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 2016 to that in 2015, and highlights significant changes between 2015 and 2014. 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 – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Management concluded, based on its evaluation, that internal control over financial reporting was effective as of December 31, 2016, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external reporting purposes.

TCPL acquired Columbia Pipeline Group, Inc. (Columbia) on July 1, 2016. As a result, management's assessment and conclusion on the effectiveness of its internal control over financial reporting did not include internal controls over financial reporting at Columbia. These exclusions are consistent with SEC Commission Staff's guidance that the assessment of a recently acquired business may be omitted from the scope of its assessment of the effectiveness of internal control over financial reporting in the year of the acquisition. Assets attributable to Columbia represented approximately 13 per cent of TCPL's total assets as at December 31, 2016, and revenues attributable to Columbia for the period July 1, 2016 to December 31, 2016 represented approximately 7 per cent of TCPL's total revenues for the year ended December 31, 2016.

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 report of KPMG LLP outlines the scope of its examination and its opinion on the consolidated financial statements.

Russell K. Girling
President and
Chief Executive Officer

Donald R. Marchand
Executive Vice-President and
Chief Financial Officer

February 15, 2017

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, 2016 and December 31, 2015, the Consolidated statements of income, comprehensive income, cash flows and equity for each of the years in the three-year period ended December 31, 2016, 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, 2016 and December 31, 2015, and its consolidated results of operations and its consolidated cash flows for each of the years in the three-year period ended December 31, 2016 in accordance with U.S. generally accepted accounting principles.

KPMG LLP

Chartered Professional Accountants
February 15, 2017
Calgary, Canada

Consolidated statement of income

year ended December 31 (millions of Canadian $)	2016	2015	2014
Revenues (Note 1)			
Canadian Natural Gas Pipelines	**3,682**	3,680	3,557
U.S. Natural Gas Pipelines	**2,526**	1,444	1,159
Mexico Natural Gas Pipelines	**378**	259	197
Liquids Pipelines	**1,755**	1,879	1,547
Energy	**4,164**	4,038	3,725
	12,505	11,300	10,185
Income from Equity Investments (Note 9)	**514**	440	522
Operating and Other Expenses			
Plant operating costs and other	**3,819**	3,250	2,973
Commodity purchases resold	**2,172**	2,237	1,836
Property taxes	**555**	517	473
Depreciation and amortization	**1,939**	1,765	1,611
Goodwill and other asset impairment charges (Note 8, 11 and 12)	**1,388**	3,745	—
	9,873	11,514	6,893
(Loss)/Gain on Assets Held for Sale/Sold (Notes 6 and 26)	**(833)**	(125)	117
Financial Charges			
Interest expense (Note 17)	**1,927**	1,398	1,235
Allowance for funds used during construction	**(419)**	(295)	(136)
Interest income and other	**(117)**	103	8
	1,391	1,206	1,107
Income/(Loss) before Income Taxes	**922**	(1,105)	2,824
Income Tax Expense/(Recovery) (Note 16)			
Current	**157**	137	146
Deferred	**192**	(102)	684
	349	35	830
Net Income/(Loss)	**573**	(1,140)	1,994
Net Income attributable to non-controlling interests (Note 19)	**252**	6	151
Net Income/(Loss) Attributable to Controlling Interests	**321**	(1,146)	1,843
Preferred share dividends	**—**	—	2
Net Income/(Loss) Attributable to Common Shares	**321**	(1,146)	1,841

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 $)	2016	2015	2014
Net Income/(Loss)	**573**	(1,140)	1,994
Other Comprehensive (Loss)/Income, Net of Income Taxes			
Foreign currency translation gains on net investment in foreign operations	**3**	813	517
Change in fair value of net investment hedges	**(10)**	(372)	(276)
Change in fair value of cash flow hedges	**30**	(57)	(69)
Reclassification to net income of gains and losses on cash flow hedges	**42**	88	(55)
Unrealized actuarial losses and gains on pension and other post-retirement benefit plans	**(26)**	51	(102)
Reclassification to net income of actuarial loss and prior service costs on pension and other post-retirement benefit plans	**16**	32	18
Other comprehensive (loss)/income on equity investments	**(87)**	47	(204)
Other comprehensive (loss)/income (Note 22)	**(32)**	602	(171)
Comprehensive Income/(Loss)	**541**	(538)	1,823
Comprehensive income attributable to non-controlling interests	**241**	312	281
Comprehensive Income/(Loss) Attributable to Controlling Interests	**300**	(850)	1,542
Preferred share dividends	**—**	—	2
Comprehensive Income/(Loss) Attributable to Common Shares	**300**	(850)	1,540

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 $)	2016	2015	2014
Cash Generated from Operations			
Net income/(loss)	**573**	(1,140)	1,994
Depreciation and amortization	**1,939**	1,765	1,611
Goodwill and other asset impairment charges (Notes 8, 11 and 12)	**1,388**	3,745	—
Deferred income taxes (Note 16)	**192**	(102)	684
Income from equity investments (Note 9)	**(514)**	(440)	(522)
Distributions received from operating activities of equity investments (Note 9)	**844**	793	726
Employee post-retirement benefits expense, net of funding (Note 23)	**(3)**	44	37
Loss/(gain) on assets held for sale/sold (Notes 6 and 26)	**833**	125	(117)
Equity allowance for funds used during construction	**(253)**	(165)	(95)
Unrealized (gains)/losses on financial instruments	**(149)**	58	74
Other	**55**	47	22
Decrease/(increase) in operating working capital (Note 25)	**251**	(307)	(189)
Net cash provided by operations	**5,156**	4,423	4,225
Investing Activities			
Capital expenditures (Note 4)	**(5,007)**	(3,918)	(3,489)
Capital projects in development (Note 4)	**(295)**	(511)	(848)
Contributions to equity investments (Note 9)	**(765)**	(493)	(256)
Acquisitions, net of cash acquired (Note 5 and 26)	**(13,608)**	(236)	(241)
Proceeds from sale of assets, net of transaction costs (Note 26)	**6**	—	196
Other distributions from equity investments (Note 9)	**727**	9	12
Deferred amounts and other	**159**	272	335
Net cash used in investing activities	**(18,783)**	(4,877)	(4,291)
Financing Activities			
Notes payable (repaid)/issued, net	**(329)**	(1,382)	544
Long-term debt issued, net of issue costs	**12,333**	5,045	1,403
Long-term debt repaid	**(7,153)**	(2,105)	(1,069)
Junior subordinated notes issued, net of issue costs	**1,549**	917	—
Advances from/(to) affiliates, net	**4,523**	(189)	(694)
Dividends on common shares	**(1,612)**	(1,446)	(1,345)
Dividends on preferred shares	**—**	—	(4)
Distributions paid to non-controlling interests	**(279)**	(224)	(174)
Common shares issued, net of issue costs	**4,661**	—	1,115
Partnership units of subsidiary issued, net of issue costs	**215**	55	79
Preferred shares of subsidiary redeemed (Note 19)	**—**	—	(200)
Net cash provided by/(used in) financing activities	**13,908**	671	(345)
Effect of Foreign Exchange Rate Changes on Cash and Cash Equivalents	**(127)**	112	—
Increase/(Decrease) in Cash and Cash Equivalents	**154**	329	(411)
Cash and Cash Equivalents			
Beginning of year	**813**	484	895
Cash and Cash Equivalents			
End of year	**967**	813	484

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

Consolidated balance sheet

at December 31 (millions of Canadian $)		2016	2015
ASSETS			
Current Assets			
Cash and cash equivalents		**967**	813
Accounts receivable (Note 29)		**2,093**	1,400
Due from affiliates (Note 29)		**—**	2,476
Inventories		**368**	323
Assets held for sale (Note 6)		**3,717**	20
Other (Note 7)		**908**	1,338
		8,053	6,370
Plant, Property and Equipment (Note 8)		**54,475**	44,817
Equity Investments (Note 9)		**6,544**	6,214
Regulatory Assets (Note 10)		**1,322**	1,184
Goodwill (Note 11)		**13,958**	4,812
Intangible and Other Assets (Note 12)		**2,947**	3,096
Restricted Investments		**642**	351
		87,941	66,844
LIABILITIES			
Current Liabilities			
Notes payable (Note 13)		**774**	1,218
Accounts payable and other (Notes 14 and 29)		**3,876**	2,661
Dividends payable		**491**	370
Due to affiliates (Note 29)		**2,358**	311
Accrued interest		**595**	520
Liabilities related to assets held for sale (Note 6)		**86**	39
Current portion of long-term debt (Note 17)		**1,838**	2,547
		10,018	7,666
Regulatory Liabilities (Note 10)		**2,121**	1,159
Other Long-Term Liabilities (Note 15)		**1,183**	1,260
Deferred Income Tax Liabilities (Note 16)		**7,662**	5,144
Long-Term Debt (Note 17)		**38,312**	28,909
Junior Subordinated Notes (Note 18)		**3,931**	2,409
		63,227	46,547
Common Units Subject to Rescission or Redemption (Note 19)		**1,179**	—
EQUITY			
Common shares, no par value (Note 20)		**20,981**	16,320
Issued and outstanding:	December 31, 2016 – 859 million shares		
	December 31, 2015 – 779 million shares		
Additional paid-in capital		**211**	210
Retained earnings		**1,577**	2,989
Accumulated other comprehensive loss (Note 22)		**(960)**	(939)
Controlling Interests		**21,809**	18,580
Non-controlling interests (Note 19)		**1,726**	1,717
		23,535	20,297
		87,941	66,844

Commitments, Contingencies and Guarantees (Note 27)
Corporate Restructuring Costs (Note 28)
Variable Interest Entities (Note 30)

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 $)	2016	2015	2014
Common Shares			
Balance at beginning of year	**16,320**	16,320	15,205
Proceeds from shares issued	**4,661**	—	1,115
Balance at end of year	**20,981**	16,320	16,320
Preferred Shares			
Balance at beginning of year	**—**	—	194
Redemption of preferred shares	**—**	—	(194)
Balance at end of year	**—**	—	—
Additional Paid-In Capital			
Balance at beginning of year	**210**	404	431
Issuance of stock options	**15**	13	7
Dilution impact from TC PipeLines, LP units issued	**24**	6	9
Redemption of preferred shares	**—**	—	(6)
Impact of asset drop downs to TC PipeLines, LP (Note 26)	**(38)**	(213)	(37)
Balance at end of year	**211**	210	404
Retained Earnings			
Balance at beginning of year	**2,989**	5,606	5,125
Net income/(loss) attributable to controlling interests	**321**	(1,146)	1,843
Common share dividends	**(1,733)**	(1,471)	(1,360)
Preferred share dividends	**—**	—	(2)
Balance at end of year	**1,577**	2,989	5,606
Accumulated Other Comprehensive Loss			
Balance at beginning of year	**(939)**	(1,235)	(934)
Other comprehensive (loss)/income attributable to controlling interests (Note 22)	**(21)**	296	(301)
Balance at end of year	**(960)**	(939)	(1,235)
Equity Attributable to Controlling Interests	**21,809**	18,580	21,095
Equity Attributable to Non-Controlling Interests			
Balance at beginning of year	**1,717**	1,583	1,417
Acquisition of non-controlling interests in Columbia Pipeline Partners LP	**1,051**	—	—
Net income/(loss) attributable to non-controlling interests			
TC PipeLines, LP	**215**	(13)	136
Portland Natural Gas Transmission System	**20**	19	15
Columbia Pipeline Partners LP	**17**	—	—
Other comprehensive (loss)/income attributable to non-controlling interests	**(11)**	306	130
Issuance of TC PipeLines, LP units			
Proceeds, net of issue costs	**215**	55	79
Decrease in TCPL's ownership of TC PipeLines, LP	**(40)**	(11)	(14)
Distributions declared to non-controlling interests	**(279)**	(222)	(180)
Reclassification to common units subject to rescission or redemption (Note 19)	**(1,179)**	—	—
Balance at end of year	**1,726**	1,717	1,583
Total Equity	**23,535**	20,297	22,678

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 core businesses, Natural Gas Pipelines, Liquids Pipelines and Energy, each of which offers different products and services. As a result of the acquisition of Columbia Pipeline Group, Inc. (Columbia) and the pending monetization of the United States (U.S.) Northeast power business, the Company has revised its reporting segments from Natural Gas Pipelines, Liquids Pipelines, Energy and Corporate, to Canadian Natural Gas Pipelines, U.S. Natural Gas Pipelines, Mexico Natural Gas Pipelines, Liquids Pipelines, Energy and Corporate as at December 31, 2016. The Corporate segment is non-operational, consisting of corporate and administrative functions. The revised structure aligns with the information reviewed by the Chief Operating Decision Maker (CODM). Historical financial results for the years ended December 31, 2015 and 2014 have been adjusted to align with this change in the Company's segmented reporting. The Company is a wholly-owned subsidiary of TransCanada Corporation (TransCanada).

Canadian Natural Gas Pipelines

The Canadian Natural Gas Pipelines segment consists of the Company's investments in 40,111 km (24,923 miles) of regulated natural gas pipelines.

U.S. Natural Gas Pipelines

The U.S. Natural Gas Pipelines segment consists of the Company's investments in 49,776 km (30,933 miles) of regulated natural gas pipelines, 535 Bcf of regulated natural gas storage facilities, midstream and other assets.

Acquired as part of Columbia on July 1, 2016, the Company owns and operates:

- Columbia Gas – an interstate natural gas transportation pipeline and storage system, which has largely operated as a means to transport gas from the Gulf Coast, via Columbia Gulf, from various pipeline interconnects and from production areas in the Appalachian region to markets in the midwest, Atlantic, and northeast regions.
- Columbia Gulf – a long-haul interstate natural gas transportation pipeline system that was originally designed to transport supply from the Gulf of Mexico to major supply markets in the U.S. Northeast. The pipeline is now transitioning and expanding to accommodate new supply from the Appalachian basin at its interconnect with Columbia Gas and other pipelines to deliver natural gas across various Gulf Coast markets.
- Millennium – a 47.5 per cent ownership interest in Millennium Pipeline, which transports natural gas primarily sourced from the Marcellus shale to markets across southern New York and the lower Hudson Valley, as well as to New York City through its pipeline interconnections.
- Crossroads – an interstate natural gas pipeline operating in Indiana and Ohio.
- Midstream – this business provides natural gas producer services including gathering, treating, conditioning, processing, compression and liquids handling in the Appalachian Basin, and includes a 47 per cent interest in Pennant Midstream.

Mexico Natural Gas Pipelines

The Mexico Natural Gas Pipelines segment consists of the Company's investments in 1,617 km (1,005 miles) of regulated natural gas pipelines in Mexico. This segment also includes the Company's 46.5 percent interest in the TransGas pipeline located in Colombia and prior to its sale in November 2014, the Company's interest in Gas Pacifico/INNERGY in South America.

Liquids Pipelines

The Liquids Pipelines segment consists of the Company's investment in 4,324 km (2,687 miles) of 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 18 power generation plants and 118 Bcf of 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, Pennsylvania and Arizona. At December 31, 2016, five power generation plants in New York and New England, Pennsylvania are classified as Assets held for sale. Refer to Note 6, Assets held for sale, for further information.

