ($43 million after-tax). This impairment charge was based on the excess of the carrying value over the fair value of the turbines, which was determined based on a comparison to similar assets available for sale in the market.

8. EQUITY INVESTMENTS

		Income / (Loss) from Equity Investments			Equity Investments	
	Ownership Interest at	year ended December 31			at December 31	
(millions of Canadian $)	December 31, 2015	2015	2014	2013	2015	2014
Natural Gas Pipelines						
Northern Border[1,2]		**85**	76	66	**664**	587
Iroquois	44.5%	**51**	43	41	**238**	210
TQM	50.0%	**12**	12	13	**72**	73
Other	Various	**31**	32	25	**73**	68
Liquids Pipelines						
Grand Rapids	50.0%	**—**	—	—	**542**	240
Canaport Energy East Marine Terminal	50.0%	**—**	—	—	**16**	—
Energy						
Bruce Power[3,4]	48.5%	**249**	314	310	**4,200**	3,995
ASTC Power Partnership	50.0%	**(23)**	8	110	**21**	29
Portlands Energy	50.0%	**30**	36	31	**321**	335
Other	Various	**5**	1	1	**67**	61
		440	522	597	**6,214**	5,598

1 The results reflect a 50.0 per cent interest in Northern Border as a result of the Company fully consolidating TC PipeLines, LP. At December 31, 2015, TCPL had an ownership interest in TC PipeLines, LP of 28.0 per cent (2014 – 28.3 and 2013 – 28.9 per cent) and its effective ownership of Northern Border, net of non-controlling interests, was 14.0 per cent (2014 – 14.2 and 2013 – 14.5 per cent).

2 At December 31, 2015, the difference between the carrying value of the investment and the underlying equity in the net assets of Northern Border Pipeline Company is US$117 million (2014 – US$117 million) due to the fair value assessment of assets at the time of acquisition.

3 As a result of TCPL's increased ownership in Bruce Power L.P. (Bruce B) and the merger of Bruce Power A L.P. (Bruce A) and Bruce B (to form Bruce Power) in December 2015, TCPL has an ownership interest in Bruce Power of 48.5 per cent. Prior to the acquisition and merger, TCPL applied equity accounting to its 48.9 per cent ownership interest in Bruce A and 31.6 per cent ownership interest in Bruce B. TCPL continues to apply equity accounting to Bruce Power. Refer to Note 25 for further information.

4 At December 31, 2015, the difference between the carrying value of the investment and the underlying equity in the net assets of Bruce Power is $973 million (2014 – $776 million) due to the fair value assessment of assets at the time of acquisitions.

Distributions received from equity investments for the year ended December 31, 2015 were $802 million (2014 – $738 million; 2013 – $733 million) of which $226 million (2014 – $159 million; 2013 – $128 million) were returns of capital and are included in Investing activities in the Consolidated statement of cash flows. The undistributed earnings from equity investments as at December 31, 2015 were $198 million (2014 – $551 million; 2013 – $754 million).

Contributions made to equity investments for the year ended December 31, 2015 were $493 million (2014 – $256 million; 2013 – $163 million) and are included in Equity investments in the Consolidated statement of cash flows.

Summarized Financial Information of Equity Investments

year ended December 31 (millions of Canadian $)	2015	2014	2013
Income			
Revenues	**4,337**	4,814	4,989
Operating and other expenses	**(3,254)**	(3,489)	(3,536)
Net income	**1,046**	1,264	1,390
Net income attributable to TCPL	**440**	522	597

at December 31 (millions of Canadian $)	2015	2014
Balance Sheet		
Current assets	**1,530**	1,412
Non-current assets	**13,190**	12,260
Current liabilities	**(1,370)**	(1,067)
Non-current liabilities	**(3,116)**	(3,255)

9. RATE-REGULATED BUSINESSES

TCPL's businesses that apply RRA currently include Canadian, U.S. and Mexican natural gas pipelines, regulated U.S. natural gas storage and certain Canadian liquids pipelines currently in development. Regulatory assets and liabilities represent future revenues that are expected to be recovered from or refunded to customers based on decisions and approvals by the applicable regulatory authorities.

Canadian Regulated Operations

The Canadian Mainline, NGTL System, Foothills and TQM pipelines are regulated by the NEB under the *National Energy Board Act*. The NEB regulates the construction and operation of facilities, and the terms and conditions of services, including rates, for the Company's Canadian regulated natural gas transmission systems.

TCPL's Canadian natural gas transmission services are supplied under natural gas transportation tariffs that provide for cost recovery, including return of and return on capital as approved by the NEB. Rates charged for these services are typically set through a process that involves filing an application with the regulator wherein forecasted operating costs, including a return of and on capital, determine the revenue requirement for the upcoming year or multiple years. To the extent that actual costs and revenues are more or less than the forecasted costs and revenues, the regulators generally allow the difference to be deferred to a future period and recovered or refunded in rates at that time. Differences between actual and forecasted costs that the regulator does not allow to be deferred are included in the determination of net income in the year they occur.

Canadian Mainline

In March 2015, TCPL filed a compliance filing with the NEB in response to the RH-001-2014 Decision on TCPL's 2015-2030 Tolls Application (the NEB 2014 Decision) and is required to file a toll review for the 2018 to 2020 period prior to December 31, 2017. In June 2015, the NEB approved the applied-for compliance tolls as filed and these tolls became effective on July 1, 2015.

The NEB's 2014 Decision acknowledged that an off-ramp had been reached on the NEB 2013 Decision (described below) and approved fixed tolls for 2015 to 2020 as well as certain parameters for a toll setting methodology to 2030. Features of the settlement reached with shippers as approved in the NEB 2014 Decision include an ROE of 10.1 per cent on deemed common equity of 40 per cent, an incentive mechanism that has both upside and downside risk and a $20 million after-tax annual TCPL contribution to reduce the revenue requirement. Toll stabilization is achieved through the continued use of deferral accounts, namely the Long-term adjustment account (LTAA) and the Bridging amortization account, to capture the surplus or the shortfall between the Company's revenues and cost of service for each year over the six-year fixed toll term of the NEB 2014 Decision.

In March 2013, the Company received a decision from the NEB which set tolls for 2013 through 2017 at competitive levels, fixing tolls for some services and providing unlimited pricing discretion for others (the NEB 2013 Decision). The decision established an ROE of 11.5 per cent on deemed common equity of 40 per cent and included mechanisms to achieve the fixed tolls through the use of a LTAA as well as the establishment of a Tolls Stabilization Account (TSA) to capture the surplus or the shortfall between revenues and cost of service for each year over the five-year term of the decision. In addition, the decision provided an opportunity to generate incentive earnings by increasing revenues and reducing costs. The NEB also identified certain circumstances that would require a new tolls application prior to the end of the five-year term. One of those circumstances occurred in 2013 when the TSA balance became positive. In December 2013, TCPL filed the 2015-2030 Tolls Application with the NEB that addressed tolls moving forward including continuation of the NEB 2013 Decision tolls for 2014.

NGTL System

In February 2015, the NEB approved the NGTL System's 2015 Revenue Requirement Settlement. The terms of the one year settlement include ROE of 10.1 per cent on 40 per cent deemed equity, a continuation of the 2014 depreciation rates and a mechanism for sharing variances above and below a fixed annual operating, maintenance and administration (OM&A) cost amount that was based on an escalation of 2014 actual costs.

The NGTL System's 2014 results reflect the terms of the 2013-2014 Revenue Requirement Settlement Application. This settlement had fixed annual OM&A costs and a 10.1 per cent ROE on deemed common equity of 40 per cent. Any variance between fixed OM&A costs in the settlement and actual costs accrued to TCPL. The settlement also included a composite depreciation rate of 3.12 per cent in 2014.

Energy East

Energy East is currently in the development stage, awaiting regulatory approval from the NEB. Tolls will be designed to provide for cost recovery including return of and on capital as approved by the NEB.

Other Canadian Pipelines

The Foothills operating model for 2014 and 2015 provides for recovery of all revenue requirement components on a flow-through basis. TQM operates under a model consisting of fixed and flow-through revenue requirement components for 2014 through 2016. Any variances between actual costs and those included in the fixed component accrue to TQM.

U.S. Regulated Operations

TCPL's U.S. natural gas pipelines are "natural gas companies" operating under the provisions of the Natural Gas Act of 1938, the Natural Gas Policy Act of 1978 (NGA) and the Energy Policy Act of 2005, and are subject to the jurisdiction of the FERC. The NGA grants the FERC authority over the construction and operation of pipelines and related facilities. The FERC also has authority to regulate rates for natural gas transportation in interstate commerce. The Company's significant regulated U.S. natural gas pipelines are described below.

ANR

ANR's natural gas transportation and storage services are provided under tariffs regulated by the FERC. These tariffs include maximum and minimum rates for services and allow ANR to discount or negotiate rates on a non-discriminatory basis. ANR Pipeline Company rates were established pursuant to a settlement approved by the FERC that was effective for all periods presented, beginning in 1997. On January 29, 2016, ANR Pipeline Company filed an application with the FERC under section 4 of the NGA to establish new rates expected to be effective, subject to refund, on August 1, 2016.

ANR Storage Company rates were established pursuant to a settlement approved by the FERC in August 2012 and ANR Storage Company is required to file for new rates to be effective no later than July 1, 2016.

TCO, another ANR-related regulated entity, began operating under FERC-approved tariff rates on November 1, 2012. As at December 31, 2015, TCO assets were classified as Assets held for sale. Refer to Note 6 for more information.

Other U.S. Natural Gas Pipelines

GTN, Great Lakes and Bison are regulated by the FERC and operate in accordance with FERC-approved tariffs that establish maximum and minimum rates for various services. Each pipeline is permitted to discount or negotiate these rates on a non-discriminatory basis.

GTN's rates were established pursuant to a settlement approved by the FERC in January 2012. On June 30, 2015, FERC approved GTN's new settlement with its shippers which satisfies GTN's obligations from the 2012 settlement for new rates to be in effect on January 1, 2016, and reduced rates on the mainline by three per cent on July 1, 2015. In January 2016, GTN's rates will decrease a further 10 percent and will continue in effect through December 31, 2019. Unless superseded by a subsequent rate case or settlement, GTN's rates will decrease an additional eight per cent for the period January 1, 2020 through December 31, 2021 when GTN will be required to establish new rates.

Great Lakes operates under rates established pursuant to a settlement approved by the FERC in November 2013. Under the settlement, Great Lakes is required to file for new rates to be effective no later than January 1, 2018.

Bison continues to operate under the rates approved by FERC in connection with Bison's initial construction and has no requirement to file a new rate proceeding.

Mexico Regulated Operations

TCPL's Mexican operations are regulated by the CRE and operate in accordance with CRE-approved tariffs. In 2014, TCPL began using RRA for all natural gas pipelines in Mexico. The rates were established based on CRE approved negotiated contracts.

Regulatory Assets and Liabilities

at December 31 (millions of Canadian $)	2015	2014	Remaining Recovery/ Settlement Period (years)
Regulatory Assets			
Deferred income taxes[1]	**848**	1,001	n/a
Operating and debt-service regulatory assets[2]	**47**	4	1
Pensions and other post retirement benefits[3]	**210**	236	n/a
Foreign exchange on long-term debt[5]	**54**	—	1-14
Other[4]	**110**	72	n/a
	1,269	1,313	
Less: Current portion included in Other current assets (Note 5)	**85**	16	
	1,184	1,297	
Regulatory Liabilities			
Foreign exchange on long-term debt[5]	**—**	42	1-14
Operating and debt-service regulatory liabilities[2]	**32**	21	1
ANR-related post-employment and retirement benefits other than pension[6]	**147**	117	n/a
Long term adjustment account[7]	**231**	64	45
Pipeline abandonment costs[8]	**285**	—	n/a
Bridging amortization account[9]	**456**	—	15
Other[4]	**52**	49	n/a
	1,203	293	
Less: Current portion included in Accounts payable and other (Note 13)	**44**	30	
	1,159	263	

1 These regulatory assets are underpinned by non-cash transactions or are recovered without an allowance for return as approved by the regulator. Accordingly, these regulatory assets are not included in rate base and do not yield a return on investment during the recovery period.

2 Operating and debt-service regulatory assets and liabilities represent the accumulation of cost and revenue variances approved by the regulatory authority for inclusion in determining tolls for the following calendar year. Pre-tax operating results in 2015 would have been $32 million lower (2014 – $28 million higher; 2013 – $76 million lower) had these amounts not been recorded as Regulatory assets and liabilities.

