

Management's Report on Internal Control over Financial Reporting

The consolidated financial statements and Management's Discussion and Analysis (MD&A) included in this Annual Report are the responsibility of the management of TransCanada Corporation (TransCanada or the Company) and have been approved by the Board of Directors of the Company. The consolidated financial statements have been prepared by management in accordance with United States generally accepted accounting principles (GAAP) and include amounts that are based on estimates and judgments. The MD&A is based on the Company's financial results. It compares the Company's financial and operating performance in 2018 to that in 2017, and highlights significant changes between 2017 and 2016. The MD&A should be read in conjunction with the consolidated financial statements and accompanying notes. Financial information contained elsewhere in this Annual Report is consistent with the consolidated financial statements.

Management is responsible for establishing and maintaining adequate internal control over financial reporting for the Company. Management has designed and maintains a system of internal control over financial reporting, including a program of internal audits to carry out its responsibility. Management believes these controls provide reasonable assurance that financial records are reliable and form a proper basis for the preparation of financial statements. The internal control over financial reporting 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 MD&A and ensuring that management fulfills its responsibilities for financial reporting and internal control. The Board of Directors carries out these responsibilities primarily through the Audit Committee, which consists of independent, non-management directors. The Audit Committee meets with management at least five times a year and meets independently with internal and external auditors and as a group to review any significant accounting, internal control and auditing matters in accordance with the terms of the Charter of the Audit Committee, which is set out in the Annual Information Form. The Audit Committee's responsibilities include overseeing management's performance in carrying out its financial reporting responsibilities and reviewing the Annual Report, including the consolidated financial statements and MD&A, before these documents are submitted to the Board of Directors for approval. The internal and independent external auditors have access to the Audit Committee without the requirement to obtain prior management approval.

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

The shareholders have appointed KPMG LLP as independent external auditors to express an opinion as to whether the consolidated financial statements present fairly, in all material respects, the Company's consolidated financial position, results of operations and cash flows in accordance with GAAP. The reports of KPMG LLP outline the scope of its examinations and its opinions on the consolidated financial statements and the effectiveness of the Company's internal control over financial reporting.



Russell K. Girling
President and
Chief Executive Officer

February 13, 2019



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

Report of Independent Registered Public Accounting Firm

To the Shareholders of TransCanada Corporation

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated balance sheets of TransCanada Corporation (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.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2018, based on the criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated February 13, 2019 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

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 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. 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.

The image shows a handwritten signature in black ink that reads "KPMG LLP". The letters are stylized and slanted to the right.

Chartered Professional Accountants

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

Calgary, Canada
February 13, 2019

Report of Independent Registered Public Accounting Firm

To the Shareholders and the Board of Directors of TransCanada Corporation

Opinion on Internal Control over Financial Reporting

We have audited TransCanada Corporation's (the Company) internal control over financial reporting as of December 31, 2018, based on the criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2018, based on criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated balance sheets of 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), and our report dated February 13, 2019 expressed an unqualified opinion on those consolidated financial statements.

Basis for Opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the 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 audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and disposition of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.



Chartered Professional Accountants
Calgary, Canada
February 13, 2019

Consolidated statement of income

| year ended December 31 | | | |
|---|---------------|-------------|-------------|
| (millions of Canadian \$, except per share amounts) | 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 26) | 170 | 631 | (833) |
| Financial Charges | | | |
| Interest expense (Note 17) | 2,265 | 2,069 | 1,998 |
| Allowance for funds used during construction | (526) | (507) | (419) |
| Interest income and other | 76 | (184) | (103) |
| | 1,815 | 1,378 | 1,476 |
| Income before Income Taxes | 3,949 | 3,306 | 837 |
| Income Tax Expense/(Recovery) (Note 16) | | | |
| Current | 315 | 149 | 156 |
| Deferred | 284 | 566 | 196 |
| Deferred – U.S. Tax Reform and 2018 FERC Actions | (167) | (804) | — |
| | 432 | (89) | 352 |
| Net Income | 3,517 | 3,395 | 485 |
| Net (loss)/income attributable to non-controlling interests (Note 19) | (185) | 238 | 252 |
| Net Income Attributable to Controlling Interests | 3,702 | 3,157 | 233 |
| Preferred share dividends | 163 | 160 | 109 |
| Net Income Attributable to Common Shares | 3,539 | 2,997 | 124 |
| Net Income per Common Share (Note 20) | | | |
| Basic | \$3.92 | \$3.44 | \$0.16 |
| Diluted | \$3.92 | \$3.43 | \$0.16 |
| Dividends Declared per Common Share | \$2.76 | \$2.50 | \$2.26 |
| Weighted Average Number of Common Shares (millions) (Note 20) | | | |
| Basic | 902 | 872 | 759 |
| Diluted | 903 | 874 | 760 |

