Management's Report on Internal Control over Financial Reporting

The consolidated financial statements 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.

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 includes 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, 2018, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external reporting purposes.

The Board of Directors is responsible for reviewing and approving the financial statements and 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, before this document is 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 13, 2019

Report of Independent Registered Public Accounting Firm

To the Shareholders of TransCanada PipeLines Limited

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated balance sheets of TransCanada PipeLines Limited (the Company) as of December 31, 2018, and 2017, the related consolidated statements of income, comprehensive income, cash flows and equity for each of the years in the three-year period ended December 31, 2018, and the related notes (collectively, the consolidated financial statements). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2018, and 2017, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2018, in conformity with U.S. generally accepted accounting principles.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits, we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

KPMG LLP

Chartered Professional Accountants

We have served as the Company's auditor since 1956.

Calgary, Canada
February 13, 2019

Consolidated statement of income

year ended December 31 (millions of Canadian $)	2018	2017	2016
Revenues (Note 5)			
Canadian Natural Gas Pipelines	**4,038**	3,693	3,682
U.S. Natural Gas Pipelines	**4,314**	3,584	2,526
Mexico Natural Gas Pipelines	**619**	570	378
Liquids Pipelines	**2,584**	2,009	1,755
Energy	**2,124**	3,593	4,206
	13,679	13,449	12,547
Income from Equity Investments (Note 9)	**714**	773	514
Operating and Other Expenses			
Plant operating costs and other	**3,591**	3,906	3,861
Commodity purchases resold	**1,488**	2,382	2,172
Property taxes	**569**	569	555
Depreciation and amortization	**2,350**	2,055	1,939
Goodwill and other asset impairment charges (Notes 8, 11 and 12)	**801**	1,257	1,388
	8,799	10,169	9,915
Gain/(Loss) on Assets Held for Sale/Sold (Note 25)	**170**	631	(833)
Financial Charges			
Interest expense (Note 17)	**2,379**	2,137	1,927
Allowance for funds used during construction	**(526)**	(507)	(419)
Interest income and other	**78**	(183)	(117)
	1,931	1,447	1,391
Income before Income Taxes	**3,833**	3,237	922
Income Tax Expense/(Recovery) (Note 16)			
Current	**316**	149	157
Deferred	**254**	548	192
Deferred – U.S. Tax Reform and 2018 FERC Actions	**(167)**	(804)	—
	403	(107)	349
Net Income	**3,430**	3,344	573
Net (loss)/income attributable to non-controlling interests (Note 19)	**(185)**	238	252
Net Income Attributable to Controlling Interests and to Common Shares	**3,615**	3,106	321

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 $)	**2018**	**2017**	**2016**
Net Income	**3,430**	3,344	573
Other Comprehensive Income/(Loss), Net of Income Taxes			
Foreign currency translation gains and losses on net investment in foreign operations	**1,358**	(749)	3
Reclassification of foreign currency translation gains on disposal of foreign operations	**—**	(77)	—
Change in fair value of net investment hedges	**(42)**	—	(10)
Change in fair value of cash flow hedges	**(10)**	3	30
Reclassification to net income of gains and losses on cash flow hedges	**21**	(2)	42
Unrealized actuarial gains and losses on pension and other post-retirement benefit plans	**(114)**	(11)	(26)
Reclassification of actuarial gains and losses on pension and other post-retirement benefit plans	**15**	16	16
Other comprehensive income/(loss) on equity investments	**86**	(106)	(87)
Other comprehensive income/(loss) (Note 21)	**1,314**	(926)	(32)
Comprehensive Income	**4,744**	2,418	541
Comprehensive (loss)/income attributable to non-controlling interests	**(13)**	83	241
Comprehensive Income Attributable to Controlling Interests and to Common Shares	**4,757**	2,335	300

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 $)	2018	2017	2016
Cash Generated from Operations			
Net income	**3,430**	3,344	573
Depreciation and amortization	**2,350**	2,055	1,939
Goodwill and other asset impairment charges (Notes 8, 11 and 12)	**801**	1,257	1,388
Deferred income taxes (Note 16)	**254**	548	192
Deferred income taxes – U.S. Tax Reform and 2018 FERC Actions (Note 16)	**(167)**	(804)	—
Income from equity investments (Note 9)	**(714)**	(773)	(514)
Distributions received from operating activities of equity investments (Note 9)	**985**	970	844
Employee post-retirement benefits funding, net of expense (Note 22)	**(35)**	(64)	(3)
(Gain)/loss on assets held for sale/sold (Note 25)	**(170)**	(631)	833
Equity allowance for funds used during construction	**(374)**	(362)	(253)
Unrealized losses/(gains) on financial instruments	**220**	(149)	(149)
Other	**(40)**	43	55
(Increase)/decrease in operating working capital (Note 24)	**(99)**	(272)	251
Net cash provided by operations	**6,441**	5,162	5,156
Investing Activities			
Capital expenditures (Note 4)	**(9,418)**	(7,383)	(5,007)
Capital projects in development (Note 4)	**(496)**	(146)	(295)
Contributions to equity investments (Notes 4 and 9)	**(1,015)**	(1,681)	(765)
Acquisitions, net of cash acquired	**—**	—	(13,608)
Proceeds from sales of assets, net of transaction costs	**614**	4,683	6
Reimbursement of costs related to capital projects in development (Note 12)	**470**	634	—
Other distributions from equity investments (Note 9)	**121**	362	727
Deferred amounts and other	**(293)**	(168)	159
Net cash used in investing activities	**(10,017)**	(3,699)	(18,783)
Financing Activities			
Notes payable issued/(repaid), net	**817**	1,038	(329)
Long-term debt issued, net of issue costs	**6,238**	3,643	12,333
Long-term debt repaid	**(3,550)**	(7,085)	(7,153)
Junior subordinated notes issued, net of issue costs	**—**	3,468	1,549
Advances from affiliate	**1,066**	193	4,523
Dividends on common shares	**(2,419)**	(2,121)	(1,612)
Distributions to non-controlling interests	**(225)**	(283)	(279)
Common shares issued	**845**	780	4,661
Partnership units of TC PipeLines, LP issued, net of issue costs	**49**	225	215
Common units of Columbia Pipeline Partners LP acquired	**—**	(1,205)	—
Net cash provided by/(used in) financing activities	**2,821**	(1,347)	13,908
Effect of Foreign Exchange Rate Changes on Cash and Cash Equivalents	**73**	(39)	(127)
(Decrease)/Increase in Cash and Cash Equivalents	**(682)**	77	154
Cash and Cash Equivalents			
Beginning of year	**1,044**	967	813
Cash and Cash Equivalents			
End of year	**362**	1,044	967

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

Consolidated balance sheet

at December 31 (millions of Canadian $)		2018	2017
ASSETS			
Current Assets			
Cash and cash equivalents		**362**	1,044
Accounts receivable		**2,548**	2,537
Inventories		**431**	378
Assets held for sale (Note 6)		**543**	—
Other (Note 7)		**1,180**	691
		5,064	4,650
Plant, Property and Equipment (Note 8)		**66,503**	57,277
Equity Investments (Note 9)		**7,113**	6,366
Regulatory Assets (Note 10)		**1,548**	1,376
Goodwill (Note 11)		**14,178**	13,084
Loan Receivable from Affiliate (Note 9)		**1,315**	919
Intangible and Other Assets (Note 12)		**1,887**	1,423
Restricted Investments		**1,207**	915
		98,815	86,010
LIABILITIES			
Current Liabilities			
Notes payable (Note 13)		**2,762**	1,763
Accounts payable and other (Note 14)		**5,426**	4,071
Dividends payable		**633**	552
Due to affiliate (Note 28)		**3,617**	2,551
Accrued interest		**646**	605
Current portion of long-term debt (Note 17)		**3,462**	2,866
		16,546	12,408
Regulatory Liabilities (Note 10)		**3,930**	4,321
Other Long-Term Liabilities (Note 15)		**1,008**	727
Deferred Income Tax Liabilities (Note 16)		**6,026**	5,403
Long-Term Debt (Note 17)		**36,509**	31,875
Junior Subordinated Notes (Note 18)		**7,508**	7,007
		71,527	61,741
EQUITY			
Common shares, no par value (Note 20)		**22,606**	21,761
Issued and outstanding:	December 31, 2018 – 887 million shares		
	December 31, 2017 – 872 million shares		
Additional paid-in capital		**20**	—
Retained earnings		**3,613**	2,387
Accumulated other comprehensive loss (Note 21)		**(606)**	(1,731)
Controlling Interests		**25,633**	22,417
Non-controlling interests (Note 19)		**1,655**	1,852
		27,288	24,269
		98,815	86,010

Commitments, Contingencies and Guarantees (Note 26)
Corporate Restructuring Costs (Note 27)
Variable Interest Entities (Note 29)
Subsequent Event (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

John E. Lowe, Director

Consolidated statement of equity

year ended December 31 (millions of Canadian $)	2018	2017	2016
Common Shares (Note 20)			
Balance at beginning of year	**21,761**	20,981	16,320
Proceeds from shares issued	**845**	780	4,661
Balance at end of year	**22,606**	21,761	20,981
Additional Paid-In Capital			
Balance at beginning of year	**—**	211	210
Issuance of stock options	**13**	12	15
Dilution from TC PipeLines, LP units issued	**7**	26	24
Asset drop-downs to TC PipeLines, LP	**—**	(202)	(38)
Columbia Pipeline Partners LP acquisition	**—**	(171)	—
Reclassification of additional paid-in capital deficit to retained earnings	**—**	124	—
Balance at end of year	**20**	—	211
Retained Earnings			
Balance at beginning of year	**2,387**	1,577	2,989
Net income attributable to controlling interests	**3,615**	3,106	321
Common share dividends	**(2,501)**	(2,184)	(1,733)
Adjustment related to income tax effects of asset drop-downs to TC PipeLines, LP (Note 3)	**95**	—	—
Reclassification of AOCI to retained earnings resulting from U.S. Tax Reform (Note 3)	**17**	—	—
Adjustment related to employee share-based payments	**—**	12	—
Reclassification of additional paid-in capital deficit to retained earnings	**—**	(124)	—
Balance at end of year	**3,613**	2,387	1,577
Accumulated Other Comprehensive Loss			
Balance at beginning of year	**(1,731)**	(960)	(939)
Other comprehensive income/(loss) attributable to controlling interests (Note 21)	**1,142**	(771)	(21)
Reclassification of AOCI to retained earnings resulting from U.S. Tax Reform (Note 3)	**(17)**	—	—
Balance at end of year	**(606)**	(1,731)	(960)
Equity Attributable to Controlling Interests	**25,633**	22,417	21,809
Equity Attributable to Non-Controlling Interests			
Balance at beginning of year	**1,852**	1,726	1,717
Net (loss)/income attributable to non-controlling interests	**(185)**	238	252
Other comprehensive income/(loss) attributable to non-controlling interests	**172**	(155)	(11)
Issuance of TC PipeLines, LP units			
Proceeds, net of issue costs	**49**	225	215
Decrease in TCPL's ownership of TC PipeLines, LP	**(9)**	(41)	(40)
Distributions declared to non-controlling interests	**(224)**	(280)	(279)
Reclassification from/(to) common units subject to rescission or redemption (Note 19)	**—**	106	(1,179)
Impact of Columbia Pipeline Partners LP acquisition	**—**	33	—
Acquisition of non-controlling interests in Columbia Pipeline Partners LP	**—**	—	1,051
Balance at end of year	**1,655**	1,852	1,726
Total Equity	**27,288**	24,269	23,535

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 five business segments, Canadian Natural Gas Pipelines, U.S. Natural Gas Pipelines, Mexico Natural Gas Pipelines, Liquids Pipelines and Energy, each of which offers different products and services. The Company also has a Corporate segment, consisting of corporate and administrative functions that provide governance, financing and other support to the Company's business segments. 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 40,686 km (25,281 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 50,199 km (31,192 miles) of regulated natural gas pipelines, 535 Bcf of regulated natural gas storage facilities, midstream and other assets.

Mexico Natural Gas Pipelines

The Mexico Natural Gas Pipelines segment consists of the Company's investments in 1,670 km (1,038 miles) of regulated natural gas pipelines.

Liquids Pipelines

The Liquids Pipelines segment consists of the Company's investments in 4,874 km (3,030 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 10 power generation facilities and 118 Bcf of non-regulated natural gas storage facilities. These include assets in Alberta, Ontario, Québec, New Brunswick and Arizona. At December 31, 2018, the Coolidge generating station is 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 variable interest entities (VIEs) for which it is considered to be the primary beneficiary as well as voting interest entities in which it has a controlling financial interest. 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. Some of the estimates and judgments the Company has to make have a material impact on the consolidated financial statements, but they do not involve significant subjectivity or uncertainty. Others also have a material impact but the assumptions underlying these accounting estimates also relate to matters that are highly uncertain at the time the estimate or judgment is made or are subjective.

Significant estimates and judgments used in the preparation of the consolidated financial statements that involve assumptions that are highly uncertain or subjective include, but are not limited to:

- fair value of plant, property and equipment and equity investments (Notes 8 and 9)
- fair value of goodwill (Note 11)
- fair value of intangible assets (Note 12) and
- fair value of assets and liabilities acquired in a business combination (Note 25).

Significant estimates and judgments used in the preparation of the consolidated financial statements that are provided by an independent expert or do not involve assumptions that are highly uncertain or subjective include, but are not limited to:

- depreciation rates of plant, property and equipment (Note 8)
- carrying value of regulatory assets and liabilities (Note 10)
- carrying value of asset retirement obligations (Note 15)
- provisions for income taxes, including U.S. Tax Reform (Note 16)
- assumptions used to measure retirement and other post-retirement obligations (Note 22)
- fair value of financial instruments (Note 23) and
- provisions for commitments, contingencies, guarantees (Note 26) and restructuring costs (Note 27).

Actual results could differ from these estimates.

Regulation

Certain Canadian, U.S. and Mexico natural gas pipeline and storage assets are regulated with respect to construction, operations and the determination of tolls. In Canada, regulated natural gas pipelines and liquids pipelines are subject to the authority of the National Energy Board (NEB), the Alberta Energy Regulator (AER) or the B.C. Oil and Gas Commission (OGC). In the U.S., regulated 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, regulated natural gas pipelines are subject to the authority of the Energy Regulatory Commission (CRE). 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 recognized in non-rate-regulated businesses to appropriately reflect the economic impact of the regulators' decisions regarding revenues and tolls. Regulatory assets represent costs that are expected to be recovered in customer rates in future periods and regulatory liabilities represent amounts that are expected to be returned to customers through future rate-setting processes. An asset qualifies for the use of RRA when it meets three criteria:

- a regulator must establish or approve the rates for the regulated services or activities
- the regulated rates must be designed to recover the cost of providing the services or products and
- it is reasonable to assume that rates set at levels to recover the cost can be charged to (and collected from) customers because of the demand for services or products and the level of direct or indirect competition.

TCPL's businesses that apply RRA currently include Canadian, U.S. and Mexico natural gas pipelines, and regulated U.S. natural gas storage. RRA is not applicable to the Company's liquids pipelines as the regulators' decisions regarding operations and tolls on those systems generally do not have an impact on timing of recognition of revenues and expenses. Once in operation, the Coastal GasLink pipeline is not expected to apply RRA.

Revenue Recognition

Canadian Natural Gas Pipelines

Capacity Arrangements and Transportation

Revenues from the Company's Canadian natural gas pipelines are generated from contractual arrangements for committed capacity and from the transportation of natural gas. Revenues earned from firm contracted capacity arrangements are recognized ratably over the term of the contract regardless of the amount of natural gas that is transported. Transportation revenues for interruptible or volumetric-based services are recognized when the service is performed.

Revenues from the Company's Canadian natural gas pipelines are subject to regulatory decisions by the NEB. The tolls charged on these pipelines are based on revenue requirements designed to recover the costs of providing natural gas capacity for transportation services, which includes a return of and on capital, as approved by the NEB. The Company's Canadian natural gas pipelines are generally 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 tolls. Revenues recognized prior to an NEB decision on rates for that period reflect the NEB's last approved return on equity (ROE) assumptions. Adjustments to revenues are recorded when the NEB decision is received. Canadian natural gas pipelines' revenues are invoiced and received on a monthly basis. The Company does not take ownership of the natural gas that it transports for customers.

U.S. Natural Gas Pipelines

Capacity Arrangements and Transportation

Revenues from the Company's U.S. natural gas pipelines are generated from contractual arrangements for committed capacity and from the transportation of natural gas. Revenues earned from firm contracted capacity arrangements are generally recognized ratably over the term of the contract regardless of the amount of natural gas that is transported. Transportation revenues for interruptible or volumetric-based services are recognized when the service is performed.

The Company's U.S. natural gas pipelines are subject to FERC regulations and, as a result, a portion of revenues collected may be subject to refund if invoiced during an interim period when a rate proceeding is ongoing. 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. U.S. natural gas pipelines' revenues are invoiced and received on a monthly basis. The Company does not take ownership of the natural gas that it transports for customers.

Natural Gas Storage and Other

Revenues from the Company's regulated U.S. natural gas storage services are generated mainly from firm committed capacity storage contracts. The performance obligation in these contracts is the reservation of a specified amount of capacity for storage including specifications with regards to the amount of natural gas that can be injected or withdrawn on a daily basis. Revenues 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. Natural gas storage services revenues are invoiced and received on a monthly basis. The Company does not take ownership of the natural gas that it stores for customers.

Revenues from the Company's midstream natural gas services, including gathering, treating, conditioning, processing, compression and liquids handling services, are generated from contractual arrangements and are recognized ratably over the term of the contract. The Company also owns mineral rights associated with certain natural gas storage facilities. These mineral rights can be leased or contributed to producers of natural gas in return for a royalty interest which is recognized when natural gas and associated liquids are produced. Midstream natural gas service revenues are invoiced and received on a monthly basis. The Company does not take ownership of the natural gas for which it provides midstream services.

Mexico Natural Gas Pipelines

Capacity Arrangements and Transportation

Revenues from the Company's Mexico natural gas pipelines are primarily collected based on CRE-approved negotiated firm capacity contracts and are generally recognized ratably over the term of the contract. Transportation revenues related to interruptible or volumetric-based services are recognized when the service is performed. Mexico natural gas pipelines' revenues are invoiced and received on a monthly basis. The Company does not take ownership of the natural gas that it transports for customers.

Liquids Pipelines

Capacity Arrangements and Transportation

Revenues from the Company's liquids pipelines are generated mainly from providing customers with firm capacity arrangements to transport crude oil. The performance obligation in these contracts is the reservation of a specified amount of capacity together with the transportation of crude oil on a monthly basis. Revenues earned from these arrangements are recognized ratably over the term of the contract regardless of the amount of crude oil that is transported. Revenues for interruptible or volumetric-based services are recognized when the service is performed. Liquids pipelines' revenues are invoiced and received on a monthly basis. The Company does not take ownership of the crude oil that it transports for customers.

Energy

Power Generation

Revenues from the Company's Energy business are primarily derived from long-term contractual commitments to provide power capacity to meet the demands of the market, and from the sale of electricity to both centralized markets and to customers. Power generation revenues also include revenues from the sale of steam to customers. Revenues and capacity payments are recognized as the services are provided and as electricity and steam is delivered. Power generation revenues are invoiced and received on a monthly basis.