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

These 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 consolidated 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 of assets and liabilities acquired in a business combination (Note 5)
- fair value and depreciation rates of plant, property and equipment (Note 8)
- carrying value of regulatory assets and liabilities (Note 10)
- fair value of goodwill (Note 11)
- fair value of intangible assets (Note 12)
- carrying value of asset retirement obligations (Note 15)
- provisions for income taxes (Note 16)
- assumptions used to measure retirement and other post-retirement obligations (Note 23)
- fair value of financial instruments (Note 24) and
- provision for commitments, contingencies, guarantees (Note 27) and restructuring (Note 28).

Actual results could differ from these 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

Transportation

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 tolls 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 generally 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, at times, are 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 rate of return on common equity (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 Mexican natural gas pipelines are primarily collected based on CRE-approved negotiated firm capacity contracts and recognized ratably over the contract period. Other volumes shipped on these pipelines are subject to CRE-approved tariffs.

The Company does not take ownership of the gas that it transports for others.

Regulated Natural Gas Storage

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 that it stores for others.

Midstream and Other

Revenues from the Company's midstream natural gas services, including gathering, treating, conditioning, processing, compression and liquids handling services, are generated from volumetric based contractual arrangements and are recognized ratably over the contract period regardless of the amount of natural gas that is subject to these services. The Company also owns mineral rights in association with certain storage facilities. These mineral rights can be leased or contributed to producers of natural gas in return for a royalty interest. Royalties from mineral interests are recognized when product is produced.

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 policy in this note.

Non-Regulated 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 natural gas inventory in storage, crude oil in transit, materials and supplies including spare parts and fuel. Inventories are all 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 Allowance for funds used during construction in the Consolidated statement of income. Interest is capitalized during construction of non-regulated natural gas pipelines.

Natural gas storage base gas, which is valued at cost, represents storage volumes that are maintained to ensure that adequate well pressure exists to deliver current gas inventory. Natural gas storage base gas is not depreciated.

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.

Midstream and Other

Plant, property and equipment for midstream assets are carried at cost. Depreciation is calculated on a straight-line basis once the assets are ready for their intended use. Gathering and processing facilities are depreciated at annual rates ranging from 1.7 per cent to 2.5 per cent, and other plant and equipment are depreciated at various rates. 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 net income.

The Company participates as a working interest partner in the development of Marcellus and Utica acreage. The working interest allows the Company to invest in the drilling activities in addition to a royalty interest in well production. The Company uses the successful efforts method of accounting for natural gas and crude oil resulting from its portion of drilling activities. Capitalized well costs are depleted based on the units of production method.

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 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 net income.

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 net income. Natural gas storage base gas, which is valued at original cost, represents storage volumes that are maintained to ensure that adequate well pressure exists to deliver current gas inventory. Natural gas storage base gas is not depreciated.

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.

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 Net income. Depreciation expense is no longer recorded once assets 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 sale price is less than the carrying value of an asset, an impairment loss is recognized for the excess of the carrying value over the estimated 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 values at the date of acquisition. The excess of the fair value of the consideration transferred over the estimated fair value of the net assets acquired is classified as goodwill. Goodwill is not amortized and is tested for impairment on an annual basis or more frequently if events or changes in circumstances indicate that it 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 the Company 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 of the reporting unit is less than its 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 arrangement (PPA) is a long-term contract for the purchase or sale of power on a predetermined basis. TCPL has PPAs for the sale of power that are accounted for as operating leases. Prior to their termination, substantially all the PPAs under which TCPL purchased power were also accounted for as operating leases, and initial payments to acquire these PPAs were recognized in Intangible and other assets and amortized on a straight-line basis over the term of the contracts. A portion of these PPAs were subleased to third parties under terms and conditions similar to the PPAs, and were also accounted for as operating leases with the margin earned from the subleases recorded in Revenues. During 2016, the Company terminated these PPAs and recorded an impairment charge. Refer to Note 12, Intangible and other assets, for further information.

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. Funds collected 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 fund the abandonment of 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 net income in the period during which they occur except for changes in balances related to the Canadian regulated natural gas pipelines which are deferred until they are refunded or recovered in tolls, as permitted by the NEB. Deferred income tax assets and liabilities are classified as non-current on the Consolidated balance sheet.

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 and other expenses.

The Company has recorded ARO related to its non-regulated natural gas storage operations, mineral rights and certain power generation facilities. The scope and timing of asset retirements related to most of the Company's 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 and certain facilities expected to be retired as part of an ongoing modernization program that will improve system integrity and enhance service reliability and flexibility on Columbia Gas.

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

TransCanada'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) and into Net income 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 Net 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 until the operations are sold at which time, the gains and losses are reclassified to Net income. 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 and certain derivative hedging instruments have 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 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, are refunded or 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 a deduction from the carrying amount of the related debt 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. The release from the obligation is recognized either over the term of the guarantee or upon expiration or settlement.

3. ACCOUNTING CHANGES

Changes in Accounting Policies for 2016

Extraordinary and unusual income statement items

In January 2015, the Financial Accounting Standards Board (FASB) issued new guidance on extraordinary and unusual income statement items. This update eliminates the concept of extraordinary items from GAAP. This new guidance was effective January 1, 2016, was applied prospectively and did not have an impact on the Company's consolidated financial statements.

Consolidation

In February 2015, the FASB issued new guidance on consolidation. This guidance requires that entities re-evaluate whether they should consolidate certain legal entities and eliminates the presumption that a general partner should consolidate a limited partnership. This new guidance was effective January 1, 2016, was applied retrospectively and did not result in any change to the Company's consolidation conclusions. Disclosure requirements outlined in the new guidance are included in Note 30, Variable interest entities.

Imputation of interest

In April 2015, the FASB issued new guidance on simplifying the accounting for debt issuance costs. This guidance requires that debt issuance costs be presented on the balance sheet as a direct deduction from the carrying amount of the related debt liability consistent with debt discounts or premiums. This new guidance was effective January 1, 2016, was applied retrospectively and resulted in a reclassification of debt issuance costs previously recorded in Intangible and other assets to an offset of their respective debt liabilities on the Company's Consolidated balance sheet.

Business combinations

In September 2015, the FASB issued guidance which intends to simplify the accounting measurement period adjustments in business combinations. The amended guidance requires an acquirer to recognize adjustments to the provisional amounts that are identified during the measurement period in the reporting period in which the adjustment amounts are determined. In the period the adjustment was determined, the guidance also requires the acquirer to record 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. This new guidance was effective January 1, 2016, was applied prospectively and did not have a material impact on the Company's consolidated financial statements.

Classification of certain cash receipts and cash payments

In August 2016, the FASB issued new guidance to clarify how entities should classify certain cash receipts and cash payments on the statement of cash flows. This new guidance is effective January 1, 2018, however, since early adoption is permitted, the Company elected to retrospectively apply this guidance effective December 31, 2016. The application of this guidance did not have a material impact on the classification of debt pre-payments or extinguishment costs, contingent consideration payments made after a business combination, proceeds from the settlement of insurance claims and proceeds from the settlement of corporate owned life insurance. The Company has elected to classify distributions received from equity method investments using the nature of distributions approach as it is more representative of the nature of the underlying activities of the investments that generated the distributions. As a result, certain comparative period distributions received from equity method investments have been reclassified from investing activities to cash generated from operations in the Consolidated statement of cash flows.

Future Accounting Changes

Revenue from contracts with customers

In 2014, the FASB issued new guidance on revenue from contracts with customers. Current guidance allows for revenue recognition when certain criteria are met. The new guidance requires that an entity recognize revenue in accordance with a five-step model. This model is used to depict the transfer of promised goods or services to customers in an amount that reflects the total consideration to which it expects to be entitled during the term of the contract in exchange for those goods or services. The Company will adopt the new standard on the effective date of January 1, 2018. There are two methods in which the new standard 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 evaluating both methods of adoption as it works through its analysis. The Company has identified all existing customer contracts that are within the scope of the new guidance and has begun to analyze individual contracts or groups of contracts to identify any significant differences and the impact on revenues as a result of implementing the new standard. As the Company continues its contract analysis, it will also quantify the impact, if any, on prior period revenues. The Company will address any system and process changes necessary to compile the information to meet the disclosure requirements of the new standard. As the Company is currently evaluating the impact of this standard, it has not yet determined the effect on its consolidated financial statements.

Inventory

In July 2015, the FASB issued new guidance on simplifying the measurement of inventory. The new guidance specifies 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.

Financial instruments

In January 2016, the FASB issued new guidance on the accounting for equity investments and financial liabilities. The new guidance will change the income statement effect of equity investments and the recognition of changes in fair value of financial liabilities when the fair value option is elected. The new guidance also requires the Company to assess valuation allowances for deferred tax assets related to available for sale debt securities in combination with their other deferred tax assets. This new guidance is effective January 1, 2018. 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.

Leases

In February 2016, the FASB issued new guidance on leases. The new guidance requires lessees to recognize most leases, including operating leases, on the balance sheet as lease assets and lease liabilities. In addition, lessees may be required to reassess assumptions associated with existing leases as well as to provide expanded qualitative and quantitative disclosures. The new standard does not make extensive changes to lessor accounting. The new guidance is effective January 1, 2019, however, the Company is evaluating the option to early adopt. The Company is currently identifying existing lease agreements that may have an impact on the Company's consolidated financial statements as a result of adopting this new guidance.

Derivatives and hedging

In March 2016, the FASB issued new guidance that clarifies the requirements for assessing whether contingent call or put options that can accelerate the payment of principal on debt instruments are clearly and closely related to their debt hosts. The new guidance requires only an assessment of the four-step decision sequence outlined in GAAP to determine whether the economic characteristics and risks of call or put options are clearly and closely related to the economic characteristics and risks. This new guidance is effective January 1, 2017 and the Company does not expect the adoption of this new guidance to have a material impact on its consolidated financial statements.

Equity method investments

In March 2016, the FASB issued new guidance that simplifies the transition to equity method accounting. In these situations, when an increase in ownership interest in an investment qualifies it for equity method accounting, the new guidance eliminates the requirement to retroactively apply the equity method of accounting. This new guidance is effective January 1, 2017 and will be applied prospectively. The Company does not expect the adoption of this new guidance to have a material impact on its consolidated financial statements.

Employee share-based payments

In March 2016, the FASB issued new guidance that simplifies several aspects of the accounting for employee share-based payment transactions, including the income tax consequences, classification of awards as either equity or liabilities, and classification on the statement of cash flows. The new guidance also permits entities to make an accounting policy election either to continue to estimate the total number of awards for which the requisite service period will not be rendered or to account for forfeitures when they occur. This new guidance is effective January 1, 2017 and the Company does not expect the adoption of this new guidance to have a material impact on its consolidated financial statements.

Measurement of credit losses on financial instruments

In June 2016, the FASB issued new guidance that significantly changes how entities measure credit losses for most financial assets and certain other instruments that are not measured at fair value through net income. The new guidance amends the impairment model of financial instruments basing it on expected losses rather than incurred losses. These expected credit losses will be recognized as an allowance rather than a direct write down of the amortized cost basis. The new guidance is effective January 1, 2020 and will be applied using a modified retrospective approach. 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.

Consolidation

In October 2016, the FASB issued new guidance on consolidation relating to interests held through related parties that are under common control. The new guidance amends the consolidation requirements such that if a decision maker is required to evaluate whether it is the primary beneficiary of a variable interest entity (VIE), it will need to consider only its proportionate indirect interest in the VIE held through a common control party. The new guidance is effective January 1, 2017 and the Company does not expect the adoption of this new guidance to have a material impact on its consolidated financial statements.

Income taxes

In October 2016, the FASB issued new guidance on income tax effects of intra-entity transfers of assets other than inventory. The new guidance requires the recognition of deferred and current income taxes for an intra-entity asset transfer when the transfer occurs. The new guidance is effective January 1, 2018 and will be applied on a modified retrospective basis. Early adoption is permitted. 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.

Restricted cash

In November 2016, the FASB issued new guidance on restricted cash and cash equivalents on the statement of cash flows. The new guidance requires that the statement of cash flows explain the change during the period in the total cash and cash equivalents, and amounts generally described as restricted cash or restricted cash equivalents. The amounts of restricted cash and cash equivalents will be included in Cash and cash equivalents when reconciling the beginning of year and end of year total amounts on the statement of cash flows. This new guidance is effective January 1, 2018 and will be applied retrospectively. Early adoption is permitted. 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.

4. SEGMENTED INFORMATION

As a result of the acquisition of Columbia and the pending monetization of the U.S. Northeast power business, the Company has changed its reporting segments. TCPL has six reportable segments, namely, Canadian Natural Gas Pipelines, U.S. Natural Gas Pipelines, Mexico Natural Gas Pipelines, Liquids Pipelines, Energy and Corporate. The Corporate segment is non-operational, consisting of corporate and administrative functions. This provides information that is aligned with the CODM's review of business performance and how decisions about business segments are made. Historical financial results for the years ended December 31, 2015 and 2014 have been adjusted to align with this change in the Company's segmented reporting.

year ended December 31, 2016 (millions of Canadian $)	**Canadian Natural Gas Pipelines**	**U.S. Natural Gas Pipelines**	**Mexico Natural Gas Pipelines**	**Liquids Pipelines**	**Energy**	**Corporate**	**Total**
Revenues	**3,682**	**2,526**	**378**	**1,755**	**4,164**	**—**	**12,505**
Income from equity investments	**12**	**214**	**(3)**	**(1)**	**292**	**—**	**514**
Plant operating costs and other	**(1,181)**	**(1,000)**	**(42)**	**(554)**	**(834)**	**(208)**	**(3,819)**
Commodity purchases resold	**—**	**—**	**—**	**—**	**(2,172)**	**—**	**(2,172)**
Property taxes	**(267)**	**(120)**	**—**	**(88)**	**(80)**	**—**	**(555)**
Depreciation and amortization	**(873)**	**(397)**	**(43)**	**(285)**	**(293)**	**(48)**	**(1,939)**
Goodwill and other asset impairment charges	**—**	**—**	**—**	**—**	**(1,388)**	**—**	**(1,388)**
Loss on assets held for sale/sold	**—**	**(4)**	**—**	**—**	**(829)**	**—**	**(833)**
Segmented earnings/(losses)	**1,373**	**1,219**	**290**	**827**	**(1,140)**	**(256)**	**2,313**
Interest expense							**(1,927)**
Allowance for funds used during construction							**419**
Interest income and other							**117**
Income before income taxes							**922**
Income tax expense							**(349)**
Net income							**573**
Net income attributable to non-controlling interests							**(252)**
Net income attributable to controlling interests and to common shares							**321**
Capital spending							
Capital expenditures	**1,372**	**1,517**	**944**	**668**	**473**	**33**	**5,007**
Capital projects in development	**153**	**—**	**—**	**142**	**—**	**—**	**295**
	1,525	**1,517**	**944**	**810**	**473**	**33**	**5,302**