3 These balances represent the regulatory offset to pension plan and other post-retirement obligations to the extent the amounts are expected to be collected from customers in future rates. The balances are excluded from the rate base and do not earn a return on investment. Pre-tax operating results in 2015 would have been $26 million higher (2014 – $46 million lower; 2013 – $171 million higher) had these amounts not been recorded as regulatory assets and liabilities.

4 Pre-tax operating results in 2015 would have been $35 million lower (2014 – $2 million higher; 2013 – $2 million higher) had these amounts not been recorded as regulatory assets and liabilities.

5 Foreign exchange on long-term debt of the NGTL System and Foothills represents the variance resulting from revaluing foreign currency-denominated debt instruments to the current foreign exchange rate from the historical foreign exchange rate at the time of issue. Foreign exchange gains and losses realized when foreign debt matures or is redeemed early are expected to be recovered or refunded through the determination of future tolls. In the absence of RRA, GAAP would have required the inclusion of these unrealized gains or losses in Net income.

6 Under the terms of ANR's last rate settlement, ANR will be required to make refunds to its customers, pursuant to a refund plan to be approved by FERC in a future rate proceeding, of those amounts in the post-retirement benefit trust fund that have not been used to pay benefits to its employees. This regulatory liability represents the difference between the amount collected in rates and the amount of post-retirement benefits expense. ANR anticipates that the resolution of this liability will be determined through the section 4 rate case ANR filed with the FERC on January 29, 2016. Since the timing of the rate case conclusion is uncertain, a settlement period cannot be determined at this time. Pre-tax operating results in 2015 would have been $30 million higher (2014 – $13 million higher; 2013 – $16 million higher) had these amounts not been recorded as regulatory assets and liabilities.

7 Pre-tax operating results in 2015 would have been $167 million higher (2014 – $418 million higher; 2013 – $247 million lower) had these amounts not been recorded as regulatory liabilities.

8 Effective January 1, 2015, NEB regulated pipelines including the Mainline, NGTL System, Foothills, Keystone and TQM are required to collect and set-aside funds received from customers to be used for future pipeline abandonment activities. Funds are collected through a surcharge mechanism, set-aside in trust accounts, and the obligation to use these funds for future pipeline abandonment activities is recorded as a regulatory liability. Pre-tax operating results in 2015 would have been $285 million higher (2014 – nil; 2013 – nil) had these amounts not been recorded as regulatory liabilities.

9 Pre-tax operating results in 2015 would have been $456 million higher (2014 – nil; 2013 – nil) had these amounts not been recorded as regulatory liabilities.

Allowance for Funds Used During Construction

The total amount of debt and equity AFUDC included in the Consolidated statement of income was $295 million in 2015 (2014 – $136 million; 2013 – $37 million).

10. GOODWILL

The Company has recorded the following Goodwill on its acquisitions in the U.S.:

(millions of Canadian $)	Natural Gas Pipelines	Energy	Total
Balance at January 1, 2014	2,816	880	3,696
Foreign exchange rate changes	258	80	338
Balance at December 31, 2014	3,074	960	4,034
Foreign exchange rate changes	**593**	**185**	**778**
Balance at December 31, 2015	**3,667**	**1,145**	**4,812**

At December 31, 2015, TCPL's Goodwill included US$573 million (2014 - US$573 million) related to the Great Lakes natural gas transportation business. TCPL's share of this Goodwill (net of non-controlling interests) was US$386 million (2014 – US$243 million). The increase in TCPL's share is a result of the impairment charge of US$199 million recorded by TC PipeLines, LP on its equity method goodwill related to Great Lakes. On a consolidated basis, TCPL's carrying value of its investment in Great Lakes is proportionately lower compared to the 46.45% owned through TC PipeLines, LP. As a result, the estimated fair value of Great Lakes exceeded TCPL's consolidated carrying value of the investment and no impairment was recorded in 2015.

The estimated fair value of Great Lakes exceeded its carrying value by less than 10 per cent. The fair value of this reporting unit was measured by using a discounted cash flow analysis. Assumptions regarding Great Lakes' ability to realize long-term value in the North American energy market have been adversely impacted by the changing natural gas flows in its market region as well as a change in the Company's view of other strategic alternatives to increase utilization of Great Lakes. As a result, the Company reduced forecasted cash flows from the reporting unit for the next ten years as compared to those utilized in previous impairment tests. There is a risk that continued reductions in future cash flow forecasts and adverse changes in other key assumptions could result in a future impairment of a portion of the Goodwill balance relating to Great Lakes.

11. INTANGIBLE AND OTHER ASSETS

at December 31 (millions of Canadian $)	2015	2014
Capital projects in development	**1,814**	1,286
PPAs	**220**	272
Fair value of derivative contracts (Note 23)	**168**	93
Loans and advances[1]	**159**	167
Employee post-retirement benefits (Note 22)	**18**	14
Deferred income tax assets and charges (Note 15)	**9**	181
Other	**797**	628
	3,185	2,641

1 TCPL held a note receivable from the seller of Ravenswood of $213 million (US$154 million) and $213 million (US$184 million) as at December 31, 2015 and at December 31, 2014, which bears interest at 6.75 per cent and matures in 2040. The current portion included in Other current assets was $55 million (US$40 million) at December 31, 2015 and $46 million (US$40 million) at December 31, 2014.

The following amounts related to PPAs are included in Intangible and other assets:

	2015			2014		
at December 31 (millions of Canadian $)	Cost	Accumulated Amortization	Net Book Value	Cost	Accumulated Amortization	Net Book Value
Sheerness (expires 2020)	**585**	**390**	**195**	585	351	234
Sundance A (expires 2017)	**225**	**200**	**25**	225	187	38
	810	**590**	**220**	810	538	272

Amortization expense for these PPAs was $52 million for the year ended December 31, 2015 (2014 and 2013 – $52 million). The expected annual amortization expense for 2016 and 2017 is $52 million, and $39 million for 2018 to 2020.

12. NOTES PAYABLE

	2015		2014	
(millions of Canadian $, unless otherwise noted)	Outstanding at December 31	Weighted Average Interest Rate per Annum at December 31	Outstanding at December 31	Weighted Average Interest Rate per Annum at December 31
Canadian	**697**	**0.8%**	1,540	1.2%
U.S. (2015 – US$376; 2014 – US$800)	**521**	**1.1%**	927	0.7%
	1,218		2,467	

At December 31, 2015, Notes payable consists of commercial paper issued by TCPL, TransCanada American Investments Ltd. (TAIL), and TransCanada Power Marketing Ltd. (TCPM). In November 2015, the TAIL credit facility was increased to US$1.5 billion from US$1.0 billion and, subsequently, TAIL and TCPM became co-borrowers under the facility and co-issuers under the related commercial paper program. At the same time, the TCPL USA credit facility was reduced from the US$1.0 billion to US$0.5 billion. In December 2015, a new US$1.0 billion credit facility and related commercial paper program was initiated for TCPL.

At December 31, 2015, total committed revolving and demand credit facilities of $8.9 billion (2014 – $6.7 billion) were available. When drawn, interest on these lines of credit is charged at prime rates of Canadian and U.S. banks, and at other negotiated financial bases. These unsecured credit facilities included the following:

at December 31, 2015					year ended December 31		
					2015	**2014**	**2013**
Amount	**Unused Capacity**	**Borrower**	**Description**	**Matures**	**Cost to maintain**		
					(millions of Canadian $)		
$3 billion	$3 billion	TCPL	Committed, syndicated, revolving, extendible TCPL credit facility	December 2020	**6**	6	4
US$1 billion	US$1 billion	TCPL	Committed, syndicated, revolving, extendible TCPL credit facility	December 2016	**—**	—	—
US$0.5 billion	US$0.5 billion	TCPL USA	Committed, syndicated, revolving, extendible TCPL USA credit facility, guaranteed by TCPL	December 2016	**3**	2	1
US$1.5 billion	US$1.5 billion	TAIL/TCPM	Committed, syndicated, revolving, extendible TAIL/TCPM credit facility, guaranteed by TCPL	December 2016	**2**	1	—
$1.7 billion	$0.7 billion	TCPL/TCPL USA	Supports the issuance of letters of credit and provides additional liquidity	Demand	**—**	—	—

At December 31, 2015, the Company's operated affiliates had an additional $0.6 billion (2014 – $0.4 billion) of undrawn capacity on committed credit facilities.

13. ACCOUNTS PAYABLE AND OTHER

at December 31 (millions of Canadian $)	**2015**	**2014**
Trade payables	**1,506**	1,624
Fair value of derivative contracts (Note 23)	**926**	749
Dividends payable	**370**	345
Regulatory liabilities (Note 9)	**44**	30
Liabilities related to assets held for sale (Note 6)	**39**	—
Other	**129**	143
	3,014	2,891

14. OTHER LONG-TERM LIABILITIES

at December 31 (millions of Canadian $)	**2015**	**2014**
Fair value of derivative contracts (Note 23)	**625**	411
Employee post-retirement benefits (Note 22)	**380**	444
Asset retirement obligations	**109**	98
Guarantees (Note 26)	**26**	20
Other	**120**	79
	1,260	1,052

15. INCOME TAXES

Provision for Income Taxes

year ended December 31 (millions of Canadian $)	**2015**	**2014**	**2013**
Current			
Canada	**45**	104	27
Foreign	**92**	42	16
	137	146	43
Deferred			
Canada	**33**	307	239
Foreign	**(135)**	377	323
	(102)	684	562
Income Tax Expense	**35**	830	605

Geographic Components of Income

year ended December 31 (millions of Canadian $)	**2015**	**2014**	**2013**
Canada	**(623)**	1,146	1,201
Foreign	**(482)**	1,678	1,298
(Loss)/Income Before Income Taxes	**(1,105)**	2,824	2,499

Reconciliation of Income Tax Expense

year ended December 31 (millions of Canadian $)	**2015**	**2014**	**2013**
(Loss)/Income before income taxes	**(1,105)**	2,824	2,499
Federal and provincial statutory tax rate	**26.0%**	25.0%	25.0%
Expected income tax (recovery)/expense	**(287)**	706	625
Income tax differential related to regulated operations	**159**	129	(13)
Higher effective foreign tax rates	**14**	25	33
Income from equity investments and non-controlling interests	**(56)**	(38)	(28)
Tax rate and legislative changes	**34**	—	(25)
Asset impairment charges[1]	**170**	—	—
Other	**1**	8	13
Actual Income Tax Expense	**35**	830	605

1 The asset impairment impact is net of $311 million attributed to higher foreign tax rates.

Deferred Income Tax Assets and Liabilities

at December 31 (millions of Canadian $)	2015	2014
Deferred Income Tax Assets		
Difference in accounting and tax bases of impaired assets	**916**	—
Tax loss and credit carryforwards	**1,325**	1,344
Regulatory and other deferred amounts	**231**	236
Unrealized foreign exchange losses on long-term debt	**589**	140
Financial instruments	**111**	104
Other	**132**	146
	3,304	1,970
Less: Valuation allowance[1]	**1,060**	125
	2,244	1,845
Deferred Income Tax Liabilities		
Difference in accounting and tax bases of plant, property and equipment and PPAs	**6,441**	5,548
Equity investments	**656**	648
Taxes on future revenue requirement	**227**	253
Other	**55**	71
	7,379	6,520
Net Deferred Income Tax Liabilities	**5,135**	4,675

1 In 2015, an increase to the valuation allowance of $935 million was recorded as the Company believes that it is more likely than not that the tax benefits related to the unrealized foreign exchange losses on long-term debt and unrealized losses on certain impaired assets will not be realized in the future.

The above deferred tax amounts have been classified in the Consolidated balance sheet as follows:

at December 31 (millions of Canadian $)	2015	2014[1]
Deferred Income Tax Assets		
Intangible and other assets (Note 11)	**9**	181
Deferred Income Tax Liabilities		
Deferred income tax liabilities	**5,144**	4,856
Net Deferred Income Tax Liabilities	**5,135**	4,675

1 As a result of retrospectively applying guidance on the presentation of deferred taxes on the Consolidated balance sheet on January 1, 2015, the Company reclassified its December 31, 2014 current Deferred income tax assets of $427 million, and current Deferred income tax liabilities of $4 million to its non-current Deferred income tax assets and liabilities.