Natural Gas Storage and Other

Non-regulated natural gas storage contracts include park, loan and term storage arrangements. Revenues are recognized as the services are provided. Term storage revenues are invoiced and received on a monthly basis. Revenues earned from the sale of proprietary natural gas are recognized in the month of delivery. Revenues from ancillary services are recognized as the service is provided. The Company does not take ownership of the natural gas that it stores for customers.

Cash and Cash Equivalents

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

Inventories

Inventories primarily consist of materials and supplies including spare parts and fuel, crude oil in transit and natural gas inventory in storage. Inventories are carried at the lower of cost and net realizable value.

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, net of selling costs, and any losses are recognized in net income. Once an asset is classified as held for sale, depreciation expense is no longer recorded.

Plant, Property and Equipment

Natural Gas Pipelines

Plant, property and equipment for natural gas pipelines is 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 seven 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 with a corresponding credit recognized in Allowance for funds used during construction in the Consolidated statement of income. The equity component of AFUDC is a non-cash expenditure. Interest is capitalized during construction of non-regulated natural gas pipelines.

Regulated natural gas storage base gas, which is valued at cost, represents gas volumes that are maintained to ensure adequate reservoir pressure exists to deliver natural gas held in 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 plant, property and equipment from service, net of any salvage proceeds, are also recorded in accumulated depreciation.

Midstream and Other

Plant, property and equipment for midstream assets is 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 are derecognized and any gain or loss is recorded in net income.

The Company participates as a working interest partner in the development of certain Marcellus and Utica acreage. The working interest allows the Company to invest in drilling activities in addition to receiving 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 is 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. When liquids pipelines retire plant, property and equipment from service, the original book cost and related accumulated depreciation are derecognized and any gain or loss is recorded in net income.

Energy

Plant, property and equipment for Energy assets 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 are derecognized and any gain or loss is recorded in net income.

Non-regulated natural gas storage base gas, which is valued at original cost, represents gas volumes that are maintained to ensure adequate reservoir pressure exists to deliver gas held in storage. Base gas is not depreciated.

Corporate

Corporate plant, property and equipment is recorded at cost and depreciated on a straight-line basis over its estimated useful life at average annual rates ranging from three per cent to 20 per cent.

Capitalized Project Costs

The Company capitalizes project costs once advancement of the project to a construction stage is probable or costs are otherwise likely to be recoverable. The Company also capitalizes interest costs for non-regulated projects in development and AFUDC for regulated projects in development. Capital projects in development are included in Intangible and other assets on the Consolidated balance sheet. 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.

Impairment of Long-Lived Assets

The Company reviews long-lived assets such as plant, property and equipment, equity investments and capital projects in development 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 that are estimated for an asset within Plant, property and equipment, or the estimated selling price of any long-lived asset, 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 combinations 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 can initially assess qualitative factors to determine whether events or changes in circumstances indicate that goodwill might be impaired and 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 Company will then perform the quantitative goodwill impairment test. The Company can elect to proceed directly to the quantitative goodwill impairment test for any of its reporting units. If the quantitative goodwill impairment test is performed, the Company compares the fair value of the reporting unit to its carrying value, including its goodwill. If the carrying value of a reporting unit including its goodwill exceeds its fair value, goodwill impairment is measured at the amount by which the reporting unit’s carrying value exceeds its fair value.

Loans and Receivables

Loans receivable from affiliates and accounts receivable are measured at cost.

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 where TCPL is the lessor. During 2016, the Company terminated its Alberta PPAs under which it purchased power and recorded an impairment charge. Prior to their termination, substantially all of these PPAs were also accounted for as operating leases, where TCPL was the lessee, 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 was subleased to third parties under terms and conditions similar to the PPAs, and was also accounted for as operating leases with the margin earned from the subleases recorded in Revenues. 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 which they occur, except for changes in balances related to regulated natural gas pipelines which are deferred until they are refunded or recovered in tolls, as permitted by the regulator. 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.

For those AROs that the Company records, the following assumptions are used:
- when the asset is expected to be retired
- the scope and cost of abandonment and reclamation activities that are required and
- appropriate inflation and discount rates.

The Company has recorded AROs related to its non-regulated natural gas storage operations, mineral rights and power generation facilities. The scope and timing of asset retirements related to most of the Company's natural gas pipelines and liquids pipelines is indeterminable because the Company intends to operate them as long as there is supply and demand. 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 its Columbia Gas pipeline.

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. These estimates, including associated legal costs, are based on available information using existing technology and enacted laws and regulations, and 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 or cancelled/retired by government agencies. 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 (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 (AOCI) and into net income over the expected 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. This is 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 for and are designated for hedge accounting treatment. This 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 change in the fair value of the hedging derivative is recognized in OCI. 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 foreign exchange gains and losses on the hedging instruments are recognized in OCI. 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 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 and Issuance Costs

The Company records long-term debt transaction costs and issuance costs as a deduction from the carrying amount of the related debt liability 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 on behalf of a partially-owned entity or by 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 or Plant, property and equipment 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 of the guarantee.

3. ACCOUNTING CHANGES

Changes in Accounting Policies for 2018

Revenue from contracts with customers

In 2014, the FASB issued new guidance on revenue from contracts with customers. The new guidance requires that an entity recognize revenue from these contracts in accordance with a prescribed model. This model is used to depict the transfer of promised goods or services to customers in amounts that reflect the total consideration to which it expects to be entitled during the term of the contract in exchange for those promised goods or services. Goods or services that are promised to a customer are referred to as the Company's "performance obligations." The total consideration to which the Company expects to be entitled can include fixed and variable amounts. The Company has variable revenue that is subject to factors outside the Company's influence, such as market prices, actions of third parties and weather conditions. The Company considers this variable revenue to be "constrained" as it cannot be reliably estimated, and therefore recognizes variable revenue when the service is provided.

The new guidance also requires additional disclosures about the nature, amount, timing and uncertainty of revenue recognition and related cash flows.

The Company's accounting policies related to revenue recognition have not substantially changed as a result of adopting the new guidance on revenue from contracts with customers. Results reported for 2018 reflect the application of the new guidance, while the 2017 and 2016 comparative results were prepared and reported under previous revenue recognition guidance which is referred to herein as "legacy U.S. GAAP." Under legacy U.S. GAAP, revenues were recognized when the risk, rewards, and benefits were transferred to the customer by the Company providing the goods or services under the contract, in an amount the Company expected to collect from the customer.

Under the new guidance applied in 2018, revenues are recognized when the Company satisfies its performance obligations by transferring control of the promised goods or services to its customers, in an amount that reflects the consideration the Company expects to be entitled to in exchange for those goods or services. The Company has elected to utilize a practical expedient to recognize revenues from its U.S. and certain Mexico natural gas pipelines contracts as customers are invoiced. The new guidance was effective January 1, 2018, was applied using the modified retrospective transition method, and did not result in any material differences in the amount and timing of revenue recognition. Refer to Note 5, Revenues, for further information related to the impact of adopting the new guidance.

Financial instruments

In January 2016, the FASB issued new guidance on the accounting for equity investments and financial liabilities. The new guidance changes the income statement effect of equity investments and the recognition of changes in the 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 was effective January 1, 2018 and did not have a material impact on the Company's consolidated financial statements.

Income taxes

In October 2016, the FASB issued new guidance on the 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 intra-entity asset transfers when the transfer occurs. The new guidance was effective January 1, 2018, was applied using a modified retrospective approach, and resulted in an adjustment to retained earnings of $95 million.

In February 2018, the FASB issued new guidance that allows a reclassification from AOCI to retained earnings for stranded tax effects resulting from U.S. Tax Reform. This guidance can be applied either in the period of adoption or retrospectively to each period (or periods) in which the effect of the change is recognized. This new guidance is effective January 1, 2019, however, early adoption is permitted. The Company elected to early adopt this guidance effective fourth quarter 2018 and used a portfolio approach for releasing the income tax effects from AOCI to retained earnings. The Company applied this guidance retrospectively, at the beginning of the period of adoption, resulting in an adjustment to retained earnings of $17 million.

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 balance, and amounts generally described as restricted cash or restricted cash equivalents. Restricted cash and cash equivalents will be included with cash and cash equivalents when reconciling the beginning of period and end of period total amounts on the statement of cash flows. This new guidance was effective January 1, 2018, was applied retrospectively, and did not have an impact on the Company's consolidated financial statements.

Employee post-retirement benefits

In March 2017, the FASB issued new guidance that requires entities to disaggregate the current service cost component from the other components of net benefit cost and present it with other current compensation costs for related employees in the income statement. The new guidance also requires that the other components of net benefit cost be presented elsewhere in the income statement and excluded from income from operations if such a subtotal is presented. In addition, the new guidance makes changes to the components of net benefit cost that are eligible for capitalization. Entities must use a retrospective transition method to adopt the requirement for separate presentation in the income statement of the components of net benefit cost, and a prospective transition method to adopt the change to capitalization of benefit costs. This new guidance was effective January 1, 2018 and did not have a material impact on the Company's consolidated financial statements.

Hedge accounting

In August 2017, the FASB issued new guidance making more financial and non-financial hedging strategies eligible for hedge accounting. The new guidance also amends the presentation requirements relating to the change in fair value of a derivative and requires additional disclosures including cumulative basis adjustments for fair value hedges and the effect of hedging on individual line items in the statement of income. This new guidance is effective January 1, 2019 with early adoption permitted. This new guidance, which the Company elected to adopt effective January 1, 2018, was applied prospectively and did not have a material impact on the Company's consolidated financial statements.

Derecognition of Nonfinancial Assets

In February 2017, the FASB issued new guidance that clarifies the scope provisions of nonfinancial assets and how to allocate consideration to each distinct asset. The FASB also amended the guidance for derecognition of a distinct nonfinancial asset in partial sale transactions. This new guidance was effective January 1, 2018, was applied using the modified retrospective transition method and did not have a material impact on the Company's consolidated financial statements.

Goodwill impairment

In January 2017, the FASB issued new guidance on simplifying the test for goodwill impairment by eliminating Step 2 of the impairment test, which is the requirement to calculate the implied fair value of goodwill to measure the impairment charge. Instead, entities will record an impairment charge based on the excess of a reporting unit’s carrying amount over its fair value. This new guidance is effective January 1, 2020 with early adoption permitted. The Company elected to adopt this guidance effective fourth quarter 2018 as it simplified goodwill impairment testing. The guidance was applied prospectively and used in the 2018 annual goodwill impairment test.

Future Accounting Changes

Leases

In February 2016, the FASB issued new guidance on the accounting for leases. The new guidance amends the definition of a lease such that, in order for an arrangement to qualify as a lease, the lessee is required to have both (1) the right to obtain substantially all of the economic benefits from the use of the asset and (2) the right to direct the use of the asset. The new guidance also establishes a right-of-use (ROU) model that requires a lessee to recognize a ROU asset and corresponding lease liability on the balance sheet for all leases with a term longer than 12 months. Lessees will classify leases as finance or operating, with classification affecting the pattern of expense recognition in the statement of income. The new guidance does not make extensive changes to lessor accounting. The Company currently expects that substantially all of its leases where the Company is the lessor will continue to be classified as operating leases under the new standard.

In January 2018, the FASB issued an optional practical expedient, to be applied upon transition, to omit the evaluation of land easements not previously accounted for as leases that existed or expired prior to the entity's adoption of the new lease guidance. An entity that elects this practical expedient is required to apply it consistently to all of its existing or expired land easements not previously accounted for as leases. The Company will apply this practical expedient upon transition to the new standard.

The new guidance is effective January 1, 2019, with early adoption permitted. The Company will adopt the new standard on its effective date. A modified retrospective transition approach is required, applying the new standard to all leases existing at the date of initial application being January 1, 2019. In July 2018, the FASB issued a transition option allowing entities to not apply the new guidance, including disclosure requirements, to the comparative periods they present in their financial statements in the year of adoption. The Company will apply this transition option and use the effective date as the date of initial application. Consequently, financial information will not be updated and disclosures required under the new standard will not be provided for dates and periods before January 1, 2019.

The Company will elect the package of practical expedients which permits entities not to reassess prior conclusions about lease identification, lease classification and initial direct costs under the rules of the new standard.

The Company believes that the most significant effects of adoption will relate to the recognition of new ROU assets and lease liabilities on the Company's balance sheet for its operating leases and providing significant new disclosures about the Company's leasing activities. The guidance will not impact the Company's income statement. On adoption, the Company will recognize ROU assets of approximately $606 million and additional operating lease liabilities of approximately $600 million based on the present value of the remaining minimum lease payments for existing operating leases. The new standard also provides practical expedients for a Company’s ongoing accounting. The Company will elect the short-term lease recognition exemption for all eligible leases. This means, for those leases that qualify, the Company will not recognize ROU assets or lease liabilities. The Company will also elect the practical expedient to not separate lease and non-lease components for all leases for which the Company is the lessee and for facility and liquids tank terminals for which the Company is the lessor.

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 financial 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 as 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.

Fair value measurement

In August 2018, the FASB issued new guidance that amends certain disclosure requirements for fair value measurements. This new guidance is effective January 1, 2020, however, early adoption of certain or all requirements is permitted. The Company is currently evaluating the timing and impact of adoption of this guidance and has not yet determined the effect on its consolidated financial statements.

Defined benefit plans

In August 2018, the FASB issued new guidance which amends and clarifies disclosure requirements related to DB pension and other post retirement benefit plans. This new guidance is effective January 1, 2021, and will be applied on a retrospective basis, however early adoption is permitted. The Company is currently evaluating the timing and impact of the adoption of this guidance and has not yet determined the effect on its consolidated financial statements.

Implementation costs of cloud computing arrangements

In August 2018, the FASB issued new guidance requiring an entity in a hosting arrangement that is a service contract to follow the guidance for internal-use software to determine which implementation costs should be capitalized as an asset and which costs should be expensed. The guidance also requires the entity to amortize the capitalized implementation costs of a hosting arrangement over the term of the arrangement. This guidance is effective January 1, 2020, however, early adoption is permitted. This guidance can be applied either retrospectively or prospectively to all implementation costs incurred after the date of adoption. The Company is currently evaluating the timing and impact of adoption of this guidance and has not yet determined the effect on its consolidated financial statements.

Consolidation

In October 2018, the FASB issued new guidance for determining whether fees paid to decision makers and service providers are variable interests for indirect interests held through related parties under common control. This new guidance is effective January 1, 2020, and will be applied on a retrospective basis, however early adoption is permitted. The Company is currently evaluating the timing and impact of the adoption of this guidance and has not yet determined the effect on its consolidated financial statements.

4. SEGMENTED INFORMATION

year ended December 31, 2018 (millions of Canadian $)	Canadian Natural Gas Pipelines	U.S. Natural Gas Pipelines	Mexico Natural Gas Pipelines	Liquids Pipelines	Energy	Corporate[1]	Total
Revenues	4,038	4,314	619	2,584	2,124	—	13,679
Intersegment revenues	—	162	—	—	56	(218) [2]	—
	4,038	4,476	619	2,584	2,180	(218)	13,679
Income from equity investments	12	256	22	64	355	5 [3]	714
Plant operating costs and other	(1,405)	(1,368)	(34)	(630)	(313)	159 [2]	(3,591)
Commodity purchases resold	—	—	—	—	(1,488)	—	(1,488)
Property taxes	(266)	(199)	—	(98)	(6)	—	(569)
Depreciation and amortization	(1,129)	(664)	(97)	(341)	(119)	—	(2,350)
Goodwill and other asset impairment charges	—	(801)	—	—	—	—	(801)
Gain on sale of assets	—	—	—	—	170	—	170
Segmented earnings/(losses)	1,250	1,700	510	1,579	779	(54)	5,764
Interest expense							(2,379)
Allowance for funds used during construction							526
Interest income and other[3]							(78)
Income before income taxes							3,833
Income tax expense							(403)
Net income							3,430
Net loss attributable to non-controlling interests							185
Net income attributable to controlling interests and to common shares							3,615
Capital spending							
Capital expenditures	2,442	5,591	463	110	767	45	9,418
Capital projects in development	36	1	—	459	—	—	496
Contributions to equity investments	—	179	334	12	490	—	1,015
	2,478	5,771	797	581	1,257	45	10,929

1 Includes intersegment eliminations.

2 The Company records intersegment sales at contracted rates. For segmented reporting, these transactions are included as Intersegment revenues in the segment providing the service and Plant operating costs and other in the segment receiving the service. These transactions are eliminated on consolidation. Intersegment profit is recognized when the product or service has been provided to third parties or otherwise realized.

3 Income from equity investments includes foreign exchange gains on the Company's inter-affiliate loan with Sur de Texas. The offsetting foreign exchange losses on the inter-affiliate loan are included in Interest income and other. The peso-denominated loan to the Sur de Texas joint venture represents the Company's proportionate share of long-term debt financing for this joint venture. Refer to Note 9, Equity investments, for further information.

year ended December 31, 2017 (millions of Canadian $)	Canadian Natural Gas Pipelines	U.S. Natural Gas Pipelines	Mexico Natural Gas Pipelines	Liquids Pipelines	Energy	Corporate[1]	Total
Revenues	3,693	3,584	570	2,009	3,593	—	13,449
Intersegment revenues	—	51	—	—	—	(51) [2]	—
	3,693	3,635	570	2,009	3,593	(51)	13,449
Income/(loss) from equity investments	11	240	(9)	(3)	471	63 [3]	773
Plant operating costs and other	(1,300)	(1,340)	(42)	(623)	(550)	(51) [2]	(3,906)
Commodity purchases resold	—	—	—	—	(2,382)	—	(2,382)
Property taxes	(260)	(181)	—	(89)	(39)	—	(569)
Depreciation and amortization	(908)	(594)	(93)	(309)	(151)	—	(2,055)
Goodwill and other asset impairment charges	—	—	—	(1,236)	(21)	—	(1,257)
Gain on sale of assets	—	—	—	—	631	—	631
Segmented earnings/(losses)	1,236	1,760	426	(251)	1,552	(39)	4,684
Interest expense							(2,137)
Allowance for funds used during construction							507
Interest income and other[3]							183
Income before income taxes							3,237
Income tax recovery							107
Net income							3,344
Net income attributable to non-controlling interests							(238)
Net income attributable to controlling interests and to common shares							3,106
Capital spending							
Capital expenditures	2,106	3,712	833	341	350	41	7,383
Capital projects in development	75	—	—	71	—	—	146
Contributions to equity investments	—	118	1,121	117	325	—	1,681
	2,181	3,830	1,954	529	675	41	9,210

1 Includes intersegment eliminations.

2 The Company records intersegment sales at contracted rates. For segmented reporting, these transactions are included as Intersegment revenues in the segment providing the service and Plant operating costs and other in the segment receiving the service. These transactions are eliminated on consolidation. Intersegment profit is recognized when the product or service has been provided to third parties or otherwise realized.

3 Income/(loss) from equity investments includes foreign exchange gains on the Company's inter-affiliate loan with Sur de Texas. The offsetting foreign exchange losses on the inter-affiliate loan are included in Interest income and other. The peso-denominated loan to the Sur de Texas joint venture represents the Company's proportionate share of long-term debt financing for this joint venture. Refer to Note 9, Equity investments, for further information.