1

year ended December 31, 2015 (millions of Canadian $)	Canadian Natural Gas Pipelines	U.S. Natural Gas Pipelines	Mexico Natural Gas Pipelines	Liquids Pipelines	Energy	Corporate	Total
Revenues	3,680	1,444	259	1,879	4,038	—	11,300
Income from equity investments	12	162	5	—	261	—	440
Plant operating costs and other	(1,162)	(555)	(49)	(491)	(786)	(207)	(3,250)
Commodity purchases resold	—	—	—	—	(2,237)	—	(2,237)
Property taxes	(272)	(77)	—	(79)	(89)	—	(517)
Depreciation and amortization	(845)	(243)	(44)	(266)	(336)	(31)	(1,765)
Asset impairment charges	—	—	—	(3,686)	(59)	—	(3,745)
Loss on assets held for sale/sold	—	(125)	—	—	—	—	(125)
Segmented earnings/(losses)	1,413	606	171	(2,643)	792	(238)	101
Interest expense							(1,398)
Allowance for funds used during construction							295
Interest income and other							(103)
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 and to common shares							(1,146)
Capital spending							
Capital expenditures	1,366	534	566	1,012	376	64	3,918
Capital projects in development	230	3	—	278	—	—	511
	1,596	537	566	1,290	376	64	4,429

1

year ended December 31, 2014 (millions of Canadian $)	Canadian Natural Gas Pipelines	U.S. Natural Gas Pipelines	Mexico Natural Gas Pipelines	Liquids Pipelines	Energy	Corporate	Total
Revenues	3,557	1,159	197	1,547	3,725	—	10,185
Income from equity investments	12	143	8	—	359	—	522
Plant operating costs and other	(1,028)	(467)	(41)	(439)	(934)	(64)	(2,973)
Commodity purchases resold	—	—	—	—	(1,836)	—	(1,836)
Property taxes	(266)	(68)	—	(62)	(77)	—	(473)
Depreciation and amortization	(821)	(211)	(31)	(216)	(309)	(23)	(1,611)
Gain on assets held for sale/sold		—	9	—	108	—	117
Segmented earnings/(losses)	1,454	556	142	830	1,036	(87)	3,931
Interest expense							(1,235)
Allowance for funds used during construction							136
Interest income and other							(8)
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	814	237	717	1,469	206	46	3,489
Capital projects in development	327	40	1	480	—	—	848
	1,141	277	718	1,949	206	46	4,337

at December 31 (millions of Canadian $)	2016	2015
Total Assets		
Canadian Natural Gas Pipelines	**15,816**	15,038
U.S. Natural Gas Pipelines	**34,422**	12,207
Mexico Natural Gas Pipelines	**5,013**	3,787
Liquids Pipelines	**16,896**	16,046
Energy	**13,169**	15,614
Corporate	**2,625**	4,152
	87,941	66,844

Geographic Information

year ended December 31 (millions of Canadian $)	2016	2015	2014
Revenues			
Canada – domestic	**3,655**	3,877	3,956
Canada – export	**1,177**	1,292	1,314
United States	**7,295**	5,872	4,718
Mexico	**378**	259	197
	12,505	11,300	10,185

at December 31 (millions of Canadian $)	2016	2015
Plant, Property and Equipment		
Canada	**20,531**	19,287
United States	**29,414**	21,899
Mexico	**4,530**	3,631
	54,475	44,817

5. ACQUISITION OF COLUMBIA

On July 1, 2016, TCPL acquired 100 per cent ownership of Columbia for a purchase price of US$10.3 billion in cash, based on US $25.50 per share for all of Columbia's outstanding common shares as well as all outstanding restricted and performance stock units. The acquisition was financed through the issuance of TCPL common shares to TransCanada and an intercompany loan due to TransCanada in connection with proceeds received from the sale of TransCanada subscription receipts. The sale of the subscription receipts was completed on April 1, 2016 through a public offering, and gross proceeds of approximately $4.4 billion were transferred to TCPL prior to the closing of the acquisition. In addition, TCPL drew on acquisition bridge facilities in the aggregate amount of US$6.9 billion. Refer to Note 20, Common shares and Note 29, Related party transactions for additional information on the common shares issued to TransCanada and on the intercompany loan due to TransCanada. Refer to Note 17, Long-term debt for additional information on the acquisition bridge facilities.

Columbia operates a portfolio of approximately 24,500 km (15,200 miles) of regulated natural gas pipelines, 285 Bcf of natural gas storage facilities and midstream and other assets in various regions in the U.S. TCPL acquired Columbia to expand the Company's natural gas business in the U.S. market, positioning the Company for additional long-term growth opportunities.

The goodwill of $10.1 billion (US$7.7 billion) arising from the acquisition principally reflects the opportunities to expand the Company's U.S. Natural Gas Pipelines segment and to gain a stronger competitive position in the North American natural gas business. The goodwill resulting from the acquisition is not deductible for income tax purposes.

The acquisition has been accounted for as a business combination using the acquisition method where the acquired tangible and intangible assets and assumed liabilities are recorded at their estimated fair values at the date of acquisition. The purchase price equation reflects management's estimate of the fair value of Columbia's assets and liabilities as at July 1, 2016.

	July 1, 2016	
(millions of $)	**U.S.**	**Canadian**[1]
Purchase Price Consideration	**10,294**	**13,392**
Fair Value of Net Assets Acquired		
Current assets	658	856
Plant, property and equipment	7,560	9,835
Equity investments	441	574
Regulatory assets	190	248
Intangibles and other assets	135	175
Current liabilities	(597)	(777)
Regulatory liabilities	(294)	(383)
Other long-term liabilities	(144)	(187)
Deferred income tax liabilities	(1,613)	(2,098)
Long-term debt	(2,981)	(3,878)
Non-controlling interests	(808)	(1,051)
Fair Value of Net Assets Acquired	**2,547**	**3,314**
Goodwill (Note 11)	**7,747**	**10,078**

1 At July 1, 2016 exchange rate of $1.30.

The fair values of current assets including cash and cash equivalents, accounts receivable, and inventories and the fair values of current liabilities including notes payable and accrued interest approximate their carrying values due to the short-term nature of these items. Certain acquisition-related working capital items resulted in an adjustment to accounts payable.

Columbia's natural gas pipelines are subject to FERC regulations and, as a result, their rate bases are expected to be recovered with a reasonable rate of return over the life of the assets. These assets, as well as related regulatory assets and liabilities, have fair values equal to their carrying values. The fair value of mineral rights included in Columbia's plant, property and equipment was determined using a discounted cash flow approach which resulted in a fair value increase of $241 million (US$185 million). The fair value of base gas included in Columbia's plant, property and equipment was determined by using a quoted market price multiplied by the volume of gas in place which resulted in a fair value increase of $840 million (US$646 million). The fair value of base gas is based on preliminary information obtained and is subject to change as the Company completes its work on the volume acquired. An adjustment to the fair value of base gas would impact the purchase price equation.

The fair value of Columbia's long-term debt was estimated using an income approach based on observable market rates for similar debt instruments from external data service providers. This resulted in a fair value increase of $300 million (US$231 million).

The following table summarizes the acquisition date fair value of Columbia's debt acquired by TCPL.

(millions of $)	Maturity Date	Type	Fair Value	Interest Rate
COLUMBIA PIPELINE GROUP INC.				
	June 2018	Senior Unsecured Notes (US$500)	US$506	2.45%
	June 2020	Senior Unsecured Notes (US$750)	US$779	3.30%
	June 2025	Senior Unsecured Notes (US$1000)	US$1,092	4.50%
	June 2045	Senior Unsecured Notes (US$500)	US$604	5.80%
			US$2,981	

The fair values of Columbia's DB plan and other post-retirement benefit plans were based on an actuarial valuation report as of the acquisition date. The fair value representing the funded status of the plans on the acquisition date resulted in an increase of $15 million (US$12 million) and $5 million (US$4 million) to Regulatory assets and Other long-term liabilities, respectively, and a decrease of $14 million (US$11 million) and $2 million (US$2 million) to Intangible and other assets and Regulatory liabilities, respectively.

Temporary differences created as a result of the fair value changes described above resulted in deferred income tax assets and liabilities that were recorded at the Company's U.S. effective tax rate of 39 per cent.

The fair value of Columbia's non-controlling interest was based on the approximately 53.8 million Columbia Pipeline Partners LP (CPPL) common units outstanding to the public as of June 30, 2016, and valued at the June 30, 2016 closing price of US$15.00 per common unit.

Acquisition expenses of approximately $36 million are included in Plant operating costs and other in the Consolidated statement of income.

Upon completing the acquisition, the Company began consolidating Columbia. Columbia's significant accounting policies are consistent with TCPL's and continue to be applied. Columbia contributed $929 million to the Company's Revenues and $132 million to the Company's Net income from the acquisition date to December 31, 2016.

The following supplemental pro forma consolidated financial information of the Company for the years ended December 31, 2016 and 2015 includes the results of operations for Columbia as if the acquisition had been completed on January 1, 2015.

year ended December 31 (millions of Canadian $)	**2016**	**2015**
Revenues	**13,404**	13,007
Net Income/(Loss)	**715**	(820)
Net Income/(Loss) Attributable to Controlling Interests and to Common Shares	**431**	(877)

6. ASSETS HELD FOR SALE

U.S. Northeast Power Assets

The Company's planned monetization of its U.S. Northeast power business, for the purposes of permanently financing the Columbia acquisition, includes the sale of Ravenswood, Ironwood, Kibby Wind, Ocean State Power, TC Hydro and the marketing business, TransCanada Power Marketing (TCPM).

On November 1, 2016, the Company entered into agreements to sell all of these assets except TCPM.

The sale of Ravenswood, Ironwood, Kibby Wind and Ocean State Power to a third party for proceeds of approximately US$2.2 billion is expected to close in the first half of 2017. As a result, a loss of approximately $829 million ($863 million after tax) was recorded in 2016 and was included in (Loss)/gain on assets held for sale/sold in the Consolidated statement of income and included the impact of an estimated $70 million of foreign currency translation gains to be reclassified from AOCI to Net income on close. At December 31, 2016, the related assets and liabilities were classified as held for sale in the Energy segment and were recorded at their fair values less costs to sell based on the proceeds expected on the close of this sale.

The sale of TC Hydro to another third party for proceeds of approximately US$1.1 billion is also expected to close in the first half of 2017, and is expected to result in an estimated gain of $710 million ($440 million after tax) including the impact of an estimated $5 million of foreign currency translation gains. This gain will be recognized upon closing of the sale transaction. At December 31, 2016, the related assets and liabilities were classified as held for sale in the Energy segment.

As of December 31, 2016, TCPM did not meet the criteria to be classified as held for sale.

The following table details the assets and liabilities held for sale at December 31, 2016.

(millions of $)	U.S.	Canadian[1]
Assets held for sale		
Accounts receivable	**13**	**18**
Inventories	**56**	**75**
Other current assets	**90**	**121**
Plant, property and equipment	**2,229**	**2,993** [2]
Intangible and other assets	**328**	**440**
Foreign currency translation gains	**—**	**70** [3]
Total assets held for sale	**2,716**	**3,717**
Liabilities related to assets held for sale		
Accounts payable and other	**32**	**43**
Other long-term liabilities	**32**	**43**
Total liabilities related to assets held for sale	**64**	**86**

1 At December 31, 2016 exchange rate of $1.34.
2 Includes $17 million (US$13 million) for a gas plant held for sale in the U.S. Natural Gas Pipelines segment.
3 Foreign currency translation gains related to the investments in Ravenswood, Ironwood, Kibby Wind and Ocean State Power will be reclassified from AOCI to Net Income on close of the sale.

TC Offshore LLC

On March 1, 2016, the Company closed the sale of TC Offshore LLC. This resulted in an additional loss on disposal of $4 million pre-tax which is included in (Loss)/gain on assets held for sale/sold in the Consolidated statement of income.

On December 18, 2015, the Company entered into an agreement to sell TC Offshore LLC to a third party. At December 31, 2015, the related assets and liabilities were classified as held for sale in the U.S. 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 was included in (Loss)/gain on assets held for sale/sold in the Consolidated statement of income. The estimated fair value of these assets was based on the proceeds expected on the close of this sale.

7. OTHER CURRENT ASSETS

at December 31 (millions of Canadian $)	2016	2015
Fair value of derivative contracts (Note 24)	**376**	442
Cash provided as collateral	**313**	590
Prepaid expenses	**131**	132
Regulatory assets (Note 10)	**33**	85
Other[1]	**55**	89
	908	1,338

1 Includes current portion of note receivable from the seller of Ravenswood of $55 million (US$40 million) at December 31, 2015. As of November 1, 2016, all Ravenswood assets including the current portion of the note receivable have been reclassified to Assets held for sale (Note 6).

8. PLANT, PROPERTY AND EQUIPMENT

at December 31 (millions of Canadian $)	2016 Cost	2016 Accumulated Depreciation	2016 Net Book Value	2015 Cost	2015 Accumulated Depreciation	2015 Net Book Value
Canadian Natural Gas Pipelines						
NGTL System						
Pipeline	**8,814**	**3,951**	**4,863**	8,456	3,820	4,636
Compression	**2,447**	**1,499**	**948**	2,188	1,404	784
Metering and other	**1,124**	**519**	**605**	1,096	489	607
	12,385	**5,969**	**6,416**	11,740	5,713	6,027
Under construction	**1,151**	**—**	**1,151**	969	—	969
	13,536	**5,969**	**7,567**	12,709	5,713	6,996
Canadian Mainline						
Pipeline	**9,502**	**6,221**	**3,281**	9,164	5,966	3,198
Compression	**3,537**	**2,361**	**1,176**	3,433	2,220	1,213
Metering and other	**605**	**198**	**407**	499	192	307
	13,644	**8,780**	**4,864**	13,096	8,378	4,718
Under construction	**219**	**—**	**219**	257	—	257
	13,863	**8,780**	**5,083**	13,353	8,378	4,975
Other Canadian Natural Gas Pipelines						
Other[1]	**1,728**	**1,273**	**455**	1,705	1,213	492
Under construction	**112**	**—**	**112**	63	—	63
	1,840	**1,273**	**567**	1,768	1,213	555
	29,239	**16,022**	**13,217**	27,830	15,304	12,526
U.S. Natural Gas Pipelines						
Columbia Gas[2]						
Pipeline	**3,072**	**13**	**3,059**	—	—	—
Compression	**1,864**	**7**	**1,857**	—	—	—
Metering and other	**2,542**	**34**	**2,508**	—	—	—
	7,478	**54**	**7,424**	—	—	—
Under construction	**1,127**	**—**	**1,127**	—	—	—
	8,605	**54**	**8,551**	—	—	—
ANR						
Pipeline	**1,468**	**349**	**1,119**	1,449	350	1,099
Compression	**1,494**	**260**	**1,234**	1,101	187	914
Metering and other	**988**	**254**	**734**	977	252	725
	3,950	**863**	**3,087**	3,527	789	2,738
Under construction	**232**	**—**	**232**	304	—	304
	4,182	**863**	**3,319**	3,831	789	3,042

at December 31 (millions of Canadian $)	2016 Cost	2016 Accumulated Depreciation	2016 Net Book Value	2015 Cost	2015 Accumulated Depreciation	2015 Net Book Value
Other U.S. Natural Gas Pipelines						
GTN	**2,221**	**810**	**1,411**	2,278	765	1,513
Great Lakes	**2,106**	**1,155**	**951**	2,157	1,155	1,002
Midstream[2,3]	**1,072**	**23**	**1,049**	—	—	—
Columbia Gulf[2]	**880**	**5**	**875**	—	—	—
Other[2,4]	**2,120**	**567**	**1,553**	2,124	521	1,603
	8,399	**2,560**	**5,839**	6,559	2,441	4,118
Under construction	**346**	**—**	**346**	8	—	8
	8,745	**2,560**	**6,185**	6,567	2,441	4,126
	21,532	**3,477**	**18,055**	10,398	3,230	7,168
Mexico Natural Gas Pipelines						
Pipeline	**2,734**	**180**	**2,554**	1,296	162	1,134
Compression	**422**	**19**	**403**	183	14	169
Metering and other	**502**	**40**	**462**	388	27	361
	3,658	**239**	**3,419**	1,867	203	1,664
Under construction	**1,108**	**—**	**1,108**	1,959	—	1,959
	4,766	**239**	**4,527**	3,826	203	3,623
Liquids Pipelines						
Keystone Pipeline System						
Pipeline	**10,572**	**901**	**9,671**	9,288	718	8,570
Pumping equipment	**928**	**121**	**807**	1,092	108	984
Tanks and other	**2,521**	**286**	**2,235**	3,034	228	2,806
	14,021	**1,308**	**12,713**	13,414	1,054	12,360
Under construction	**1,434**	**—**	**1,434**	1,826	—	1,826
	15,455	**1,308**	**14,147**	15,240	1,054	14,186
Energy[5]						
Natural Gas – Ravenswood	**—**	**—**	**—**	2,607	654	1,953
Natural Gas – Other[6,7]	**2,696**	**696**	**2,000**	3,361	1,164	2,197
Hydro, Wind and Solar	**1,180**	**245**	**935**	2,417	476	1,941
Natural Gas Storage and Other	**731**	**146**	**585**	740	132	608
	4,607	**1,087**	**3,520**	9,125	2,426	6,699
Under construction	**729**	**—**	**729**	430	—	430
	5,336	**1,087**	**4,249**	9,555	2,426	7,129
Corporate	**410**	**130**	**280**	267	82	185
	76,738	**22,263**	**54,475**	67,116	22,299	44,817