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 | 3,517 | 3,395 | 485 |
| 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 22) | 1,314 | (926) | (32) |
| Comprehensive Income | 4,831 | 2,469 | 453 |
| Comprehensive (loss)/income attributable to non-controlling interests | (13) | 83 | 241 |
| Comprehensive Income Attributable to Controlling Interests | 4,844 | 2,386 | 212 |
| Preferred share dividends | 163 | 160 | 109 |
| Comprehensive Income Attributable to Common Shares | 4,681 | 2,226 | 103 |

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 | 3,517 | 3,395 | 485 |
| 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) | 284 | 566 | 196 |
| 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 23) | (35) | (64) | (3) |
| (Gain)/loss on assets held for sale/sold (Note 26) | (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 25) | (102) | (273) | 248 |
| Net cash provided by operations | 6,555 | 5,230 | 5,069 |
| 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 | (295) | (168) | 159 |
| Net cash used in investing activities | (10,019) | (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 |
| Dividends on common shares | (1,571) | (1,339) | (1,436) |
| Dividends on preferred shares | (158) | (155) | (100) |
| Distributions to non-controlling interests | (225) | (283) | (279) |
| Common shares issued, net of issue costs | 1,148 | 274 | 7,747 |
| Common shares repurchased (Note 20) | — | — | (14) |
| Preferred shares issued, net of issue costs | — | — | 1,474 |
| 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 | 2,748 | (1,419) | 14,007 |
| Effect of Foreign Exchange Rate Changes on Cash and Cash Equivalents | 73 | (39) | (127) |
| (Decrease)/Increase in Cash and Cash Equivalents | (643) | 73 | 166 |
| Cash and Cash Equivalents | | | |
| Beginning of year | 1,089 | 1,016 | 850 |
| Cash and Cash Equivalents | | | |
| End of year | 446 | 1,089 | 1,016 |

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 | | | 446 | 1,089 |
| Accounts receivable | | | 2,535 | 2,522 |
| Inventories | | | 431 | 378 |
| Assets held for sale (Note 6) | | | 543 | — |
| Other (Note 7) | | | 1,180 | 691 |
| | | | 5,135 | 4,680 |
| 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) | | | 1,921 | 1,484 |
| Restricted Investments | | | 1,207 | 915 |
| | | | 98,920 | 86,101 |
| LIABILITIES | | | | |
| Current Liabilities | | | | |
| Notes payable (Note 13) | | | 2,762 | 1,763 |
| Accounts payable and other (Note 14) | | | 5,408 | 4,057 |
| Dividends payable | | | 668 | 586 |
| Accrued interest | | | 646 | 605 |
| Current portion of long-term debt (Note 17) | | | 3,462 | 2,866 |
| | | | 12,946 | 9,877 |
| 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 |
| | | | 67,927 | 59,210 |
| EQUITY | | | | |
| Common shares, no par value (Note 20) | | | 23,174 | 21,167 |
| Issued and outstanding: | | December 31, 2018 – 918 million shares December 31, 2017 – 881 million shares | | |
| Preferred shares (Note 21) | | | 3,980 | 3,980 |
| Additional paid-in capital | | | 17 | — |
| Retained earnings | | | 2,773 | 1,623 |
| Accumulated other comprehensive loss (Note 22) | | | (606) | (1,731) |
| Controlling Interests | | | 29,338 | 25,039 |
| Non-controlling interests (Note 19) | | | 1,655 | 1,852 |
| | | | 30,993 | 26,891 |
| | | | 98,920 | 86,101 |

Commitments, Contingencies and Guarantees (Note 27)

Corporate Restructuring Costs (Note 28)

Variable Interest Entities (Note 29)