At December 31, 2015, the Company has recognized the benefit of unused non-capital loss carryforwards of $1,276 million (2014 – $1,131 million) for federal and provincial purposes in Canada, which expire from 2026 to 2035. The Company also has Ontario minimum tax credits of $57 million (2014 – $50 million), which expire from 2016 to 2035.

At December 31, 2015, the Company has recognized the benefit of unused net operating loss carryforwards of US$1,617 million (2014 – US$2,267 million) for federal purposes in the U.S., which expire from 2029 to 2034. The Company also has alternative minimum tax credits of US$41 million (2014 – US$26 million).

Unremitted Earnings of Foreign Investments

Income taxes have not been provided on the unremitted earnings of foreign investments that the Company does not intend to repatriate in the foreseeable future. Deferred income tax liabilities would have increased at December 31, 2015 by approximately $308 million (2014 – $236 million) if there had been a provision for these taxes.

Income Tax Payments

Income tax payments of $164 million, net of refunds, were made in 2015 (2014 – payments, net of refunds, of $109 million; 2013 – payments, net of refunds, of $206 million).

Reconciliation of Unrecognized Tax Benefit

Below is the reconciliation of the annual changes in the total unrecognized tax benefit:

at December 31 (millions of Canadian $)	**2015**	**2014**	**2013**
Unrecognized tax benefit at beginning of year	**13**	19	45
Gross increases – tax positions in prior years	**2**	2	3
Gross decreases – tax positions in prior years	**(2)**	(8)	(28)
Gross increases – tax positions in current year	**1**	1	2
Lapses of statute of limitations	**(1)**	(1)	(3)
Unrecognized Tax Benefit at End of Year	**13**	13	19

TCPL recognized a favourable income tax adjustment of approximately $25 million due to the enactment of certain Canadian federal tax legislation in June 2013.

Subject to the results of audit examinations by taxing authorities and other legislative amendments, TCPL does not anticipate further adjustments to the unrecognized tax benefits during the next 12 months that would have a material impact on its financial statements.

TCPL and its subsidiaries are subject to either Canadian federal and provincial income tax, U.S. federal, state and local income tax or the relevant income tax in other international jurisdictions. The Company has substantially concluded all Canadian federal and provincial income tax matters for the years through 2007. Substantially all material U.S. federal, state and local income tax matters have been concluded for years through 2010.

TCPL's practice is to recognize interest and penalties related to income tax uncertainties in Income tax expense. Income tax expense for the year ended December 31, 2015 reflects a $1 million reversal of Interest expense and nil for penalties (2014 – nil for Interest expense and nil for penalties; 2013 – nil for Interest expense and nil for penalties). At December 31, 2015, the Company had $4 million accrued for Interest expense and nil accrued for penalties (December 31, 2014 –$5 million accrued for Interest expense and nil accrued for penalties).

16. LONG-TERM DEBT

Outstanding amounts (millions of Canadian $, unless otherwise noted)	Maturity Dates	2015 Outstanding at December 31	2015 Interest Rate[1]	2014 Outstanding at December 31	2014 Interest Rate[1]
TRANSCANADA PIPELINES LIMITED					
Debentures					
Canadian	2017 to 2020	**599**	**10.7%**	749	10.9%
U.S. (2015 and 2014 – US$400)	2021	**554**	**9.9%**	464	9.9%
Medium-Term Notes					
Canadian	2016 to 2041	**5,192**	**5.3%**	4,048	5.7%
Senior Unsecured Notes					
U.S. (2015 – US$14,723; 2014 – US$13,526)	2016 to 2045	**20,340**	**4.8%**	15,655	5.0%
		26,685		20,916	
NOVA GAS TRANSMISSION LTD.					
Debentures and Notes					
Canadian[2]	2016 to 2024	**325**	**11.5%**	325	11.5%
U.S. (2015 and 2014 – US$200)	2023	**277**	**7.9%**	232	7.9%
Medium-Term Notes					
Canadian	2025 to 2030	**504**	**7.4%**	504	7.4%
U.S. (2015 and 2014 – US$33)	2026	**45**	**7.5%**	38	7.5%
		1,151		1,099	
ANR PIPELINE COMPANY					
Senior Unsecured Notes					
U.S. (2015 and 2014 – US$432)	2021 to 2025	**598**	**8.9%**	502	8.9%
GAS TRANSMISSION NORTHWEST LLC					
Unsecured Term Loan					
U.S. (2015 – US$75)	2019	**104**	**1.4%**	—	—
Senior Unsecured Notes					
U.S. (2015 – US$250; 2014 – US$325)	2020 to 2035	**346**	**5.6%**	377	5.5%
		450		377	
TC PIPELINES, LP					
Unsecured Loan					
U.S. (2015 – US$200; 2014 – US$330)	2017	**277**	**1.6%**	383	1.4%
Unsecured Term Loan Facility					
U.S. (2015 and 2014 – US$500)	2018	**692**	**1.6%**	580	1.4%
Unsecured Term Loan					
U.S. (2015 – US$170)	2018	**235**	**1.6%**	—	—
Senior Unsecured Notes					
U.S. (2015 – US$698; 2014 – US$350)	2021 to 2025	**967**	**4.7%**	405	4.7%
		2,171		1,368	
GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP					
Senior Unsecured Notes					
U.S. (2015 – US$297; 2014 – US$316)	2018 to 2030	**411**	**7.8%**	367	7.8%

TUSCARORA GAS TRANSMISSION COMPANY					
Senior Secured Notes					
U.S. (2015 – US$16; 2014 – US$20)	2017	**22**	**4.0%**	23	4.0%
PORTLAND NATURAL GAS TRANSMISSION SYSTEM					
Senior Secured Notes[3]					
U.S. (2015 – US$69; 2014 – US$90)	2018	**96**	**6.1%**	105	6.1%
		31,584		24,757	
Less: Current portion of Long-term debt		**2,547**		1,797	
		29,037		22,960	

1 Interest rates are the effective interest rates except for those pertaining to Long-term debt issued for the Company's Canadian regulated natural gas operations, in which case the weighted average interest rate is presented as approved by the regulators. Weighted average and effective interest rates are stated as at the respective outstanding dates.

2 Debentures issued by NGTL in the amount of $225 million have retraction provisions that entitle the holders to periodically require redemption of up to eight per cent of the then outstanding principal plus accrued and unpaid interest on specified repayment dates. No redemptions were made in 2015 or 2014.

3 Secured by shipper transportation contracts, existing and new guarantees, letters of credit and collateral requirements.

Principal Repayments

At December 31, 2015, principal repayments on the Long-term debt of the Company for the next five years are approximately as follows:

(millions of Canadian $)	**2016**	**2017**	**2018**	**2019**	**2020**
Principal repayments on Long-term debt	2,547	2,150	3,379	1,228	1,801

Long-Term Debt Issued

The Company issued Long-term debt over the three years ended December 31, 2015 as follows:

(millions of Canadian $, unless otherwise noted)					
Company	**Issue date**	**Type**	**Maturity date**	**Amount**	**Interest Rate**
TRANSCANADA PIPELINES LIMITED					
	November 2015	Senior Unsecured Notes	November 2017	US 1,000	1.625%
	October 2015	Medium-Term Notes	November 2041	400	4.55%
	July 2015	Medium-Term Notes	July 2025	750	3.30%
	March 2015	Senior Unsecured Notes	March 2045	US 750	4.60%
	January 2015	Senior Unsecured Notes	January 2018	US 500	1.875%
	January 2015	Senior Unsecured Notes	January 2018	US 250	Floating
	February 2014	Senior Unsecured Notes	March 2034	US 1,250	4.63%
	October 2013	Senior Unsecured Notes	October 2023	US 625	3.75%
	October 2013	Senior Unsecured Notes	October 2043	US 625	5.00%
	July 2013	Senior Unsecured Notes	June 2016	US 500	Floating
	July 2013	Medium-Term Notes	July 2023	450	3.69%
	July 2013	Medium-Term Notes	November 2041	300	4.55%
	January 2013	Senior Unsecured Notes	January 2016	US 750	0.75%
TC PIPELINES, LP					
	September 2015	Unsecured Term Loan	October 2018	US 170	Floating
	March 2015	Senior Unsecured Notes	March 2025	US 350	4.375%
	July 2013	Unsecured Term Loan Facility	July 2018	US 500	Floating
GAS TRANSMISSION NORTHWEST LLC					
	June 2015	Unsecured Term Loan	June 2019	US 75	Floating

Long-Term Debt Retired

The Company retired Long-term debt over the three years ended December 31, 2015 as follows:

(millions of Canadian $, unless otherwise noted) Company	Retirement date	Type	Amount	Interest Rate
TRANSCANADA PIPELINES LIMITED				
	August 2015	Debentures	150	11.90%
	June 2015	Senior Unsecured Notes	US 500	3.40%
	March 2015	Senior Unsecured Notes	US 500	0.875%
	January 2015	Senior Unsecured Notes	US 300	4.875%
	June 2014	Debentures	125	11.10%
	February 2014	Medium-Term Notes	300	5.05%
	January 2014	Medium-Term Notes	450	5.65%
	August 2013	Senior Unsecured Notes	US 500	5.05%
	June 2013	Senior Unsecured Notes	US 350	4.00%
GAS TRANSMISSION NORTHWEST LLC				
	June 2015	Senior Unsecured Notes	US 75	5.09%
NOVA GAS TRANSMISSION LTD.				
	June 2014	Debentures	53	11.20%

Interest Expense

Interest expense over the three years ended December 31 was as follows:

year ended December 31 (millions of Canadian $)	**2015**	**2014**	**2013**
Interest on Long-term debt	**1,487**	1,317	1,216
Interest on Junior subordinated notes (Note 17)	**116**	70	65
Interest on short-term debt	**44**	52	73
Capitalized interest	**(280)**	(259)	(287)
Amortization and other financial charges[1]	**31**	55	(21)
	1,398	1,235	1,046

1 Amortization and other financial charges includes amortization of transaction costs and debt discounts calculated using the effective interest method and changes in the fair value of derivatives used to manage the Company's exposure to changes in interest rates.

The Company made interest payments of $1,295 million in 2015 (2014 – $1,160 million; 2013 – $1,047 million) on Long-term debt, Junior subordinated notes and Notes payable, net of interest capitalized.

17. JUNIOR SUBORDINATED NOTES

Outstanding loan amount (millions of Canadian $, unless otherwise noted)	Maturity Date	2015 Outstanding at December 31	2015 Effective Interest Rate	2014 Outstanding at December 31	2014 Effective Interest Rate
TRANSCANADA PIPELINES LIMITED					
U.S. (2015 and 2014 – US$1,000)[1]	2067	**1,384**	**6.4%**	1,160	6.5%
U.S. (2015 – US$750)[1]	2075	**1,038**	**5.3%**	—	—
		2,422		1,160	

1 The Junior subordinated notes are subordinated in right of payment to existing and future senior indebtedness or other obligations of TCPL.

Junior subordinated notes of US$1.0 billion mature in May 2067 and bear interest at 6.35 per cent per annum until May 15, 2017, when interest will convert to a floating rate that is reset quarterly to the three-month London Interbank Offered Rate (LIBOR) plus 2.21 per cent. The Company has the option to defer payment of interest for periods of up to 10 years without giving rise to a default or permitting acceleration of payment under the terms of the Junior subordinated notes, however, the Company would be prohibited from paying dividends during any such deferral period. The Junior subordinated notes are callable at the Company's option at any time on or after May 15, 2017 at 100 per cent of the principal amount plus accrued and unpaid interest to the date of redemption. The Junior subordinated notes are callable earlier, in whole or in part, upon the occurrence of certain events and at the Company's option at an amount equal to the greater of 100 per cent of the principal amount plus accrued and unpaid interest to the date of redemption and an amount determined by a specified formula in accordance with their terms.

In May 2015, TransCanada Trust (the Trust), a financing trust subsidiary wholly-owned by TCPL, issued US$750 million Trust Notes - Series 2015-A (Trust Notes) to third party investors at a fixed interest rate of 5.625 per cent for the first 10 years converting to a floating rate thereafter. All of the proceeds of the issuance by the Trust were loaned to TCPL for US$750 million of Junior subordinated notes of TCPL at a rate of 5.875 per cent, including a 0.25 per cent administration charge. The rate will reset commencing May 2025 until May 2045 to the three month LIBOR plus 3.778 per cent per annum; from May 2045 to May 2075 the interest rate will reset to the three month LIBOR plus 4.528 per cent per annum. The Junior subordinated notes of TCPL are callable at TCPL's option at any time on or after May 20, 2025 at 100 per cent of the principal amount plus accrued and unpaid interest to the date of redemption. While the obligations of the Trust are fully and unconditionally guaranteed by TCPL on a subordinated basis, the Trust is not consolidated in TCPL's financial statements because TCPL does not have a variable interest in the Trust and the only substantive assets of the Trust are receivables from TCPL.