1 Includes Foothills and Venture LP.
2 Acquired as part of Columbia on July 1, 2016. Refer to Note 5, Acquisition of Columbia for further information.
3 Includes Midstream and mineral rights at December 31, 2016.
4 Includes Bison, Portland Natural Gas Transmission System, North Baja, Tuscarora, and Crossroads.
5 U.S. Northeast power assets except TCPM are excluded from the Energy net book value at December 31, 2016 as they have been classified as Assets held for sale. Refer to Note 6, Assets held for sale for further information.
6 Includes facilities with long-term PPAs that are accounted for as operating leases. The cost and accumulated depreciation of these facilities was $1,319 million and $335 million, respectively, at December 31, 2016 (2015 – $1,341 million and $302 million, respectively). Revenues of $212 million were recognized in 2016 (2015 – $235 million; 2014 – $223 million) through the sale of electricity under the related PPAs.
7 Includes Halton Hills, Coolidge, Bécancour, Mackay River and other natural gas-fired facilities.

Keystone XL

At December 31, 2016, the Company reviewed its remaining investment in Keystone XL and related projects with a carrying value of $526 million (2015 – $621 million) and found no events or changes in circumstance indicating that the carrying value may not be recoverable.

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 in its Liquids Pipelines segment 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 included $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, included in the estimated fair value of $621 million was $463 million related to plant and equipment. The fair value of these assets was based on the price that would be received on sale of the plant and equipment in its condition at December 31, 2015. Key assumptions used in the determination of selling price included an estimated two year disposal period and the then 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.

At December 31, 2015, $158 million related to terminal assets, including KHT, was included in the fair value of $621 million. The fair value was determined using a discounted cash flow approach. 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 was classified within Level III of the fair value hierarchy at December 31, 2015 . Refer to Note 24, Risk management and financial instruments 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) in the Energy segment. This impairment charge was based on the excess of the carrying value over the estimated fair value of the turbines, which was determined based on a comparison to similar assets available for sale in the market.

9. EQUITY INVESTMENTS

(millions of Canadian $)	Ownership Interest at December 31, 2016	Income/(Loss) from Equity Investments year ended December 31			Equity Investments at December 31	
		2016	2015	2014	2016	2015
Canadian Natural Gas Pipelines						
TQM	50.0%	**12**	12	12	**71**	72
U.S. Natural Gas Pipelines						
Northern Border[1]	50.0%	**92**	85	76	**597**	664
Iroquois[2]	50.0%	**54**	51	43	**309**	238
Millennium[3]	47.5%	**33**	—	—	**295**	—
Pennant Midstream[3]	47.0%	**6**	—	—	**246**	—
Other	Various	**29**	26	24	**93**	31
Mexico Natural Gas Pipelines						
Sur de Texas[4]	60.0%	**(3)**	—	—	**255**	—
Other[5]	Various	**—**	5	8	**28**	42
Liquids Pipelines						
Grand Rapids	50.0%	**(1)**	—	—	**876**	542
Other	Various	**—**	—	—	**39**	16
Energy						
Bruce Power[6,7]	48.5%	**293**	249	314	**3,356**	4,200
Portlands Energy	50.0%	**33**	30	36	**313**	321
ASTC Power Partnership	50.0%	**(37)**	(23)	8	**—**	21
Other	Various	**3**	5	1	**66**	67
		514	440	522	**6,544**	6,214

1 At December 31, 2016, the difference between the carrying value of the investment and the underlying equity in the net assets of Northern Border Pipeline Company is US$116 million (2015 – US$117 million) due to the fair value assessment of assets at the time of acquisition.

2 After the acquisition of an additional 4.87 per cent interest on March 31, 2016 and 0.65 per cent interest on May 1, 2016, TCPL has an ownership interest of 50.0 per cent in Iroquois. Prior to these acquisitions, TCPL had an ownership interest of 44.5 per cent. Refer to Note 26, Other acquisitions and dispositions for further information.

3 Acquired as part of Columbia. Reflects equity earnings from the date of acquisition to December 31, 2016.

4 TCPL has an ownership interest of 60.0 per cent in Sur de Texas, which is a jointly controlled entity resulting in equity accounting.

5 Includes TCPL's share of equity income from TransGas pipeline and Gas Pacifico/INNERGY. In November 2014, the Company sold its interest in Gas Pacifico/INNERGY.

6 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 26, Other acquisitions and dispositions for further information.

7 At December 31, 2016, the difference between the carrying value of the investment and the underlying equity in the net assets of Bruce Power is $942 million (2015 – $973 million) due to the fair value assessment of assets at the time of acquisitions.

On March 7, 2016, TCPL issued notice to the Balancing Pool of the decision to terminate its Sundance B PPA held through ASTC Power Partnership. In accordance with a provision in the PPA, a buyer is permitted to terminate the arrangement if a change in law occurs that makes the arrangement unprofitable or more unprofitable. As a result of changes in law surrounding the Alberta Specified Gas Emitters Regulation, the Company expected increasing costs related to carbon emissions to continue throughout the remaining term of the PPA resulting in increasing unprofitability. As a result, at March 31, 2016, the company recognized a non-cash impairment charge of $29 million ($21 million after tax) in its Energy segment income from equity investments which represented the carrying value of the equity investment in ASTC Partnership. The PPA termination was settled in December 2016.

Distributions received from equity investments for the year ended December 31, 2016 were $1,571 million (2015 – $802 million; 2014 – $738 million) of which $727 million (2015 – $9 million; 2014 – $12 million) were returns of capital and are included in Investing activities in the Consolidated statement of cash flows. The returns of capital were mainly for distributions received from Bruce Power in 2016 from its financing program. Undistributed earnings from equity investments were $198 million and $551 million at December 31, 2015 and December 31, 2014 respectively.

Contributions made to equity investments for the year ended December 31, 2016 were $765 million (2015 – $493 million; 2014 – $256 million) and are included in Investing activities in the Consolidated statement of cash flows.

Summarized Financial Information of Equity Investments

year ended December 31 (millions of Canadian $)	**2016**	**2015**	**2014**
Income			
Revenues	**4,336**	4,337	4,814
Operating and other expenses	**(3,143)**	(3,254)	(3,489)
Net income	**1,080**	1,046	1,264
Net income attributable to TCPL	**514**	440	522

at December 31 (millions of Canadian $)	**2016**	**2015**
Balance Sheet		
Current assets	**1,669**	1,530
Non-current assets	**15,853**	13,190
Current liabilities	**(1,120)**	(1,370)
Non-current liabilities	**(5,867)**	(3,116)

10. 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. Rate-regulated businesses account for and report assets and liabilities consistent with the economic impact of the way in which regulators establish rates, provided the rates established are designed to recover the costs of providing the regulated service and the competitive environment makes it probable that such rates can be charged and collected. Certain expenses and credits subject to utility regulation or rate determination normally reflected in the income statement are deferred on the balance sheet and are recognized in the income statement as the related amounts are included in service rates and recovered from or refunded to customers.

Canadian Regulated Operations

TCPL's Canadian natural gas 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. The Company's significant Canadian natural gas pipelines are described below.

NGTL System

In April 2016, the NEB approved the NGTL System's 2016-2017 Revenue Requirement Settlement. The terms of the two-year settlement include an ROE of 10.1 per cent on 40 per cent deemed equity, a continuation of the 2015 depreciation rates, a mechanism for sharing variances above and below a fixed annual operating, maintenance and administration (OM&A) cost amount and flow-through treatment of all other costs.

The NGTL System's 2015 results reflect the terms of the 2015 Revenue Requirement Settlement. This one year settlement included a 10.1 per cent ROE on deemed common equity of 40 per cent, a continuation of the 2014 depreciation rates, a mechanism for sharing variances above and below a fixed annual OM&A cost amount that was based on an escalation of 2014 actual costs and flow-through treatment of all other costs.

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

Canadian Mainline

The Canadian Mainline currently operates under the terms of the 2015-2030 Tolls Application approved in 2014 (the NEB 2014 Decision). The terms of the settlement 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. A toll review filing will be required for the 2018 to 2020 period.

The Canadian Mainline's 2014 results reflect the terms of 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 fixed tolls through use of the LTAA as well as 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 NEB 2013 Decision provided an opportunity to generate incentive earnings by increasing revenues and reducing costs.

U.S. Regulated Operations

TCPL's U.S. natural gas pipelines operate 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, including the regulation of tariffs which incorporates maximum and minimum rates for services and allows U.S. natural gas pipelines to discount or negotiate rates on a non-discriminatory basis. The Company's significant regulated U.S. natural gas pipelines, based on effective ownership and total operated pipe length, are described below.

Columbia Gas

Columbia Gas' natural gas transportation and storage services are provided under a tariff at rates subject to FERC approval. In 2013, the FERC approved a modernization settlement which provides for cost recovery and return on investment of up to US$1.5 billion over a five-year period to modernize the Columbia Gas system to improve system integrity and enhance service reliability and flexibility. In March 2016, an extension of this settlement was approved by the FERC, which will allow for the cost recovery and return on additional expanded scope investment of US$1.1 billion over a three-year period through 2020.

Columbia Gulf

Columbia Gulf's natural gas transportation services are provided under a tariff at rates subject to FERC approval. In September 2016, the FERC issued an order approving an uncontested settlement following a FERC-initiated rate proceeding pursuant to section 5 of the NGA, which required a reduction in Columbia Gulf's daily maximum recourse rate and addressed treatment of post-retirement benefits other than pensions, pension expense, and regulatory expenses. The FERC order also requires Columbia Gulf to file a general rate case under section 4 of the NGA by January 31, 2020, for rates to take effect by August 1, 2020.

ANR Pipeline Company

ANR Pipeline Company previously operated under rates established pursuant to a settlement approved by the FERC that was effective for all periods presented, beginning in 1997 through July 31, 2016. Effective August 1, 2016, ANR Pipeline Company began operating under new rates pursuant to a FERC-approved rate settlement in September 2016. Under terms of the September 2016 settlement, neither ANR Pipeline Company nor the settling parties can file to change or modify the new settlement rates to become effective earlier than August 1, 2019. However, ANR Pipeline Company is required to file for new rates to be effective no later than August 1, 2022.

Great Lakes

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.

Mexico Regulated Operations

TCPL's Mexican operations are regulated by the CRE and operate in accordance with CRE-approved tariffs. The rates in effect on TCPL's Mexican gas pipelines were established based on CRE-approved contracts that provide for the recovery of costs of providing services.

Regulatory Assets and Liabilities

at December 31 (millions of Canadian $)	2016	2015	Remaining Recovery/ Settlement Period (years)
Regulatory Assets			
Deferred income taxes[1]	**861**	894	n/a
Operating and debt-service regulatory assets[2]	**1**	47	1
Pensions and other post retirement benefits[3]	**382**	210	n/a
Foreign exchange on long-term debt[1,4]	**37**	54	1-13
Other	**74**	64	n/a
	1,355	1,269	
Less: Current portion included in Other current assets (Note 7)	**33**	85	
	1,322	1,184	
Regulatory Liabilities			
Operating and debt-service regulatory liabilities[2]	**47**	32	1
Pensions and other post retirement benefits[3]	**180**	—	n/a
ANR related post-employment and retirement benefits other than pension[5]	**141**	147	n/a
Long term adjustment account[6]	**659**	231	45
Pipeline abandonment costs	**541**	285	n/a
Bridging amortization account[6]	**451**	456	14
Cost of removal[7]	**226**	36	n/a
Other	**54**	16	n/a
	2,299	1,203	
Less: Current portion included in Accounts payable and other (Note 14)	**178**	44	
	2,121	1,159	

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.

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.

4 Foreign exchange on long-term debt of the NGTL System 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.

5 This balance represents what ANR estimated that it would be required to refund to its customers for post-retirement and post-employment benefit amounts collected through its FERC-approved rates that have not been used to pay benefits to its employees since a 1997 rate settlement. Pursuant to a FERC-approved September 2016 rate settlement, $106 million of the regulatory liability balance that accumulated between January 2007 and July 2016 will be resolved through a refund of $53 million to its customers and ANR amortizing $53 million over a three year period that began August 1, 2016. A remaining $41 million balance accumulated prior to 2007 is subject to resolution through future regulatory proceedings, and accordingly a settlement period cannot be determined at this time.

6 These regulatory accounts are used to capture Canadian Mainline revenue and cost variances and stabilize tolls during the 2015-2030 settlement term.

7 This balance represents anticipated costs of removal that have been, and continue to be, included in depreciation rates and collected in the service rates of certain rate-regulated subsidiaries for future costs to be incurred.

11. GOODWILL

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

(millions of Canadian $)	U.S. Natural Gas Pipelines	Energy	Total
Balance at January 1, 2015	3,074	960	4,034
Foreign exchange rate changes	593	185	778
Balance at December 31, 2015	3,667	1,145	4,812
Acquisition of Columbia (Note 5)	**10,078**	**—**	**10,078**
Impairment charge	**—**	**(1,085)**	**(1,085)**
Foreign exchange rate changes	**213**	**(60)**	**153**
Balance at December 31, 2016	**13,958**	**—**	**13,958**

As a result of information received during the process to monetize the Company's U.S. Northeast power business in the third quarter 2016, it was determined that the fair value of Ravenswood did not exceed its carrying value, including goodwill. The fair value of the reporting unit was determined using a combination of methods including a discounted cash flow approach and a range of expected consideration from a potential sale. The expected cash flows were discounted using a risk-adjusted discount rate to determine the fair value. As a result, the Company recorded a goodwill impairment charge on the full carrying value of Ravenswood goodwill of $1,085 million ($656 million after tax) within the Energy segment. The impairment charge was recorded prior to reclassification to Assets held for sale. Refer to Note 6, Assets held for sale for further detail.