The accompanying Notes to the consolidated financial statements are an integral part of these statements.
On behalf of the Board:



Russell K. Girling, Director



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 | 21,167 | 20,099 | 12,102 |
| Shares issued: | | | |
| Under at-the-market equity issuance program, net of issue costs | 1,118 | 216 | — |
| Under dividend reinvestment and share purchase plan | 855 | 790 | 177 |
| On exercise of stock options | 34 | 62 | 74 |
| Under public offerings, net of issue costs | — | — | 7,752 |
| Shares repurchased | — | — | (6) |
| Balance at end of year | 23,174 | 21,167 | 20,099 |
| Preferred Shares | | | |
| Balance at beginning of year | 3,980 | 3,980 | 2,499 |
| Shares issued under public offerings, net of issue costs | — | — | 1,481 |
| Balance at end of year | 3,980 | 3,980 | 3,980 |
| Additional Paid-In Capital | | | |
| Balance at beginning of year | — | — | 7 |
| Issuance of stock options, net of exercises | 10 | 6 | 6 |
| 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) | — |
| Common shares repurchased (Note 20) | — | — | (8) |
| Reclassification of additional paid-in capital deficit to retained earnings | — | 341 | 9 |
| Balance at end of year | 17 | — | — |
| Retained Earnings | | | |
| Balance at beginning of year | 1,623 | 1,138 | 2,769 |
| Net income attributable to controlling interests | 3,702 | 3,157 | 233 |
| Common share dividends | (2,501) | (2,184) | (1,733) |
| Preferred share dividends | (163) | (159) | (122) |
| 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 | — | (341) | (9) |
| Balance at end of year | 2,773 | 1,623 | 1,138 |
| Accumulated Other Comprehensive Loss | | | |
| Balance at beginning of year | (1,731) | (960) | (939) |
| Other comprehensive income/(loss) attributable to controlling interests (Note 22) | 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 | 29,338 | 25,039 | 24,257 |
| 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 TransCanada'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 | 30,993 | 26,891 | 25,983 |

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

Notes to consolidated financial statements

1. DESCRIPTION OF TRANSCANADA'S BUSINESS

TransCanada Corporation (TransCanada 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.

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 TransCanada 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. TransCanada 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. TransCanada 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, TransCanada 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 26).

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 23)
- fair value of financial instruments (Note 24) and
- provisions for commitments, contingencies, guarantees (Note 27) and restructuring costs (Note 28).

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 TransCanada'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.

TransCanada'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. TransCanada has PPAs for the sale of power that are accounted for as operating leases where TransCanada 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 TransCanada 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), TransCanada 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 TransCanada are not attributed a value for accounting purposes. When required, TransCanada 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 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. Upon exercise of stock options, amounts originally recorded against Additional paid-in capital are reclassified to Common shares on the Consolidated balance sheet.

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 | Corporate¹ | 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 | | | | | | | (2,265) |
| Allowance for funds used during construction | | | | | | | 526 |
| Interest income and other ³ | | | | | | | (76) |
| Income before income taxes | | | | | | | 3,949 |
| Income tax expense | | | | | | | (432) |
| Net income | | | | | | | 3,517 |
| Net loss attributable to non-controlling interests | | | | | | | 185 |
| Net income attributable to controlling interests | | | | | | | 3,702 |
| Preferred share dividends | | | | | | | (163) |
| Net income attributable to common shares | | | | | | | 3,539 |
| 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 | Corporate¹ | 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 | | | | | | | (2,069) |
| Allowance for funds used during construction | | | | | | | 507 |
| Interest income and other ³ | | | | | | | 184 |
| Income before income taxes | | | | | | | 3,306 |
| Income tax recovery | | | | | | | 89 |
| Net income | | | | | | | 3,395 |
| Net income attributable to non-controlling interests | | | | | | | (238) |
| Net income attributable to controlling interests | | | | | | | 3,157 |
| Preferred share dividends | | | | | | | (160) |
| Net income attributable to common shares | | | | | | | 2,997 |
| 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 | Corporate¹ | 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 | | | | | | | (1,998) |
| Allowance for funds used during construction | | | | | | | 419 |
| Interest income and other | | | | | | | 103 |
| Income before income taxes | | | | | | | 837 |
| Income tax expense | | | | | | | (352) |
| Net income | | | | | | | 485 |
| Net income attributable to non-controlling interests | | | | | | | (252) |
| Net income attributable to controlling interests | | | | | | | 233 |
| Preferred share dividends | | | | | | | (109) |
| Net income attributable to common shares | | | | | | | 124 |
| 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 | 3,513 | 3,642 |
| | 98,920 | 86,101 |