Pursuant to the terms of the Trust Notes and related agreements, in certain circumstances (1) TCPL may issue deferral preferred shares to holders of the Trust Notes in lieu of interest; and (2) TransCanada and TCPL would be prohibited from declaring or paying dividends on or redeeming their outstanding preferred shares (or, if none are outstanding, their respective common shares) until all deferral preferred shares are redeemed by TCPL. The Trust Notes may also be automatically exchanged for preferred shares of TCPL upon certain kinds of bankruptcy and insolvency events. All of these preferred shares would rank equally with other outstanding first preferred shares of TCPL.

18. NON-CONTROLLING INTERESTS

The Company's Non-controlling interests included in the Consolidated balance sheet are as follows:

at December 31 (millions of Canadian $)	2015	2014
Non-controlling interest in TC PipeLines, LP	**1,590**	1,479
Non-controlling interest in PNGTS	**127**	104
	1,717	1,583

The Company's Non-controlling interests included in the Consolidated statement of income are as follows:

year ended December 31 (millions of Canadian $)	2015	2014	2013
Non-controlling interest in TC PipeLines, LP	**(13)**	136	93
Non-controlling interest in PNGTS	**19**	15	12
	6	151	105

During 2015, the Non-controlling interest in TC PipeLines, LP increased from 71.7 per cent to 72.0 per cent due to periodic issuances of common units in TC PipeLines, LP to non-controlling interests. In 2014, the Non-controlling interest in TC PipeLines, LP ranged between 71.1 per cent and 71.7 per cent and, in 2013, between 66.7 per cent and 71.1 per cent.

At December 31, 2015, TC PipeLines, LP recorded an impairment charge of US$199 million related to its equity investment in Great Lakes. The Non-controlling interest's share of this charge was US$143 million and is included in the $13 million Non-controlling interest in TC PipeLines, LP in the Consolidated statement of income.

The Non-controlling interest in PNGTS as at December 31, 2015 represented the 38.3 per cent interest held by third parties (2014 and 2013 – 38.3 per cent).

In 2015, TCPL received fees of $4 million from TC PipeLines, LP (2014 and 2013 – $3 million) and $11 million from PNGTS (2014 – $8 million; 2013 – $7 million) for services provided.

19. COMMON SHARES

	Number of Shares (thousands)	Amount (millions of Canadian $)
Outstanding at January 1, 2013	738,381	14,306
Issuance of common shares for cash	18,733	899
Outstanding at December 31, 2013	757,114	15,205
Issuance of common shares for cash	22,365	1,115
Outstanding at December 31, 2014	779,479	16,320
Outstanding at December 31, 2015	**779,479**	**16,320**

Common Shares Issued and Outstanding

The Company is authorized to issue an unlimited number of common shares without par value.

Restrictions on Dividends

Certain terms of the Company's debt instruments can limit the amount of dividends the Company can pay on preferred and common shares. At December 31, 2015 these terms limit the company from paying dividends in excess of $4.1 billion (2014 – $8.7 billion; 2013 – $1.3 billion). Under the agreements, TCPL can adjust this limit throughout the year if required, at is sole discretion, without incurring significant costs.

Stock Option Plan

Certain key employees, including officers, are granted stock options from TransCanada to purchase common shares at the market price on the grant date. Stock options vest equally over three years, beginning on the first anniversary of the grant date, and expire after seven years.

The Company used a binomial model for determining the fair value of options granted applying the following weighted average assumptions:

year ended December 31	2015	2014	2013
Expected life (years)	**5.8**	6.0	6.0
Interest rate	**1.1%**	1.8%	1.7%
Volatility[1]	**18%**	17%	18%
Dividend yield	**3.7%**	3.8%	3.7%
Forfeiture rate	**5%**	5%	15%

1 Volatility is derived based on the average of both the historical and implied volatility of the Company's common shares.

The amount expensed for stock options, with a corresponding increase in Additional paid-in capital, was $11 million in 2015 (2014 – $9 million; 2013 – $6 million).

The following table summarizes additional stock option information:

year ended December 31 (millions of Canadian $, unless otherwise noted)	2015	2014	2013
Total intrinsic value of options exercised	**37**	68	25
Fair value of options that have vested	**91**	95	64
Total options vested	**2.0 million**	1.7 million	1.3 million

As at December 31, 2015, the aggregate intrinsic value of the total options exercisable was $23 million and the total intrinsic value of options outstanding was $23 million.

20. PREFERRED SHARES

In March 2014, TCPL redeemed all of the 4 million outstanding Series Y preferred shares at a redemption price of $50 per share for a gross payment of $200 million.

In October 2013, TCPL redeemed all of the 4 million outstanding Series U preferred shares at a redemption price of $50 per share for a gross payment of $200 million.

21. OTHER COMPREHENSIVE INCOME/(LOSS) AND ACCUMULATED OTHER COMPREHENSIVE LOSS

Components of Other comprehensive income/(loss), including the portion attributable to non-controlling interests and related tax effects, are as follows:

year ended December 31, 2015 (millions of Canadian $)	**Before Tax Amount**	**Income Tax Recovery/ (Expense)**	**Net of Tax Amount**
Foreign currency translation gains on net investment in foreign operations	**798**	**15**	**813**
Change in fair value of net investment hedges	**(505)**	**133**	**(372)**
Change in fair value of cash flow hedges	**(92)**	**35**	**(57)**
Reclassification to net income of gains and losses on cash flow hedges	**144**	**(56)**	**88**
Unrealized actuarial gains and losses on pension and other post-retirement benefit plans	**74**	**(23)**	**51**
Reclassification to net income of actuarial gains and losses and prior service costs on pension and other post-retirement benefit plans	**41**	**(9)**	**32**
Other comprehensive income on equity investments	**62**	**(15)**	**47**
Other Comprehensive Income	**522**	**80**	**602**

year ended December 31, 2014 (millions of Canadian $)	**Before Tax Amount**	**Income Tax Recovery/ (Expense)**	**Net of Tax Amount**
Foreign currency translation gains on net investment in foreign operations	462	55	517
Change in fair value of net investment hedges	(373)	97	(276)
Change in fair value of cash flow hedges	(118)	49	(69)
Reclassification to net income of gains and losses on cash flow hedges	(95)	40	(55)
Unrealized actuarial gains and losses on pension and other post-retirement benefit plans	(146)	44	(102)
Reclassification to net income of actuarial gains and losses and prior service costs on pension and other post-retirement benefit plans	25	(7)	18
Other comprehensive loss on equity investments	(272)	68	(204)
Other Comprehensive Loss	(517)	346	(171)

year ended December 31, 2013 (millions of Canadian $)	**Before Tax Amount**	**Income Tax Recovery/ (Expense)**	**Net of Tax Amount**
Foreign currency translation gains on net investment in foreign operations	269	114	383
Change in fair value of net investment hedges	(323)	84	(239)
Change in fair value of cash flow hedges	121	(50)	71
Reclassification to net income of gains and losses on cash flow hedges	60	(19)	41
Unrealized actuarial gains and losses on pension and other post-retirement benefit plans	96	(29)	67
Reclassification to net income of actuarial gains and losses and prior service costs on pension and other post-retirement benefit plans	34	(11)	23
Other comprehensive income on equity investments	313	(79)	234
Other Comprehensive Income	570	10	580

The changes in AOCI by component are as follows:

	Currency Translation Adjustments	**Cash Flow Hedges**	**Pension and Other Post-Retirement Benefit Plan Adjustments**	**Equity Investments**	**Total**[1]
AOCI balance at January 1, 2013	(707)	(116)	(287)	(338)	(1,448)
Other comprehensive income before reclassifications[2]	78	71	67	219	435
Amounts reclassified from accumulated other comprehensive loss	—	41	23	15	79
Net current period other comprehensive income	78	112	90	234	514
AOCI balance at December 31, 2013	(629)	(4)	(197)	(104)	(934)
Other comprehensive income/(loss) before reclassifications[2]	111	(69)	(102)	(206)	(266)
Amounts reclassified from accumulated other comprehensive loss	—	(55)	18	2	(35)
Net current period other comprehensive income/(loss)	111	(124)	(84)	(204)	(301)
AOCI balance at December 31, 2014	(518)	(128)	(281)	(308)	(1,235)
Other comprehensive income/(loss) before reclassifications[2]	**135**	**(57)**	**51**	**33**	**162**
Amounts reclassified from accumulated other comprehensive loss[3]	**—**	**88**	**32**	**14**	**134**
Net current period other comprehensive income	**135**	**31**	**83**	**47**	**296**
AOCI balance at December 31, 2015	**(383)**	**(97)**	**(198)**	**(261)**	**(939)**

1 All amounts are net of tax. Amounts in parentheses indicate losses recorded to OCI.

2 Other comprehensive income before reclassifications on currency translation adjustments is net of non-controlling interest gains of $306 million in 2015 (2014 – $130 million gains; 2013 – $66 million gains).

3 Losses related to cash flow hedges reported in AOCI and expected to be reclassified to Net income in the next 12 months are estimated to be $83 million ($51 million, net of tax) at December 31, 2015. These estimates assume constant commodity prices, interest rates and foreign exchange rates over time, however, the amounts reclassified will vary based on the actual value of these factors at the date of settlement.

Details about reclassifications out of AOCI into the Consolidated statement of income are as follows:

year ended December 31	Amounts Reclassified From Accumulated Other Comprehensive Loss[1]			Affected Line Item in the Consolidated Statement of Income
(millions of Canadian $)	**2015**	**2014**	**2013**	
Cash flow hedges				
Commodities	**(128)**	111	(44)	Revenues (Energy)
Interest	**(16)**	(16)	(16)	Interest expense
	(144)	95	(60)	Total before tax
	56	(40)	19	Income tax expense/(recovery)
	(88)	55	(41)	Net of tax
Pension and other post-retirement benefit plan adjustments				
Amortization of actuarial loss and past service cost	**(41)**	(25)	(34)	[2]
	9	7	11	Income tax recovery
	(32)	(18)	(23)	Net of tax
Equity investments				
Equity income	**(19)**	(2)	(20)	Income from equity investments
	5	—	5	Income tax recovery
	(14)	(2)	(15)	Net of tax

1 All amounts in parentheses indicate expenses to the Consolidated statement of income.

2 These Accumulated other comprehensive loss components are included in the computation of net benefit cost. Refer to Note 22 for further information.

22. EMPLOYEE POST-RETIREMENT BENEFITS

The Company sponsors DB Plans for its employees. Pension benefits provided under the DB Plans are based on years of service and highest average earnings over three consecutive years of employment. Upon commencement of retirement, pension benefits in the Canadian DB Plan increase annually by a portion of the increase in the Consumer Price Index. Net actuarial gains or losses are amortized out of AOCI over the expected average remaining service life of employees, which is approximately nine years at December 31, 2015 (2014 and 2013 – nine years).

The Company also provides its employees with a savings plan in Canada, DC Plans consisting of 401(k) Plans in the U.S., and post-employment benefits other than pensions, including termination benefits and life insurance and medical benefits beyond those provided by government-sponsored plans. Net actuarial gains or losses are amortized out of AOCI over the expected average remaining life expectancy of former employees, which was approximately 12 years at December 31, 2015 (2014 – 12 years; 2013 – 11 years). In 2015, the Company expensed $41 million (2014 – $37 million; 2013 – $29 million) for the savings and DC Plans.

Total cash contributions by the Company for employee post-retirement benefits were as follows:

year ended December 31			
(millions of Canadian $)	**2015**	**2014**	**2013**
DB Plans	**96**	73	79
Other post-retirement benefit plans	**6**	6	6
Savings and DC Plans	**41**	37	29
	143	116	114

Current Canadian pension legislation allows for partial funding of solvency requirements over a number of years through letters of credit in lieu of cash contributions, up to certain limits. As such, in addition to the cash contributions noted above, the Company provided a $33 million letter of credit to the Canadian DB Plan in 2015 (2014 – $47 million; 2013 – $59 million), resulting in a total of $214 million provided to the Canadian DB Plan under letters of credit at December 31, 2015.