At December 31, 2016, TCPL's Goodwill included US$573 million (2015 – US$573 million) related to the Great Lakes natural gas transportation business. During 2015, TCPL's share of this goodwill (net of non-controlling interests) increased by US$143 million, to US$386 million, as a result of a 2015 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 was proportionately lower compared to the 46.45 per cent 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.

At December 31, 2016, 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 using a discounted cash flow analysis in its most recent valuation. Assumptions used in the analysis regarding Great Lakes' ability to realize long-term value in the North American energy market included the impact of 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. Although evolving market conditions and other factors relevant to Great Lakes' long term financial performance have remained relatively stable, there is a risk that reductions in future cash flow forecasts or adverse changes in other key assumptions could result in a future impairment of a portion of the goodwill balance relating to Great Lakes.

At December 31, 2016, the estimated fair value of ANR exceeded its carrying value by less than 10 per cent. The fair value of this reporting unit was measured using a discounted cash flow analysis. Assumptions regarding ANR's ability to realize long-term value depend upon trends in value for its storage services, continued growth in its asset base and favourable outcomes of future rate proceedings. The Company reduced long-term forecast cash flows from the reporting unit as compared to those utilized in previous impairment tests thereby reflecting the continued changes in the business environment. 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 ANR. The goodwill balance related to ANR at December 31, 2016 was US$1.9 billion (2015 – US$1.9 billion).

12. INTANGIBLE AND OTHER ASSETS

at December 31 (millions of Canadian $)	2016	2015
Capital projects in development	**2,094**	1,814
Deferred income tax assets (Note 16)	**313**	9
Employee post-retirement benefits (Note 23)	**189**	18
Fair value of derivative contracts (Note 24)	**133**	168
PPAs	**—**	220
Prepaid rent[1]	**—**	230
Loans and advances[1]	**—**	159
Other	**218**	478
	2,947	3,096

1 TCPL held a note receivable from the seller of Ravenswood of $165 million (US$123 million) and $214 million (US$154 million) as at December 31, 2016 and at December 31, 2015, respectively, which bears interest at 6.75 per cent and matures in 2040. As of November 1, 2016, all Ravenswood assets including prepaid rent and the note receivable have been reclassified to Assets held for sale (Note 6). The current portion included in Other current assets was $55 million (US$40 million) at December 31, 2015.

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

	2016			2015		
at December 31 (millions of Canadian $)	Cost	Accumulated Amortization	Net Book Value	Cost	Accumulated Amortization	Net Book Value
Sheerness	—	—	—	585	390	195
Sundance A	—	—	—	225	200	25
	—	—	—	810	590	220

On March 7, 2016, TCPL issued notice to the Balancing Pool of the decision to terminate its Sheerness and Sundance A PPAs. In accordance with a provision in the PPAs, a buyer is permitted to terminate the arrangement if a change in law occurs that makes the arrangement unprofitable or more unprofitable. As a result of recent changes in law surrounding the Alberta Specified Gas Emitters Regulation, the Company expected increasing costs related to carbon emissions to continue throughout the remaining terms of the PPAs resulting in increasing unprofitability. As such, in 2016, the Company recognized a non-cash impairment charge of $211 million ($155 million after tax) in its Energy segment, which represented the carrying value of the PPAs. Upon final settlement of the PPA terminations in December 2016, TCPL transferred to the Balancing Pool a package of environmental credits that were being held to offset the PPA emissions costs and recorded a non-cash charge of $92 million ($68 million after tax) related to the carrying value of these environmental credits.

Amortization expense of $9 million was recognized in the Consolidated statement of income for the year ended December 31, 2016 (2015 and 2014 – $52 million), prior to the termination of the arrangements.

13. NOTES PAYABLE

	2016		2015	
(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	**509**	**0.9%**	697	0.8%
U.S. (2016 – US$197; 2015 – US$376)	**265**	**0.5%**	521	1.1%
	774		1,218	

At December 31, 2016, Notes payable consists of commercial paper issued by the Company, TransCanada American Investments Ltd. (TAIL) and TransCanada PipeLines USA Limited (TCPL USA).

In December 2016, Columbia entered into a new US$1.0 billion credit facility. At December 31, 2016, total committed revolving and demand credit facilities were $11.1 billion (2015 – $8.9 billion). 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, 2016					year ended December 31 (millions of Canadian $) 2016	2015	2014
Amount	**Unused Capacity**	**Borrower**	**Description**	**Matures**	**Cost to maintain**		
$3 billion	$3 billion	TCPL	Committed, syndicated, revolving, extendible credit facility that supports TCPL's Canadian commercial paper program and general corporate purposes	December 2021	**6**	6	6
US$2 billion	US$2 billion	TCPL	Committed, syndicated, revolving, extendible credit facility that supports TCPL's U.S. commercial paper program	December 2017	**1**	—	—
US$1 billion	US$0.9 billion	TCPL USA	Committed, syndicated, revolving, extendible credit facility that is used for TCPL USA general corporate purposes, guaranteed by TCPL	December 2017	**1**	3	2
US$1 billion	US$1 billion	Columbia	Committed, syndicated, revolving, extendible credit facility that is issued for Columbia's general corporate purposes and provides additional liquidity, guaranteed by TCPL	December 2017	**—**	—	—
US$0.5 billion	US$0.5 billion	TAIL	Committed, syndicated, revolving, extendible credit facility that supports TAIL's commercial paper program, guaranteed by TCPL	December 2017	**2**	2	1
$2.1 billion	$0.7 billion	TCPL/TCPL USA	Supports the issuance of letters of credit and provides additional liquidity	Demand	**—**	—	—

At December 31, 2016, the Company's operated affiliates had an additional $0.6 billion (2015 – $0.6 billion) of undrawn capacity on committed credit facilities.

14. ACCOUNTS PAYABLE AND OTHER

at December 31 (millions of Canadian $)	2016	2015
Trade payables	**2,443**	1,506
Fair value of derivative contracts (Note 24)	**607**	926
Unredeemed shares of Columbia	**317**	—
Regulatory liabilities (Note 10)	**178**	44
Other	**331**	185
	3,876	2,661

15. OTHER LONG-TERM LIABILITIES

at December 31 (millions of Canadian $)	2016	2015
Fair value of derivative contracts (Note 24)	**330**	625
Employee post-retirement benefits (Note 23)	**448**	380
Asset retirement obligations	**108**	109
Guarantees (Note 27)	**82**	26
Other	**215**	120
	1,183	1,260

16. INCOME TAXES

Provision for Income Taxes

year ended December 31 (millions of Canadian $)	2016	2015	2014
Current			
Canada	**117**	45	104
Foreign	**40**	92	42
	157	137	146
Deferred			
Canada	**97**	33	307
Foreign	**95**	(135)	377
	192	(102)	684
Income Tax Expense	**349**	35	830

Geographic Components of Income

year ended December 31 (millions of Canadian $)	2016	2015	2014
Canada	**304**	(623)	1,146
Foreign	**618**	(482)	1,678
Income/(Loss) before Income Taxes	**922**	(1,105)	2,824

Reconciliation of Income Tax Expense

year ended December 31 (millions of Canadian $)	2016	2015	2014
Income/(Loss) before income taxes	**922**	(1,105)	2,824
Federal and provincial statutory tax rate	**27%**	26%	25%
Expected income tax expense/(recovery)	**249**	(287)	706
Income tax differential related to regulated operations	**81**	159	129
Foreign tax rate differentials	**(196)**	14	25
Income from equity investments and non-controlling interests	**(68)**	(56)	(38)
Asset impairment charges[1]	**242**	170	—
Non-deductible amounts	**18**	—	—
Tax rate and legislative changes	**—**	34	—
Other	**23**	1	8
Actual Income Tax Expense	**349**	35	830

1 Net of $112 million (2015 - $311 million) attributed to higher foreign tax rates.

Deferred Income Tax Assets and Liabilities

at December 31 (millions of Canadian $)	2016	2015
Deferred Income Tax Assets		
Tax loss and credit carryforwards	**2,049**	1,325
Difference in accounting and tax bases of impaired assets and assets held for sale	**1,168**	916
Regulatory and other deferred amounts	**277**	231
Unrealized foreign exchange losses on long-term debt	**446**	589
Financial instruments	**34**	111
Other	**287**	132
	4,261	3,304
Less: valuation allowance[1]	**1,336**	1,060
	2,925	2,244
Deferred Income Tax Liabilities		
Difference in accounting and tax bases of plant, property and equipment and PPAs	**9,015**	6,441
Equity investments	**905**	656
Taxes on future revenue requirement	**198**	227
Other	**156**	55
	10,274	7,379
Net Deferred Income Tax Liabilities	**7,349**	5,135

1 In 2016, an increase to the valuation allowance of $276 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, unrealized losses on certain impaired assets, certain operating losses and capital losses 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 $)	2016	2015
Deferred Income Tax Assets		
Intangible and other assets (Note 12)	**313**	9
Deferred Income Tax Liabilities		
Deferred income tax liabilities	**7,662**	5,144
Net Deferred Income Tax Liabilities	**7,349**	5,135

At December 31, 2016, the Company has recognized the benefit of unused non-capital loss carryforwards of $1,736 million (2015 – $1,276 million) for federal and provincial purposes in Canada, which expire from 2029 to 2036. In addition, the Company has not recognized the benefit of capital loss carry forwards of $654 million (2015 – $75 million) for federal and provincial purposes in Canada. The Company also has Ontario minimum tax credits of $68 million (2015 – $57 million), which expire from 2027 to 2036.

At December 31, 2016, the Company has recognized the benefit of unused net operating loss carryforwards of US$2,545 million (2015 – US$1,617 million) for federal purposes in the U.S., which expire from 2028 to 2036. The Company has not recognized the benefit of unused net operating loss carryforwards of US$58 million (2015 - nil) for federal purposes in the U.S. The Company also has alternative minimum tax credits of US$37 million (2015 – US$41 million).

At December 31, 2016, the Company has recognized the benefit of unused net operating loss carryforwards of US$54 million (2015 – US$70 million) in Mexico, which expire from 2024 to 2025.

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, 2016 by approximately $481 million (2015 – $308 million) if there had been a provision for these taxes.

Income Tax Payments

Income tax payments of $105 million, net of refunds, were made in 2016 (2015 – payments, net of refunds, of $164 million; 2014 – payments, net of refunds, of $109 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 $)	2016	2015	2014
Unrecognized tax benefit at beginning of year	**13**	13	19
Gross increases – tax positions in prior years	**3**	2	2
Gross decreases – tax positions in prior years	**—**	(2)	(8)
Gross increases – tax positions in current year	**2**	1	1
Settlement	**(1)**	—	—
Lapse of statutes of limitations	**(2)**	(1)	(1)
Unrecognized Tax Benefit at End of Year	**15**	13	13

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 2008. Substantially all material U.S. federal, state and local income tax matters have been concluded for years through 2011.

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, 2016 reflects nil of interest expense and nil for penalties (2015 – $1 million reversal of interest expense and nil for penalties; 2014 – nil of interest expense and nil for penalties). At December 31, 2016, the Company had $4 million accrued for interest expense and nil accrued for penalties (December 31, 2015 – $4 million accrued for interest expense and nil accrued for penalties).

17. LONG-TERM DEBT 1

Outstanding amounts (millions of Canadian $, unless otherwise noted)	Maturity Dates	2016 Outstanding at December 31	2016 Interest Rate[1]	2015 Outstanding at December 31	2015 Interest Rate[1]
TRANSCANADA PIPELINES LIMITED					
Debentures					
Canadian	2017 to 2020	**599**	**10.7%**	599	10.7%
U.S. (2016 and 2015 – US$400)	2021	**536**	**9.9%**	553	9.9%
Medium Term Notes					
Canadian	2017 to 2046	**5,787**	**4.6%**	5,175	5.3%
Senior Unsecured Notes					
U.S. (2016 – US$14,517; 2015 – US$14,641)	2017 to 2045	**19,521**	**5.1%**	20,245	4.8%
Acquisition Bridge Facility (2016 – US$2,006)[2]	2018	**2,693**	**1.9%**	—	—
		29,136		26,572	
NOVA GAS TRANSMISSION LTD.					
Debentures and Notes					
Canadian	2024	**100**	**9.9%**	324	11.5%
U.S. (2016 and 2015 – US$200)	2023	**268**	**7.9%**	276	7.9%
Medium Term Notes					
Canadian	2025 to 2030	**503**	**7.4%**	503	7.4%
U.S. (2016 and 2015 – US$33)	2026	**43**	**7.5%**	44	7.5%
		914		1,147	
TRANSCANADA PIPELINE USA LTD.					
Acquisition Bridge Facility (2016 – US$1,695)[2]	2018	**2,276**	**1.9%**	—	—
COLUMBIA PIPELINE GROUP, INC.					
Senior Unsecured Notes					
U.S. (2016 – US$2,968)[3]	2018 to 2045	**3,985**	**3.7%**	—	—
TC PIPELINES, LP					
Unsecured Loan Facility					
U.S. (2016 – US$158; 2015 – US$200)	2021	**213**	**1.9%**	277	1.6%
Unsecured Term Loan					
U.S. (2016 and 2015 – US$670)	2018	**899**	**1.9%**	927	1.6%
Senior Unsecured Notes					
U.S. (2016 and 2015 – US$694)	2021 to 2025	**932**	**4.7%**	957	4.7%
		2,044		2,161	
ANR PIPELINE COMPANY					
Senior Unsecured Notes					
U.S. (2016 – US$671; 2015 – US$432)	2021 to 2026	**901**	**7.2%**	597	8.9%
GAS TRANSMISSION NORTHWEST LLC					
Unsecured Term Loan					
U.S. (2016 – US$65; 2015 – US$75)	2019	**87**	**1.6%**	104	1.4%
Senior Unsecured Notes					
U.S. (2016 and 2015 – US$250)	2020 to 2035	**335**	**5.6%**	346	5.6%
		422		450	
GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP					
Senior Unsecured Notes					
U.S. (2016 – US$278; 2015 – US$297)	2018 to 2030	**373**	**7.7%**	411	7.8%

Outstanding amounts (millions of Canadian $, unless otherwise noted)	Maturity Dates	2016 Outstanding at December 31	2016 Interest Rate[1]	2015 Outstanding at December 31	2015 Interest Rate[1]
PORTLAND NATURAL GAS TRANSMISSION SYSTEM					
Senior Secured Notes[4]					
U.S. (2016 – US$52; 2015 – US$69)	2018	**70**	**6.0%**	96	6.1%
TUSCARORA GAS TRANSMISSION COMPANY					
Unsecured Term Loan					
U.S. (2016 – US$10)	2019	**13**	**1.9%**	—	—
Senior Secured Notes					
U.S. (2016 – US$12; 2015 – US$16)	2017	**16**	**4.0%**	22	4.0%
		29		22	
		40,150		31,456	
Less: Current portion of Long-term debt		**1,838**		2,547	
		38,312		28,909	

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 These facilities were put in place to finance a portion of the Columbia acquisition and bear interest at London Interbank Offered Rate (LIBOR) plus an applicable margin. Proceeds from the U.S. Northeast power business monetization will be used to repay the majority of these facilities.

3 Certain subsidiaries of Columbia have guaranteed the principal payments of Columbia's senior unsecured notes. Each guarantor of Columbia's obligations is required to comply with covenants under the debt indenture and in the event of default, the guarantors would be obligated to pay the principal and related interest.