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 24, 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 | 2,522 | (62) | 2,460 |
| Other ¹ | 691 | 79 | 770 |
| Current Liabilities | | | |
| Accounts payable and other ² | 4,057 | 17 | 4,074 |

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:

| (millions of Canadian \$) | December 31, 2018 | |
|---------------------------|-------------------|--|
| | As reported | Pro-forma using legacy U.S. GAAP |
| Current Assets | | |
| Accounts receivable | 2,535 | 2,694 |
| 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, TransCanada 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 sale¹ | (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 24) | 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 | | | 2017 | | |
|---|--------|--------------------------|----------------|--------|--------------------------|----------------|
| | Cost | Accumulated Depreciation | Net Book Value | Cost | Accumulated Depreciation | 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 | | | 2017 | | |
|---|--------|--------------------------|----------------|--------|--------------------------|----------------|
| | Cost | Accumulated Depreciation | Net Book Value | Cost | Accumulated Depreciation | 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 26, 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 | | | Equity Investments | |
|--------------------------------|---|---------------------------------------|------|------|--------------------|-------|
| | | year ended December 31 | | | at December 31 | |
| | | 2018 | 2017 | 2016 | 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 TransCanada 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, TransCanada 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, TransCanada 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 TransCanada'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 TransCanada | 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

TransCanada 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, TransCanada 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 TransCanada'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

TransCanada'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

TransCanada'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.

TransCanada'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 TransCanada 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 TransCanada 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

TransCanada'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

TransCanada 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 TransCanada.

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

TransCanada's Mexico natural gas pipelines are regulated by the CRE and operate in accordance with CRE-approved tariffs. The rates in effect on TransCanada'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 26) | 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) | 322 | 316 |
| Employee post-retirement benefits (Note 23) | 192 | 193 |
| Fair value of derivative contracts (Note 24) | 61 | 73 |
| Other | 295 | 306 |
| | 1,921 | 1,484 |

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 TransCanada 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 TransCanada 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, TransCanada 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, TransCanada 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 | | 2017 | |
|---|----------------------------|---|----------------------------|---|
| | Outstanding at December 31 | Weighted Average Interest Rate per Annum at December 31 | Outstanding at December 31 | Weighted Average Interest Rate per Annum at December 31 |
| 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 TransCanada PipeLines Limited (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 | | 2017 |
| | | | Total Facilities | Unused Capacity | 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 and preferred 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 24) | 922 | 387 |
| Unredeemed shares of Columbia | 357 | 312 |
| Regulatory liabilities (Note 10) | 591 | 263 |
| Other | 314 | 248 |
| | 5,408 | 4,057 |

15. OTHER LONG-TERM LIABILITIES

| at December 31 | | |
|--|--------------|-------------|
| (millions of Canadian \$) | 2018 | 2017 |
| Employee post-retirement benefits (Note 23) | 569 | 389 |
| Asset retirement obligations | 90 | 98 |
| Fair value of derivative contracts (Note 24) | 42 | 72 |
| Guarantees (Note 27) | 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. TransCanada 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 | 65 | 113 | 116 |
| Foreign | 250 | 36 | 40 |
| | 315 | 149 | 156 |
| Deferred | | | |
| Canada | 49 | (185) | 101 |
| Foreign | 235 | 751 | 95 |
| Foreign – U.S. Tax Reform and 2018 FERC Actions | (167) | (804) | — |
| | 117 | (238) | 196 |
| Income Tax Expense/(Recovery) | 432 | (89) | 352 |

Geographic Components of Income before Income Taxes

| year ended December 31 (millions of Canadian \$) | 2018 | 2017 | 2016 |
|--|--------------|--------------|-------------|
| Canada | 433 | (339) | 219 |
| Foreign | 3,516 | 3,645 | 618 |
| Income before Income Taxes | 3,949 | 3,306 | 837 |