The most recent actuarial valuation of the pension plans for funding purposes was as at January 1, 2015 and the next required valuation will be as at January 1, 2016.

The Company's funded status at December 31 is comprised of the following:

at December 31	Pension Benefit Plans		Other Post-Retirement Benefit Plans	
(millions of Canadian $)	**2015**	**2014**	**2015**	**2014**
Change in Benefit Obligation[1]				
Benefit obligation – beginning of year	**2,658**	2,224	**216**	191
Service cost	**108**	85	**3**	2
Interest cost	**115**	113	**10**	10
Employee contributions	**4**	4	**—**	—
Benefits paid	**(129)**	(102)	**(7)**	(7)
Actuarial (gain)/loss	**(57)**	302	**(11)**	14
Foreign exchange rate changes	**81**	32	**14**	6
Benefit obligation – end of year	**2,780**	2,658	**225**	216
Change in Plan Assets				
Plan assets at fair value – beginning of year	**2,398**	2,152	**39**	35
Actual return on plan assets	**160**	246	**(1)**	2
Employer contributions[2]	**96**	73	**6**	6
Employee contributions	**4**	4	**—**	—
Benefits paid	**(129)**	(102)	**(7)**	(7)
Foreign exchange rate changes	**62**	25	**8**	3
Plan assets at fair value – end of year	**2,591**	2,398	**45**	39
Funded Status – Plan Deficit	**(189)**	(260)	**(180)**	(177)

1 The benefit obligation for the Company's pension benefit plans represents the projected benefit obligation. The benefit obligation for the Company's other post-retirement benefit plans represents the accumulated post-retirement benefit obligation

2 Excludes $214 million in letters of credit provided to the Canadian DB Plans for funding purposes (2014 – $181 million).

The amounts recognized in the Company's Consolidated balance sheet for its DB Plans and other post-retirement benefits plans are as follows:

at December 31	Pension Benefit Plans		Other Post-Retirement Benefit Plans	
(millions of Canadian $)	**2015**	**2014**	**2015**	**2014**
Intangible and other assets (Note 11)	**—**	—	**18**	14
Accounts payable and other	**—**	—	**(7)**	(7)
Other long-term liabilities (Note 14)	**(189)**	(260)	**(191)**	(184)
	(189)	(260)	**(180)**	(177)

Included in the above benefit obligation and fair value of plan assets were the following amounts for plans that are not fully funded:

at December 31	Pension Benefit Plans		Other Post-Retirement Benefit Plans	
(millions of Canadian $)	**2015**	**2014**	**2015**	**2014**
Projected benefit obligation[1]	**(2,780)**	(2,658)	**(198)**	(191)
Plan assets at fair value	**2,591**	2,398	**—**	—
Funded Status – Plan Deficit	**(189)**	(260)	**(198)**	(191)

1 The projected benefit obligation for the pension benefit plan differs from the accumulated benefit obligation in that it includes an assumption with respect to future compensation levels.

The funded status based on the accumulated benefit obligation for all DB Plans is as follows:

at December 31		
(millions of Canadian $)	**2015**	**2014**
Accumulated benefit obligation	**(2,600)**	(2,437)
Plan assets at fair value	**2,591**	2,398
Funded Status – Plan Deficit	**(9)**	(39)

Included in the above accumulated benefit obligation and fair value of plan assets are the following amounts in respect of plans that are not fully funded.

at December 31		
(millions of Canadian $)	**2015**	**2014**
Accumulated benefit obligation	**(807)**	(715)
Plan assets at fair value	**680**	597
Funded Status – Plan Deficit	**(127)**	(118)

The Company pension plans' weighted average asset allocations and target allocations by asset category were as follows:

	Percentage of Plan Assets		Target Allocations
at December 31	**2015**	**2014**	**2015**
Debt securities	**34%**	31%	**25% to 35%**
Equity securities	**66%**	69%	**50% to 70%**
Alternatives	—	—	**5 % to 15%**
	100%	100%	

Debt and equity securities include the Company's debt and common shares as follows:

at December 31			Percentage of Plan Assets	
(millions of Canadian $)	**2015**	**2014**	**2015**	**2014**
Debt securities	**2**	1	**0.1%**	0.1%
Equity securities	**4**	1	**0.1%**	0.1%

Pension plan assets are managed on a going concern basis, subject to legislative restrictions, and are diversified across asset classes to maximize returns at an acceptable level of risk. Asset mix strategies consider plan demographics and may include traditional equity and debt securities, as well as alternative assets such as infrastructure, private equity, real estate and derivatives to diversify risk. Derivatives are not used for speculative purposes and the use of leveraged derivatives is prohibited.

All investments are measured at fair value using market prices. Where the fair value cannot be readily determined by reference to generally available price quotations, the fair value is determined by considering the discounted cash flows on a risk-adjusted basis and by comparison to similar assets which are publicly traded. In Level I, the fair value of assets is determined by reference to quoted prices in active markets for identical assets that the Company has the ability to access at the measurement date. In Level II, the fair value of assets is determined using valuation techniques, such as option pricing models and extrapolation using significant inputs, which are observable directly or indirectly. In Level III, the fair value of assets is determined using a market approach based on inputs that are unobservable and significant to the overall fair value measurement.

The following table presents plan assets for DB Plans and other post-retirement benefits measured at fair value, which have been categorized into the three categories based on a fair value hierarchy. For further information on the fair value hierarchy, refer to Note 23.

at December 31	**Quoted Prices in Active Markets (Level I)**		**Significant Other Observable Inputs (Level II)**		**Significant Unobservable Inputs (Level III)**		**Total**		**Percentage of Total Portfolio**	
(millions of Canadian $)	**2015**	**2014**	**2015**	**2014**	**2015**	**2014**	**2015**	**2014**	**2015**	**2014**
Asset Category										
Cash and Cash Equivalents	**44**	20	**2**	—	**—**	—	**46**	20	**2**	1
Equity Securities:										
Canadian	**317**	361	**147**	142	**—**	—	**464**	503	**17**	21
U.S.	**589**	516	**40**	35	**—**	—	**629**	551	**24**	23
International	**38**	218	**300**	147	**—**	—	**338**	365	**13**	15
Global	**—**	—	**154**	141	**—**	—	**154**	141	**6**	6
Emerging	**7**	7	**143**	80	**—**	—	**150**	87	**6**	3
Fixed Income Securities:										
Canadian Bonds:										
Federal	**—**	—	**206**	218	**—**	—	**206**	218	**8**	9
Provincial	**—**	—	**202**	180	**—**	—	**202**	180	**8**	7
Municipal	**—**	—	**7**	7	**—**	—	**7**	7	**—**	—
Corporate	**—**	—	**113**	76	**—**	—	**113**	76	**4**	3
U.S. Bonds:										
State	**—**	—	**50**	47	**—**	—	**50**	47	**2**	2
Corporate	**—**	—	**57**	59	**—**	—	**57**	59	**2**	2
International:										
Corporate	**—**	—	**25**	14	**—**	—	**25**	14	**1**	1
Mortgage backed	**—**	—	**58**	39	**—**	—	**58**	39	**2**	2
Other Investments:										
Private equity funds	**—**	—	**—**	—	**14**	13	**14**	13	**—**	—
Funds held on deposit	**123**	117	**—**	—	**—**	—	**123**	117	**5**	5
	1,118	1,239	**1,504**	1,185	**14**	13	**2,636**	2,437	**100**	100

The following table presents the net change in the Level III fair value category:

(millions of Canadian $, pre-tax)	**Private Equity Funds**
Balance at December 31, 2013	18
Purchases and sales	(7)
Realized and unrealized gains	2
Balance at December 31, 2014	13
Purchases and sales	**(1)**
Realized and unrealized gains	**2**
Balance at December 31, 2015	**14**

The Company's expected funding contributions in 2016 are approximately $70 million for the DB Plans, approximately $7 million for the other post-retirement benefit plans and approximately $37 million for the savings plan and DC Plans. The Company expects to provide an additional estimated $33 million letter of credit to the Canadian DB Plan for the funding of solvency requirements.

The following are estimated future benefit payments, which reflect expected future service:

(millions of Canadian $)	**Pension Benefits**	**Other Post-Retirement Benefits**
2016	129	8
2017	133	9
2018	138	9
2019	142	9
2020	146	10
2021 to 2025	808	51

The rate used to discount pension and other post-retirement benefit plan obligations was developed based on a yield curve of corporate AA bond yields at December 31, 2015. This yield curve is used to develop spot rates that vary based on the duration of the obligations. The estimated future cash flows for the pension and other post-retirement obligations were matched to the corresponding rates on the spot rate curve to derive a weighted average discount rate.

The significant weighted average actuarial assumptions adopted in measuring the Company's benefit obligations were as follows:

	Pension Benefit Plans		**Other Post-Retirement Benefit Plans**	
at December 31	**2015**	**2014**	**2015**	**2014**
Discount rate	**4.20%**	4.15%	**4.40%**	4.20%
Rate of compensation increase	**0.50%**	3.15%	**—%**	—%

The significant weighted average actuarial assumptions adopted in measuring the Company's net benefit plan costs were as follows:

	Pension Benefit Plans			**Other Post-Retirement Benefit Plans**		
year ended December 31	**2015**	**2014**	**2013**	**2015**	**2014**	**2013**
Discount rate	**4.15%**	4.95%	4.35%	**4.20%**	5.00%	4.35%
Expected long-term rate of return on plan assets	**6.95%**	6.90%	6.70%	**4.60%**	4.60%	4.60%
Rate of compensation increase	**3.15%**	3.15%	3.15%	—	—	—

The overall expected long-term rate of return on plan assets is based on historical and projected rates of return for the portfolio in aggregate and for each asset class in the portfolio. Assumed projected rates of return are selected after analyzing historical experience and estimating future levels and volatility of returns. Asset class benchmark returns, asset mix and anticipated benefit payments from plan assets are also considered in determining the overall expected rate of return. The discount rate is based on market interest rates of high-quality bonds that match the timing and benefits expected to be paid under each plan.

A seven per cent average annual rate of increase in the per capita cost of covered health care benefits was assumed for 2016 measurement purposes. The rate was assumed to decrease gradually to five per cent by 2021 and remain at this level thereafter. A one per cent change in assumed health care cost trend rates would have the following effects:

(millions of Canadian $)	**Increase**	**Decrease**
Effect on total of service and interest cost components	1	(1)
Effect on post-retirement benefit obligation	14	(12)

The Company's net benefit cost recognized is as follows:

at December 31	**Pension Benefit Plans**			**Other Post-Retirement Benefit Plans**		
(millions of Canadian $)	**2015**	**2014**	**2013**	**2015**	**2014**	**2013**
Service cost	**108**	85	84	**3**	2	2
Interest cost	**115**	113	96	**10**	10	7
Expected return on plan assets	**(155)**	(139)	(120)	**(2)**	(2)	(2)
Amortization of actuarial loss	**35**	21	30	**3**	2	2
Amortization of past service cost	**2**	2	2	**1**	—	—
Amortization of regulatory asset	**23**	18	30	**1**	1	1
Amortization of transitional obligation related to regulated business	**—**	—	—	**2**	2	2
Net Benefit Cost Recognized	**128**	100	122	**18**	15	12

Pre-tax amounts recognized in AOCI were as follows:

at December 31	**2015**		**2014**		**2013**	
(millions of Canadian $)	**Pension Benefits**	**Other Post-Retirement Benefits**	**Pension Benefits**	**Other Post-Retirement Benefits**	**Pension Benefits**	**Other Post-Retirement Benefits**
Net loss	**247**	**28**	348	39	236	32
Prior service cost	**—**	**—**	2	1	3	1
	247	**28**	350	40	239	33

The estimated net loss for the DB Plans and for the other post-retirement benefit plans that will be amortized from AOCI into net periodic benefit cost in 2016 is $21 million and $3 million respectively.

Pre-tax amounts recognized in OCI were as follows:

at December 31	**2015**		**2014**		**2013**	
(millions of Canadian $)	**Pension Benefits**	**Other Post-Retirement Benefits**	**Pension Benefits**	**Other Post-Retirement Benefits**	**Pension Benefits**	**Other Post-Retirement Benefits**
Amortization of net loss from AOCI to OCI	**(34)**	**(4)**	(21)	(2)	(30)	(2)
Amortization of prior service costs from AOCI to OCI	**(2)**	**(1)**	(2)	—	(2)	—
Funded status adjustment	**(67)**	**(7)**	137	9	(96)	—
	(103)	**(12)**	114	7	(128)	(2)

23. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

Risk Management Overview

TCPL has exposure to market risk and counterparty credit risk, and has strategies, policies and limits in place to manage the impact of these risks on earnings and cash flow.