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[1]	Total
Revenues	3,682	2,526	378	1,755	4,206	—	12,547
Intersegment revenues	—	56	—	—	—	(56) [2]	—
	3,682	2,582	378	1,755	4,206	(56)	12,547
Income/(loss) from equity investments	12	214	(3)	(1)	292	—	514
Plant operating costs and other	(1,245)	(1,057)	(43)	(568)	(884)	(64) [2]	(3,861)
Commodity purchases resold	—	—	—	—	(2,172)	—	(2,172)
Property taxes	(267)	(120)	—	(88)	(80)	—	(555)
Depreciation and amortization	(875)	(425)	(45)	(292)	(302)	—	(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)	1,307	1,190	287	806	(1,157)	(120)	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
Contributions to equity investments	—	5	198	327	235	—	765
	1,525	1,522	1,142	1,137	708	33	6,067

1 Includes intersegment eliminations.

2 The Company records intersegment sales at contracted rates. For segmented reporting, these transactions are included as Intersegment revenues in the segment providing the service and Plant operating costs and other in the segment receiving the service. These transactions are eliminated on consolidation. Intersegment profit is recognized when the product or service has been provided to third parties or otherwise realized.

at December 31 (millions of Canadian $)	2018	2017
Total Assets by segment		
Canadian Natural Gas Pipelines	**18,407**	16,904
U.S. Natural Gas Pipelines	**44,115**	35,898
Mexico Natural Gas Pipelines	**7,058**	5,716
Liquids Pipelines	**17,352**	15,438
Energy	**8,475**	8,503
Corporate	**3,408**	3,551
	98,815	86,010

Geographic Information

year ended December 31 (millions of Canadian $)	2018	2017	2016
Revenues			
Canada – domestic	**4,187**	3,618	3,697
Canada – export	**1,075**	1,255	1,177
United States	**7,798**	8,006	7,295
Mexico	**619**	570	378
	13,679	13,449	12,547

at December 31 (millions of Canadian $)	2018	2017
Plant, Property and Equipment		
Canada	**23,226**	21,632
United States	**37,385**	30,693
Mexico	**5,892**	4,952
	66,503	57,277

5. REVENUES

On January 1, 2018, the Company adopted new FASB guidance on revenue from contracts with customers using the modified retrospective transition method for all contracts that were in effect on the date of adoption. Results reported for 2018 reflect the application of the new guidance, while the 2017 and 2016 comparative results were prepared and reported under previous revenue recognition guidance which is referred to herein as "legacy U.S. GAAP."

Disaggregation of Revenues

The following tables summarizes total Revenues for the year ended December 31, 2018.

(millions of Canadian $)	Canadian Natural Gas Pipelines	U.S. Natural Gas Pipelines	Mexico Natural Gas Pipelines	Liquids Pipelines	Energy	Total
Revenues from contracts with customers						
Capacity arrangements and transportation	**4,038**	**3,549**	**614**	**2,079**	**—**	**10,280**
Power generation	**—**	**—**	**—**	**—**	**1,771**	**1,771**
Natural gas storage and other	**—**	**654**	**5**	**3**	**81**	**743**
	4,038	**4,203**	**619**	**2,082**	**1,852**	**12,794**
Other revenues[1,2]	**—**	**111**	**—**	**502**	**272**	**885**
	4,038	**4,314**	**619**	**2,584**	**2,124**	**13,679**

1 Other revenues include income from the Company's marketing activities, financial instruments and lease arrangements within each operating segment. Income from lease arrangements includes certain long term PPAs, as well as certain liquids pipelines capacity and transportation arrangements. These arrangements are not in the scope of the new guidance, therefore, revenues related to these contracts are excluded from revenues from contracts with customers. Refer to Note 23, Risk management and financial instruments, for further information on income from financial instruments.

2 Other revenues from U.S. Natural Gas Pipelines include the amortization of the net regulatory liabilities resulting from U.S. Tax Reform. Refer to Note 16, Income taxes, for further information.

Revenues from contracts with customers are recognized net of any taxes collected from customers which are subsequently remitted to governmental authorities. The Company's contracts with customers include natural gas and liquids pipelines capacity arrangements and transportation contracts, power generation contracts, natural gas storage and other contracts.

Financial Statement Impact of Adopting Revenue from Contracts with Customers

The Company adopted the new guidance using the modified retrospective transition method. As a practical expedient under this transition method, the Company is not required to analyze completed contracts at the date of adoption. As a result, of adopting the new guidance, the Company made the adjustments described below on January 1, 2018.

Capacity Arrangements and Transportation

For certain natural gas pipeline capacity contracts, amounts are invoiced to the customer in accordance with the terms of the contract, however, the related revenues are recognized when the Company satisfies its performance obligation to provide committed capacity ratably over the term of the contract. This difference in timing between revenue recognition and amounts invoiced creates a contract asset or contract liability under the new revenue recognition guidance. Under legacy U.S. GAAP, these differences were recorded as Accounts receivable. Under the new guidance, contract assets are included in Other current assets and Intangibles and other assets and contract liabilities are included in Accounts payable and other and Other long-term liabilities.

Impact of New Revenue Recognition Guidance on Date of Adoption

The following table illustrates the impact of the adoption of the new revenue recognition guidance on the Company's previously reported consolidated balance sheet line items:

(millions of Canadian $)	As reported December 31, 2017	Adjustment	January 1, 2018
Current Assets			
Accounts receivable	2,537	(62)	2,475
Other[1]	691	79	770
Current Liabilities			
Accounts payable and other[2]	4,071	17	4,088

1 Adjustment relates to contract assets previously included in Accounts receivable.
2 Adjustment relates to contract liabilities previously included in Accounts receivable.

Pro-forma Financial Statements under Legacy U.S. GAAP

As required by the new revenue recognition guidance, the following tables illustrate the pro-forma impact on the affected line items on the Consolidated balance sheet, as at December 31, 2018, using legacy U.S. GAAP:

	December 31, 2018	
(millions of Canadian $)	As reported	Pro-forma using legacy U.S. GAAP
Current Assets		
Accounts receivable	**2,548**	**2,707**
Other	**1,180**	**1,021**

Contract Balances

(millions of Canadian $)	December 31, 2018	January 1, 2018
Receivables from contracts with customers	**1,684**	1,736
Contract assets[1]	**159**	79
Long-term contract assets[2]	**21**	—
Contract liabilities[3]	**11**	17
Long-term contract liabilities[4]	**121**	—

1 Recorded as part of Other current assets on the Consolidated balance sheet.
2 Recorded as part of Intangibles and other assets on the Consolidated balance sheet.
3 Comprised of deferred revenue recorded in Accounts payable and other on the Consolidated balance sheet. During the year ended December 31, 2018, $17 million of revenue was recognized that was included in the contract liability at the beginning of the year.
4 Comprised of deferred revenue recorded in Other long-term liabilities on the Consolidated balance sheet.

Contract assets and long-term contract assets primarily relate to the Company's right to revenues for services completed but not invoiced at the reporting date on long-term committed capacity natural gas pipelines contracts. The change in contract assets is primarily related to the transfer to Accounts receivable when these rights become unconditional and the customer is invoiced, as well as the recognition of additional revenues that remain to be invoiced. Contract liabilities and long-term contract liabilities primarily relate to force majeure fixed capacity payments received on long-term capacity arrangements in Mexico.

Future Revenues from Remaining Performance Obligations

As required by the new revenue recognition guidance, the following provides disclosure on future revenues allocated to remaining performance obligations representing contracted revenues that have not yet been recognized. Certain contracts that qualify for the use of one of the following practical expedients are excluded from the future revenues disclosures:

1. The original expected duration of the contract is one year or less.
2. The Company recognizes revenue from the contract that is equal to the amount invoiced, where the amount invoiced represents the value to the customer of the service performed to date. This is referred to as the "right to invoice" practical expedient.
3. The variable revenue generated from the contract is allocated entirely to a wholly unsatisfied performance obligation or to a wholly unsatisfied promise to transfer a distinct good or service that forms part of a single performance obligation in a series. A single performance obligation in a series occurs when the promises under a contract are a series of distinct services that are substantially the same and have the same pattern of transfer to the customer over time.

The following provides a discussion of the transaction price allocated to future performance obligations as well as practical expedients used by the Company.

Capacity Arrangements and Transportation

As at December 31, 2018, future revenues from long-term pipeline capacity arrangements and transportation contracts extending through 2043 are approximately $30.1 billion, of which approximately $6.0 billion is expected to be recognized in 2019.

Future revenues from long-term capacity arrangements and transportation contracts do not include constrained variable revenues or arrangements to which the right to invoice practical expedient has been applied. As a result, these amounts are not representative of potential total future revenues expected from these contracts.

Future revenues from the Company's Canadian natural gas pipelines' regulated firm capacity contracts include fixed revenues for the time periods that tolls under current rate settlements are in effect, which is approximately one to three years. Many of these contracts are long-term in nature and revenues from the remaining performance obligations that extend beyond the current rate settlement term are considered to be fully constrained since future tolls remain unknown. Revenues from these contracts will be recognized once the performance obligation to provide capacity has been satisfied and the regulator has approved the applicable tolls. In addition, the Company considers interruptible transportation service revenues to be variable revenues since volumes cannot be estimated. These variable revenues are recognized on a monthly basis when the Company satisfies the performance obligation and have been excluded from the future revenues disclosure as the Company applies the practical expedient related to variable revenues to these contracts. The future variable revenues earned under these contracts are allocated entirely to unsatisfied performance obligations at December 31, 2018.

The Company also applies the right to invoice practical expedient to all of its U.S. and certain of its Mexico regulated natural gas pipeline capacity arrangements and flow-through revenues. Revenues from regulated capacity arrangements are recognized based on current rates and flow-through revenues are earned from the recovery of operating expenses. These revenues are recognized on a monthly basis as the Company performs the services and are excluded from future revenues disclosures.

Revenues from liquids pipelines capacity arrangements have a variable component based on volumes transported. As a result, these variable revenues are excluded from the future revenues disclosures as the Company applies the practical expedient related to variable revenues to these contracts. The future variable revenues earned under these contracts are allocated entirely to unsatisfied performance obligations at December 31, 2018.

Power Generation

The Company has long-term power generation contracts extending through 2030. Revenues from power generation have a variable component related to market prices that are subject to factors outside the Company’s influence. These revenues are considered to be fully constrained and are recognized on a monthly basis when the Company satisfies the performance obligation. The Company applies the practical expedient related to variable revenues to these contracts. As a result, future revenues from these contracts are excluded from the disclosures.

Natural Gas Storage and Other

As at December 31, 2018, future revenues from long-term natural gas storage and other contracts extending through 2033 are approximately $1.2 billion, of which approximately $283 million is expected to be recognized in 2019. The Company applies the practical expedients related to contracts that are for a duration of one year or less and where it recognizes variable consideration, and therefore excludes the related revenues from the future revenues disclosure. As a result, this amount is lower than the potential total future revenues from these contracts.

6. ASSETS HELD FOR SALE

Coolidge Generating Station

On December 14, 2018, TCPL entered into an agreement to sell its Coolidge generating station in Arizona to SWG Coolidge Holdings, LLC for approximately US$465 million, subject to timing of the close and related adjustments. In January 2019, pursuant to the terms of the Coolidge PPA, Salt River Project Agriculture Improvement and Power District, the counterparty to this arrangement, exercised their right of first refusal on this sale.

The sale will result in an estimated gain of approximately $65 million ($50 million after tax) including the impact of an estimated $10 million of foreign currency translation gains. This gain will be recognized upon closing of the sale transaction, which is expected to occur mid-2019.

At December 31, 2018, the related assets and liabilities were classified as held for sale in the Energy segment as follows:

(millions of Canadian $)	
Assets held for sale	
Accounts receivable	**6**
Plant, property and equipment	**537**
Total assets held for sale	**543**
Liabilities related to assets held for sale	
Other long-term liabilities	**(3)**
Total liabilities related to assets held for sale[1]	**(3)**

1 Included in Accounts payable and other on the Consolidated balance sheet.

7. OTHER CURRENT ASSETS

at December 31 (millions of Canadian $)	**2018**	**2017**
Fair value of derivative contracts (Note 23)	**737**	332
Contract assets (Note 5)	**159**	—
Regulatory assets (Note 10)	**83**	23
Cash provided as collateral	**55**	99
Prepaid expenses	**41**	109
Other	**105**	128
	1,180	691

8. PLANT, PROPERTY AND EQUIPMENT

at December 31 (millions of Canadian $)	2018 Cost	2018 Accumulated Depreciation	2018 Net Book Value	2017 Cost	2017 Accumulated Depreciation	2017 Net Book Value
Canadian Natural Gas Pipelines						
NGTL System						
Pipeline	**10,764**	**4,500**	**6,264**	10,153	4,190	5,963
Compression	**3,289**	**1,677**	**1,612**	3,021	1,593	1,428
Metering and other	**1,247**	**613**	**634**	1,188	569	619
	15,300	**6,790**	**8,510**	14,362	6,352	8,010
Under construction	**2,111**	**—**	**2,111**	940	—	940
	17,411	**6,790**	**10,621**	15,302	6,352	8,950
Canadian Mainline						
Pipeline	**10,077**	**6,777**	**3,300**	9,763	6,455	3,308
Compression	**3,642**	**2,656**	**986**	3,605	2,499	1,106
Metering and other	**652**	**241**	**411**	655	207	448
	14,371	**9,674**	**4,697**	14,023	9,161	4,862
Under construction	**149**	**—**	**149**	156	—	156
	14,520	**9,674**	**4,846**	14,179	9,161	5,018
Other Canadian Natural Gas Pipelines[1]						
Other	**1,842**	**1,420**	**422**	1,815	1,363	452
Under construction	**124**	**—**	**124**	4	—	4
	1,966	**1,420**	**546**	1,819	1,363	456
	33,897	**17,884**	**16,013**	31,300	16,876	14,424
U.S. Natural Gas Pipelines						
Columbia Gas						
Pipeline	**6,711**	**251**	**6,460**	3,550	125	3,425
Compression	**2,932**	**132**	**2,800**	1,547	64	1,483
Metering and other	**2,884**	**75**	**2,809**	2,306	37	2,269
	12,527	**458**	**12,069**	7,403	226	7,177
Under construction	**4,347**	**—**	**4,347**	3,332	—	3,332
	16,874	**458**	**16,416**	10,735	226	10,509
ANR						
Pipeline	**1,600**	**443**	**1,157**	1,427	365	1,062
Compression	**1,978**	**388**	**1,590**	1,582	286	1,296
Metering and other	**1,217**	**324**	**893**	961	268	693
	4,795	**1,155**	**3,640**	3,970	919	3,051
Under construction	**272**	**—**	**272**	358	—	358
	5,067	**1,155**	**3,912**	4,328	919	3,409

at December 31 (millions of Canadian $)	2018 Cost	2018 Accumulated Depreciation	2018 Net Book Value	2017 Cost	2017 Accumulated Depreciation	2017 Net Book Value
Other U.S. Natural Gas Pipelines						
GTN	**2,322**	**951**	**1,371**	2,107	822	1,285
Great Lakes	**2,180**	**1,251**	**929**	1,988	1,113	875
Columbia Gulf	**1,753**	**74**	**1,679**	1,115	37	1,078
Midstream	**1,212**	**91**	**1,121**	1,085	54	1,031
Other[2]	**1,190**	**474**	**716**	1,950	574	1,376
	8,657	**2,841**	**5,816**	8,245	2,600	5,645
Under construction	**846**	**—**	**846**	699	—	699
	9,503	**2,841**	**6,662**	8,944	2,600	6,344
	31,444	**4,454**	**26,990**	24,007	3,745	20,262
Mexico Natural Gas Pipelines						
Pipeline	**3,172**	**301**	**2,871**	2,872	214	2,658
Compression	**506**	**41**	**465**	448	30	418
Metering and other	**640**	**91**	**549**	573	65	508
	4,318	**433**	**3,885**	3,893	309	3,584
Under construction	**1,990**	**—**	**1,990**	1,368	—	1,368
	6,308	**433**	**5,875**	5,261	309	4,952
Liquids Pipelines						
Keystone Pipeline System						
Pipeline	**9,780**	**1,271**	**8,509**	9,002	992	8,010
Pumping equipment	**1,065**	**184**	**881**	1,022	152	870
Tanks and other[3]	**3,598**	**488**	**3,110**	3,314	385	2,929
	14,443	**1,943**	**12,500**	13,338	1,529	11,809
Under construction[4]	**18**	**—**	**18**	456	—	456
	14,461	**1,943**	**12,518**	13,794	1,529	12,265
Intra-Alberta Pipelines[5]						
Pipeline	**762**	**22**	**740**	748	3	745
Pumping equipment	**104**	**3**	**101**	104	—	104
Tanks and other	**291**	**8**	**283**	259	1	258
	1,157	**33**	**1,124**	1,111	4	1,107
Under construction	**84**	**—**	**84**	47	—	47
	1,241	**33**	**1,208**	1,158	4	1,154
	15,702	**1,976**	**13,726**	14,952	1,533	13,419
Energy						
Natural Gas[6]	**2,062**	**708**	**1,354**	2,645	743	1,902
Wind[7]	**—**	**—**	**—**	673	204	469
Natural Gas Storage and Other	**741**	**169**	**572**	734	156	578
	2,803	**877**	**1,926**	4,052	1,103	2,949
Under construction	**1,735**	**—**	**1,735**	1,028	—	1,028
	4,538	**877**	**3,661**	5,080	1,103	3,977
Corporate	**448**	**210**	**238**	411	168	243
	92,337	**25,834**	**66,503**	81,011	23,734	57,277

1 Includes Foothills, Ventures LP, Great Lakes Canada and Coastal GasLink.
2 Includes Portland, North Baja, Tuscarora and Crossroads as well as Bison for 2017. Bison's remaining carrying value was fully impaired at December 31, 2018.
3 Includes tanks that are accounted for as operating leases. The cost and accumulated depreciation of these facilities were $194 million and $23 million, respectively, at December 31, 2018 (2017 – $184 million and $19 million, respectively), while revenues of $15 million were recognized in 2018 (2017 – $16 million; 2016 – $16 million).
4 Certain costs related to the Keystone XL project were recorded in Plant, property and equipment at December 31, 2017. In 2018, these costs were reclassified to Capital projects in development as the Company recommenced capitalizing Keystone XL development costs.
5 Includes Northern Courier and White Spruce. Northern Courier is accounted for as an operating lease and was placed in service on November 1, 2017. The cost and accumulated depreciation of this facility were $1,130 million and $32 million, respectively, at December 31, 2018 (2017 – $1,111 million and $4 million, respectively), while revenues of $142 million were recognized in 2018 (2017 – $20 million).
6 Includes Coolidge, Grandview, Bécancour, Halton Hills and the Alberta cogeneration natural gas-fired facilities. Coolidge, Grandview and Bécancour have long-term PPAs that are accounted for as operating leases. The cost and accumulated depreciation of these facilities were $655 million and $268 million, respectively, at December 31, 2018 (2017 – $1,264 million and $354 million, respectively). At December 31, 2018, the cost and accumulated depreciation of Coolidge were reclassified to Assets held for sale. Refer to Note 6, Assets held for sale, for further information. Revenues of $216 million were recognized in 2018 (2017 – $215 million; 2016 – $212 million) through the sale of electricity under the related PPAs for these assets.
7 The Company closed the sale of its Cartier Wind power assets on October 24, 2018. Refer to Note 25, Acquisitions and dispositions, for further information.