Reconciliation of Income Tax Expense/(Recovery)

| year ended December 31 (millions of Canadian \$) | 2018 | 2017 | 2016 |
|---|------------|-------------|------------|
| Income before income taxes | 3,949 | 3,306 | 837 |
| Federal and provincial statutory tax rate | 27% | 27% | 27% |
| Expected income tax expense | 1,066 | 893 | 226 |
| 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 | 46 |
| Other | (20) | 13 | 21 |
| Income Tax Expense/(Recovery) | 432 | (89) | 352 |

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 | 1,379 |
| 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 | 292 | 227 |
| | 3,453 | 2,995 |
| Less: valuation allowance | 1,159 | 832 |
| | 2,294 | 2,163 |
| 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 | 5,704 | 5,087 |

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) | 322 | 316 |
| Deferred Income Tax Liabilities | | |
| Deferred income tax liabilities | 6,026 | 5,403 |
| Net Deferred Income Tax Liabilities | 5,704 | 5,087 |

At December 31, 2018, the Company has recognized the benefit of unused non-capital loss carryforwards of \$1,867 million (2017 – \$1,280 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 | 15 | 18 | 17 |
| 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 | (4) | (4) | (3) |
| Unrecognized Tax Benefit at End of Year | 19 | 15 | 18 |

Subject to the results of audit examinations by taxing authorities and other legislative amendments, TransCanada 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.

TransCanada 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.

TransCanada'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 \$1 million of interest recovery 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 | | 2017 | |
|--|----------------|----------------------------|----------------------------|----------------------------|----------------------------|
| | | Outstanding at December 31 | Interest Rate ¹ | Outstanding at December 31 | 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 | | 2017 | |
|--|-------------------|-------------------------------|-------------------------------|-------------------------------|-------------------------------|
| | | Outstanding at December 31 | Interest Rate ¹ | Outstanding at December 31 | 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 24, 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 | 73 | 33 | 18 |
| Capitalized interest | (124) | (173) | (176) |
| Amortization and other financial charges ¹ | 48 | 67 | 211 |
| | 2,265 | 2,069 | 1,998 |

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. In 2016, this amount includes dividend equivalent payments of \$109 million on the subscription receipts issued to partially fund the Columbia acquisition. Refer to Note 20, Common shares, for further information.

The Company made interest payments of \$2,156 million in 2018 (2017 – \$1,987 million; 2016 – \$1,721 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 | | 2017 | |
|--|---------------|----------------------------|--------------------------------------|----------------------------|--------------------------------------|
| | | Outstanding at December 31 | Effective Interest Rate ¹ | Outstanding at December 31 | 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 TransCanada's financial statements since TCPL does not have a variable interest in the Trust and the only substantive assets of the Trust are junior subordinated notes of TCPL.

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 TransCanada sold its remaining interest in Portland to TC PipeLines, LP. Refer to Note 26, 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, TransCanada 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, TransCanada sold 49.9 per cent of Portland to TC PipeLines, LP. Refer to Note 26, Acquisitions and dispositions for further information.

Columbia Pipeline Partners LP

On July 1, 2016, TransCanada acquired Columbia, which included a 53.5 per cent non-controlling interest in Columbia Pipeline Partners LP (CPPL). On February 17, 2017, TransCanada 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 TransCanada'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 | 702,614 | 12,102 |
| Issued under public offerings ¹ | 156,825 | 7,752 |
| Dividend reinvestment and share purchase plan | 2,942 | 177 |
| Exercise of options | 1,683 | 74 |
| Repurchase of shares | (305) | (6) |
| Outstanding at December 31, 2016 | 863,759 | 20,099 |
| Dividend reinvestment and share purchase plan | 12,824 | 790 |
| At-the-market equity issuance program ¹ | 3,462 | 216 |
| Exercise of options | 1,331 | 62 |
| Outstanding at December 31, 2017 | 881,376 | 21,167 |
| At-the-market equity issuance program ¹ | 20,050 | 1,118 |
| Dividend reinvestment and share purchase plan | 15,937 | 855 |
| Exercise of options | 734 | 34 |
| Outstanding at December 31, 2018 | 918,097 | 23,174 |

¹ Net of issue costs and deferred income taxes.