Risk management strategies, policies and limits are designed to ensure TCPL's risks and related exposures are in line with the Company's business objectives and risk tolerance. Market risk and counterparty credit risk are managed within limits ultimately established by the Company's Board of Directors, implemented by senior management and monitored by the Company's risk management and internal audit groups. The Board of Directors' Audit Committee oversees how management monitors compliance with market risk and counterparty credit risk management policies and procedures, and oversees management's review of the adequacy of the risk management framework.

Market Risk

The Company constructs and invests in energy infrastructure projects, purchases and sells commodities, issues short-term and long-term debt, including amounts in foreign currencies, and invests in foreign operations. Certain of these activities expose the Company to market risk from changes in commodity prices, foreign exchange rates and interest rates, which may affect the Company's earnings and the value of the financial instruments it holds.

The Company uses derivatives as part of its overall risk management strategy to assist in managing the exposure to market risk that results from these activities. These derivative contracts may consist of the following:

- Forwards and futures contracts – contractual agreements to purchase or sell a specific financial instrument or commodity at a specified price and date in the future. TCPL enters into foreign exchange and commodity forwards and futures to manage the impact of changes in foreign exchange rates and commodity prices.
- Swaps – contractual agreements between two parties to exchange streams of payments over time according to specified terms. The Company enters into interest rate, cross-currency and commodity swaps to manage the impact of changes in interest rates, foreign exchange rates and commodity prices.
- Options – contractual agreements that convey the right, but not the obligation of the purchaser to buy or sell a specific amount of a financial instrument or commodity at a fixed price, either at a fixed date or at any time within a specified period. The Company enters into option agreements to manage the impact of changes in interest rates, foreign exchange rates and commodity prices.

Commodity Price Risk

The Company is exposed to commodity price movements as part of its normal business operations. A number of strategies are used to manage these exposures, including the following:

- Subject to its overall risk management strategy, the Company commits a portion of its expected power supply to fixed-price medium-term or long-term sales contracts, while reserving an amount of unsold supply to manage operational and price risks in its asset portfolio.
- The Company purchases a portion of the natural gas required for its power plants or enters into contracts that base the sale price of electricity on the cost of natural gas, effectively locking in a margin.
- The Company's power sales commitments are fulfilled through power generation or through purchased contracts, thereby reducing the Company's exposure to fluctuating commodity prices.
- The Company enters into offsetting or back-to-back positions using derivative instruments to manage price risk exposure in power and natural gas commodities created by certain fixed and variable pricing arrangements for different pricing indices and delivery points.

Natural Gas Storage Commodity Price Risk

TCPL manages its exposure to seasonal natural gas price spreads in its non-regulated Natural Gas Storage business by economically hedging storage capacity with a portfolio of third-party storage capacity contracts and proprietary natural gas purchases and sales. TCPL simultaneously enters into a forward purchase of natural gas for injection into storage and an offsetting forward sale of natural gas for withdrawal at a later period, thereby locking in future positive margins and effectively eliminating exposure to natural gas price movements. Unrealized gains and losses on fair value adjustments recorded each period on these forward contracts are not necessarily representative of the amounts that will be realized on settlement.

Foreign Exchange and Interest Rate Risk

Foreign exchange and interest rate risk is created by fluctuations in the fair value or cash flow of financial instruments due to changes in foreign exchange rates and interest rates.

A portion of TCPL's earnings from its Natural Gas Pipelines, Liquids Pipelines and Energy segments are generated in U.S. dollars and, therefore, fluctuations in the value of the Canadian dollar relative to the U.S. dollar can affect TCPL's net income. As the Company's U.S. dollar-denominated operations continue to grow, exposure to changes in currency rates increases; some of this foreign exchange impact is partially offset by interest expense on U.S. dollar-denominated debt of the Company's foreign operations and by using foreign exchange derivatives.

The Company uses foreign currency and interest rate derivatives to manage the foreign exchange and interest rate risks related to other U.S. dollar-denominated transactions including those that may arise on some of the Company's regulated assets. The realized gains and losses on these derivatives are deferred as regulatory assets and liabilities until they are recovered from or paid to the shippers.

TCPL has floating interest rate debt which subjects it to interest rate cash flow risk. The Company uses a combination of interest rate swaps and options to manage its exposure to this risk.

Net Investment in Foreign Operations

The Company hedges its net investment in foreign operations (on an after-tax basis) with U.S. dollar-denominated debt, cross-currency interest rate swaps, foreign exchange forward contracts and foreign exchange options.

U.S. Dollar-Denominated Debt Designated as a Net Investment Hedge

at December 31 (millions of Canadian $, unless otherwise noted)	2015	2014
Carrying value	**23,000 (US 16,600)**	17,000 (US 14,700)
Fair value	**23,800 (US 17,200)**	19,000 (US 16,400)

Derivatives Designated as a Net Investment Hedge

at December 31 (millions of Canadian $, unless otherwise noted)	2015 Fair Value[1]	2015 Notional or Principal Amount	2014 Fair Value[1]	2014 Notional or Principal Amount
U.S. dollar cross-currency interest rate swaps (maturing 2016 to 2019)[2]	**(730)**	**US3,150**	(431)	US 2,900
U.S. dollar foreign exchange forward contracts (maturing 2016 to 2017)	**50**	**US1,800**	(28)	US 1,400
	(680)	**US4,950**	(459)	US 4,300

1 Fair values equal carrying values.

2 In 2015, net realized gains of $8 million (2014 – gains of $21 million) related to the interest component of cross-currency swap settlements are included in Interest expense.

Counterparty Credit Risk

Counterparty credit risk represents the financial loss the Company would experience if a counterparty to a financial instrument failed to meet its obligations in accordance with the terms and conditions of the related contract or agreement with the Company.

The Company manages its exposure to this potential loss by using recognized credit management techniques, including:

- Dealing with creditworthy counterparties – a significant amount of the Company's credit exposure is with investment grade counterparties or, if not, is generally partially supported by financial assurances from investment grade parties

- Setting limits on the amount TCPL can transact with any one counterparty – the Company monitors and manages the concentration of risk exposure with any one counterparty, and reduces the exposure when necessary and when it is allowed under the terms of the contracts
- Using contract netting arrangements and obtaining financial assurances such as guarantees, letters of credit or cash when deemed necessary.

There is no guarantee that these techniques will protect the Company from material losses.

TCPL's maximum counterparty credit exposure with respect to financial instruments at December 31, 2015, without taking into account security held, consisted of accounts receivable, available for sale assets recorded at fair value, the fair value of derivative assets, notes, loans and advances receivable. The Company regularly reviews its accounts receivable and records an allowance for doubtful accounts as necessary using the specific identification method. At December 31, 2015, there were no significant amounts past due or impaired, and there were no significant credit losses during the year.

The Company had a credit risk concentration due from a counterparty of $248 million (US$179 million) and $258 million (US$222 million) at December 31, 2015 and 2014, respectively. This amount is expected to be fully collectible and is secured by a guarantee from the counterparty's investment grade parent company.

TCPL has significant credit and performance exposures to financial institutions as they hold cash deposits and provide committed credit lines and letters of credit that help manage the Company's exposure to counterparties and provide liquidity in commodity, foreign exchange and interest rate derivative markets.

Fair Value of Non-Derivative Financial Instruments

The fair value of the Company's Notes receivable is calculated by discounting future payments of interest and principal using forward interest rates. The fair value of Long-term debt and Junior subordinated notes is estimated using an income approach based on quoted market prices for the same or similar debt instruments from external data service providers.

Available for sale assets are recorded at fair value which is calculated using quoted market prices where available. Certain non-derivative financial instruments included in Cash and cash equivalents, Accounts receivable, Due from affiliates, Intangible and other assets, Notes payable, Accounts payable and other, Due to affiliates, Accrued interest and Other long-term liabilities have carrying amounts that approximate their fair value due to the nature of the item or the short time to maturity and would also be classified in Level II of the fair value hierarchy.

Credit risk has been taken into consideration when calculating the fair value of non-derivative instruments.

Balance Sheet Presentation of Non-Derivative Financial Instruments

The following table details the fair value of the non-derivative financial instruments, excluding those where carrying amounts approximate fair value, and would be classified in Level II of the fair value hierarchy:

	2015		2014	
at December 31 (millions of Canadian $)	**Carrying Amount**	**Fair Value**	**Carrying Amount**	**Fair Value**
Notes receivable[1]	**214**	**265**	213	263
Current and Long-term debt[2,3] (Note 16)	**(31,584)**	**(34,309)**	(24,757)	(28,713)
Junior subordinated notes (Note 17)	**(2,422)**	**(2,011)**	(1,160)	(1,157)
	(33,792)	**(36,055)**	(25,704)	(29,607)

1 Notes receivable are included in Other current assets and Intangible and other assets on the Consolidated balance sheet.
2 Long-term debt is recorded at amortized cost, except for US$850 million (2014 – US$400 million) that is attributed to hedged risk and recorded at fair value.
3 Consolidated Net income in 2015 included gains of $2 million (2014 – losses of $3 million) for fair value adjustments attributable to the hedged interest rate risk associated with interest rate swap fair value hedging relationships on US$850 million of Long-term debt at December 31, 2015 (2014 – US$400 million). There were no other unrealized gains or losses from fair value adjustments to the non-derivative financial instruments.

Available for Sale Assets Summary

The following tables summarize additional information about the Company's restricted investments that are classified as available for sale assets:

at December 31 (millions of Canadian $)	2015 LMCI Restricted Investments[1]	2015 Other Restricted Investments[2]	2014 LMCI Restricted Investments[1]	2014 Other Restricted Investments[2]
Fair values				
Fixed income securities (maturing within 5 years)	**—**	**90**	—	75
Fixed income securities (maturing after 10 years)	**261**	**—**	—	—
	261	**90**	—	75

1 Gains and losses arising from changes in the fair value of LMCI restricted investments impact the subsequent amounts to be collected through tolls to cover future pipeline abandonment costs. As a result, the Company would record these gains and losses as regulatory assets or liabilities. In 2015 and 2014, there were no net realized or unrealized gains or losses on LMCI restricted investments.

2 Other restricted investments have been set aside to fund insurance claim losses to be paid by the Company's wholly-owned captive insurance subsidiary. In 2015 and 2014, there were no net realized or unrealized gains or losses on other restricted investments.

Fair Value of Derivative Instruments

The fair value of foreign exchange and interest rate derivatives has been calculated using the income approach which uses year-end market rates and applies a discounted cash flow valuation model. The fair value of commodity derivatives has been calculated using quoted market prices where available. In the absence of quoted market prices, third-party broker quotes or other valuation techniques have been used. The fair value of options has been calculated using the Black-Scholes pricing model. Credit risk has been taken into consideration when calculating the fair value of derivative instruments.

In some cases, even though the derivatives are considered to be effective economic hedges, they do not meet the specific criteria for hedge accounting treatment or are not designated as a hedge and are accounted for at fair value with changes in fair value recorded in net income in the period of change. This may expose the Company to increased variability in reported earnings because the fair value of the derivative instruments can fluctuate significantly from period to period.