Bison Impairment

At December 31, 2018, the Company evaluated its investment in its Bison natural gas pipeline for impairment in connection with the termination of certain customer transportation agreements. The termination of these agreements released the Company from providing any future services. With the loss of these future cash flows and the persistence of unfavourable market conditions which have inhibited system flows on the pipeline, the Company determined that the asset's remaining carrying value was no longer recoverable and recognized a non-cash impairment charge of $722 million pre-tax in its U.S. Natural Gas Pipelines segment. The non-cash charge was recorded in Goodwill and other asset impairment charges on the Consolidated statement of income. As Bison is a TC PipeLines, LP asset, in which the Company has a 25.5 per cent interest, the Company's share of the impairment charge, after tax and net of non-controlling interests, was $140 million.

The termination of the transportation agreements resulted in the receipt of $130 million in termination payments which were recorded in Revenues in 2018. The Company's share of this amount, after tax and net of non-controlling interests, was $25 million.

Energy East and Related Projects Impairment

On October 5, 2017, the Company informed the NEB that it will not proceed with the Energy East, Eastern Mainline and Upland projects. Based on this decision, the Company evaluated the carrying value of its Property, plant and equipment related to the Eastern Mainline project including AFUDC. Due to the inability to reach a regulatory decision for this project, there were no recoveries of costs from third parties. As a result, the Company recognized a non-cash impairment charge of $83 million ($64 million after tax) in the Liquids Pipelines segment. The non-cash charge was recorded in Goodwill and other asset impairment charges on the Consolidated statement of income.

Energy Turbine Impairment

At December 31, 2017, the Company recognized a non-cash impairment charge of $21 million ($16 million after tax) in the Energy segment related to the remaining carrying value of certain equipment after determining that it was no longer recoverable. This turbine equipment was previously purchased for a power development project that did not proceed. The non-cash charge was recorded in Goodwill and other asset impairment charges on the Consolidated statement of income.

9. EQUITY INVESTMENTS

(millions of Canadian $)	Ownership Interest at December 31, 2018	Income/(Loss) from Equity Investments year ended December 31 2018	2017	2016	Equity Investments at December 31 2018	2017
Canadian Natural Gas Pipelines						
TQM	50.0%	**12**	11	12	**71**	68
U.S. Natural Gas Pipelines						
Northern Border[1]	50.0%	**87**	87	92	**677**	641
Iroquois[2]	50.0%	**60**	59	54	**291**	280
Millennium[3]	47.5%	**75**	66	33	**511**	291
Pennant Midstream[3]	47.0%	**17**	11	6	**256**	228
Other	Various	**17**	17	29	**113**	92
Mexico Natural Gas Pipelines						
Sur de Texas[4]	60.0%	**27**	66	(3)	**627**	399
TransGas	nil	**—**	(12)	—	**—**	—
Liquids Pipelines						
Grand Rapids[5]	50.0%	**65**	17	(1)	**1,028**	996
Other[6]	Various	**(1)**	(20)	—	**21**	20
Energy						
Bruce Power[7]	48.3%	**311**	434	293	**3,166**	2,987
Portlands Energy[8]	50.0%	**36**	31	33	**289**	301
ASTC Power Partnership	50.0%	**—**	—	(37)	**—**	—
Other	Various	**8**	6	3	**63**	63
		714	773	514	**7,113**	6,366

1 At December 31, 2018, the difference between the carrying value of the investment and the underlying equity in the net assets of Northern Border Pipeline Company was US$115 million (2017 – US$115 million) due to the fair value assessment of assets at the time of acquisition.

2 At December 31, 2018, the difference between the carrying value of the investment and the underlying equity in the net assets of Iroquois was US$41 million (2017 – US$41 million) due mainly to the fair value assessment of the assets at the time of acquisition.

3 Acquired as part of Columbia Pipeline Group, Inc. (Columbia) on July 1, 2016. Income from Equity investments reflects equity earnings from the date of acquisition.

4 TCPL has an ownership interest of 60.0 per cent in Sur de Texas which, as a jointly controlled entity, applies the equity method of accounting. Income from equity investments includes foreign exchange gains and losses recorded in the Corporate segment which are fully offset in Interest income and other in the Consolidated statement of income.

5 Grand Rapids was placed in service in August 2017. At December 31, 2018, the difference between the carrying value of the investment and the underlying equity in the net assets of Grand Rapids was $102 million (2017 – $105 million) due mainly to interest capitalized during construction and the fair value of guarantees.

6 Includes investments in Canaport Energy East Marine Terminal Limited Partnership and HoustonLink Pipeline Company LLC. At December 31, 2018 and 2017, the Canaport Energy East Marine Terminal Limited Partnership investment was nil.

7 At December 31, 2018, the difference between the carrying value of the investment and the underlying equity in the net assets of Bruce Power was $870 million (2017 – $902 million) due to the fair value assessment of assets at the time of acquisitions.

8 At December 31, 2018, the difference between the carrying value of the investment and the underlying equity in the net assets of Portlands Energy was $73 million (2017 – $73 million) due mainly to interest capitalized during construction.

TransGas de Occidente S.A. Impairment

In August 2017, TCPL recognized an impairment charge of $12 million on its 46.5 per cent equity investment in TransGas de Occidente S.A. (TransGas). TransGas constructed and operated a natural gas pipeline in Colombia for a 20-year contract term. As per the terms of the agreement, upon completion of the 20-year contract in August 2017, TransGas transferred its pipeline assets to Transportadora de Gas Internacional S.A. The non-cash impairment charge represented the write-down of the remaining carrying value of the equity investment which was recognized in Income from equity investments in the Consolidated statement of income.

Canaport Energy East Marine Terminal Limited Partnership Impairment
On October 5, 2017, the Company informed the NEB that it will not be proceeding with the Energy East, Eastern Mainline and Upland projects. As a result, in October 2017, the Company recognized a non-cash impairment charge of $20 million in Income from equity investments in its Liquids Pipelines segment which represented the carrying value of the equity investment in the Canaport Energy East Marine Terminal Limited Partnership. Due to the inability to reach a regulatory decision for this project, there were no recoveries of costs from third parties.

ASTC Power Partnership Impairment
In March 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 was 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, in first quarter 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 and Contributions

Distributions received from equity investments for the year ended December 31, 2018 were $1,106 million (2017 – $1,332 million; 2016 – $1,571 million) of which $121 million (2017 – $362 million; 2016 – $727 million) was included in Investing activities in the Consolidated statement of cash flows with respect to distributions received from Bruce Power from its financing program.

Contributions made to equity investments for the year ended December 31, 2018 were $1,015 million (2017 – $1,681 million; 2016 – $765 million) and are included in Investing activities in the Consolidated statement of cash flows. For 2018, contributions include $179 million (2017 – $977 million) related to TCPL's proportionate share of the Sur de Texas debt financing requirements.

Summarized Financial Information of Equity Investments

year ended December 31 (millions of Canadian $)	**2018**	**2017**	**2016**
Income			
Revenues	**4,836**	4,913	4,336
Operating and other expenses	**(3,545)**	(2,993)	(3,068)
Net income	**1,515**	1,636	1,080
Net income attributable to TCPL	**714**	773	514

at December 31 (millions of Canadian $)	**2018**	**2017**
Balance Sheet		
Current assets	**2,209**	2,176
Non-current assets	**20,647**	17,869
Current liabilities	**(2,049)**	(1,577)
Non-current liabilities	**(9,042)**	(8,217)

Loan receivable from affiliate

TCPL holds a 60 per cent equity interest in a joint venture with IEnova to build, own and operate the Sur de Texas pipeline. In 2017, TCPL entered into a MXN$21.3 billion unsecured revolving credit facility with the joint venture, which bears interest at a floating rate and matures in March 2022. At December 31, 2018, the Company's consolidated balance sheet included a MXN $18.9 billion or $1.3 billion (2017 – MXN$14.4 billion or $0.9 billion) loan receivable from the Sur de Texas joint venture which represents TCPL's proportionate share of long-term debt financing requirements related to the joint venture. Interest income and other included interest income of $120 million in 2018 (2017 – $34 million) from this joint venture with a corresponding proportionate share of interest expense recorded in Income from equity investments.

10. RATE-REGULATED BUSINESSES

TCPL's businesses that apply RRA currently include certain Canadian, U.S. and Mexico natural gas pipelines, and certain regulated U.S. natural gas storage operations. Rate-regulated businesses account for and report assets and liabilities consistent with the resulting economic impact of the regulators' established rates, provided the rates 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 that would otherwise be reflected in the statement of income are deferred on the balance sheet and are expected to be included in future service rates and recovered from or refunded to customers in subsequent years.

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 actual costs and revenues are more or less than 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 most significant regulated Canadian natural gas pipelines are described below.

NGTL System

NGTL's 2018 results reflect the terms of the 2018-2019 Revenue Requirement Settlement (the 2018-2019 Settlement) approved by the NEB in June 2018. This two-year settlement includes an ROE of 10.1 per cent on 40 per cent deemed common equity, a composite depreciation rate of approximately 3.5 per cent, 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.

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 use of deferral accounts, namely the bridging amortization account and the long-term adjustment account (LTAA), to capture the surplus or shortfall between the Company's revenues and cost of service for each year over the 2015-2020 six-year fixed toll term of the NEB 2014 Decision. The NEB 2014 Decision also directed TCPL to file an application to review tolls for the 2018-2020 period. In December 2018, an NEB decision was received on the 2018-2020 Tolls Review (NEB 2018 Decision) which included an accelerated amortization of the December 31, 2017 LTAA balance and an increase to the composite depreciation rate from 3.2 per cent to 3.9 per cent.

U.S. Regulated Operations

TCPL's U.S. regulated 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. regulated natural gas pipelines to discount or negotiate rates on a non-discriminatory basis. The Company's most significant regulated U.S. natural gas pipelines, based on effective ownership and total operated pipe length, are described below.

In 2018, FERC prescribed changes (2018 FERC Actions) related to U.S. Tax Reform and income taxes for rate-making purposes in a master limited partnership (MLP) that impact future earnings and cash flows of FERC-regulated pipelines. The 2018 FERC Actions also established a process and schedule by which all FERC-regulated interstate pipelines and natural gas storage facilities had to either (i) file a new uncontested rate settlement or (ii) file a FERC Form 501-G that quantifies the isolated impact of U.S. Tax Reform on FERC-regulated pipelines and natural gas storage assets as well as the impact of the 2018 FERC Actions on pipelines held by MLPs.

The impact of the 2018 FERC Actions on the Company's more significant U.S. regulated natural gas pipelines is included 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.

In response to the 2018 FERC Actions, Columbia Gas filed a Form 501-G including a statement explaining its rationale why the pipeline's rates are not required to change.

ANR Pipeline

ANR Pipeline operates under rates established under a FERC-approved rate settlement in 2016. Under terms of the 2016 settlement, neither ANR Pipeline nor the settling parties could file for new rates to become effective earlier than August 1, 2019. However, ANR Pipeline is required to file for new rates to be effective no later than August 1, 2022.

In December 2018, ANR Pipeline filed a Form 501-G including a statement explaining its rationale why the pipeline's rates are not required to change.

Columbia Gulf

Columbia Gulf's natural gas transportation services are provided under a tariff at rates subject to FERC approval. In September 2016, 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 required 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.

In response to the 2018 FERC Actions, Columbia Gulf filed a Form 501-G including a statement explaining its rationale why the pipeline's rates are not required to change.

TC PipeLines, LP

TCPL owns a 25.5 per cent interest in TC PipeLines, LP, which has ownership interests in eight wholly-owned or partially-owned natural gas pipelines serving major markets in the U.S. As TC PipeLines, LP is an MLP, all pipelines it owns wholly or in part were potentially impacted by the 2018 FERC Actions which creates a presumption that entities whose earnings are not taxed through a corporation should not be permitted to recover an income tax allowance in their regulated cost-of-service rates. Additionally, to the extent an entity's income tax allowance is eliminated from rates, it must also eliminate its existing accumulated deferred income tax (ADIT) balance from its rate base. Refer to Note 16, Income Taxes for further information regarding the impact of these changes to TCPL.

Great Lakes

Great Lakes reached a rate settlement with its customers, which was approved by FERC on February 22, 2018, decreasing Great Lakes' maximum transportation rates by 27 per cent effective October 1, 2017. This settlement does not contain a moratorium and Great Lakes will be required to file for new rates no later than March 31, 2022, with new rates to be effective October 1, 2022. As a result of the 2018 FERC Actions, Great Lakes made a limited Section 4 filing which had the effect of reducing rates by 2 per cent from what was in place prior to the FERC changes in 2018. The reduction in rates became effective on February 1, 2019 after the limited Section 4 filing was accepted by FERC on January 31, 2019.

Mexico Regulated Operations

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

Regulatory Assets and Liabilities

at December 31 (millions of Canadian $)	2018	2017	Remaining Recovery/ Settlement Period (years)
Regulatory Assets			
Deferred income taxes[1]	**1,051**	940	n/a
Operating and debt-service regulatory assets[2]	**12**	—	1
Pensions and other post-retirement benefits[1,3]	**379**	388	n/a
Foreign exchange on long-term debt[1,4]	**46**	—	1-11
Other	**143**	71	n/a
	1,631	1,399	
Less: Current portion included in Other current assets (Note 7)	**83**	23	
	1,548	1,376	
Regulatory Liabilities			
Operating and debt-service regulatory liabilities[2]	**96**	188	1
Pensions and other post-retirement benefits[3]	**53**	164	n/a
ANR related post-employment and retirement benefits other than pension[5]	**54**	66	n/a
Long term adjustment account[6]	**1,015**	1,142	2-45
Bridging amortization account[6]	**305**	202	12
Pipeline abandonment trust balance	**1,113**	825	n/a
Cost of removal[7]	**261**	216	n/a
Deferred income taxes	**165**	75	n/a
Deferred income taxes – U.S. Tax Reform[8]	**1,394**	1,659	n/a
Other	**65**	47	n/a
	4,521	4,584	
Less: Current portion included in Accounts payable and other (Note 14)	**591**	263	
	3,930	4,321	

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 regulator 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 or refunded to customers in future rates.

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 the amount ANR estimates 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. Pursuant to a FERC-approved September 2016 rate settlement, $11 million (US$8 million) of the regulatory liability balance at December 31, 2018 (2017 – $26 million; US$21 million) which accumulated between January 2007 and July 2016 will be fully amortized at July 31, 2019. The remaining $43 million (US$32 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 plus toll stabilization during the 2015-2030 settlement term. The 2018 LTAA balance of $1,015 million consists of $932 million to be amortized over two years with the remaining balance to be amortized over 45 years.

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 operations for future costs to be incurred.

8 These balances represent the impact of U.S. Tax Reform. The regulatory liabilities will be amortized over varying terms that approximate the expected reversal of the underlying deferred tax liabilities that gave rise to the regulatory liabilities. See Note 16, Income taxes, for further information on U.S. Tax Reform.

11. GOODWILL

The Company has recorded the following Goodwill on its acquisitions:

(millions of Canadian $)	U.S. Natural Gas Pipelines
Balance at January 1, 2017	13,958
Columbia adjustment (Note 25)	71
Foreign exchange rate changes	(945)
Balance at December 31, 2017	13,084
Tuscarora impairment charge	**(79)**
Foreign exchange rate changes	**1,173**
Balance at December 31, 2018	**14,178**

Tuscarora

In the fourth quarter of 2018, the Company finalized its regulatory filing for Tuscarora in response to the 2018 FERC Actions and Form 501-G requirements. In January 2019, Tuscarora reached a settlement-in-principle with its customers which was filed with FERC. As a result of these developments, as well as changes to other valuation assumptions responsive to Tuscarora's commercial environment, it was determined that the fair value of Tuscarora did not exceed its carrying value, including goodwill. The fair value of the reporting unit was determined using a discounted cash flow analysis. 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 of $79 million pre-tax within the U.S. Natural Gas Pipelines segment. This non-cash charge was recorded in Goodwill and other asset impairment charges on the Consolidated statement of income. As Tuscarora is a TC PipeLines, LP asset, the Company's share of this amount, after tax and net of non-controlling interests, was $15 million. The goodwill balance related to Tuscarora at December 31, 2018 was US$23 million (2017 – US$82 million).

Great Lakes

At December 31, 2018, 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 its 501-G election, revenue opportunities on the system as well as changes to other valuation assumptions responsive to Great Lakes' commercial environment. Although evolving market conditions and other factors relevant to Great Lakes' long term financial performance have been positive, 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. The goodwill balance related to Great Lakes at December 31, 2018 was US$573 million (2017 – US$573 million).

Ravenswood

As a result of information received during the process to monetize the Company's U.S. Northeast power business in 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 analysis 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, in 2016, 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.

12. INTANGIBLE AND OTHER ASSETS

at December 31 (millions of Canadian $)	2018	2017
Capital projects in development	**1,051**	596
Deferred income tax assets (Note 16)	**288**	255
Employee post-retirement benefits (Note 22)	**192**	193
Fair value of derivative contracts (Note 23)	**61**	73
Other	**295**	306
	1,887	1,423

Capital projects in development

Keystone XL

In January 2018, the Company recommenced capitalizing development costs related to Keystone XL. In addition, certain project costs that were recorded in Plant, property and equipment at December 31, 2017 were transferred to Capital projects in development in 2018. These costs were related to the net realizable value of Keystone XL assets after an impairment charge was recorded in 2015. As a result, at December 31, 2018, Capital projects in development for this project were $0.8 billion (2017 – nil).

Reimbursement of Coastal GasLink pipeline costs

In accordance with provisions in the agreements with the LNG Canada joint venture participants, all five parties elected to reimburse TCPL for their share of costs incurred prior to receiving the Final Investment Decision (FID) on the Coastal GasLink pipeline project. In November 2018, the Company received payments totaling $470 million which were recorded as a reduction of the carrying value of Coastal GasLink.

Prince Rupert Gas Transmission

In July 2017, the Company was notified that Pacific Northwest LNG would not be proceeding with its proposed LNG project and that Progress Energy (Progress) would be terminating its agreement with TCPL for the development of the PRGT project effective August 10, 2017. In accordance with the terms of the agreement, all project costs incurred to advance the project, including carrying charges, were fully recoverable upon termination. In October 2017, the Company received full payment of the $634 million reimbursement from Progress.

Energy East and Related Projects Impairment

On October 5, 2017, the Company informed the NEB that it will not proceed with the Energy East, Eastern Mainline and Upland projects. Based on this decision, the Company evaluated its Capital projects in development balance related to the Energy East and Upland projects including AFUDC. As a result, the Company recognized a non-cash impairment charge of $1,153 million ($870 million after tax) in the Liquids Pipelines segment. Due to the inability to reach a regulatory decision for this project, there were no recoveries of costs from third parties. The non-cash charge was recorded in Goodwill and other asset impairment charges on the Consolidated statement of income.

Power Purchase Arrangements Impairment

In March 2016, TCPL terminated its Sheerness and Sundance A PPAs. In accordance with a provision in the PPAs, a buyer was permitted to terminate the arrangement if a change in law occurs that makes the arrangement unprofitable or more unprofitable. 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, representing the carrying value of the PPAs which was recorded in Intangible and other assets. 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.

13. NOTES PAYABLE

(millions of Canadian $, unless otherwise noted)	2018 Outstanding at December 31	2018 Weighted Average Interest Rate per Annum at December 31	2017 Outstanding at December 31	2017 Weighted Average Interest Rate per Annum at December 31
Canada	**2,117**	**2.5%**	884	1.6%
U.S. (2018 – US$448; 2017 – US$688)	**611**	**3.1%**	862	2.2%
Mexico (2018 – US$25; 2017 – MXN$275)	**34**	**3.3%**	17	8.0%
	2,762		1,763	

At December 31, 2018, Notes payable consists of short-term borrowings in Canada by TCPL, in the U.S. by TransCanada PipeLine USA Ltd. (TCPL USA) and TransCanada American Investments Ltd. (TAIL), and in Mexico by a Mexican subsidiary.