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

Principal Repayments

At December 31, 2016, principal repayments on the Long-term debt of the Company for the next five years are approximately as follows:

(millions of Canadian $)	2017	2018	2019	2020	2021
Principal repayments on Long-term debt	1,838	8,941	1,742	2,762	2,165

Long-Term Debt Issued

The Company issued Long-term debt over the three years ended December 31, 2016 as follows:

(millions of Canadian $, unless otherwise noted)					
Company	**Issue Date**	**Type**	**Maturity Date**	**Amount**	**Interest Rate**
TRANSCANADA PIPELINES LIMITED					
	June 2016	Acquisition Bridge Facility[1]	June 2018	US 5,213	Floating
	June 2016	Medium Term Notes	July 2023	300	3.69% [2]
	June 2016	Medium Term Notes	June 2046	700	4.35%
	January 2016	Senior Unsecured Notes	January 2026	US 850	4.875%
	January 2016	Senior Unsecured Notes	January 2019	US 400	3.125%
	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%
TRANSCANADA PIPELINE USA LTD.					
	June 2016	Acquisition Bridge Facility[1]	June 2018	US 1,700	Floating
ANR PIPELINE COMPANY					
	June 2016	Senior Unsecured Notes	June 2026	US 240	4.14%
TUSCARORA GAS TRANSMISSION COMPANY					
	April 2016	Term Loan	April 2019	US 10	Floating
TC PIPELINES, LP					
	September 2015	Unsecured Term Loan	October 2018	US 170	Floating
	March 2015	Senior Unsecured Notes	March 2025	US 350	4.375%
GAS TRANSMISSION NORTHWEST LLC					
	June 2015	Unsecured Term Loan	June 2019	US 75	Floating

1 These facilities were put in place to finance a portion of the Columbia acquisition and bear interest at LIBOR plus an applicable margin. Proceeds from the monetization of the U.S. Northeast power business will be used to repay these facilities.

2 Reflects coupon rate on re-opening of a pre-existing medium term notes (MTN) issue. The MTN were issued at premium to par, resulting in a re-issuance yield of 2.69 per cent.

Long-Term Debt Retired/Repaid

The Company retired/repaid Long-term debt over the three years ended December 31, 2016 as follows:

(millions of Canadian $, unless otherwise noted) Company	Retirement/ Repayment Date	Type	Amount	Interest Rate
TRANSCANADA PIPELINES LIMITED				
	November 2016	Acquisition Bridge Facility[1]	US 3,200	Floating
	October 2016	Medium Term Notes	400	4.65%
	June 2016	Senior Unsecured Notes	US 84	7.69%
	June 2016	Senior Unsecured Notes	US 500	Floating
	January 2016	Senior Unsecured Notes	US 750	0.75%
	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%
NOVA GAS TRANSMISSION LTD.				
	February 2016	Debentures	225	12.20%
	June 2014	Debentures	53	11.20%
GAS TRANSMISSION NORTHWEST LLC				
	June 2015	Senior Unsecured Notes	US 75	5.09%

1 Proceeds from the November 2016 common share issuance and TransCanada's repayment of the Company's discount note, were used to partially repay the Acquisition Bridge Facility. Refer to Note 20, Common Shares and Note 29, Related Party Transactions for further information.

Interest Expense

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

year ended December 31 (millions of Canadian $)	**2016**	**2015**	**2014**
Interest on Long-term debt	**1,765**	1,487	1,317
Interest on Junior subordinated notes (Note 18)	**180**	116	70
Interest on short-term debt	**56**	44	52
Capitalized interest	**(176)**	(280)	(259)
Amortization and other financial charges[1]	**102**	31	55
	1,927	1,398	1,235

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 $1,757 million in 2016 (2015 – $1,295 million; 2014 – $1,160 million) on long-term debt, junior subordinated notes and notes payable, net of interest capitalized.

18. JUNIOR SUBORDINATED NOTES

Outstanding loan amount (millions of Canadian $, unless otherwise noted)	Maturity Date	2016 Outstanding at December 31	2016 Effective Interest Rate	2015 Outstanding at December 31	2015 Effective Interest Rate
TRANSCANADA PIPELINES LIMITED					
U.S. (2016 and 2015 – US$1,000)[1]	2067	**1,342**	**6.4%**	1,382	6.4%
U.S. (2016 and 2015 – US$742)[1, 2]	2075	**996**	**5.5%**	1,027	5.3%
U.S. (2016 – US$1,186)[1, 2]	2076	**1,593**	**6.2%**	—	—
		3,931		2,409	

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

2 The Junior subordinated notes were issued to TransCanada Trust (the Trust), a financing trust subsidiary wholly-owned by TCPL. While the obligations of the Trust are fully and unconditionally guaranteed by TCPL on a subordinated basis, the Trust is not consolidated in TransCanada's financial statements since TCPL does not have a variable interest in the Trust and the only substantive assets of the Trust are junior subordinated notes of TCPL.

In August 2016, TransCanada Trust (the Trust) issued US$1.2 billion of Trust Notes – Series 2016-A (Trust Notes) to third party investors at a fixed interest rate of 5.875 per cent for the first ten years, converting to a floating rate thereafter. All of the issuance proceeds of the Trust were loaned to TCPL for US$1.2 billion of junior subordinated notes of TCPL at an initial fixed rate of 6.125 per cent, including a 0.25 per cent administration charge. The rate will reset commencing August 2026 until August 2046 to the three month LIBOR plus 4.89 per cent per annum; from August 2046 to August 2076 the interest rate will reset to the three month LIBOR plus 5.64 per cent per annum. The junior subordinated notes are callable at TCPL's option at any time on or after August 15, 2026 at 100 per cent of the principal amount plus accrued and unpaid interest to the date of redemption.

In May 2015, the Trust 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 ten years, converting to a floating rate thereafter. All of the issuance proceeds of the Trust were loaned to TCPL for US$750 million of junior subordinated notes of TCPL at an initial fixed 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.

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.

Junior subordinated notes of US$1.0 billion mature in May 2067 and bear interest at a fixed rate of 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 LIBOR plus 2.21 per cent. TCPL has the option to defer payment of interest for periods of up to ten years without giving rise to a default or permitting acceleration of payment under the terms of the junior subordinated notes, however, both TransCanada and TCPL would be prohibited from paying dividends during any such deferral period. The junior subordinated notes are callable at TCPL'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.

19. NON-CONTROLLING INTERESTS

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

at December 31 (millions of Canadian $)	2016	2015
Non-controlling interest in TC PipeLines, LP	**1,596**	1,590
Non-controlling interest in Portland Natural Gas Transmission System	**130**	127
	1,726	1,717

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

year ended December 31 (millions of Canadian $)	2016	2015	2014
Non-controlling interest in TC PipeLines, LP	**215**	(13)	136
Non-controlling interest in Portland Natural Gas Transmission System	**20**	19	15
Non-controlling interest in Columbia Pipeline Partners LP	**17**	—	—
	252	6	151

During 2016, the non-controlling interest in TC PipeLines, LP increased from 72.0 per cent to 73.2 per cent due to periodic issuances of common units in TC PipeLines, LP to third parties under an at-the-market issuance program (ATM program). In 2015, the non-controlling interest in TC PipeLines, LP ranged between 71.7 per cent and 72.0 per cent and, in 2014, between 71.1 per cent and 71.7 per cent.

On July 1, 2016, TCPL acquired Columbia, which included a 53.5 per cent non-controlling interest in CPPL. On November 1, 2016, TCPL announced that it had entered into an agreement to acquire, for cash, all outstanding publicly held common units of CPPL. The transaction is expected to close in the first quarter of 2017 subject to receipt of CPPL unitholder approval and customary closing conditions.

At December 31, 2016, the entire $1,073 million (US$799 million) of TCPL's non-controlling interest in CPPL was recorded as Common units subject to rescission or redemption on the Consolidated balance sheet. The Company classified this non-controlling interest outside of equity because the potential rights of the units are not within the control of the Company.

The non-controlling interest in Portland Natural Gas Transmission System (PNGTS) as at December 31, 2016 represented the 38.3 per cent interest held by third parties (2015 and 2014 – 38.3 per cent). On January 1, 2016, TCPL sold 49.9 per cent of PNGTS to TC PipeLines, LP. Refer to Note 26, Other acquisitions and disposition for further information.

In 2016, TCPL received fees of $4.5 million from TC PipeLines, LP (2015 – $4 million and 2014 – $3 million) and $8 million from PNGTS (2015 – $11 million; 2014 – $8 million) for services provided.

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 was included in the Net income attributable to non-controlling interests in the Consolidated statement of income.

Common Units of TC PipeLines, LP Subject to Rescission

In connection with a late filing of an employee-related Form 8-K with the SEC, in March 2016, TC PipeLines, LP became ineligible to use the then effective shelf registration statement upon filing of its 2015 Annual Report. As a result, it was determined that the purchasers of the 1.6 million common units that were issued from March 8, 2016 to May 19, 2016 under the TC PipeLines, LP ATM program may have a rescission right for an amount equal to the purchase price paid for the units, plus statutory interest and less any distributions paid, upon the return of such units to TC PipeLines, LP. No unitholder has claimed or attempted to exercise any rescission rights to date and these rights expire one year from the date of purchase of the unit.

At December 31, 2016, $106 million (US$82 million) was recorded as Common units subject to rescission or redemption on the Consolidated balance sheet. The Company classified these 1.6 million common units outside equity because the potential rescission rights of the units are not within the control of the Company.

20. COMMON SHARES

	Number of Shares (thousands)	Amount (millions of Canadian $)
Outstanding at January 1, 2014	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
Issuance of common shares for cash	**79,656**	**4,661**
Outstanding at December 31, 2016	**859,135**	**20,981**

Common Shares Issued and Outstanding

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

On June 28, 2016, the Company issued 43.3 million common shares to TransCanada. The proceeds of approximately $2.5 billion were used to finance the acquisition of Columbia.

In November 2016, the Company issued 33.6 million common shares to TransCanada. The proceeds of approximately $2.0 billion were used to partially repay the Acquisition Bridge Facility.

In December 2016, the Company issued an additional 2.8 million common shares to TransCanada for proceeds of $175 million.

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, 2016 these terms limit the Company from paying dividends in excess of $9.7 billion (2015 – $4.1 billion ; 2014 – $8.7 billion). Under the agreements, TCPL can adjust this limit throughout the year if required, at its 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.

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

year ended December 31	2016	2015	2014
Weighted average fair value	**$5.67**	$6.45	$5.54
Expected life (years)	**5.8**	5.8	6.0
Interest rate	**0.7%**	1.1%	1.8%
Volatility[1]	**21%**	18%	17%
Dividend yield	**4.9%**	3.7%	3.8%
Forfeiture rate	**5%**	5%	5%

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 $15 million in 2016 (2015 – $13 million; 2014 – $7 million).

The following table summarizes additional stock option information:

year ended December 31 (millions of Canadian $, unless otherwise noted)	**2016**	**2015**	**2014**
Total intrinsic value of options exercised	**31**	10	21
Fair value of options that have vested	**126**	91	95
Total options vested	**2.1 million**	2.0 million	1.7 million

As at December 31, 2016, the aggregate intrinsic value of the total options exercisable was $86 million and the total intrinsic value of options outstanding was $130 million.

21. 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.

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

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

year ended December 31, 2016 (millions of Canadian $)	**Before Tax Amount**	**Income Tax Recovery/ (Expense)**	**Net of Tax Amount**
Foreign currency translation gains on net investment in foreign operations	**3**	**—**	**3**
Change in fair value of net investment hedges	**(14)**	**4**	**(10)**
Change in fair value of cash flow hedges	**44**	**(14)**	**30**
Reclassification to net income of gains and losses on cash flow hedges	**71**	**(29)**	**42**
Unrealized actuarial gains and losses on pension and other post-retirement benefit plans	**(38)**	**12**	**(26)**
Reclassification to net income of actuarial loss on pension and other post-retirement benefit plans	**22**	**(6)**	**16**
Other comprehensive loss on equity investments	**(117)**	**30**	**(87)**
Other Comprehensive Loss	**(29)**	**(3)**	**(32)**

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 loss 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 loss 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)

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, 2014	(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	—	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)
Other comprehensive income/(loss) before reclassifications[2]	**7**	**27**	**(26)**	**(101)**	**(93)**
Amounts reclassified from accumulated other comprehensive loss[3]	**—**	**42**	**16**	**14**	**72**
Net current period other comprehensive income/(loss)	**7**	**69**	**(10)**	**(87)**	**(21)**
AOCI balance at December 31, 2016	**(376)**	**(28)**	**(208)**	**(348)**	**(960)**

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

2 Other comprehensive (loss)/income before reclassifications on currency translation adjustments and cash flow hedges is net of non-controlling interest losses of $14 million (2015 – $306 million gains; 2014 – $130 million gains) and gains of $3 million (2015 and 2014 - nil), respectively in 2016.

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 $5 million ($3 million, net of tax) at December 31, 2016. 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 (millions of Canadian $)	Amounts Reclassified From Accumulated Other Comprehensive Loss[1] 2016	 2015	 2014	Affected Line Item in the Consolidated Statement of Income
Cash flow hedges				
Commodities	**(57)**	(128)	111	Revenues (Energy)
Interest	**(14)**	(16)	(16)	Interest expense
	(71)	(144)	95	Total before tax
	29	56	(40)	Income tax expense/(recovery)
	(42)	(88)	55	Net of tax
Pension and other post-retirement benefit plan adjustments				
Amortization of actuarial loss and past service cost	**(22)**	(41)	(25)	Plant operating costs and other[2]
	6	9	7	Income tax expense
	(16)	(32)	(18)	Net of tax
Equity investments				
Equity income	**(19)**	(19)	(2)	Income from equity investments
	5	5	—	Income tax expense
	(14)	(14)	(2)	Net of tax

1 All amounts in parentheses indicate expenses to the Consolidated statement of income.
2 These AOCI components are included in the computation of net benefit cost. Refer to Note 23, Employee post-retirement benefits for further information.

23. 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, 2016 (2015 and 2014 – 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, 2016 (2015 – 12 years; 2014 – 12 years). In 2016, the Company expensed $52 million (2015 – $41 million; 2014 – $37 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 $)	2016	2015	2014
DB Plans	**111**	96	73
Other post-retirement benefit plans	**8**	6	6
Savings and DC Plans	**52**	41	37
	171	143	116

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 $20 million letter of credit to the Canadian DB Plan in 2016 (2015 – $33 million; 2014 – $47 million), resulting in a total of $233 million provided to the Canadian DB Plan under letters of credit at December 31, 2016.

The most recent actuarial valuation of the pension plans for funding purposes was as at January 1, 2016 and the next required valuation will be as at January 1, 2017.