Balance Sheet Presentation of Derivative Instruments

The balance sheet classification of the fair value of the derivative instruments as at December 31, 2015 is as follows:

at December 31, 2015 (millions of Canadian $)	**Cash Flow Hedges**[1]	**Fair Value Hedges**[1]	**Net Investment Hedges**[1]	**Held for Trading**[1]	**Total Fair Value of Derivative Instruments**
Other current assets (Note 5)					
Commodities[2]	**46**	**—**	**—**	**326**	**372**
Foreign exchange	**—**	**—**	**65**	**2**	**67**
Interest rate	**—**	**1**	**—**	**2**	**3**
	46	**1**	**65**	**330**	**442**
Intangible and other assets (Note 11)					
Commodities[2]	**11**	**—**	**—**	**126**	**137**
Foreign exchange	**—**	**—**	**29**	**—**	**29**
Interest rate	**—**	**2**	**—**	**—**	**2**
	11	**2**	**29**	**126**	**168**
Total Derivative Assets	**57**	**3**	**94**	**456**	**610**
Accounts payable and other (Note 13)					
Commodities[2]	**(112)**	**—**	**—**	**(443)**	**(555)**
Foreign exchange	**—**	**—**	**(313)**	**(54)**	**(367)**
Interest rate	**(1)**	**(1)**	**—**	**(2)**	**(4)**
	(113)	**(1)**	**(313)**	**(499)**	**(926)**
Other long-term liabilities (Note 14)					
Commodities[2]	**(31)**	**—**	**—**	**(131)**	**(162)**
Foreign exchange	**—**	**—**	**(461)**	**—**	**(461)**
Interest rate	**(1)**	**(1)**	**—**	**—**	**(2)**
	(32)	**(1)**	**(461)**	**(131)**	**(625)**
Total Derivative Liabilities	**(145)**	**(2)**	**(774)**	**(630)**	**(1,551)**

1 Fair value equals carrying value.

2 Includes purchases and sales of power and natural gas.

The balance sheet classification of the fair value of the derivative instruments as at December 31, 2014 is as follows:

at December 31, 2014 (millions of Canadian $)	**Cash Flow Hedges**[1]	**Fair Value Hedges**[1]	**Net Investment Hedges**[1]	**Held for Trading**[1]	**Total Fair Value of Derivative Instruments**
Other current assets (Note 5)					
Commodities[2]	39	—	—	359	398
Foreign exchange	—	—	5	1	6
Interest rate	—	2	—	3	5
	39	2	5	363	409
Intangible and other assets (Note 11)					
Commodities[2]	18	—	—	72	90
Foreign exchange	—	—	1	—	1
Interest rate	—	1	—	1	2
	18	1	1	73	93
Total Derivative Assets	57	3	6	436	502
Accounts payable and other (Note 13)					
Commodities[2]	(136)	—	—	(422)	(558)
Foreign exchange	—	—	(155)	(32)	(187)
Interest rate	(1)	—	—	(3)	(4)
	(137)	—	(155)	(457)	(749)
Other long-term liabilities (Note 14)					
Commodities[2]	(27)	—	—	(72)	(99)
Foreign exchange	—	—	(310)	—	(310)
Interest rate	(1)	—	—	(1)	(2)
	(28)	—	(310)	(73)	(411)
Total Derivative Liabilities	(165)	—	(465)	(530)	(1,160)

1 Fair value equals carrying value.
2 Includes purchases and sales of power and natural gas.

The majority of derivative instruments held for trading have been entered into for risk management purposes and all are subject to the Company's risk management strategies, policies and limits. These include derivatives that have not been designated as hedges or do not qualify for hedge accounting treatment but have been entered into as economic hedges to manage the Company's exposures to market risk.

Notional and Maturity Summary

The following tables present the maturity and notional principal or quantity outstanding related to the Company's derivative instruments excluding hedges of the net investment in foreign operations:

at December 31, 2015	Power	Natural Gas	Foreign Exchange	Interest
Purchases[1]	**70,331**	**133**	**—**	**—**
Sales[1]	**54,382**	**70**	**—**	**—**
Millions of dollars	**—**	**—**	**US 1,476**	**US 1,100**
Maturity dates	**2016–2020**	**2016–2020**	**2016**	**2016–2019**

1 Volumes for power and natural gas derivatives are in GWh and Bcf, respectively.

at December 31, 2014	Power	Natural Gas	Foreign Exchange	Interest
Purchases[1]	53,217	60	—	—
Sales[1]	39,429	38	—	—
Millions of dollars	—	—	US 1,374	US 650
Maturity dates	2015–2019	2015–2020	2015	2015–2018

1 Volumes for power and natural gas derivatives are in GWh and Bcf, respectively.

Unrealized and Realized (Losses)/Gains of Derivative Instruments

The following summary does not include hedges of the net investment in foreign operations.

year ended December 31 (millions of Canadian $)	2015	2014
Derivative instruments held for trading[1]		
Amount of unrealized losses in the year		
Commodities	**(37)**	(40)
Foreign exchange	**(21)**	(20)
Amount of realized losses in the year		
Commodities	**(151)**	(28)
Foreign exchange	**(112)**	(28)
Derivative instruments in hedging relationships[2,3]		
Amount of realized (losses)/gains in the year		
Commodities	**(179)**	130
Interest rate	**8**	4

1 Realized and unrealized gains and losses on held for trading derivative instruments used to purchase and sell commodities are included net in Revenues. Realized and unrealized gains and losses on interest rate and foreign exchange derivative instruments held for trading are included net in Interest expense and Interest income and other, respectively.

2 In 2015, net realized gains on fair value hedges were $11 million (2014 – gains of $7 million) and were included in Interest expense.

3 In 2015 and 2014, there were no gains or losses included in Net Income relating to discontinued cash flow hedges where it was probable that the anticipated transaction would not occur.

Derivatives in Cash Flow Hedging Relationships

The components of OCI (Note 21) related to derivatives in cash flow hedging relationships are as follows:

year ended December 31 (millions of Canadian $, pre-tax)	2015	2014
Change in fair value of derivative instruments recognized in OCI (effective portion)[1]		
Commodities	**(92)**	(128)
Foreign exchange	**—**	10
	(92)	(118)
Reclassification of gains/(losses) on derivative instruments from AOCI to Net income (effective portion)[1]		
Commodities[2]	**128**	(111)
Interest rate[3]	**16**	16
	144	(95)
Losses on derivative instruments recognized in Net income (ineffective portion)		
Commodities[2]	**—**	(13)

1 No amounts have been excluded from the assessment of hedge effectiveness. Amounts in parentheses indicate losses recorded to OCI.
2 Reported within Revenues on the Consolidated statement of income.
3 Reported within Interest expense on the Consolidated statement of income.

Offsetting of Derivative Instruments

The Company enters into derivative contracts with the right to offset in the normal course of business as well as in the event of default. TCPL has no master netting agreements, however, similar contracts are entered into containing rights to offset. The Company has elected to present the fair value of derivative instruments with the right to offset on a gross basis in the Consolidated balance sheet. The following table shows the impact on the presentation of the fair value of derivative instrument assets and liabilities had the Company elected to present these contracts on a net basis:

at December 31, 2015 (millions of Canadian $)	Gross Derivative Instruments Presented on the Balance Sheet	Amounts Available for Offset[1]	Net Amounts
Derivative - Asset			
Commodities	**509**	**(418)**	**91**
Foreign exchange	**96**	**(93)**	**3**
Interest rate	**5**	**(1)**	**4**
	610	**(512)**	**98**
Derivative - Liability			
Commodities	**(717)**	**418**	**(299)**
Foreign exchange	**(828)**	**93**	**(735)**
Interest rate	**(6)**	**1**	**(5)**
	(1,551)	**512**	**(1,039)**

1 Amounts available for offset do not include cash collateral pledged or received.

The following table shows the impact on the presentation of the fair value of derivative instrument assets and liabilities had the Company elected to present these contracts on a net basis as at December 31, 2014:

at December 31, 2014 (millions of Canadian $)	**Gross Derivative Instruments Presented on the Balance Sheet**	**Amounts Available for Offset**[1]	**Net Amounts**
Derivative - Asset			
Commodities	488	(387)	101
Foreign exchange	7	(7)	—
Interest rate	7	(1)	6
	502	(395)	107
Derivative - Liability			
Commodities	(657)	387	(270)
Foreign exchange	(497)	7	(490)
Interest rate	(6)	1	(5)
	(1,160)	395	(765)

1 Amounts available for offset do not include cash collateral pledged or received.

With respect to the derivative instruments presented above as at December 31, 2015, the Company had provided cash collateral of $482 million (2014 – $459 million) and letters of credit of $41 million (2014 – $26 million) to its counterparties. The Company held nil (2014 – $1 million) in cash collateral and $2 million (2014 – $1 million) in letters of credit from counterparties on asset exposures at December 31, 2015.

Credit Risk Related Contingent Features of Derivative Instruments

Derivative contracts entered into to manage market risk often contain financial assurance provisions that allow parties to the contracts to manage credit risk. These provisions may require collateral to be provided if a credit-risk-related contingent event occurs, such as a downgrade in the Company's credit rating to non-investment grade.

Based on contracts in place and market prices at December 31, 2015, the aggregate fair value of all derivative instruments with credit-risk-related contingent features that were in a net liability position was $32 million (2014 – $15 million), for which the Company has provided collateral in the normal course of business of nil (2014 – nil). If the credit-risk-related contingent features in these agreements were triggered on December 31, 2015, the Company would have been required to provide additional collateral of $32 million (2014 – $15 million) to its counterparties. Collateral may also need to be provided should the fair value of derivative instruments exceed pre-defined contractual exposure limit thresholds.

The Company has sufficient liquidity in the form of cash and undrawn committed revolving bank lines to meet these contingent obligations should they arise.

Fair Value Hierarchy

The Company's financial assets and liabilities recorded at fair value have been categorized into three categories based on a fair value hierarchy.

Levels	How fair value has been determined
Level I	Quoted prices in active markets for identical assets and liabilities that the Company has the ability to access at the measurement date.
Level II	Valuation based on the extrapolation of inputs, other than quoted prices included within Level I, for which all significant inputs are observable directly or indirectly. Inputs include published exchange rates, interest rates, interest rate swap curves, yield curves and broker quotes from external data service providers. This category includes interest rate and foreign exchange derivative assets and liabilities where fair value is determined using the income approach and commodity derivatives where fair value is determined using the market approach. Transfers between Level I and Level II would occur when there is a change in market circumstances.
Level III	Valuation of assets and liabilities are measured using a market approach based on extrapolation of inputs that are unobservable or where observable data does not support a significant portion of the fair value of the derivatives. This category includes long-dated commodity transactions in certain markets where liquidity is low and inputs may include long-term broker quotes. Valuation of options is based on the Black-Scholes pricing model. Long-term electricity prices may also be estimated using a third-party modeling tool which takes into account physical operating characteristics of generation facilities in the markets in which the Company operates. Model inputs include market fundamentals such as fuel prices, power supply additions and retirements, power demand, seasonal hydro conditions and transmission constraints. Long-term North American natural gas prices might be estimated on a view of future natural gas supply and demand, as well as exploration and development costs. Significant decreases in fuel prices or demand for electricity or natural gas, increases in the supply of electricity or natural gas, or a small number of transactions in markets with lower liquidity are expected to or may result in a lower fair value measurement of contracts included in Level III. Assets and liabilities measured at fair value can fluctuate between Level II and Level III depending on the proportion of the value of the contract that extends beyond the time frame for which significant inputs are considered to be observable. As contracts near maturity and observable market data becomes available, they are transferred out of Level III and into Level II.

The fair value of the Company's derivative assets and liabilities measured on a recurring basis, including both current and non-current portions for 2015, are categorized as follows:

at December 31, 2015 (millions of Canadian $)	**Quoted Prices in Active Markets Level I**[1]	**Significant Other Observable Inputs Level II**[1]	**Significant Unobservable Inputs Level III**[1]	**Total**
Derivative Instrument Assets:				
Commodities	**34**	**462**	**13**	**509**
Foreign exchange	**—**	**96**	**—**	**96**
Interest rate	**—**	**5**	**—**	**5**
Derivative Instrument Liabilities:				
Commodities	**(102)**	**(611)**	**(4)**	**(717)**
Foreign exchange	**—**	**(828)**	**—**	**(828)**
Interest rate	**—**	**(6)**	**—**	**(6)**
	(68)	**(882)**	**9**	**(941)**

1 There were no transfers from Level I to Level II or from Level II to Level III for the year ended December 31, 2015.

The fair value of the Company's derivative assets and liabilities measured on a recurring basis, including both current and non-current portions for 2014, are categorized as follows:

at December 31, 2014 (millions of Canadian $)	**Quoted Prices in Active Markets Level I**[1]	**Significant Other Observable Inputs Level II**[1]	**Significant Unobservable Inputs Level III**[1]	**Total**
Derivative Instrument Assets:				
Commodities	40	441	7	488
Foreign exchange	—	7	—	7
Interest rate	—	7	—	7
Derivative Instrument Liabilities:				
Commodities	(86)	(568)	(3)	(657)
Foreign exchange	—	(497)	—	(497)
Interest rate	—	(6)	—	(6)
	(46)	(616)	4	(658)

1 There were no transfers from Level I to Level II or from Level II to Level III for the year ended December 31, 2014.

The following table presents the net change in fair value of derivative assets and liabilities classified as Level III of the fair value hierarchy:

(millions of Canadian $, pre-tax)	2015	2014
Balance at beginning of year	**4**	1
Transfers out of Level III	**5**	—
Total gains included in Net income	**3**	3
Sales	**(2)**	—
Settlements	**(1)**	—
Balance at end of year[1]	**9**	4

1 Revenues include unrealized gains attributed to derivatives in the Level III category that were still held at December 31, 2015 of $7 million (2014 – $3 million).