At December 31, 2018, total committed revolving and demand credit facilities were $12.9 billion (2017 – $11.0 billion). When drawn, interest on these lines of credit is charged at negotiated floating rates of Canadian and U.S. banks, and at other negotiated financial bases. These unsecured credit facilities included the following:

at December 31 (billions of Canadian $, unless otherwise noted) Borrower	Description	Matures	2018 Total Facilities	2018 Unused Capacity	2017 Total Facilities
Committed, syndicated, revolving, extendible, senior unsecured credit facilities[1]:					
TCPL	Supports TCPL's Canadian dollar commercial paper program and for general corporate purposes	December 2023	**3.0**	**3.0**	3.0
TCPL/TCPL USA/ Columbia/TAIL	Supports TCPL, TCPL USA and TAIL's U.S. dollar commercial paper programs and is used for general corporate purposes of the borrowers, guaranteed by TCPL	December 2019	**US 4.5**	**US 4.5**	—
TCPL/TCPL USA/ Columbia/TAIL	Used for general corporate purposes of the borrowers, guaranteed by TCPL	December 2021	**US 1.0**	**US 1.0**	—
TCPL	Supports TCPL's U.S. dollar commercial paper program and for general corporate purposes		**—**	**—**	US 2.0
TCPL USA	Used for TCPL USA general corporate purposes, guaranteed by TCPL		**—**	**—**	US 1.0
Columbia	Used for Columbia general corporate purposes, guaranteed by TCPL		**—**	**—**	US 1.0
TAIL	Supports TAIL's U.S. dollar commercial paper program and for general corporate purposes, guaranteed by TCPL		**—**	**—**	US 0.5
Demand senior unsecured revolving credit facilities[1]:					
TCPL/TCPL USA	Supports the issuance of letters of credit and provides additional liquidity, TCPL USA facility guaranteed by TCPL	Demand	**2.1**	**1.0**	1.9
Mexico subsidiary	Used for Mexico general corporate purposes, guaranteed by TCPL	Demand	**MXN 5.0**	**MXN 4.5**	MXN 5.0

1 Provisions of various credit arrangements with the Company's subsidiaries can restrict their ability to declare and pay dividends or make distributions under certain circumstances. If such restrictions apply, they may, in turn, have an impact on the Company's ability to declare and pay dividends on common shares. These credit arrangements also require the Company to comply with various affirmative and negative covenants and maintain certain financial ratios. At December 31, 2018, the Company was in compliance with all debt covenants.

For the year ended December 31, 2018, the cost to maintain the above facilities was $12 million (2017 – $7 million; 2016 – $10 million).

At December 31, 2018, the Company's operated affiliates had an additional $0.8 billion (2017 – $0.4 billion) of undrawn capacity on committed credit facilities.

14. ACCOUNTS PAYABLE AND OTHER

at December 31 (millions of Canadian $)	2018	2017
Trade payables	**3,224**	2,847
Fair value of derivative contracts (Note 23)	**922**	387
Unredeemed shares of Columbia	**357**	312
Regulatory liabilities (Note 10)	**591**	263
Other	**332**	262
	5,426	4,071

15. OTHER LONG-TERM LIABILITIES

at December 31 (millions of Canadian $)	2018	2017
Employee post-retirement benefits (Note 22)	**569**	389
Asset retirement obligations	**90**	98
Fair value of derivative contracts (Note 23)	**42**	72
Guarantees (Note 26)	**12**	16
Other	**295**	152
	1,008	727

16. INCOME TAXES

U.S. Tax Reform

On December 22, 2017, the President of the United States signed H.R.1, the Tax Cuts and Jobs Act (U.S. Tax Reform or the Act) into law. As a result, among other things, the enacted U.S. federal corporate income tax rate was reduced from 35 per cent to 21 per cent effective January 1, 2018 and resulted in a remeasurement of existing deferred income tax assets and deferred income tax liabilities related to the Company's U.S. businesses to reflect the new lower income tax rate as at December 31, 2017.

For the Company's U.S. businesses not subject to RRA, the reduction in enacted income tax rates resulted in a decrease in net deferred income tax liabilities and a deferred income tax recovery of $816 million in 2017. For the Company's U.S. businesses subject to RRA, the reduction in income tax rates resulted in a reduction in net deferred income tax liabilities and the recognition of a net regulatory liability of $1,686 million on the Consolidated balance sheet at December 31, 2017.

Net deferred income tax liabilities related to the cumulative remeasurements of employee post-retirement benefits included in AOCI were also adjusted with a corresponding increase in deferred income tax expense of $12 million in 2017.

Given the significance of the legislation, the U.S. Securities and Exchange Commission (SEC) staff issued guidance which allowed registrants to record provisional amounts at December 31, 2017 which may be adjusted as information becomes available, prepared or analyzed during a measurement period not to exceed one year. The SEC guidance summarized a three-step process to be applied at each reporting period to identify: (1) where the accounting is complete; (2) provisional amounts where the accounting is not yet complete, but a reasonable estimate has been determined; and (3) where a reasonable estimate cannot yet be determined and therefore income taxes are reflected in accordance with law prior to the enactment of the Act.

At December 31, 2017, the Company considered amounts recorded related to U.S. Tax Reform to be reasonable estimates, however, certain amounts were provisional as the Company's interpretation, assessment and presentation of the impact of the tax law change were further clarified with additional guidance from regulatory, tax and accounting authorities received in 2018. With additional guidance provided during the one-year measurement period and upon finalizing its 2017 annual tax return for its U.S. businesses, in fourth quarter 2018 the Company recognized further adjustments to its deferred income tax liability and net regulatory liability balances as well as a deferred income tax recovery of $52 million in fourth quarter 2018.

In addition, the 2018 FERC Actions established that, to the extent an entity's income tax allowance should be eliminated from rates, it must also eliminate its existing ADIT balance from its rate base. In accordance with the FERC Form 501-G and uncontested rate settlement filings, the ADIT balances for all pipelines held wholly or in part by TC PipeLines, LP were eliminated from their respective rate bases. As a result, net regulatory liabilities recorded for these assets pursuant to U.S. Tax Reform were written off, resulting in a further deferred income tax recovery of $115 million in fourth quarter 2018.

Commencing January 1, 2018, the Company amortized the net regulatory liabilities, recorded per U.S. Tax Reform, using the Reverse South Georgia methodology. Under this methodology, rate-regulated entities determine and immediately begin recording amortization based on their composite depreciation rates. In 2018, amortization of these net regulatory liabilities in the amount of $58 million was recorded and included in Revenues in the Consolidated statement of income. The net regulatory liability related to U.S. Tax Reform at December 31, 2018 was $1,394 million (2017 – $1,686 million).

Further to U.S. Tax Reform, the U.S. Treasury and the U.S. Internal Revenue Service issued proposed regulations in November and December of 2018 which provided administrative guidance and clarified certain aspects of the new laws with respect to interest deductibility, base erosion and anti-abuse tax, the new dividend received deduction and anti-hybrid rules. Based on the Company's review and analysis of these proposed regulations, no material adjustments were recorded in the 2018 Consolidated financial statements. The proposed regulations are complex and comprehensive, and considerable uncertainty continues to exist until the final regulations are released, which is expected to occur later in 2019. TCPL continues to review and analyze these proposed regulations as well as assess their potential impact on the Company.

Provision for Income Taxes

year ended December 31 (millions of Canadian $)	**2018**	**2017**	**2016**
Current			
Canada	**66**	113	117
Foreign	**250**	36	40
	316	149	157
Deferred			
Canada	**19**	(203)	97
Foreign	**235**	751	95
Foreign – U.S. Tax Reform and 2018 FERC Actions	**(167)**	(804)	—
	87	(256)	192
Income Tax Expense/(Recovery)	**403**	(107)	349

Geographic Components of Income before Income Taxes

year ended December 31 (millions of Canadian $)	**2018**	**2017**	**2016**
Canada	**317**	(408)	304
Foreign	**3,516**	3,645	618
Income before Income Taxes	**3,833**	3,237	922

Reconciliation of Income Tax Expense/(Recovery)

year ended December 31 (millions of Canadian $)	2018	2017	2016
Income before income taxes	**3,833**	3,237	922
Federal and provincial statutory tax rate	**27%**	27%	27%
Expected income tax expense	**1,035**	874	249
U.S. Tax Reform and 2018 FERC Actions	**(167)**	(804)	—
Foreign income tax rate differentials	**(432)**	(81)	(196)
Loss/(income) from equity investments and non-controlling interests	**50**	(64)	(68)
Income tax differential related to regulated operations	**(54)**	(42)	81
Non-taxable portion of capital gains	**(11)**	(42)	—
Asset impairment charges[1]	**—**	34	242
Non-deductible amounts	**—**	4	18
Other	**(18)**	14	23
Income Tax Expense/(Recovery)	**403**	(107)	349

1 Net of nil (2017 – nil, 2016 — $112 million) attributed to higher foreign tax rates.

Deferred Income Tax Assets and Liabilities

at December 31 (millions of Canadian $)	2018	2017
Deferred Income Tax Assets		
Tax loss and credit carryforwards	**1,238**	1,365
Difference in accounting and tax bases of impaired assets and assets held for sale	**574**	651
Regulatory and other deferred amounts	**858**	512
Unrealized foreign exchange losses on long-term debt	**491**	216
Financial instruments	**—**	10
Other	**258**	180
	3,419	2,934
Less: valuation allowance	**1,159**	832
	2,260	2,102
Deferred Income Tax Liabilities		
Difference in accounting and tax bases of plant, property and equipment and PPAs	**6,449**	6,240
Equity investments	**1,069**	632
Taxes on future revenue requirement	**300**	238
Other	**180**	140
	7,998	7,250
Net Deferred Income Tax Liabilities	**5,738**	5,148

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

at December 31 (millions of Canadian $)	2018	2017
Deferred Income Tax Assets		
Intangible and other assets (Note 12)	**288**	255
Deferred Income Tax Liabilities		
Deferred income tax liabilities	**6,026**	5,403
Net Deferred Income Tax Liabilities	**5,738**	5,148

At December 31, 2018, the Company has recognized the benefit of unused non-capital loss carryforwards of $1,867 million (2017 – $1,231 million) for federal and provincial purposes in Canada, which expire from 2030 to 2038. The Company has not recognized the benefit of capital loss carry forwards of $821 million (2017 – $668 million) for federal and provincial purposes in Canada. The Company also has recognized the benefit of Ontario minimum tax credits of $91 million (2017 – $82 million), which expire from 2026 to 2038.

At December 31, 2018, the Company has recognized the benefit of unused net operating loss carryforwards of US$889 million (2017 – US$1,800 million) for federal purposes in the U.S., which expire from 2029 to 2037. The Company has not recognized the benefit of unused net operating loss carryforwards of US$706 million (2017 – US$710 million) for federal purposes in the U.S. The Company also has recognized the benefit of alternative minimum tax credits of US$1 million (2017 – US$56 million).

At December 31, 2018, the Company has recognized the benefit of unused net operating loss carryforwards of US$3 million (2017 – US$7 million) in Mexico, which expire from 2024 to 2028.

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, 2018 by approximately $619 million (2017 – $569 million) if there had been a provision for these taxes.

Income Tax Payments

Income tax payments of $338 million, net of refunds, were made in 2018 (2017 – payments, net of refunds, of $247 million; 2016 – payments, net of refunds, of $105 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 $)	**2018**	**2017**	**2016**
Unrecognized tax benefit at beginning of year	**13**	15	13
Gross increases – tax positions in prior years	**13**	—	3
Gross decreases – tax positions in prior years	**(5)**	(1)	—
Gross increases – tax positions in current year	**—**	2	2
Settlement	**—**	—	(1)
Lapse of statutes of limitations	**(3)**	(3)	(2)
Unrecognized Tax Benefit at End of Year	**18**	13	15

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 2010. 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, 2018 reflects nil of interest expense and nil for penalties (2017 – nil of interest expense and nil for penalties; 2016 – nil of interest expense and nil for penalties). At December 31, 2018, the Company had $3 million accrued for interest expense and nil accrued for penalties (December 31, 2017 – $4 million accrued for interest expense and nil accrued for penalties).

17. LONG-TERM DEBT

Outstanding amounts (millions of Canadian $, unless otherwise noted)	Maturity Dates	2018 Outstanding at December 31	2018 Interest Rate[1]	2017 Outstanding at December 31	2017 Interest Rate[1]
TRANSCANADA PIPELINES LIMITED					
Debentures					
Canadian	2019 to 2020	**350**	**11.4%**	500	10.8%
U.S. (2018 and 2017 – US$400)	2021	**546**	**9.9%**	501	9.9%
Medium Term Notes					
Canadian	2019 to 2048	**7,504**	**4.8%**	6,504	4.9%
Senior Unsecured Notes					
U.S. (2018 – US$17,192; 2017 – US$14,892)	2019 to 2049	**23,456**	**5.1%**	18,644	5.1%
		31,856		26,149	
NOVA GAS TRANSMISSION LTD.					
Debentures and Notes					
Canadian	2024	**100**	**9.9%**	100	9.9%
U.S. (2018 and 2017 – US$200)	2023	**273**	**7.9%**	250	7.9%
Medium Term Notes					
Canadian	2025 to 2030	**504**	**7.4%**	504	7.4%
U.S. (2018 and 2017 – US$33)	2026	**44**	**7.5%**	41	7.5%
		921		895	
COLUMBIA PIPELINE GROUP, INC.					
Senior Unsecured Notes					
U.S. (2018 – US$2,250; 2017 – US$2,750)[2]	2020 to 2045	**3,070**	**4.4%**	3,443	4.0%
TC PIPELINES, LP					
Unsecured Loan Facility					
U.S. (2018 – US$40; 2017 – US$185)	2021	**55**	**3.8%**	232	2.7%
Unsecured Term Loan					
U.S. (2018 – US$500; 2017 – US$670)[3]	2022	**682**	**3.6%**	839	2.7%
Senior Unsecured Notes					
U.S. (2018 and 2017 – US$1,200)	2021 to 2027	**1,637**	**4.4%**	1,502	4.4%
		2,374		2,573	
ANR PIPELINE COMPANY					
Senior Unsecured Notes					
U.S. (2018 and 2017 – US$672)	2021 to 2026	**918**	**7.2%**	842	7.2%
GAS TRANSMISSION NORTHWEST LLC					
Unsecured Term Loan					
U.S. (2018 – US$35; 2017 – US$55)	2019	**48**	**3.3%**	69	1.1%
Senior Unsecured Notes					
U.S. (2018 and 2017 – US$250)	2020 to 2035	**341**	**5.6%**	313	5.6%
		389		382	
GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP					
Senior Unsecured Notes					
U.S. (2018 – US$240; 2017 – US$259)	2021 to 2030	**327**	**7.7%**	324	7.7%

Outstanding amounts (millions of Canadian $, unless otherwise noted)	Maturity Dates	2018 Outstanding at December 31	2018 Interest Rate[1]	2017 Outstanding at December 31	2017 Interest Rate[1]
PORTLAND NATURAL GAS TRANSMISSION SYSTEM					
Unsecured Loan Facility					
U.S. (2018 – US$19; 2017 – nil)	2023	**26**	**3.6%**	—	—
Senior Secured Notes[4]					
U.S. (2018 – nil; 2017 – US$30)		**—**	**—**	38	6.0%
		26		38	
TUSCARORA GAS TRANSMISSION COMPANY					
Unsecured Term Loan					
U.S. (2018 – US$24; 2017 – US$25)	2020	**33**	**3.5%**	31	1.1%
NORTH BAJA PIPELINE, LLC					
Unsecured Term Loan					
U.S. (2018 – US$50; 2017 – nil)	2021	**68**	**3.5%**	—	—
		39,982		34,677	
Current portion of long-term debt		**(3,462)**		(2,866)	
Unamortized debt discount and issue costs		**(241)**		(174)	
Fair value adjustments[5]		**230**		238	
		36,509		31,875	

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. The effective interest rate is calculated by discounting the expected future interest payments, adjusted for loan fees, premium and discounts. Weighted average and effective interest rates are stated as at the respective outstanding dates.

2 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.

3 The US$500 million term loan facility was amended in September 2017 to extend the maturity dates from 2018 to 2022.

4 These notes were secured by shipper transportation contracts, existing and new guarantees, letters of credit and collateral requirements.

5 The fair value adjustments include $232 million (2017 – $242 million) related to the acquisition of Columbia. The fair value adjustments also include a decrease of $2 million (2017 – $4 million) related to hedged interest rate risk. Refer to Note 23, Risk management and financial instruments, for further information.

Principal Repayments

At December 31, 2018, principal repayments for the next five years on the Company's long-term debt are approximately as follows:

(millions of Canadian $)	2019	2020	2021	2022	2023
Principal repayments on long-term debt	3,465	2,834	2,098	2,100	1,930

Long-Term Debt Issued

The Company issued long-term debt over the three years ended December 31, 2018 as follows:

(millions of Canadian $, unless otherwise noted) Company	Issue Date	Type	Maturity Date	Amount	Interest Rate
TRANSCANADA PIPELINES LIMITED					
	October 2018	Senior Unsecured Notes	March 2049	US 1,000	5.10%
	October 2018	Senior Unsecured Notes	May 2028	US 400	4.25% [1]
	July 2018	Medium Term Notes	July 2048	800	4.18%
	July 2018	Medium Term Notes	March 2028	200	3.39% [2]
	May 2018	Senior Unsecured Notes	May 2028	US 1,000	4.25%
	May 2018	Senior Unsecured Notes	May 2048	US 1,000	4.875%
	May 2018	Senior Unsecured Notes	May 2038	US 500	4.75%
	November 2017	Senior Unsecured Notes	November 2019	US 550	Floating
	November 2017	Senior Unsecured Notes	November 2019	US 700	2.125%
	September 2017	Medium Term Notes	March 2028	300	3.39%
	September 2017	Medium Term Notes	September 2047	700	4.33%
	June 2016	Acquisition Bridge Facility[3]	June 2018	US 5,213	Floating
	June 2016	Medium Term Notes	July 2023	300	3.69% [4]
	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%
NORTH BAJA PIPELINE, LLC					
	December 2018	Unsecured Term Loan	December 2021	US 50	Floating
PORTLAND NATURAL GAS TRANSMISSION SYSTEM					
	April 2018	Unsecured Loan Facility	April 2023	US 19	Floating
TUSCARORA GAS TRANSMISSION COMPANY					
	August 2017	Unsecured Term Loan	August 2020	US 25	Floating
	April 2016	Unsecured Term Loan	April 2019	US 10	Floating
TC PIPELINES, LP					
	May 2017	Senior Unsecured Notes	May 2027	US 500	3.90%
TRANSCANADA PIPELINE USA LTD.					
	June 2016	Acquisition Bridge Facility[3]	June 2018	US 1,700	Floating
ANR PIPELINE COMPANY					
	June 2016	Senior Unsecured Notes	June 2026	US 240	4.14%

1 Reflects coupon rate on re-opening of a pre-existing senior unsecured notes issue. The notes were issued at a discount to par, resulting in a re-issuance yield of 4.439 per cent.

2 Reflects coupon rate on re-opening of a pre-existing medium term notes (MTN) issue. The MTNs were issued at a discount to par, resulting in a re-issuance yield of 3.41 per cent.