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 $)	**2016**	**2015**	**2016**	**2015**
Change in Benefit Obligation[1]				
Benefit obligation – beginning of year	**2,780**	2,658	**225**	216
Service cost	**107**	108	**3**	3
Interest cost	**127**	115	**13**	10
Employee contributions	**4**	4	**2**	—
Benefits paid	**(204)**	(129)	**(16)**	(7)
Actuarial loss/(gain)	**111**	(57)	**(8)**	(11)
Acquisition of Columbia	**527**	—	**151**	—
Settlement loss	**2**	—	**—**	—
Foreign exchange rate changes	**2**	81	**2**	14
Benefit obligation – end of year	**3,456**	2,780	**372**	225
Change in Plan Assets				
Plan assets at fair value – beginning of year	**2,591**	2,398	**45**	39
Actual return on plan assets	**227**	160	**14**	(1)
Employer contributions[2]	**111**	96	**8**	6
Employee contributions	**4**	4	**2**	—
Benefits paid	**(204)**	(129)	**(16)**	(7)
Acquisition of Columbia	**475**	—	**294**	—
Foreign exchange rate changes	**4**	62	**7**	8
Plan assets at fair value – end of year	**3,208**	2,591	**354**	45
Funded Status – Plan Deficit	**(248)**	(189)	**(18)**	(180)

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 $233 million in letters of credit provided to the Canadian DB Plans for funding purposes (2015 – $214 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 $)	**2016**	**2015**	**2016**	**2015**
Intangible and other assets (Note 12)	**—**	—	**189**	18
Accounts payable and other	**—**	—	**(7)**	(7)
Other long-term liabilities (Note 15)	**(248)**	(189)	**(200)**	(191)
	(248)	(189)	**(18)**	(180)

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 $)	**2016**	**2015**	**2016**	**2015**
Projected benefit obligation[1]	**(3,456)**	(2,780)	**(207)**	(198)
Plan assets at fair value	**3,208**	2,591	**—**	—
Funded Status – Plan Deficit	**(248)**	(189)	**(207)**	(198)

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 $)	2016	2015
Accumulated benefit obligation	**(3,202)**	(2,600)
Plan assets at fair value	**3,208**	2,591
Funded Status – Plan Surplus/(Deficit)	**6**	(9)

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 $)	2016	2015
Accumulated benefit obligation	**(990)**	(807)
Plan assets at fair value	**868**	680
Funded Status – Plan Deficit	**(122)**	(127)

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	2016	2015	2016
Debt securities	**31%**	34%	**25% to 40%**
Equity securities	**63%**	66%	**45% to 75%**
Alternatives	**6%**	—	**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 $)	2016	2015	2016	2015
Debt securities	**9**	2	**0.2%**	0.1%
Equity securities	**4**	4	**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 24, Risk management and financial instruments.

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 $)	**2016**	2015	**2016**	2015	**2016**	2015	**2016**	2015	**2016**	2015
Asset Category										
Cash and Cash Equivalents	**22**	44	**12**	2	**—**	—	**34**	46	**1**	2
Equity Securities:										
Canadian	**388**	317	**143**	147	**—**	—	**531**	464	**15**	17
U.S.	**504**	589	**476**	40	**—**	—	**980**	629	**27**	24
International	**39**	38	**327**	300	**—**	—	**366**	338	**10**	13
Global	**—**	—	**235**	154	**—**	—	**235**	154	**7**	6
Emerging	**7**	7	**137**	143	**—**	—	**144**	150	**4**	6
Fixed Income Securities:										
Canadian Bonds:										
Federal	**—**	—	**192**	206	**—**	—	**192**	206	**5**	8
Provincial	**—**	—	**179**	202	**—**	—	**179**	202	**5**	8
Municipal	**—**	—	**8**	7	**—**	—	**8**	7	**—**	—
Corporate	**—**	—	**126**	113	**—**	—	**126**	113	**4**	4
U.S. Bonds:										
Federal	**—**	—	**82**	—	**—**	—	**82**	—	**2**	—
State	**—**	—	**41**	50	**—**	—	**41**	50	**1**	2
Municipal	**—**	—	**39**	—	**—**	—	**39**	—	**1**	—
Corporate	**—**	—	**188**	57	**—**	—	**188**	57	**5**	2
International:										
Government	**—**	—	**6**	—	**—**	—	**6**	—	**—**	—
Corporate	**—**	—	**21**	25	**—**	—	**21**	25	**1**	1
Mortgage backed	**—**	—	**62**	58	**—**	—	**62**	58	**2**	2
Other Investments:										
Real Estate	**—**	—	**—**	—	**133**	—	**133**	—	**4**	—
Infrastructure	**—**	—	**—**	—	**58**	—	**58**	—	**2**	—
Private equity funds	**—**	—	**—**	—	**8**	14	**8**	14	**—**	—
Funds held on deposit	**129**	123	**—**	—	**—**	—	**129**	123	**4**	5
	1,089	1,118	**2,274**	1,504	**199**	14	**3,562**	2,636	**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, 2014	13
Purchases and sales	(1)
Realized and unrealized gains	2
Balance at December 31, 2015	14
Purchases and sales	**183**
Realized and unrealized gains	**2**
Balance at December 31, 2016	**199**

The Company's expected funding contributions in 2017 are approximately $100 million for the DB Plans, approximately $7 million for the other post-retirement benefit plans and approximately $51 million for the savings plan and DC Plans. The Company expects to provide an additional estimated $20 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
2017	178	19
2018	183	19
2019	189	20
2020	196	20
2021	200	20
2022 to 2026	1,067	97

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, 2016. 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	**2016**	**2015**	**2016**	**2015**
Discount rate	**4.00%**	4.20%	**4.15%**	4.40%
Rate of compensation increase	**1.20%**	0.50%	—	—

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	**2016**	**2015**	**2014**	**2016**	**2015**	**2014**
Discount rate	**4.20%**	4.15%	4.95%	**4.30%**	4.20%	5.00%
Expected long-term rate of return on plan assets	**6.70%**	6.95%	6.90%	**5.95%**	4.60%	4.60%
Rate of compensation increase	**0.80%**	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.

An eight per cent weighted average annual rate of increase in the per capita cost of covered health care benefits was assumed for 2017 measurement purposes. The rate was assumed to decrease gradually to five per cent by 2024 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	15	(13)

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

at December 31	Pension Benefit Plans			Other Post-Retirement Benefit Plans		
(millions of Canadian $)	2016	2015	2014	2016	2015	2014
Service cost	**107**	108	85	**3**	3	2
Interest cost	**127**	115	113	**13**	10	10
Expected return on plan assets	**(175)**	(155)	(139)	**(11)**	(2)	(2)
Amortization of actuarial loss	**20**	35	21	**2**	3	2
Amortization of past service cost	**—**	2	2	**—**	1	—
Amortization of regulatory asset	**27**	23	18	**1**	1	1
Amortization of transitional obligation related to regulated business	**—**	—	—	**2**	2	2
Net Benefit Cost Recognized	**106**	128	100	**10**	18	15

Pre-tax amounts recognized in AOCI were as follows:

at December 31	2016		2015		2014	
(millions of Canadian $)	Pension Benefits	Other Post-Retirement Benefits	Pension Benefits	Other Post-Retirement Benefits	Pension Benefits	Other Post-Retirement Benefits
Net loss	**268**	**23**	247	28	348	39
Prior service cost	**—**	**—**	—	—	2	1
	268	**23**	247	28	350	40

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 2017 is $20 million and $2 million, respectively.

Pre-tax amounts recognized in OCI were as follows:

at December 31	2016		2015		2014	
(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	**(20)**	**(2)**	(34)	(4)	(21)	(2)
Amortization of prior service costs from AOCI to OCI	**—**	**—**	(2)	(1)	(2)	—
Funded status adjustment	**43**	**(5)**	(67)	(7)	137	9
	23	**(7)**	(103)	(12)	114	7

24. 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 assesses contracts used to manage market risk to determine whether all, or a portion, meets the definition of a derivative.

Derivative contracts the Company uses to assist in managing the exposure to market risk 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 interest rates, 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.

Liquids marketing commodity price risk

The liquids marketing business began operations in 2016. TCPL enters into short-term or long-term pipeline and storage terminal capacity contracts, primarily on the Company's assets, increasing the utilization of those assets and earning the market value of the capacity. Derivative instruments are used to fix a portion of the variable price exposures that arise from physical liquids transactions.

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. TCPL generates revenues and incurs expenses that are denominated in currencies other than Canadian dollars. As a result, our earnings and cash flows are expected to fluctuate.

A portion of TCPL's earnings from its U.S. Natural Gas Pipelines, Mexico 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. This foreign exchange impact is partially offset by interest expense on U.S. dollar-denominated debt 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 and foreign exchange forward contracts and foreign exchange options.

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

The notional amounts and fair value of U.S. dollar-denominated debt designated as a net investment hedge were as follows:

at December 31 (millions of Canadian $, unless otherwise noted)	2016	2015
Notional amount	**26,600 (US 19,800)**	23,100 (US 16,700)
Fair value	**29,400 (US 21,900)**	23,800 (US 17,200)

Derivatives Designated as a Net Investment Hedge

The fair values and notional or principal amounts for the derivatives designated as a net investment hedge were as follows:

at December 31 (millions of Canadian $, unless otherwise noted)	2016 Fair Value[1]	2016 Notional or Principal Amount	2015 Fair Value[1]	2015 Notional or Principal Amount
U.S. dollar cross-currency interest rate swaps (maturing 2017 to 2019)[2]	**(425)**	**US 2,350**	(730)	US 3,150
U.S. dollar foreign exchange forward contracts (maturing 2017)	**(7)**	**US 150**	50	US 1,800
	(432)	**US 2,500**	(680)	US 4,950

1 Fair values equal carrying values.
2 In 2016, net realized gains of $6 million (2015 – gains of $8 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, 2016, without taking into account security held, consisted of cash and cash equivalents, 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, 2016, 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 $200 million (US$149 million) and $248 million (US$179 million) at December 31, 2016 and 2015, 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.

For TCPL's Canadian regulated gas pipeline assets, counterparty credit risk is managed through application of tariff provisions as approved by the NEB.

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:

at December 31 (millions of Canadian $)	2016		2015	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Notes receivable[1]	**165**	**211**	214	265
Current and Long-term debt[2,3] (Note 17)	**(40,150)**	**(45,047)**	(31,456)	(34,309)
Junior subordinated notes (Note 18)	**(3,931)**	**(3,825)**	(2,409)	(2,011)
	(43,916)	**(48,661)**	(33,651)	(36,055)

1 Notes receivable are included in Assets held for sale on the Consolidated balance sheet at December 31, 2016 and in Other current assets and Intangible and other assets on the Consolidated balance sheet at December 31, 2015. The fair value is calculated based on the original contract terms.

2 Long-term debt is recorded at amortized cost, except for US$850 million (2015 – US$850 million) that is attributed to hedged risk and recorded at fair value.

3 Consolidated net income in 2016 included unrealized gains of $2 million (2015 – gains of $2 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, 2016 (2015 – US$850 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:

(millions of Canadian $)	2016 LMCI Restricted Investments[2]	2016 Other Restricted Investments[3]	2015 LMCI Restricted Investments[2]	2015 Other Restricted Investments[3]
Fair values[1]				
Fixed income securities (maturing within 1 year)	**—**	**19**	—	26
Fixed income securities (maturing within 1-5 years)	**—**	**117**	—	64
Fixed income securities (maturing within 5-10 years)	**9**	**—**	—	—
Fixed income securities (maturing after 10 years)	**513**	**—**	261	—
Total fair value at December 31	**522**	**136**	261	90
Net unrealized losses for the year ended December 31	**(28)**	**(1)**	—	—

1 Available for sale assets are recorded at fair value and included in Other current assets and Restricted investments on the Consolidated balance sheet.
2 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 records these gains and losses as regulatory assets or liabilities.
3 Other restricted investments have been set aside to fund insurance claim losses to be paid by the Company's wholly-owned captive insurance subsidiary. Unrealized gains and losses on other restricted investments are included in OCI.

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.

The recognition of gains and losses on derivatives for Canadian natural gas regulated pipeline 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 or refunded 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.

Balance Sheet Presentation of Derivative Instruments

The balance sheet classification of the fair value of the derivative instruments as at December 31, 2016 is as follows:

at December 31, 2016 (millions of Canadian $)	Cash Flow Hedges	Fair Value Hedges	Net Investment Hedges	Held for Trading	Total Fair Value of Derivative Instruments[1]
Other current assets (Note 7)					
Commodities[2]	6	—	—	351	357
Foreign exchange	—	—	6	10	16
Interest rate	1	1	—	1	3
	7	1	6	362	376
Intangible and other assets (Note 12)					
Commodities[2]	4	—	—	118	122
Foreign exchange	—	—	10	—	10
Interest rate	1	—	—	—	1
	5	—	10	118	133
Total Derivative Assets	12	1	16	480	509
Accounts payable and other (Note 14)					
Commodities[2]	—	—	—	(330)	(330)
Foreign exchange	—	—	(237)	(38)	(275)
Interest rate	(1)	(1)	—	—	(2)
	(1)	(1)	(237)	(368)	(607)
Other long-term liabilities (Note 15)					
Commodities[2]	—	—	—	(118)	(118)
Foreign exchange	—	—	(211)	—	(211)
Interest rate	—	(1)	—	—	(1)
	—	(1)	(211)	(118)	(330)
Total Derivative Liabilities	(1)	(2)	(448)	(486)	(937)

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

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	Fair Value Hedges	Net Investment Hedges	Held for Trading	Total Fair Value of Derivative Instruments[1]
Other current assets (Note 7)					
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 12)					
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 14)					
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 15)					
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 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 maturity and notional principal or quantity outstanding related to the Company's derivative instruments excluding hedges of the net investment in foreign operations is as follows:

at December 31, 2016	Power	Natural Gas	Liquids	Foreign Exchange	Interest
Purchases[1]	**86,887**	**182**	**6**	**—**	**—**
Sales[1]	**58,561**	**147**	**6**	**—**	**—**
Millions of dollars	**—**	**—**	**—**	**US 2,394**	**US 1,550**
Maturity dates	**2017-2021**	**2017-2020**	**2017**	**2017**	**2017-2019**

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

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.

Unrealized and Realized Gains/(Losses) of Derivative Instruments

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

year ended December 31 (millions of Canadian $)	2016	2015
Derivative instruments held for trading[1]		
Amount of unrealized gains/(losses) in the year		
Commodities[2]	**123**	(37)
Foreign exchange	**25**	(21)
Amount of realized (losses)/gains in the year		
Commodities	**(204)**	(151)
Foreign exchange	**62**	(112)
Derivative instruments in hedging relationships		
Amount of realized (losses)/gains in the year		
Commodities	**(167)**	(179)
Foreign exchange	**(101)**	—
Interest rate	**4**	8

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 Following the March 17, 2016 announcement of the Company's intention to sell the U.S. Northeast power assets, losses of $49 million and gains of $7 million (2015 - nil) were recorded in net income in 2016 relating to discontinued cash flow hedges where it was probable that the anticipated underlying transaction would not occur as a result of a future sale.

Derivatives in cash flow hedging relationships

The components of OCI (Note 22) related to derivatives in cash flow hedging relationships including the portion attributable to non-controlling interests are as follows:

year ended December 31 (millions of Canadian $, pre-tax)	2016	2015
Change in fair value of derivative instruments recognized in OCI (effective portion)[1]		
Commodities[2]	**39**	(92)
Interest rate[3]	**5**	—
	44	(92)
Reclassification of gains on derivative instruments from AOCI to Net income (effective portion)[1]		
Commodities[2]	**57**	128
Interest rate[3]	**14**	16
	71	144
Losses on derivative instruments recognized in Net income (ineffective portion)		
Commodities[2]	**—**	—

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, 2016 (millions of Canadian $)	**Gross Derivative Instruments Presented on the Balance Sheet**	**Amounts Available for Offset**[1]	**Net Amounts**
Derivative – Asset			
Commodities	**479**	**(362)**	**117**
Foreign exchange	**26**	**(26)**	**—**
Interest rate	**4**	**(1)**	**3**
	509	**(389)**	**120**
Derivative – Liability			
Commodities	**(448)**	**362**	**(86)**
Foreign exchange	**(486)**	**26**	**(460)**
Interest rate	**(3)**	**1**	**(2)**
	(937)	**389**	**(548)**

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, 2015:

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.