Common Shares Issued and Outstanding

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

Dividend Reinvestment and Share Purchase Plan

Effective July 1, 2016, the Company re-initiated the issuance of common shares from treasury under its Dividend Reinvestment Plan (DRP) and Share Purchase Plan. Under these plans, eligible holders of common and preferred shares of TransCanada can reinvest their dividends and make optional cash payments to obtain TransCanada common shares. Under the DRP, common shares were issued from treasury at a discount of two per cent.

TransCanada Corporation At-the-Market Equity Issuance Program

In June 2017, the Company established an At-the-Market Equity Issuance Program (ATM program) that allows, from time to time, for the issuance of common shares from treasury at the prevailing market price when sold through the Toronto Stock Exchange (TSX), the New York Stock Exchange (NYSE) or any other existing trading market for TransCanada common shares in Canada or the United States. The ATM program, which is effective for a 25-month period, is utilized as appropriate in order to manage the Company's capital structure over time. Under the original ATM program, the Company could issue up to \$1.0 billion in common shares or the U.S. dollar equivalent.

In 2017, 3.5 million common shares were issued under the ATM program at an average price of \$63.03 per share for proceeds of \$216 million, net of approximately \$2 million of related commissions and fees.

In June 2018, the Company replenished the capacity available under its existing ATM program. This allows for the issuance of additional common shares from treasury for an aggregate gross sales price of up to \$1.0 billion, for a revised total of \$2.0 billion or its U.S. dollar equivalent. The ATM program, as amended, is effective to July 23, 2019.

In 2018, 20 million common shares were issued under the ATM program at an average price of \$56.13 per share for proceeds of \$1.1 billion, net of approximately \$10 million of related commissions and fees.

Common Share Public Offering and Subscription Receipts

To partially fund the Columbia acquisition, in April 2016, the Company issued 96.6 million subscription receipts at a price of \$45.75 each for gross proceeds of approximately \$4.4 billion. Holders of subscription receipts received one common share in exchange for each subscription receipt on July 1, 2016 upon closing of the acquisition. Holders of record at close of business on April 15, 2016 and June 30, 2016 received a cash payment per subscription receipt that was equal in amount to dividends declared on each common share. For the year ended December 31, 2016, \$109 million of dividend equivalent payments on these subscription receipts were recorded as Interest expense.

In November 2016, the Company issued 60.2 million common shares at a price of \$58.50 each for gross proceeds of approximately \$3.5 billion. Proceeds from this offering were used to repay a portion of the US\$6.9 billion acquisition bridge facilities which were used to partially fund the Columbia acquisition.

Common Shares Repurchased

In November 2015, the Company received approval from the TSX for a normal course issuer bid (NCIB) allowing it to repurchase, for cancellation, up to 21 million of its common shares representing three per cent of its then issued and outstanding common shares. Under the NCIB, which expired in November 2016, the Company purchased these common shares through the facilities of the TSX and other designated exchanges and published markets in Canada, or through off-exchange block purchases by way of private agreement.

In January 2016, the Company repurchased 305,407 of its common shares at an average price of \$44.90 for a total of \$14 million. These shares had a weighted average cost of \$6 million with the difference of \$8 million between the total price paid and the weighted average cost recorded in Additional paid-in capital.

Basic and Diluted Net Income per Common Share

Net income per common share is calculated by dividing Net income attributable to common shares by the weighted average number of common shares outstanding. The higher weighted average number of shares for the diluted earnings per share calculation is due to options exercisable under TransCanada's Stock Option Plan and shares issuable under the DRP.

| Weighted Average Common Shares Outstanding (millions) | 2018 | 2017 | 2016 |
|--|------|------|------|
| Basic | 902 | 872 | 759 |
| Diluted | 903 | 874 | 760 |

Stock Options

| | Number of Options (thousands) | Weighted Average Exercise Prices | Weighted Average Remaining Contractual Life (years) |
|---|-------------------------------------|--|---|
| Options outstanding at January 1, 2018 | 11,026 | \$51.38 | |
| Options granted | 2,250 | \$56.89 | |
| Options exercised | (734) | \$42.65 | |
| Options forfeited/expired | (138) | \$57.23 | |
| Options Outstanding at December 31, 2018 | 12,404 | \$52.83 | 3.6 |
| Options Exercisable at December 31, 2018 | 8,189 | \$50.72 | 2.6 |

At December 31, 2018, an additional 9,790,373 common shares were reserved for future issuance from treasury under TransCanada's Stock Option Plan. 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.