3 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 issuance of common shares in fourth quarter 2016 and proceeds from the sale of the U.S. Northeast power assets were used to fully retire the remaining acquisition bridge facilities in second quarter 2017.

4 Reflects coupon rate on re-opening of a pre-existing MTN issue. The MTNs were issued at premium to par, resulting in a re-issuance yield of 2.69 per cent.

Long-Term Debt Retired

The Company retired/repaid long-term debt over the three years ended December 31, 2018 as follows:

(millions of Canadian $, unless otherwise noted) Company	Retirement/ Repayment Date	Type	Amount	Interest Rate
TRANSCANADA PIPELINES LIMITED				
	August 2018	Senior Unsecured Notes	US 850	6.50%
	March 2018	Debentures	150	9.45%
	January 2018	Senior Unsecured Notes	US 500	1.875%
	January 2018	Senior Unsecured Notes	US 250	Floating
	December 2017	Debentures	100	9.80%
	November 2017	Senior Unsecured Notes	US 1,000	1.625%
	June 2017	Acquisition Bridge Facility[1]	US 1,513	Floating
	February 2017	Acquisition Bridge Facility[1]	US 500	Floating
	January 2017	Medium Term Notes	300	5.10%
	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%
TC PIPELINES, LP				
	December 2018	Unsecured Term Loan	US 170	Floating
COLUMBIA PIPELINE GROUP, INC.				
	June 2018	Senior Unsecured Notes	US 500	2.45%
PORTLAND NATURAL GAS TRANSMISSION SYSTEM				
	May 2018	Senior Secured Notes	US 18	5.90%
GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP				
	March 2018	Senior Unsecured Notes	US 9	6.73%
TUSCARORA GAS TRANSMISSION COMPANY				
	August 2017	Senior Secured Notes	US 12	3.82%
TRANSCANADA PIPELINE USA LTD.				
	June 2017	Acquisition Bridge Facility[1]	US 630	Floating
	April 2017	Acquisition Bridge Facility[1]	US 1,070	Floating
NOVA GAS TRANSMISSION LTD.				
	February 2016	Debentures	225	12.20%

1 These facilities were put in place to finance a portion of the Columbia acquisition and were fully retired in second quarter 2017.

Interest Expense

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

year ended December 31 (millions of Canadian $)	2018	2017	2016
Interest on long-term debt	**1,877**	1,794	1,765
Interest on junior subordinated notes	**391**	348	180
Interest on short-term debt	**187**	101	56
Capitalized interest	**(124)**	(173)	(176)
Amortization and other financial charges[1]	**48**	67	102
	2,379	2,137	1,927

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 $2,268 million in 2018 (2017 – $2,055 million; 2016 – $1,757 million) on long-term debt, junior subordinated notes and short-term debt, net of interest capitalized.

18. JUNIOR SUBORDINATED NOTES

Outstanding loan amount (millions of Canadian $, unless otherwise noted)	Maturity Date	2018 Outstanding at December 31	2018 Effective Interest Rate[1]	2017 Outstanding at December 31	2017 Effective Interest Rate[1]
TRANSCANADA PIPELINES LIMITED[2]					
US$1,000 notes issued 2007 at 6.35%[3]	2067	**1,364**	**5.6%**	1,252	5.0%
US$750 notes issued 2015 at 5.875%[4,5]	2075	**1,024**	**6.5%**	939	5.9%
US$1,200 notes issued 2016 at 6.125%[4,5]	2076	**1,637**	**7.2%**	1,502	6.6%
US$1,500 notes issued 2017 at 5.55%[4,5]	2077	**2,047**	**6.2%**	1,878	5.6%
$1,500 notes issued 2017 at 4.90%[4,5]	2077	**1,500**	**5.5%**	1,500	5.1%
		7,572		7,071	
Unamortized debt discount and issue costs		**(64)**		(64)	
		7,508		7,007	

1 The effective interest rate is calculated by discounting the expected future interest payments using the coupon rate and any estimated future rate resets, adjusted for loan fees and discounts.

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

3 In May 2017, Junior subordinated notes of US$1 billion converted from a fixed rate of 6.35 per cent to a floating rate that is reset quarterly to the three month LIBOR plus 2.21 per cent.

4 The Junior subordinated notes were issued to TransCanada 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 TCPL'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.

5 The coupon rate is initially a fixed interest rate for the first ten years and converts to a floating rate thereafter.

In March 2017, TransCanada Trust (the Trust) issued US$1.5 billion of Trust Notes – Series 2017-A to third party investors with a fixed interest rate of 5.30 per cent for the first ten years converting to a floating rate thereafter. All of the proceeds of the issuance by the Trust were loaned to TCPL for US$1.5 billion of junior subordinated notes of TCPL at an initial fixed rate of 5.55 per cent, including a 0.25 per cent administration charge. The rate will reset commencing March 2027 until March 2047 to the then three month LIBOR plus 3.458 per cent per annum; from March 2047 until March 2077, the interest rate will reset to the then three month LIBOR plus 4.208 per cent per annum. The junior subordinated notes are redeemable at TCPL's option at any time on or after March 15, 2027 at 100 per cent of the principal amount plus accrued and unpaid interest to the date of redemption.

In May 2017, the Trust issued $1.5 billion of Trust Notes – Series 2017-B to third party investors with a fixed interest rate of 4.65 per cent for the first ten years converting to a floating rate thereafter. All of the proceeds of the issuance by the Trust were loaned to TCPL for $1.5 billion of junior subordinated notes of TCPL at an initial fixed rate of 4.90 per cent, including a 0.25 per cent administration charge. The rate will reset commencing May 2027 until May 2047 to the then three month Bankers' Acceptance rate plus 3.33 per cent per annum; from May 2047 until May 2077, the interest rate will reset to the then three month Bankers' Acceptance rate plus 4.08 per cent per annum. The junior subordinated notes are redeemable at TCPL's option at any time on or after May 18, 2027 at 100 per cent of the principal amount plus accrued and unpaid interest to the date of redemption.

In August 2016, the Trust issued US$1.2 billion of Trust Notes – Series 2016-A 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 then three month LIBOR plus 4.89 per cent per annum; from August 2046 to August 2076 the interest rate will reset to the then three month LIBOR plus 5.64 per cent per annum. The junior subordinated notes are redeemable 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.

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 any other outstanding first preferred shares of TCPL.

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 $)	**2018**	**2017**
Non-controlling interest in TC PipeLines, LP	**1,655**	1,852

The Company's Net (loss)/income attributable to non-controlling interests included in the Consolidated statement of income are as follows:

year ended December 31 (millions of Canadian $)	**2018**	**2017**	**2016**
Non-controlling interest in TC PipeLines, LP	**(185)**	220	215
Non-controlling interest in Portland Natural Gas Transmission System[1]	**—**	9	20
Non-controlling interest in Columbia Pipeline Partners LP[2]	**—**	9	17
	(185)	238	252

1 Non-controlling interest in 2017 for the period January 1 to May 31 when TCPL sold its remaining interest in Portland to TC PipeLines, LP. Refer to Note 25, Acquisitions and dispositions for further information.

2 Non-controlling interest up to February 17, 2017 acquisition of all publicly held common units of Columbia Pipeline Partners LP.

TC PipeLines, LP

During 2018, the non-controlling interest in TC PipeLines, LP increased from 74.3 per cent to 74.5 per cent due to periodic issuances of common units in TC PipeLines, LP to third parties under an at-the-market issuance program. In 2017, the non-controlling interest in TC PipeLines, LP ranged between 73.2 per cent and 74.3 per cent, and in 2016, between 72.0 per cent and 73.2 per cent.

Portland Natural Gas Transmission System

On June 1, 2017, TCPL sold its remaining 11.81 per cent directly held interest in Portland to TC PipeLines, LP and, as a result, at December 31, 2017 and 2018, non-controlling interest in Portland was nil. On January 1, 2016, TCPL sold 49.9 per cent of Portland to TC PipeLines, LP. Refer to Note 25, Acquisitions and dispositions for further information.

Columbia Pipeline Partners LP

On July 1, 2016, TCPL acquired Columbia, which included a 53.5 per cent non-controlling interest in Columbia Pipeline Partners LP (CPPL). On February 17, 2017, TCPL acquired all outstanding publicly held common units of CPPL at a price of US$17.00 and a stub period distribution payment of US$0.10 per common unit for an aggregate transaction value of US$921 million. As this was a transaction between entities under common control, it was recognized in equity.

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 as the potential redemption rights of the units were not within the control of the Company.

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 at-the-market issuance program may have had 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 within one year of purchase.

As a result, 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 were not within the control of the Company. At December 31, 2017, all rescission rights previously classified outside of equity had lapsed and been reclassified to equity. These rights expired one year from the date of purchase of each unit and no unitholder claimed or attempted to exercise any of these rescission rights while they remained outstanding.

20. COMMON SHARES

	Number of Shares (thousands)	Amount (millions of Canadian $)
Outstanding at January 1, 2016	779,479	16,320
Issuance of common shares for cash[1]	79,656	4,661
Outstanding at December 31, 2016	859,135	20,981
Issuance of common shares for cash	12,499	780
Outstanding at December 31, 2017	871,634	21,761
Issuance of common shares for cash	15,572	845
Outstanding at December 31, 2018	**887,206**	**22,606**

1 Proceeds of $2.5 billion were used to finance the acquisition of Columbia and proceeds of $2.0 billion were used to repay a portion of the US$6.9 billion acquisition bridge facilities

Common Shares Issued and Outstanding

The Company is authorized to issue an unlimited number of common shares without par value. TCPL issued the following common shares to TransCanada during 2018:

- 3.4 million shares on January 31, 2018 for proceeds of $192 million
- 4.3 million shares on April 30, 2018 for proceeds of $234 million
- 3.6 million shares on July 31, 2018 for proceeds of $207 million
- 4.3 million shares on October 31, 2018 for proceeds of $212 million.

Restrictions on Dividends

Provisions of various credit arrangements with the Company's subsidiaries can restrict their ability to declare and pay dividends or make distributions under certain circumstances. If such restrictions apply, they may, in turn, have an impact on the Company's ability to declare and pay dividends on common shares. At December 31, 2018, the Company had no restrictions to declare or pay dividends.

Stock Options

TransCanada's Stock Option Plan permits options for the purchase of TransCanada common shares to be awarded to certain employees, including officers. The contractual life of options granted is seven years. Options may be exercised at a price determined at the time the option is awarded and vest on the anniversary date in each of the three years following the award. Forfeiture of stock options results from their expiration and, if not previously vested, upon resignation or termination of the option holder's employment.

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

year ended December 31	2018	2017	2016
Weighted average fair value	**$5.80**	$7.22	$5.67
Expected life (years)[1]	**5.7**	5.7	5.8
Interest rate	**2.1%**	1.2%	0.7%
Volatility[2]	**16%**	18%	21%
Dividend yield	**4.2%**	3.6%	4.9%
Forfeiture rate[3]	**—**	—	5%

1 Expected life is based on historical exercise activity.
2 Volatility is derived based on the average of both the historical and implied volatility of the Company's common shares.
3 On January 1, 2017, TransCanada made an election to account for forfeitures when they occur as a result of new GAAP guidance.

The amount expensed for TransCanada stock options, with a corresponding increase in Additional paid-in capital, was $13 million in 2018 (2017 – $12 million; 2016 – $15 million). At December 31, 2018, unrecognized compensation costs related to non-vested stock options was $16 million. The cost is expected to be fully recognized over a three-year period.

The following table summarizes additional stock option information:

year ended December 31 (millions of Canadian $, unless otherwise noted)	2018	2017	2016
Total intrinsic value of options exercised	**10**	28	31
Fair value of options that have vested	**101**	140	126
Total options vested	**2.1 million**	2.3 million	2.1 million

As at December 31, 2018, the aggregate intrinsic value of the total options exercisable was $8 million and the total intrinsic value of options outstanding was $9 million.

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

Components of OCI, including the portion attributable to non-controlling interests and related tax effects, are as follows:

year ended December 31, 2018 (millions of Canadian $)	Before Tax Amount	Income Tax Recovery/ (Expense)	Net of Tax Amount
Foreign currency translation gains on net investment in foreign operations	**1,323**	**35**	**1,358**
Change in fair value of net investment hedges	**(57)**	**15**	**(42)**
Change in fair value of cash flow hedges	**(14)**	**4**	**(10)**
Reclassification to net income of gains and losses on cash flow hedges	**27**	**(6)**	**21**
Unrealized actuarial gains and losses on pension and other post-retirement benefit plans	**(153)**	**39**	**(114)**
Reclassification of actuarial gains and losses on pension and other post-retirement benefit plans	**20**	**(5)**	**15**
Other comprehensive income on equity investments	**113**	**(27)**	**86**
Other Comprehensive Income	**1,259**	**55**	**1,314**

year ended December 31, 2017 (millions of Canadian $)	Before Tax Amount	Income Tax Recovery/ (Expense)	Net of Tax Amount
Foreign currency translation losses on net investment in foreign operations	(746)	(3)	(749)
Reclassification of foreign currency translation gains on disposal of foreign operations	(77)	—	(77)
Change in fair value of cash flow hedges	3	—	3
Reclassification to net income of gains and losses on cash flow hedges	(3)	1	(2)
Unrealized actuarial gains and losses on pension and other post-retirement benefit plans	(14)	3	(11)
Reclassification of actuarial gains and losses on pension and other post-retirement benefit plans	21	(5)	16
Other comprehensive loss on equity investments	(141)	35	(106)
Other Comprehensive Loss	(957)	31	(926)

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 of actuarial gains and losses 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)

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, 2016	(383)	(97)	(198)	(261)	(939)
Other comprehensive income/(loss) before reclassifications[2]	7	27	(26)	(101)	(93)
Amounts reclassified from AOCI	—	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)
Other comprehensive (loss)/income before reclassifications[2,3]	(590)	(1)	(11)	(117)	(719)
Amounts reclassified from AOCI	(77)	(2)	16	11	(52)
Net current period other comprehensive (loss)/income	(667)	(3)	5	(106)	(771)
AOCI balance at December 31, 2017	(1,043)	(31)	(203)	(454)	(1,731)
Other comprehensive income/(loss) before reclassifications[2]	**1,150**	**(9)**	**(114)**	**72**	**1,099**
Amounts reclassified from AOCI[4,5]	**—**	**16**	**15**	**12**	**43**
Net current period other comprehensive income/(loss)	**1,150**	**7**	**(99)**	**84**	**1,142**
Reclassification of AOCI to retained earnings resulting from U.S. Tax Reform	**—**	**1**	**(12)**	**(6)**	**(17)**
AOCI balance at December 31, 2018	**107**	**(23)**	**(314)**	**(376)**	**(606)**

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

2 In 2018, other comprehensive income before reclassifications on currency translation adjustments and cash flow hedges are net of non-controlling interest gains of $166 million (2017 – $159 million losses; 2016 – $14 million losses) and losses of $1 million (2017 – $4 million gains and 2016 – $3 million gains), respectively.

3 Other comprehensive (loss)/income before reclassification on pension and other post-retirement benefit plan adjustments includes a $27 million reduction on settlements and curtailments.

4 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 $15 million ($11 million, net of tax) at December 31, 2018. 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.

5 Amounts reclassified from AOCI on cash flow hedges and equity investments are net of non-controlling interest gains of $5 million and $2 million, respectively.

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

year ended December 31	Amounts Reclassified From AOCI[1]			Affected Line Item in the Consolidated Statement of Income
(millions of Canadian $)	**2018**	**2017**	**2016**	
Cash flow hedges				
Commodities	**(4)**	20	(57)	Revenues (Energy)
Interest	**(18)**	(17)	(14)	Interest expense
	(22)	3	(71)	Total before tax
	6	(1)	29	Income tax expense
	(16)	2	(42)	Net of tax[1,3]
Pension and other post-retirement benefit plan adjustments				
Amortization of actuarial gains and losses	**(16)**	(15)	(22)	Plant operating costs and other[2]
Settlement charge	**(4)**	(2)	—	Plant operating costs and other[2]
	(20)	(17)	(22)	Total before tax
	5	5	6	Income tax expense
	(15)	(12)	(16)	Net of tax[1]
Equity investments				
Equity income	**(16)**	(15)	(19)	Income from equity investments
	4	4	5	Income tax expense
	(12)	(11)	(14)	Net of tax[1,3]
Currency translation adjustments				
Realization of foreign currency translation gains on disposal of foreign operations	**—**	77	—	Gain/(loss) on assets held for sale/sold
	—	—	—	Income tax expense
	—	77	—	Net of tax[1]

1 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 22, Employee post-retirement benefits for further information.

3 Amounts reclassified from AOCI on cash flow hedges and equity investments are net of non-controlling interest gains of $5 million (2017 – nil , 2016 – nil) and $2 million (2017 – nil, 2016 – nil), respectively.

22. EMPLOYEE POST-RETIREMENT BENEFITS

The Company sponsors DB Plans for its employees. Pension benefits provided under the DB Plans are based on years of service and highest average earnings over three consecutive years of employment. Upon commencement of retirement, pension benefits in the Canadian DB Plan increase annually by a portion of the increase in the Consumer Price Index. Net actuarial gains or losses are amortized out of AOCI over the expected average remaining service life of employees, which is approximately nine years at December 31, 2018 (2017 and 2016 – nine years).

On December 31, 2017, the Columbia DB Plan merged with TCPL's U.S. DB Plan. Members accruing benefits in the Columbia DB Plan as of December 31, 2017 were provided an option to either continue receiving benefits in the Columbia DB Plan or instead participate in the existing U.S. DC plan. In addition, on January 1, 2018, the Columbia other post-retirement benefit plan merged with TCPL's U.S. other post-retirement benefit plan.

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 for the plans are amortized out of AOCI over the expected average remaining service life of employees, which was approximately 12 years at December 31, 2018 (2017 and 2016 – 12 years). In 2018, the Company expensed $59 million (2017 – $42 million; 2016 – $52 million) for the savings and DC Plans.

Effective April 1, 2017, the Company closed its U.S. DB Plan to non-union new entrants. As of April 1, 2017, all non-union hires participate in the existing DC plan. Non-union U.S. employees who participated in the DC Plan, had one final election opportunity to become a member of the U.S. DB Plan as of January 1, 2018.

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

year ended December 31 (millions of Canadian $)	2018	2017	2016
DB Plans	**103**	163	111
Other post-retirement benefit plans	**23**	7	8
Savings and DC Plans	**59**	42	52
	185	212	171

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 $17 million letter of credit to the Canadian DB Plan in 2018 (2017 – $27 million; 2016 – $20 million), resulting in a total of $277 million provided to the Canadian DB Plan under letters of credit at December 31, 2018.

The most recent actuarial valuation of the pension plans for funding purposes was as at January 1, 2018 and the next required valuation will be as at January 1, 2019.

In December 2018, the Company recorded a settlement resulting from lump sum payments made in 2018 to certain terminated non-union vested participants in the Company's U.S. DB Plan related to voluntary cash settlement options available to these participants. The impact of the settlement was determined using assumptions consistent with those employed at December 31, 2017. The settlement reduced the Company's U.S. DB Plan's unrealized actuarial losses by $4 million which was included in OCI and resulted in a settlement charge of$4 million which was recorded in net benefit costs in 2018. Effective December 1, 2018, the plan was amended to include this unlimited lump sum payment option for certain union employees who were not previously eligible.