A 10 per cent increase or decrease in commodity prices, with all other variables held constant, would result in a $2 million decrease or increase, respectively, in the fair value of outstanding derivative instruments included in Level III as at December 31, 2015.

24. CHANGES IN OPERATING WORKING CAPITAL

year ended December 31 (millions of Canadian $)	2015	2014	2013
Increase in Accounts receivable	**(20)**	(205)	(60)
Increase in Inventories	**(3)**	(27)	(30)
(Increase)/decrease in Other current assets	**(268)**	(386)	40
(Decrease)/increase in Accounts payable and other	**(159)**	393	(291)
Increase in Accrued interest	**91**	36	7
Increase in Operating Working Capital	**(359)**	(189)	(334)

25. ACQUISITIONS AND DISPOSITIONS

Natural Gas Pipelines

TC PipeLines, LP

On April 1, 2015, TCPL completed the sale of its remaining 30 per cent interest in Gas Transmission Northwest LLC (GTN) to TC PipeLines, LP for an aggregate purchase price of US$457 million. Proceeds were comprised of US$264 million in cash, the assumption of US$98 million in proportional GTN LLC debt and US$95 million of new Class B units of TC PipeLines, LP.

On October 1, 2014, TCPL completed the sale of its remaining 30 per cent interest in Bison Pipeline LLC (Bison LLC) to TC PipeLines, LP for an aggregate purchase price of US$215 million.

In May 2013, TC PipeLines, LP completed a public offering of 8,855,000 common units at a price of US$43.85 per unit, resulting in gross proceeds of approximately US$388 million and net proceeds of US$373 million after unit issuance costs. TCPL contributed approximately US$8 million to maintain its two per cent general partnership interest and did not purchase any other units. Upon completion of this offering, TCPL's ownership interest in TC PipeLines, LP decreased from 33.3 per cent to 28.9 per cent and an after-tax dilution gain of $29 million ($47 million pre-tax) was recorded in Additional paid-in capital.

In July 2013, TCPL completed the sale of a 45 per cent interest in each of GTN LLC and Bison LLC to TC PipeLines, LP for an aggregate purchase price of US$1.05 billion, which included US$146 million for the assumption of 45 per cent of GTN LLC debt outstanding, plus normal closing adjustments. GTN LLC and Bison LLC own the GTN and Bison natural gas pipelines, respectively.

Gas Pacifico/INNERGY

On November 26, 2014, TCPL sold its 30 per cent equity investments in Gas Pacifico and INNERGY for aggregate gross proceeds of $9 million and recognized a gain of $9 million ($8 million after-tax).

Energy

Bruce Power

On December 3, 2015, TCPL exercised its option to acquire an additional 14.89 per cent ownership interest in Bruce B from the Ontario Municipal Employees Retirement System (OMERS) for $236 million, increasing its ownership interest to 46.5 per cent. The difference between the purchase price and the underlying carrying value of Bruce B is primarily related to the estimated fair value of the amended agreement with Ontario's Independent Electricity System Operator to extend the operating life of the Bruce Power facility to 2064. On December 4, 2015, Bruce B and Bruce A merged to form a single limited partnership (Bruce Power). This merger was accounted for as a transaction between entities under common control whereby the assets and liabilities of Bruce A and Bruce B were combined at their carrying values. Upon completion of the merger, TCPL applied equity accounting to its 48.5 per cent ownership interest in Bruce Power. Prior to the acquisition, TCPL applied equity accounting to its 48.9 per cent ownership interest in Bruce A and 31.6 per cent ownership interest in Bruce B.

Ontario Solar

As part of a purchase agreement with Canadian Solar Solutions Inc. signed in 2011, TCPL completed the acquisition of four Ontario solar facilities for $241 million in 2014. In 2013, TCPL completed the acquisition of four solar facilities for $216 million. The Company's total investment in the eight solar facilities is $457 million. All power produced by the solar facilities is sold under 20-year PPAs with the Ontario Power Authority.

Cancarb

On April 15, 2014, TCPL sold Cancarb Limited and its related power generation for aggregate gross proceeds of $190 million and recognized a gain of $108 million ($99 million after-tax).

26. COMMITMENTS, CONTINGENCIES AND GUARANTEES

Commitments

Operating Leases

Future annual payments under the Company's operating leases for various premises, services and equipment as well as fixed payments on Alberta PPAs, net of sublease receipts, are approximately as follows:

year ended December 31 (millions of Canadian $)	**Minimum Lease Payments**	**Amounts Recoverable under Sub-leases**	**Net Payments**
2016	354	46	308
2017	355	45	310
2018	270	26	244
2019	248	24	224
2020	185	20	165
2021 and thereafter	311	1	310
	1,723	162	1,561

The operating lease agreements for premises, services and equipment expire at various dates through 2052, with an option to renew certain lease agreements for periods of one year to 25 years. Net rental expense on operating leases in 2015 was $131 million (2014 – $114 million; 2013 – $98 million).

TCPL's commitments under the Alberta PPAs are considered to be operating leases and a portion of these PPAs have been subleased to third parties under similar terms and conditions. Fixed payments under these PPAs have been included in the above operating leases table. Variable payments have been excluded as these payments are dependent upon plant availability and other factors. TCPL's share of payments under the PPAs in 2015 was $348 million (2014 – $391 million; 2013 – $242 million). The generating capacities and expiry dates of the PPAs are as follows:

	MW	Expiry Date
Sundance A	560	December 31, 2017
Sheerness	756	December 31, 2020

TCPL and its affiliates have long-term natural gas transportation and natural gas purchase arrangements as well as other purchase obligations, all of which are transacted at market prices and in the normal course of business.

Other Commitments

Capital expenditure commitments include obligations related to the construction of growth projects and are based on the projects proceeding as planned. Changes to these projects, including cancellation, would reduce or possibly eliminate these commitments as a result of cost mitigation efforts.

At December 31, 2015, TCPL was committed to Natural Gas Pipelines capital expenditures totaling approximately $0.9 billion (2014 – $0.9 billion), primarily related to construction costs related to the NGTL System, Mexican and other natural gas pipeline projects.

At December 31, 2015, the Company was committed to Liquids Pipelines capital expenditures totaling approximately $0.8 billion (2014 – $1.8 billion), primarily related to construction costs of Grand Rapids and Northern Courier.

At December 31, 2015, the Company was committed to Energy capital expenditures totaling approximately $0.6 billion (2014 – $0.2 billion), related to capital costs of the Napanee Generating Station. The Company also entered into an agreement to acquire the Ironwood natural gas fired, combined cycle power plant for US$657 million, before post-closing adjustments.

Contingencies

TCPL is subject to laws and regulations governing environmental quality and pollution control. As at December 31, 2015, the Company had accrued approximately $32 million (2014 – $31 million; 2013 – $32 million) related to operating facilities, which represents the present value of the estimated future amount it expects to expend to remediate the sites. However, additional liabilities may be incurred as assessments occur and remediation efforts continue.

TCPL and its subsidiaries are subject to various legal proceedings, arbitrations and actions arising in the normal course of business. While the final outcome of such legal proceedings and actions cannot be predicted with certainty, it is the opinion of management that the resolution of such proceedings and actions, other than the Keystone XL legal proceeding described in Note 29, will not have a material impact on the Company's consolidated financial position or results of operations.

Guarantees

TCPL and its joint venture partner on Bruce Power, OMERS, have each severally guaranteed certain contingent financial obligations of Bruce Power related to a lease agreement and contractor and supplier services. The Company's exposure under certain of these guarantees is unlimited.

In addition to the guarantees for Bruce Power, the Company and its partners in certain other jointly owned entities have either (i) jointly and severally, (ii) jointly or (iii) severally guaranteed the financial performance of these entities related primarily to redelivery of natural gas, PPA payments and the payment of liabilities. For certain of these entities, any payments made by TCPL under these guarantees in excess of its ownership interest are to be reimbursed by its partners.

The carrying value of these guarantees has been included in Other long-term liabilities. Information regarding the Company's guarantees is as follows:

year ended December 31 (millions of Canadian $)	Term	2015		2014	
		Potential Exposure[1]	Carrying Value	Potential Exposure[1]	Carrying Value
Bruce Power	Ranging to 2018[2]	**88**	**2**	634	6
Other jointly owned entities	Ranging to 2040	**139**	**24**	104	14
		227	**26**	738	20

1 TCPL's share of the potential estimated current or contingent exposure.
2 Except for one guarantee with no termination date.

27. CORPORATE RESTRUCTURING COSTS

At December 31, 2015, the Company had incurred $122 million pre-tax of corporate restructuring charges primarily related to severance, and recorded a provision of $87 million pre-tax related to planned severance costs in 2016 and expected losses under lease commitments. Of the total corporate restructuring charges of $209 million pre-tax, $157 million was recorded in Plant operating costs and other in the Consolidated statement of income which was partially offset by $58 million recorded in Revenues in the Consolidated statement of income related to costs that were recoverable through regulatory and tolling structures. In addition, $44 million was recorded as a Regulatory asset on the Consolidated balance sheet as it is expected to be recovered through regulatory and tolling structures in future periods and $8 million was capitalized to projects impacted by the corporate restructuring.

28. RELATED PARTY TRANSACTIONS

The following amounts are included in Due from affiliates:

(millions of Canadian $)	Maturity Date	2015		2014	
		Outstanding at December 31	Effective Interest Rate	Outstanding at December 31	Effective Interest Rate
Discount Notes[1]	2016	**2,376**	**0.9%**	2,597	1.3%
Credit Facility[2]		**100**	**2.7%**	245	3.0%
		2,476		2,842	

1 Issued to TransCanada. Interest on the discount notes is equivalent to current commercial paper rates.
2 Issued to TransCanada. This facility is repayable on demand and bears interest at the Royal Bank of Canada prime rate per annum.

In 2015, Interest income included $29 million as a result of inter-corporate lending to TransCanada (2014 – $37 million; 2013 – $38 million).

At December 31, 2015, Accounts receivable included $13 million due from TransCanada (December 31, 2014 – $59 million).

The following amounts are included in Due to affiliates:

(millions of Canadian $)	Maturity Date	2015		2014	
		Outstanding at December 31	Effective Interest Rate	Outstanding at December 31	Effective Interest Rate
Credit Facility[1]	2016	**311**	**3.5%**	866	3.8%
		311		866	

1 TransCanada has an unsecured $3.5 billion credit facility with a subsidiary of TCPL. Interest on this facility is charged at Reuters prime rate plus 75 basis points.

In 2015, Interest expense included $28 million of interest charges as a result of inter-corporate borrowing (2014 – $37 million; 2013 - $62 million).

At December 31, 2015, Accounts payable and other included $12 million due to TransCanada (December 31, 2014 – $16 million).

At December 31, 2015, Accrued interest included nil of interest payable to TransCanada (December 31, 2014 – $1 million).

In 2015, the Company made interest payments of $29 million to TransCanada (2014 – $37 million; 2013 – $62 million).

29. SUBSEQUENT EVENTS

Portland Natural Gas Transmission System

On January 1, 2016, TCPL completed the sale of a 49.9 per cent interest in PNGTS to TC PipeLines, LP for an aggregate purchase price of US$223 million.

Keystone XL legal proceeding

On January 6, 2016, TCPL filed a Notice of Intent to initiate a claim under Chapter 11 of North American Free Trade Agreement (NAFTA) in response to the denial of the U.S. Presidential permit for the Keystone XL Pipeline. Through the NAFTA claim, the Company is seeking to recover more than US$15 billion in costs and damages that it estimates it has suffered as a result of the U.S. Administration's breach of its NAFTA obligations. This litigation is in a preliminary stage and the likelihood of success and resulting impact on the Company's financial position or results of operations is unknown at this time.

U.S. Senior Notes Issue

On January 27, 2016, TCPL completed an offering of US$850 million, 4.875 per cent Senior Notes due January 15, 2026 and US$400 million, 3.125 per cent Senior Notes due January 15, 2019.

Ironwood

On February 1, 2016, TCPL acquired the Ironwood natural gas fired, combined cycle power plant in Lebanon, Pennsylvania, with a capacity of 778 MW, for US$657 million, before post-closing adjustments.