With respect to the derivative instruments presented above as at December 31, 2016, the Company had provided cash collateral of $305 million (2015 – $482 million) and letters of credit of $27 million (2015 – $41 million) to its counterparties. The Company held nil (2015 – nil) in cash collateral and $3 million (2015 – $2 million) in letters of credit from counterparties on asset exposures at December 31, 2016.

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, 2016, the aggregate fair value of all derivative instruments with credit-risk-related contingent features that were in a net liability position was $19 million (2015 – $32 million), for which the Company has provided collateral in the normal course of business of nil (2015 – nil). If the credit-risk-related contingent features in these agreements were triggered on December 31, 2016, the Company would have been required to provide additional collateral of $19 million (2015 – $32 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 derivative's fair value. This category mainly includes long-dated commodity transactions in certain markets where liquidity is low and the Company uses the most observable inputs available or, if not available, long-term broker quotes to estimate the fair value for these transactions. Valuation of options is based on the Black-Scholes pricing model. 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 2016, are categorized as follows:

at December 31, 2016 (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	**134**	**326**	**19**	**479**
Foreign exchange	—	**26**	—	**26**
Interest rate	—	**4**	—	**4**
Derivative Instrument Liabilities:				
Commodities	**(102)**	**(343)**	**(3)**	**(448)**
Foreign exchange	—	**(486)**	—	**(486)**
Interest rate	—	**(3)**	—	**(3)**
	32	**(476)**	**16**	**(428)**

1 There were no transfers from Level I to Level II or from Level II to Level III for the year ended December 31, 2016.

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 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)	2016	2015
Balance at beginning of year	**9**	4
Total gains included in Net income	**13**	3
Sales	**(3)**	(2)
Settlements	**(2)**	(1)
Transfers out of Level III	**(1)**	5
Balance at end of year[1]	**16**	9

1 Revenues include unrealized gains attributed to derivatives in the Level III category that were still held at December 31, 2016 of $7 million (2015 – $7 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, 2016.

25. CHANGES IN OPERATING WORKING CAPITAL

year ended December 31 (millions of Canadian $)	2016	2015	2014
Increase in Accounts receivable	**(487)**	(19)	(205)
Increase in Inventories	**(87)**	(3)	(27)
Increase in Assets held for sale	**(13)**	—	—
Decrease/(increase) in Other current assets	**328**	(273)	(386)
Increase/(decrease) in Accounts payable and other	**432**	(103)	393
Increase in Accrued interest	**62**	91	36
Increase in Liabilities related to assets held for sale	**16**	—	—
Decrease/(increase) in Operating Working Capital	**251**	(307)	(189)

26. OTHER ACQUISITIONS AND DISPOSITIONS

U.S. Natural Gas Pipelines

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. Proceeds were comprised of US$188 million in cash and the assumption of US$35 million of a proportional share of PNGTS debt.

TC Offshore LLC

On March 1, 2016, the Company closed the sale of TC Offshore LLC. This resulted in an additional loss on disposal of $4 million pre-tax which is included in (Loss)/gain on sale of assets held for sale/sold in the Consolidated statement of income.

Iroquois Gas Transmission System LP

On March 31, 2016, TCPL acquired a 4.87 per cent interest in Iroquois for an aggregate purchase price of US$54 million, increasing TCPL's interest in Iroquois to 49.35 per cent. On May 1, 2016, the Company acquired an additional 0.65 per cent interest for an aggregate purchase price of US$7 million, further increasing TCPL's interest in Iroquois to 50 per cent.

Gas Transmission Northwest LLC

In April 2015, TCPL completed the sale of its remaining 30 per cent interest in 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 of a proportional share of GTN debt and US$95 million of new Class B units of TC PipeLines, LP.

Bison Pipeline LLC

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

Mexico Natural Gas Pipelines

Gas Pacifico/INNERGY

In November 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

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$653 million in cash after post-acquisition adjustments. The Ironwood power plant delivers energy into the PJM power market. The evaluation of assigned fair value of acquired assets and liabilities did not result in the recognition of goodwill. The Company began consolidating Ironwood as of the date of acquisition which has not had a material impact on the Revenues and Net income of the Company. In addition, the pro forma incremental impact on the Company's Revenues and Net income for each of the periods presented is not material. At December 31, 2016, Ironwood is classified as an asset held for sale. Refer to Note 6, Assets held for sale for further information.

Bruce Power

In December 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 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. In December 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 resulting 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. All power produced by the solar facilities is sold under 20-year PPAs with the Ontario Power Authority.

Cancarb

In April 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).

27. COMMITMENTS, CONTINGENCIES AND GUARANTEES

Commitments

Operating leases

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

year ended December 31 (millions of Canadian $)	Minimum Lease Payments	Amounts Recoverable under Subleases	Net Payments
2017	129	5	124
2018	122	4	118
2019	106	2	104
2020	69	2	67
2021	69	1	68
2022 and thereafter	621	3	618
	1,116	17	1,099

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 2016 was $145 million (2015 – $131 million; 2014 – $114 million).

TCPL's commitments at December 31, 2016 include future payments related to our U.S. Northeast power business. At the close of the sale of Ravenswood, TCPL's commitments are expected to decrease by $54 million in 2017 and 2018, $35 million in 2019 and $106 million in 2022 and beyond.

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, 2016, TCPL was committed to Canadian Natural Gas Pipelines capital expenditures totaling approximately $0.8 billion (2015 – $0.5 billion), primarily related to construction costs associated with the NGTL System natural gas pipeline projects.

At December 31, 2016, TCPL was committed to U.S. Natural Gas Pipelines capital expenditures totaling approximately $0.1 billion (2015 – $0.2 billion), primarily related to construction costs associated with the ANR natural gas pipeline projects.

At December 31, 2016, TCPL was committed to Mexico Natural Gas Pipelines capital expenditures totaling approximately $2.1 billion (2015 – $0.2 billion), primarily related to construction on the Sur de Texas, Tula and Villa de Reyes Mexico gas pipeline projects.

At December 31, 2016, the Company was committed to Liquids Pipelines capital expenditures totaling approximately $0.2 billion (2015 – $0.8 billion), primarily related to construction costs of Northern Courier.

At December 31, 2016, the Company was committed to Energy capital expenditures totaling approximately $0.5 billion (2015 – $0.6 billion), primarily related to construction costs of the Napanee Generating Station.

At December 31, 2016, the Company was committed to Corporate expenditures totaling approximately $0.2 billion (2015 – $0.1 billion), primarily related to an information technology services agreement.

Contingencies

TCPL is subject to laws and regulations governing environmental quality and pollution control. As at December 31, 2016, the Company had accrued approximately $39 million (2015 – $32 million; 2014 – $31 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. The amounts involved in such proceedings are not reasonably estimable as the final outcome of such legal proceedings cannot be predicted with certainty. It is the opinion of management that the ultimate resolution of such proceedings and actions, other than the Keystone XL legal proceeding described below, will not have a material impact on the Company's consolidated financial position or results of operations.

In June 2016, TCPL filed a Request for Arbitration in a dispute against the U.S. Government pursuant to the Convention on Settlement of Investment Disputes between States and Nationals of Other States, the Rules of Procedure for the Institution of Conciliation and Arbitration Proceedings and Chapter 11 of the North American Free Trade Agreement (NAFTA). The claim arises out of the November 6, 2015 denial of our application for a Presidential Permit to construct Keystone XL. TCPL has requested an award of damages arising from the U.S. Government's breaches of its NAFTA obligations in an amount of more than US$15 billion together with applicable interest and the costs of arbitration. This arbitration 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.

Guarantees

TCPL and its joint venture partner on Bruce Power, BPC Generation Infrastructure Trust, have each severally guaranteed a contingent financial obligation of Bruce Power related to a lease agreement. The Bruce Power guarantee has a term to 2018.

The Company and its partners in certain jointly owned entities, including Sur de Texas, have either (i) jointly and severally, (ii) jointly or (iii) severally guaranteed the financial performance of these entities. Such agreements include guarantees and letters of credit which are primarily related to delivery of natural gas, construction services including purchase agreements 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		**2016**		**2015**	
(millions of Canadian $)	**Term**	**Potential Exposure**[1]	**Carrying Value**	**Potential Exposure**[1]	**Carrying Value**
Sur de Texas	Ranging to 2040	**805**	**53**	—	—
Bruce Power	Ranging to 2018	**88**	**1**	88	2
Other jointly owned entities	Ranging to 2040	**87**	**28**	139	24
		980	**82**	227	26

1 TCPL's share of the potential estimated current or contingent exposure.

28. CORPORATE RESTRUCTURING COSTS

In mid-2015, the Company commenced a business restructuring and transformation initiative to reduce overall costs and maximize the effectiveness and efficiency of our existing operations.

Restructuring costs consist primarily of severance and expected future losses under lease commitments. In 2015, the Company incurred $122 million before tax of restructuring costs and recorded a provision of $87 million before tax related to planned severance costs in 2016 and 2017 and expected future losses under lease commitments.

In 2016, an additional provision of $44 million before tax was recorded related to changes to the expected future losses under lease commitments. Approximately $157 million and $22 million was recorded in Plant operating costs and other in the Consolidated statement of income for the years ended December 31, 2015 and 2016, respectively. In 2015, $58 million was recorded in Revenues in the Consolidated statement of income related to costs that were recoverable through regulatory and tolling structures. In addition, $44 million and $22 million was recorded as a Regulatory asset on the Consolidated balance sheet at December 31, 2015 and 2016, respectively, as these amounts are expected to be recovered through regulatory and tolling structures in future periods, and $8 million was capitalized in 2015 to projects impacted by the corporate restructuring.

Changes in the restructuring liability were as follows:

(millions of Canadian $)	Employee Severance	Lease Commitments	Total
Restructuring liability as at December 31, 2015	60	27	87
Restructuring charges	—	44	44
Cash payments	(24)	(8)	(32)
Restructuring Liability as at December 31, 2016	**36**	**63**	**99**

29. RELATED PARTY TRANSACTIONS

The following amounts are included in Due from affiliates:

		2016		2015	
(millions of Canadian $)	Maturity Date	Outstanding December 31	Effective Interest Rate	Outstanding December 31	Effective Interest Rate
Discount Notes[1]	November 2016	—	**0.9%**	2,376	0.9%
Credit Facility[2]	Demand	—	—	100	2.7%
		—		2,476	

1 In November 2016, discount notes were repaid in full by TransCanada. Proceeds from the repayment were used to partially repay the Acquisition Bridge Facility.
2 TCPL has an unsecured $3.0 billion credit facility issued to TransCanada. This facility is repayable on demand and bears interest at the prime rate per annum.

In 2016, Interest income and other included $19 million as a result of inter-affiliate lending to TransCanada (2015 - $29 million; 2014 - $37 million).

At December 31, 2016, Accounts receivable included nil due from TransCanada (December 31, 2015 - $13 million).

The following amounts are included in Due to affiliates:

		2016		2015	
(millions of Canadian $)	Maturity Date	Outstanding December 31	Effective Interest Rate	Outstanding December 31	Effective Interest Rate
Credit Facility[1]	December 2016	—	—	311	3.5%
Credit Facility[2]	Demand	**2,358**	**2.7%**	—	—
		2,358		311	

1 TransCanada has an unsecured $3.5 billion credit facility with a subsidiary of TCPL. Interest on this facility is charged at the prime rate per annum.
2 TransCanada has an unsecured $3.0 billion credit facility with TCPL. Interest on this facility is charged at prime rate per annum. This credit facility includes $1.8 billion due to TransCanada related to the acquisition of Columbia. Refer to Note 5, Acquisition of Columbia for more information.

In 2016, Interest expense included $38 million of interest charges as a result of inter-affiliate borrowing (2015 - $28 million; 2014 - $37 million).

At December 31, 2016, Accounts payable and other included $19 million due to TransCanada (December 31, 2015 - $12 million).

The Company made interest payments of $36 million to TransCanada in 2016 (2015 - $29 million; 2014 - $37 million).

30. VARIABLE INTEREST ENTITIES

As a result of the implementation of the new FASB guidance on consolidation, a number of entities controlled by TCPL are now considered to be VIEs. A VIE is a legal entity that does not have sufficient equity at risk to finance its activities without additional subordinated financial support or is structured such that equity investors lack the ability to make significant decisions relating to the entity's operations through voting rights or do not substantively participate in the gains and losses of the entity.

In the normal course of business, the Company consolidates VIEs in which it has a variable interest and for which it is considered to be the primary beneficiary. VIEs in which the Company has a variable interest but is not the primary beneficiary are accounted for as equity investments.

Consolidated VIEs

The Company's consolidated VIEs consist of legal entities where the Company is the primary beneficiary. As the primary beneficiary, the Company has the power, through voting or similar rights, to direct the activities of the VIE that most significantly impact economic performance including purchasing or selling significant assets; maintenance and operations of assets; incurring additional indebtedness; or determining the strategic operating direction of the entity. In addition, the Company has the obligation to absorb losses or the right to receive benefits from the consolidated VIE that could potentially be significant to the VIE.

A significant portion of the Company's assets are held through VIEs in which the Company holds a 100 per cent voting interest, the VIE meets the definition of a business and the VIE's assets can be used for general corporate purposes. The assets and liabilities of the consolidated VIEs whose assets cannot be used for purposes other than the settlement of the VIE's obligations are as follows:

at December 31 (millions of Canadian $)	**2016**	**2015**
ASSETS		
Current Assets		
Cash and cash equivalents	**77**	54
Accounts receivable	**71**	55
Inventories	**25**	25
Other	**10**	6
	183	140
Plant, Property and Equipment	**3,685**	3,704
Equity Investments	**606**	664
Goodwill	**525**	541
Intangible and Other Assets	**1**	—
	5,000	5,049
LIABILITIES		
Current Liabilities		
Accounts payable and other	**80**	74
Accrued interest	**21**	21
Current portion of long-term debt	**76**	45
	177	140
Regulatory Liabilities	**34**	33
Other Long-Term Liabilities	**4**	4
Deferred Income Tax Liabilities	**7**	—
Long-Term Debt	**2,827**	2,998
	3,049	3,175

Non-Consolidated VIEs

The Company's non-consolidated VIEs consist of legal entities where the Company is not the primary beneficiary as it does not have the power to direct the activities that most significantly impact the economic performance of these VIEs or where this power is shared with third parties. The Company contributes capital to these VIEs and receives ownership interests that provide it with residual claims on assets after liabilities are paid.

The carrying value of these VIEs and the maximum exposure to loss as a result of the Company's involvement with these VIEs are as follows:

at December 31 (millions of Canadian $)	2016	2015
Balance sheet		
Equity investments	**4,964**	5,410
Off-balance sheet		
Potential exposure to guarantees	**163**	227
Maximum exposure to loss	**5,127**	5,637