In 2017, as a result of settlements and curtailments that occurred upon the completion of the U.S. Northeast power generation asset sales, interim remeasurements were performed on TCPL's U.S. DB Plan and other post-retirement benefit plans using a weighted average discount rate of 4.10 per cent. All other assumptions were consistent with those employed at December 31, 2016. The impact of these remeasurements reduced the U.S. DB Plan's unrealized actuarial losses by $3 million, which was included in OCI, and resulted in a settlement charge of $2 million which was recorded in net benefit cost in 2017. These remeasurements had no impact on the other post-retirement benefit plan's unrealized actuarial losses.

Also in 2017, lump sum payouts exceeded service and interest costs for the Columbia DB Plan. As a result, an interim remeasurement was performed on the Columbia DB Plan at September 30, 2017 using a discount rate of 3.70 per cent. The interim remeasurement of the Columbia DB Plan increased the Company's unrealized actuarial gains by $16 million, of which $14 million was recorded in Regulatory assets and $2 million was recorded in OCI. All other assumptions were consistent with those employed at December 31, 2016.

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

at December 31	Pension Benefit Plans		Other Post-Retirement Benefit Plans	
(millions of Canadian $)	**2018**	**2017**	**2018**	**2017**
Change in Benefit Obligation[1]				
Benefit obligation – beginning of year	**3,646**	3,456	**375**	372
Service cost	**121**	113	**4**	4
Interest cost	**134**	135	**14**	14
Employee contributions	**5**	5	**—**	3
Benefits paid	**(177)**	(166)	**(23)**	(19)
Actuarial (gain)/loss	**(92)**	253	**43**	19
Curtailment	**—**	(14)	**—**	(2)
Settlement	**(71)**	(66)	**—**	—
Foreign exchange rate changes	**87**	(70)	**17**	(16)
Benefit obligation – end of year	**3,653**	3,646	**430**	375
Change in Plan Assets				
Plan assets at fair value – beginning of year	**3,451**	3,208	**365**	354
Actual return on plan assets	**(73)**	358	**(15)**	45
Employer contributions[2]	**103**	163	**23**	7
Employee contributions	**5**	5	**—**	3
Benefits paid	**(176)**	(166)	**(27)**	(19)
Settlement	**(71)**	(57)	**—**	—
Foreign exchange rate changes	**82**	(60)	**30**	(25)
Plan assets at fair value – end of year	**3,321**	3,451	**376**	365
Funded Status – Plan Deficit	**(332)**	(195)	**(54)**	(10)

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 a $17 million letter of credit provided to the Canadian DB Plan for funding purposes (2017 – $27 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 $)	**2018**	**2017**	**2018**	**2017**
Intangible and other assets (Note 12)	**—**	—	**192**	193
Accounts payable and other	**(1)**	(1)	**(8)**	(8)
Other long-term liabilities (Note 15)	**(331)**	(194)	**(238)**	(195)
	(332)	(195)	**(54)**	(10)

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 $)	**2018**	**2017**	**2018**	**2017**
Projected benefit obligation[1]	**(3,653)**	(3,646)	**(246)**	(203)
Plan assets at fair value	**3,321**	3,451	**—**	—
Funded Status – Plan Deficit	**(332)**	(195)	**(246)**	(203)

1 The projected benefit obligation for the pension benefit plans differ 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 $)	**2018**	**2017**
Accumulated benefit obligation	**(3,347)**	(3,372)
Plan assets at fair value	**3,321**	3,451
Funded Status	**(26)**	79

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 $)	**2018**	**2017**
Accumulated benefit obligation	**(3,347)**	(944)
Plan assets at fair value	**3,321**	925
Funded Status – Plan Deficit	**(26)**	(19)

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	**2018**	**2017**	**2018**
Debt securities	**33%**	30%	**25% to 45%**
Equity securities	**56%**	64%	**40% to 70%**
Alternatives	**11%**	6%	**5% to 15%**
	100%	100%	

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

at December 31 (millions of Canadian $)	2018	2017	Percentage of Plan Assets 2018	 2017
Debt securities	**8**	7	**0.3%**	0.2%
Equity securities	**7**	3	**0.2%**	0.1%

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

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

The following table presents plan assets for DB Plans and other post-retirement benefits measured at fair value, which have been categorized into the three categories based on a fair value hierarchy. For further information on the fair value hierarchy, refer to Note 23, 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 $)	**2018**	**2017**	**2018**	**2017**	**2018**	**2017**	**2018**	**2017**	**2018**	**2017**
Asset Category										
Cash and Cash Equivalents	**48**	44	**—**	17	**—**	—	**48**	61	**1**	2
Equity Securities:										
Canadian	**355**	410	**138**	151	**—**	—	**493**	561	**13**	15
U.S.	**460**	543	**116**	354	**—**	—	**576**	897	**16**	24
International	**40**	45	**281**	322	**—**	—	**321**	367	**9**	10
Global	**116**	—	**268**	301	**—**	—	**384**	301	**10**	8
Emerging	**8**	8	**138**	147	**—**	—	**146**	155	**4**	4
Fixed Income Securities:										
Canadian Bonds:										
Federal	**—**	—	**186**	193	**—**	—	**186**	193	**5**	5
Provincial	**—**	—	**198**	194	**—**	—	**198**	194	**5**	5
Municipal	**—**	—	**8**	8	**—**	—	**8**	8	**1**	—
Corporate	**—**	—	**112**	122	**—**	—	**112**	122	**3**	3
U.S. Bonds:										
Federal	**350**	—	**—**	244	**—**	—	**350**	244	**9**	6
State	**—**	—	**—**	41	**—**	—	**—**	41	**—**	1
Municipal	**—**	—	**—**	4	**—**	—	**—**	4	**—**	—
Corporate	**145**	—	**51**	234	**—**	—	**196**	234	**5**	6
International:										
Government	**6**	—	**4**	4	**—**	—	**10**	4	**1**	—
Corporate	**19**	—	**18**	5	**—**	—	**37**	5	**1**	—
Mortgage backed	**128**	—	**—**	73	**—**	—	**128**	73	**3**	2
Other Investments:										
Real estate	**—**	—	**—**	—	**196**	140	**196**	140	**5**	4
Infrastructure	**—**	—	**—**	—	**163**	70	**163**	70	**4**	2
Private equity funds	**—**	—	**—**	—	**3**	6	**3**	6	**1**	—
Funds held on deposit	**142**	136	**—**	—	**—**	—	**142**	136	**4**	3
	1,817	1,186	**1,518**	2,414	**362**	216	**3,697**	3,816	**100**	100

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

(millions of Canadian $, pre-tax)	
Balance at December 31, 2016	199
Purchases and sales	11
Realized and unrealized gains	6
Balance at December 31, 2017	216
Purchases and sales	**127**
Realized and unrealized gains	**19**
Balance at December 31, 2018	**362**

The Company's expected funding contributions in 2019 are approximately $113 million for the DB Plans, approximately $7 million for the other post-retirement benefit plans and approximately $61 million for the savings plan and DC Plans. The Company expects to provide an additional estimated $17 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
2019	190	24
2020	193	23
2021	198	23
2022	203	23
2023	207	23
2024 to 2028	1,081	114

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, 2018. 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	**2018**	**2017**	**2018**	**2017**
Discount rate	**3.90%**	3.60%	**4.10%**	3.70%
Rate of compensation increase	**3.00%**	3.00%	**—**	—

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	**2018**	**2017**	**2016**	**2018**	**2017**	**2016**
Discount rate	**3.60%**	3.95%	4.20%	**3.70%**	4.15%	4.30%
Expected long-term rate of return on plan assets	**6.70%**	6.50%	6.70%	**4.00%**	6.05%	5.95%
Rate of compensation increase	**3.00%**	1.20%	0.80%	**—**	—	—

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

A six per cent weighted average annual rate of increase in the per capita cost of covered health care benefits was assumed for 2019 measurement purposes. The rate was assumed to decrease gradually to 4.50% by 2028 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	25	(21)

The net benefit cost recognized for the Company's pension benefit plans and other post-retirement benefit plans is as follows:

at December 31	Pension Benefit Plans			Other Post-Retirement Benefit Plans		
(millions of Canadian $)	**2018**	2017	2016	**2018**	2017	2016
Service cost[1]	**121**	108	107	**4**	4	3
Other components of net benefit cost[1]						
Interest cost	**134**	122	127	**14**	14	13
Expected return on plan assets	**(221)**	(178)	(175)	**(16)**	(21)	(11)
Amortization of actuarial loss	**15**	14	20	**1**	1	2
Amortization of regulatory asset	**18**	37	27	**—**	1	1
Amortization of transitional obligation related to regulated business	**—**	—	—	**—**	—	2
Settlement charge – regulatory asset	**—**	2	—	**—**	—	—
Settlement charge – AOCI	**4**	2	—	**—**	—	—
	(50)	(1)	(1)	**(1)**	(5)	7
Net Benefit Cost Recognized	**71**	107	106	**3**	(1)	10

1 Service cost and other components of net benefit cost are included in Plant operating costs and other in the Consolidated statement of income.

Pre-tax amounts recognized in AOCI were as follows:

at December 31	2018		2017		2016	
(millions of Canadian $)	Pension Benefits	Other Post-Retirement Benefits	Pension Benefits	Other Post-Retirement Benefits	Pension Benefits	Other Post-Retirement Benefits
Net loss	**364**	**53**	273	11	270	21

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 2019 is $12 million and $2 million, respectively.

Pre-tax amounts recognized in OCI were as follows:

at December 31	2018		2017		2016	
(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	**(15)**	**(1)**	(18)	(1)	(20)	(2)
Curtailment	**—**	**—**	(14)	(2)	—	—
Settlement	**(4)**	**—**	(11)	—	—	—
Funded status adjustment	**110**	**43**	46	(7)	43	(5)
	91	**42**	3	(10)	23	(7)

23. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

Risk Management Overview

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

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 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 – agreements to purchase or sell a specific financial instrument or commodity at a specified price and date in the future
- Swaps – agreements between two parties to exchange streams of payments over time according to specified terms
- Options – 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.

Commodity price risk

The following strategies may be used to manage exposure to commodity price risk in the Company's non-regulated businesses:

- In the Company's power generation business, TCPL manages the exposure to fluctuating commodity prices through long-term contracts and hedging activities including selling and purchasing power and natural gas in forward markets
- In the Company's non-regulated natural gas storage business, TCPL's exposure to seasonal natural gas price spreads is managed with a portfolio of third-party storage capacity contracts and through offsetting purchases and sales of natural gas in forward markets to lock in future positive margins
- In the Company's liquids marketing business, TCPL enters into pipeline and storage terminal capacity contracts. TCPL fixes a portion of its exposure on these contracts by entering into derivative instruments to manage its variable price fluctuations that arise from physical liquids transactions.

The Company's exposure to electricity price risk has been greatly reduced following the sales of its U.S. Northeast power generation assets in 2017 and its U.S. Northeast power retail contracts on March 1, 2018 as well as the continued wind-down of its remaining U.S. Power marketing contracts.

Interest rate risk

TCPL utilizes short-term and long-term debt to finance its operations which exposes the Company to interest rate risk. TCPL typically pays fixed rates of interest on its long-term debt and floating rates on its commercial paper programs and amounts drawn on its credit facilities. A small portion of TCPL's long-term debt is at floating interest rates. In addition, the Company is exposed to interest rate risk on financial instruments and contractual obligations containing variable interest rate components. The Company manages its interest rate risk using a combination of interest rate swaps and option derivatives.

Foreign exchange risk

TCPL generates revenues and incurs expenses that are denominated in currencies other than Canadian dollars. As a result, the Company's earnings and cash flows are exposed to currency fluctuations.

A portion of TCPL's businesses generate earnings in U.S. dollars, but since its financial results are reported in Canadian dollars, changes in the value of the U.S. dollar against the Canadian dollar can affect its net income. As the Company's U.S. dollar-denominated operations continue to grow, this exposure increases. A portion of this risk is offset by interest expense on U.S. dollar-denominated debt. The balance of the exposure is hedged on a rolling one-year basis using foreign exchange derivatives, but the exposure remains beyond that period.

Net investment hedges

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

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

at December 31 (millions of Canadian $, unless otherwise noted)	2018		2017	
	Fair Value[1,2]	Notional Amount	Fair Value[1,2]	Notional Amount
U.S. dollar cross-currency interest rate swaps (maturing 2019)[3]	**(43)**	**US 300**	(199)	US 1,200
U.S. dollar foreign exchange options (maturing 2019 to 2020)	**(47)**	**US 2,500**	5	US 500
	(90)	**US 2,800**	(194)	US 1,700

1 Fair value equals carrying value.

2 No amounts have been excluded from the assessment of hedge effectiveness.

3 In 2018, Net income includes net realized gains of $2 million (2017 – gains of $4 million) related to the interest component of cross-currency swap settlements which are reported within Interest expense.

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)	2018	2017
Notional amount	**31,000 (US 22,700)**	25,400 (US 20,200)
Fair value	**31,700 (US 23,200)**	28,900 (US 23,100)

Counterparty Credit Risk

TCPL's maximum counterparty credit exposure with respect to financial instruments at December 31, 2018, without taking into account security held, consisted of cash and cash equivalents, accounts receivable, available-for-sale assets, derivative assets and a loan receivable.

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 dealing with creditworthy counterparties, obtaining financial assurances such as guarantees, letters of credit or cash where considered necessary, and setting limits on the amount TCPL can transact with any one counterparty. There is no guarantee that these techniques will protect the Company from material losses.

The Company monitors its counterparties and regularly reviews its accounts receivable. The Company records an allowance for doubtful accounts as necessary using the specific identification method. At December 31, 2018 and 2017, there were no significant amounts past due or impaired, no significant credit risk concentration and no significant credit losses during the year.

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

Fair Value of Non-Derivative Financial Instruments

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, intangible and other assets, notes payable, accounts payable and other, due to affiliate, 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 financial instruments.

Balance Sheet Presentation of Non-Derivative Financial Instruments

The following table details the fair value of 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 $)	2018		2017	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt, including current portion[1,2] (Note 17)	**(39,971)**	**(42,284)**	(34,741)	(40,180)
Junior subordinated notes (Note 18)	**(7,508)**	**(6,665)**	(7,007)	(7,233)
	(47,479)	**(48,949)**	(41,748)	(47,413)

1 Long-term debt is recorded at amortized cost, except for US$750 million (2017 – US$1.1 billion) that is attributed to hedged risk and recorded at fair value.

2 Net income in 2018 included unrealized losses of $2 million (2017 – gains of $4 million) for fair value adjustments attributable to the hedged interest rate risk associated with interest rate swap fair value hedging relationships on US$750 million of long-term debt at December 31, 2018 (2017 – US$1.1 billion). There were no other unrealized gains or losses from fair value adjustments to the non-derivative financial instruments.

Available-for-Sale Assets Summary

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

at December 31 (millions of Canadian $)	2018		2017	
	LMCI Restricted Investments	Other Restricted Investments[1]	LMCI Restricted Investments	Other Restricted Investments[1]
Fair value of fixed income securities[2]				
Fixed income securities (maturing within 1 year)	**—**	**22**	—	23
Fixed income securities (maturing within 1-5 years)	**—**	**110**	—	107
Fixed income securities (maturing within 5-10 years)	**140**	**—**	14	—
Fixed income securities (maturing after 10 years)	**952**	**—**	790	—
	1,092	**132**	804	130

1 Other restricted investments have been set aside to fund insurance claim losses to be paid by the Company's wholly-owned captive insurance subsidiary.

2 Available-for-sale assets are recorded at fair value and included in Other current assets and Restricted investments on the Company's Consolidated balance sheet.

year ended December 31 (millions of Canadian $)	2018		2017		2016	
	LMCI restricted investments[1]	Other restricted investments	LMCI restricted investments[1]	Other restricted investments	LMCI restricted investments[1]	Other restricted investments
Net unrealized gains/(losses)	**11**	**—**	(3)	1	(28)	(1)
Net realized losses[2]	**(4)**	**—**	(1)	—	—	—

1 Gains and losses arising from changes in the fair value of LMCI restricted investments impact the subsequent amounts to be collected through tolls to cover future pipeline abandonment costs. As a result, the Company records these gains and losses as regulatory assets or liabilities.

2 The realized gains and losses on the sale of LMCI restricted investment securities are determined using the average cost basis.

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 a market approach. The market approach bases the fair value measures on a comparable transaction using quoted market prices, or in the absence of quoted market prices, third-party broker quotes or other valuation techniques. 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. Unrealized gains and losses on derivative instruments are not necessarily representative of the amounts that will be realized on settlement.

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 derivative instruments as at December 31, 2018 is as follows:

at December 31, 2018 (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]	**1**	**—**	**—**	**716**	**717**
Foreign exchange	**—**	**—**	**16**	**1**	**17**
Interest rate	**3**	**—**	**—**	**—**	**3**
	4	**—**	**16**	**717**	**737**
Intangible and other assets (Note 12)					
Commodities[2]	**1**	**—**	**—**	**50**	**51**
Foreign exchange	**—**	**—**	**1**	**—**	**1**
Interest rate	**8**	**1**	**—**	**—**	**9**
	9	**1**	**1**	**50**	**61**
Total Derivative Assets	**13**	**1**	**17**	**767**	**798**
Accounts payable and other (Note 14)					
Commodities[2]	**(4)**	**—**	**—**	**(622)**	**(626)**
Foreign exchange	**—**	**—**	**(105)**	**(188)**	**(293)**
Interest rate	**—**	**(3)**	**—**	**—**	**(3)**
	(4)	**(3)**	**(105)**	**(810)**	**(922)**
Other long-term liabilities (Note 15)					
Commodities[2]	**—**	**—**	**—**	**(28)**	**(28)**
Foreign exchange	**—**	**—**	**(2)**	**—**	**(2)**
Interest rate	**(11)**	**(1)**	**—**	**—**	**(12)**
	(11)	**(1)**	**(2)**	**(28)**	**(42)**
Total Derivative Liabilities	**(15)**	**(4)**	**(107)**	**(838)**	**(964)**
Total Derivatives	**(2)**	**(3)**	**(90)**	**(71)**	**(166)**

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 derivative instruments as at December 31, 2017 is as follows:

at December 31, 2017 (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]	1	—	—	249	250
Foreign exchange	—	—	8	70	78
Interest rate	3	—	—	1	4
	4	—	8	320	332
Intangible and other assets (Note 12)					
Commodities[2]	—	—	—	69	69
Interest rate	4	—	—	—	4
	4	—	—	69	73
Total Derivative Assets	8	—	8	389	405
Accounts payable and other (Note 14)					
Commodities[2]	(6)	—	—	(208)	(214)
Foreign exchange	—	—	(159)	(10)	(169)
Interest rate	—	(4)	—	—	(4)
	(6)	(4)	(159)	(218)	(387)
Other long-term liabilities (Note 15)					
Commodities[2]	(2)	—	—	(26)	(28)
Foreign exchange	—	—	(43)	—	(43)
Interest rate	—	(1)	—	—	(1)
	(2)	(1)	(43)	(26)	(72)
Total Derivative Liabilities	(8)	(5)	(202)	(244)	(459)
Total Derivatives	—	(5)	(194)	145	(54)

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

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.

Derivatives in fair value hedging relationships

The following table details amounts recorded on the Consolidated balance sheet in relation to cumulative adjustments for fair value hedges included in the carrying amount of the hedged liabilities:

at December 31	**Carrying amount**		**Fair value hedging adjustments**[1]	
(millions of Canadian $)	**2018**	**2017**	**2018**	**2017**
Current portion of long-term debt	**(748)**	(688)	**3**	1
Long-term debt	**(273)**	(685)	**—**	4
	(1,021)	(1,373)	**3**	5

1 At December 31, 2018 and 2017, adjustments for discontinued hedging relationships included in these balances were nil.

Notional and Maturity Summary

The maturity and notional amount 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, 2018	Power	Natural Gas	Liquids	Foreign Exchange	Interest Rate
Purchases[1]	**23,865**	**44**	**59**	**—**	**—**
Sales[1]	**17,689**	**56**	**79**	**—**	**—**
Millions of U.S. dollars	**—**	**—**	**—**	**3,862**	**1,650**
Maturity dates	**2019-2023**	**2019-2027**	**2019**	**2019**	**2019-2030**

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

at December 31, 2017	Power	Natural Gas	Liquids	Foreign Exchange	Interest Rate
Purchases[1]	66,132	133	6	—	—
Sales[1]	42,836	135	7	—	—
Millions of U.S. dollars	—	—	—	2,931	2,300
Millions of Mexican pesos	—	—	—	100	—
Maturity dates	2018-2022	2018-2021	2018	2018	2018-2022

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

Unrealized and Realized Gains/(Losses) on Derivative Instruments

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

year ended December 31 (millions of Canadian $)	2018	2017	2016
Derivative instruments held for trading[1]			
Amount of unrealized gains/(losses) in the year			
Commodities[2]	**28**	62	123
Foreign exchange	**(248)**	88	25
Interest rate	**—**	(1)	—
Amount of realized gains/(losses) in the year			
Commodities	**351**	(107)	(204)
Foreign exchange	**(24)**	18	62
Interest rate	**—**	1	—
Derivative instruments in hedging relationships			
Amount of realized (losses)/gains in the year			
Commodities	**(1)**	23	(167)
Foreign exchange	**—**	5	(101)
Interest rate	**(1)**	1	4

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

2 In 2018 and 2017, there were no gains or losses included in Net Income relating to discontinued cash flow hedges where it was probable that the anticipated transaction would not occur (2016 – net loss of $42 million).

Derivatives in cash flow hedging relationships

The components of OCI (Note 21) 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)	2018	2017	2016
Change in fair value of derivative instruments recognized in OCI[1]			
Commodities	**(1)**	(1)	39
Interest rate	**(13)**	4	5
	(14)	3	44

1 No amounts have been excluded from the assessment of hedge effectiveness. Amounts in parentheses indicate losses recorded to OCI and AOCI.

Effect of fair value and cash flow hedging relationships

The following table details amounts presented on the Consolidated statement of income in which the effects of fair value or cash flow hedging relationships are recorded.

year ended December 31	Revenues (Energy)			Interest Expense		
(millions of Canadian $)	2018	2017	2016	2018	2017	2016
Total Amount Presented in the Consolidated Statement of Income	**2,124**	3,593	4,206	**(2,379)**	(2,137)	(1,927)
Fair Value Hedges						
Interest rate contracts						
Hedged items	**—**	—	—	**(71)**	(74)	(74)
Derivatives designated as hedging instruments	**—**	—	—	**(4)**	1	8
Cash Flow Hedges						
Reclassification of gains/(losses) on derivative instruments from AOCI to net income[1,2]						
Interest rate contracts	**—**	—	—	**22**	17	14
Commodity contracts	**5**	(20)	57	**—**	—	—

1 Refer to Note 21, Other comprehensive income/(loss) and accumulated other comprehensive loss, for the components of OCI related to derivatives in cash flow hedging relationships including the portion attributable to non-controlling interests.

2 There are no amounts recognized in earnings that were excluded from effectiveness testing.

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 as at December 31, 2018:

at December 31, 2018 (millions of Canadian $)	Gross Derivative Instruments	Amounts Available for Offset[1]	Net Amounts
Derivative – Asset			
Commodities	**768**	**(626)**	**142**
Foreign exchange	**18**	**(18)**	**—**
Interest rate	**12**	**(4)**	**8**
	798	**(648)**	**150**
Derivative – Liability			
Commodities	**(654)**	**626**	**(28)**
Foreign exchange	**(295)**	**18**	**(277)**
Interest rate	**(15)**	**4**	**(11)**
	(964)	**648**	**(316)**

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, 2017:

at December 31, 2017 (millions of Canadian $)	Gross Derivative Instruments	Amounts Available for Offset[1]	Net Amounts
Derivative – Asset			
Commodities	319	(198)	121
Foreign exchange	78	(56)	22
Interest rate	8	(1)	7
	405	(255)	150
Derivative – Liability			
Commodities	(242)	198	(44)
Foreign exchange	(212)	56	(156)
Interest rate	(5)	1	(4)
	(459)	255	(204)

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

With respect to the derivative instruments presented above, the Company provided cash collateral of $143 million and letters of credit of $22 million (2017 – $165 million and $30 million) to its counterparties. At December 31, 2018, the Company held nil in cash collateral and $1 million in letters of credit (2017 – nil and $3 million) from counterparties on asset exposures.

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. The company may also need to provide collateral if the fair value of its derivative financial instruments exceeds pre-defined exposure limits.

Based on contracts in place and market prices at December 31, 2018, the aggregate fair value of all derivative instruments with credit-risk-related contingent features that were in a net liability position was $6 million (2017 – $2 million), for which the Company has provided no collateral in the normal course of business. If the credit-risk-related contingent features in these agreements were triggered on December 31, 2018, the Company would have been required to provide collateral of $6 million (2017 – $2 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. An active market is a market in which frequency and volume of transactions provides pricing information on an ongoing basis.
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 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 2018, are categorized as follows:

at December 31, 2018 (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	**581**	**187**	**—**	**768**
Foreign exchange	**—**	**18**	**—**	**18**
Interest rate	**—**	**12**	**—**	**12**
Derivative Instrument Liabilities:				
Commodities	**(555)**	**(95)**	**(4)**	**(654)**
Foreign exchange	**—**	**(295)**	**—**	**(295)**
Interest rate	**—**	**(15)**	**—**	**(15)**
	26	**(188)**	**(4)**	**(166)**

1 There were no transfers from Level I to Level II or from Level II to Level III for the year ended December 31, 2018.

The fair value of the Company's derivative assets and liabilities measured on a recurring basis, including both current and non-current portions for 2017, are categorized as follows:

at December 31, 2017 (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	21	283	15	319
Foreign exchange	—	78	—	78
Interest rate	—	8	—	8
Derivative Instrument Liabilities:				
Commodities	(27)	(193)	(22)	(242)
Foreign exchange	—	(212)	—	(212)
Interest rate	—	(5)	—	(5)
	(6)	(41)	(7)	(54)

1 There were no transfers from Level I to Level II or from Level II to Level III for the year ended December 31, 2017.

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

(millions of Canadian $, pre-tax)	2018	2017
Balance at beginning of year	**(7)**	16
Transfers out of Level III	**5**	(19)
Total gains/(losses) included in Net income	**8**	(17)
Settlements	**(9)**	18
Sales	**—**	(5)
Foreign exchange	**(1)**	—
Balance at end of year[1]	**(4)**	(7)

1 Revenues include unrealized losses of $5 million attributed to derivatives in the Level III category that were still held at December 31, 2018 (2017 – unrealized losses of $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, 2018.

24. CHANGES IN OPERATING WORKING CAPITAL

year ended December 31 (millions of Canadian $)	2018	2017	2016
Increase in Accounts receivable	**(68)**	(573)	(487)
Increase in Inventories	**(49)**	(38)	(87)
Decrease/(increase) in Assets held for sale	**—**	14	(13)
Decrease in Other current assets	**45**	189	328
(Decrease)/increase in Accounts payable and other	**(68)**	149	432
Increase in Accrued interest	**41**	12	62
(Decrease)/increase in Liabilities related to assets held for sale	**—**	(25)	16
(Increase)/decrease in Operating Working Capital	**(99)**	(272)	251

25. ACQUISITIONS AND DISPOSITIONS

U.S. Natural Gas Pipelines

Iroquois Gas Transmission System and Portland Natural Gas Transmission System

On June 1, 2017, TCPL closed the sale of 49.34 per cent of its 50 per cent interest in Iroquois, along with an option to sell the remaining 0.66 per cent at a later date, to TC PipeLines, LP. At the same time, TCPL closed the sale of its remaining 11.81 per cent interest in Portland to TC PipeLines, LP. Proceeds from these transactions were US$765 million, before post-closing adjustments, and were comprised of US$597 million in cash and US$168 million representing a proportionate share of Iroquois and Portland debt.

In January 2016, TCPL closed the sale of a 49.9 per cent interest in Portland 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 Portland debt.

In March 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.

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, an intercompany loan due to TransCanada in connection with proceeds received from the sale of TransCanada subscription receipts and draws on acquisition bridge facilities in the aggregate amount of US$6.9 billion. 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. Refer to Note 20, Common shares, Note 28, Related party transactions and Note 17, Long-term debt for further information on the common shares issued to TransCanada, the intercompany loan due to TransCanada and the acquisition bridge facilities.

At the date of acquisition, Columbia operated 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 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 was accounted for as a business combination using the acquisition method where the acquired tangible and intangible assets and assumed liabilities were 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.

(millions of $)	July 1, 2016 U.S.	 Canadian[1]
Purchase Price Consideration	**10,294**	**13,392**
Fair Value		
Current assets	658	856
Plant, property and equipment	7,560	9,835
Equity investments	441	574
Regulatory assets	190	248
Intangible 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	**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 approximated 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, had fair values equal to their carrying values on acquisition. 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). On acquisition date, 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 estimated volume of base gas in place which resulted in a fair value increase of $840 million (US$646 million).

In second quarter 2017, the Company completed its procedures over measuring the volume of base gas acquired and, as a result, decreased its fair value by $116 million (US$90 million). This impacted the purchase price equation by decreasing property, plant and equipment by $116 million (US$90 million), decreasing deferred income tax liabilities by $45 million (US$35 million) and increasing goodwill by $71 million (US$55 million) to a total of US$7,802 million (2016 – US$7,747 million) at December 31, 2017. This adjustment did not impact the Company's net income.

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$1,000)	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 of the funded status of the plans as of the acquisition date which 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 then U.S. effective tax rate of 39 per cent.

The fair value of Columbia's non-controlling interests was based on the approximately 53.8 million 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. On February 17, 2017, TCPL acquired all outstanding publicly held common units of CPPL. Refer to Note 19, Non-controlling interests, for further information.

In 2016, acquisition expenses of approximately $36 million were included in Plant operating costs and other in the Consolidated statement of income.

Upon completion of the acquisition, the Company began consolidating Columbia. Columbia's significant accounting policies were consistent with TCPL's and continued to be applied. Columbia contributed $929 million to the Company's Revenues and $132 million to the Company's net income from July 1, 2016 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)

Energy

Cartier Wind

On October 24, 2018, the Company completed the sale of its 62 per cent interest in the Cartier Wind power facilities to Innergex Renewable Energy Inc for proceeds of $630 million, before post-closing adjustments. As a result, the Company recorded a gain on sale of $170 million ($143 million after tax) which is included in Gain/(loss) on assets held for sale/sold in the Consolidated statement of income.

Ontario Solar Assets

On December 19, 2017, the Company completed the sale of its Ontario solar assets to a third party for proceeds of $541 million, before post-closing adjustments. As a result, the Company recorded a gain on sale of $127 million ($136 million after tax) which is included in Gain/(loss) on assets held for sale/sold in the Consolidated statement of income.

U.S. Northeast Power Assets

In 2018, upon finalizing its 2017 annual tax return for its U.S. operations, the Company recorded a $27 million income tax recovery related to the sale of its U.S. Northeast power generation assets.

On April 19, 2017, the Company completed the sale of TC Hydro for proceeds of approximately US$1.07 billion, before post-closing adjustments. As a result, in 2017 the Company recorded a gain on sale of $715 million ($440 million after tax) including the impact of $5 million of foreign currency translation gains which were reclassified from AOCI to net income.

On June 2, 2017, TCPL completed the sale of Ravenswood, Ironwood, Kibby Wind and Ocean State Power for proceeds of approximately US$2.029 billion, before post-closing adjustments. In 2016, the Company recorded a loss of $829 million ($863 million after tax) which included the impact of $70 million of foreign currency translation gains that were reclassified from AOCI to net income on close. The Company recorded an additional loss on sale of $211 million ($167 million after tax) in 2017 which included $2 million in foreign currency translation gains. This additional loss primarily related to adjustments to the purchase price and repair costs for an unplanned outage at Ravenswood prior to close of the sale.

Gains and losses from these sales are included in Gain/(loss) on assets held for sale/sold in the Consolidated statement of income. The proceeds received from the sale of the U.S. Northeast Power assets were used to repay the outstanding balances on the Company's acquisition bridge facilities that partially funded the acquisition of Columbia.

Ironwood

In February 2016, TCPL acquired the Ironwood natural gas fired, combined cycle power plant for US$653 million in cash after post-closing adjustments. 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 did not have a material impact on the Revenues and Net income of the Company. In addition, the pro forma incremental impact of Ironwood on the Company's Revenues and Net income from the date of acquisition to the date of sale was not material.

26. 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
2019	81	7	74
2020	78	7	71
2021	76	4	72
2022	69	3	66
2023	67	3	64
2024 and thereafter	390	8	382
	761	32	729

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 2018 was $84 million (2017 – $93 million; 2016 – $145 million).

Other commitments

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.

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, 2018, TCPL had the following capital expenditure commitments:

- approximately $4.6 billion for its Canadian natural gas pipelines, primarily related to construction costs associated with the construction of the Coastal GasLink and NGTL System pipeline projects
- approximately $0.1 billion for its U.S. natural gas pipelines, primarily related to construction costs associated with Columbia Gas and Columbia Gulf growth projects
- approximately $0.3 billion for its Mexico natural gas pipelines, primarily related to construction of the Sur de Texas, Villa de Reyes and Tula pipeline projects
- approximately $0.4 billion for its Liquids pipelines, primarily related to the development of Keystone XL and construction of White Spruce
- approximately $0.7 billion for its Energy business, primarily related to its proportionate share of commitments for Bruce Power's life extension program
- approximately $0.1 billion for its Corporate segment related to various information technology services agreements.

Contingencies

TCPL is subject to laws and regulations governing environmental quality and pollution control. As at December 31, 2018, the Company had accrued approximately $40 million (2017 – $34 million) related to operating facilities, which represents the present value of the estimated future amount it expects to spend to remediate the sites. However, additional liabilities may be incurred as assessments take place 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 will not have a material impact on the Company's consolidated financial position or results of operations.

Guarantees

TCPL and its partner on the Sur de Texas pipeline, IEnova, have jointly guaranteed the financial performance of this entity. Such agreements include a guarantee and a letter of credit which are primarily related to construction services and the delivery of natural gas.

TCPL and its joint venture partner on Bruce Power, BPC Generation Infrastructure Trust, have each severally guaranteed certain contingent financial obligations of Bruce Power related to a lease agreement and contractor and supplier services.

The Company and its partners in certain other jointly owned entities have either (i) jointly and severally, (ii) jointly or (iii) severally guaranteed the financial performance of these entities. Such agreements include guarantees and letters of credit which are primarily related to delivery of natural gas, construction services 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 recorded in Other long-term liabilities on the Consolidated balance sheet. Information regarding the Company's guarantees is as follows:

		2018		2017	
at December 31 (millions of Canadian $)	**Term**	**Potential Exposure**[1]	**Carrying Value**	**Potential Exposure**[1]	**Carrying Value**
Sur de Texas	ranging to 2020	**183**	**1**	315	2
Bruce Power	ranging to 2021	**88**	**—**	88	1
Other jointly owned entities	ranging to 2059	**104**	**11**	104	13
		375	**12**	507	16

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

27. 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 its existing operations. The Company incurred corporate restructuring costs and recorded a provision to allow for planned severance costs in future years, as well as expected future losses under lease commitments.

Cumulatively to December 31, 2018, the Company has incurred costs of $86 million for employee severance and $60 million for lease commitments, net of $157 million related to costs that were recoverable through regulatory and tolling structures. The Company recorded additional provisions in 2018 to reflect the changes in expected future losses under lease commitments. The remaining lease commitments provision at December 31, 2018 is expected to be fully realized by 2027.

Changes in the restructuring liability were as follows:

(millions of Canadian $)	Employee Severance	Lease Commitments	Total
Restructuring liability as at December 31, 2016	36	63	99
Restructuring charges[1]	—	6	6
Accretion expense	—	1	1
Cash payments	(27)	(17)	(44)
Restructuring liability as at December 31, 2017	9	53	62
Restructuring charges[1]	**—**	**42**	**42**
Accretion expense	**—**	**1**	**1**
Cash payments	**(9)**	**(15)**	**(24)**
Restructuring Liability as at December 31, 2018	**—**	**81**	**81**

1 At December 31, 2018, the Company recorded an additional $21 million in Plant operating costs and other in the Consolidated statement of income and $21 million as a regulatory asset on the Consolidated balance sheet related to costs that are recoverable through regulatory and tolling structures in future periods (2017 – $3 million and $3 million, respectively).

28. RELATED PARTY TRANSACTIONS

Related party transactions are conducted in the normal course of business and are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties.

In 2018, Interest income and other included nil as a result of inter-affiliate lending to TransCanada (2017 - nil; 2016 - $19 million).

The following amounts are included in Due to affiliates:

		2018		2017	
(millions of Canadian $)	Maturity Date	Outstanding December 31	Effective Interest Rate	Outstanding December 31	Effective Interest Rate
Credit Facility[1]	Demand	**3,617**	**3.95%**	2,551	**3.2%**

1 TCPL has an unsecured $4.5 billion credit facility with TransCanada. Interest on this facility is charged at the prime rate per annum.

In 2018, Interest expense included $114 million of interest charges as a result of inter-affiliate borrowing (2017 - $68 million; 2016 - $38 million).

At December 31, 2018, Accounts payable and other included $19 million due to TransCanada (December 31, 2017 - $16 million).The company made interest payments of $99 million to TransCanada in 2018 (2017 - $68 million; 2016 - $36 million).

29. VARIABLE INTEREST ENTITIES

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 Consolidated VIEs whose assets cannot be used for purposes other than for the settlement of the VIE's obligations are as follows:

at December 31 (millions of Canadian $)	**2018**	**2017**
ASSETS		
Current Assets		
Cash and cash equivalents	**45**	41
Accounts receivable	**79**	63
Inventories	**24**	23
Other	**13**	11
	161	138
Plant, Property and Equipment	**3,026**	3,535
Equity Investments	**965**	917
Goodwill	**453**	490
Intangible and Other Assets	**8**	3
	4,613	5,083
LIABILITIES		
Current Liabilities		
Accounts payable and other	**88**	137
Dividends payable	**—**	1
Accrued interest	**24**	23
Current portion of long-term debt	**79**	88
	191	249
Regulatory Liabilities	**43**	34
Other Long-Term Liabilities	**3**	3
Deferred Income Tax Liabilities	**13**	13
Long-Term Debt	**3,125**	3,244
	3,375	3,543

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 $)	2018	2017
Balance sheet		
Equity investments	**4,575**	4,372
Off-balance sheet		
Potential exposure to guarantees	**170**	171
Maximum exposure to loss	**4,745**	4,543

30. SUBSEQUENT EVENT

Common Share Issuance

On January 31, 2019, the Company issued 3.8 million common shares to TransCanada for proceeds of $214 million.