The Company 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 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.

Shareholder Rights Plan

TransCanada's Shareholder Rights Plan is designed to provide the Board of Directors with sufficient time to explore and develop alternatives for maximizing shareholder value in the event of a takeover offer for the Company and to encourage the fair treatment of shareholders in connection with any such offer. Attached to each common share is one right that, under certain circumstances, entitles certain holders to purchase an additional common share of the Company for half the then current market price of one common share.

21. PREFERRED SHARES

| at December 31 | Number of Shares Outstanding (thousands) | Current Yield | Annual Dividend Per Share | Redemption Price Per Share | Redemption and Conversion Option Date | Right to Convert Into ^{1,2} | 2018 (millions of Canadian \$) ³ | 2017 | 2016 |
|-----------------------------------|---|-----------------------|---------------------------------|----------------------------------|---|--|--|-------|-------|
| Cumulative First Preferred Shares | | | | | | | | | |
| Series 1 | 9,498 | 3.266% | \$0.8165 | \$25.00 | December 31, 2019 | Series 2 | 233 | 233 | 233 |
| Series 2 | 12,502 | Floating ⁴ | Floating | \$25.00 | December 31, 2019 | Series 1 | 306 | 306 | 306 |
| Series 3 | 8,533 | 2.152% | \$0.538 | \$25.00 | June 30, 2020 | Series 4 | 209 | 209 | 209 |
| Series 4 | 5,467 | Floating ⁴ | Floating | \$25.00 | June 30, 2020 | Series 3 | 134 | 134 | 134 |
| Series 5 | 12,714 | 2.263% | \$0.56575 | \$25.00 | January 30, 2021 | Series 6 | 310 | 310 | 310 |
| Series 6 | 1,286 | Floating ⁴ | Floating | \$25.00 | January 30, 2021 | Series 5 | 32 | 32 | 32 |
| Series 7 | 24,000 | 4.00% | \$1.00 | \$25.00 | April 30, 2019 | Series 8 | 589 | 589 | 589 |
| Series 9 | 18,000 | 4.25% | \$1.0625 | \$25.00 | October 30, 2019 | Series 10 | 442 | 442 | 442 |
| Series 11 | 10,000 | 3.80% | \$0.95 | \$25.00 | November 30, 2020 | Series 12 | 244 | 244 | 244 |
| Series 13 | 20,000 | 5.50% | \$1.375 | \$25.00 | May 31, 2021 | Series 14 | 493 | 493 | 493 |
| Series 15 | 40,000 | 4.90% | \$1.225 | \$25.00 | May 31, 2022 | Series 16 | 988 | 988 | 988 |
| Carrying value | | | | | | | 3,980 | 3,980 | 3,980 |

- Each of the even-numbered series of preferred shares, if in existence, will be entitled to receive floating rate cumulative quarterly preferential dividends per share at an annualized rate equal to the 90-day Government of Canada Treasury bill rate (T-bill rate) plus 1.92 per cent (Series 2), 1.28 per cent (Series 4), 1.54 per cent (Series 6), 2.38 per cent (Series 8), 2.35 per cent (Series 10), 2.96 per cent (Series 12), 4.69 per cent (Series 14) and 3.85 per cent (Series 16). These rates reset quarterly with the then current T-Bill rate.
- The odd-numbered series of preferred shares, if in existence, will be entitled to receive fixed rate cumulative quarterly preferential dividends, which will reset on the redemption and conversion option date and every fifth year thereafter, at an annualized rate equal to the then five-year Government of Canada bond yield plus 1.92 per cent (Series 1), 1.28 per cent (Series 3), 1.54 per cent (Series 5), 2.38 per cent (Series 7), 2.35 per cent (Series 9), 2.96 per cent (Series 11), 4.69 per cent, subject to a minimum of 5.50 per cent (Series 13) and 3.85 per cent, subject to a minimum of 4.90 per cent (Series 15).
- Net of underwriting commissions and deferred income taxes.
- The floating quarterly dividend rate for the Series 2 preferred shares is 3.633 per cent and for the Series 4 preferred shares is 2.993 per cent for the period starting December 31, 2018 to, but excluding, March 29, 2019. The floating quarterly dividend rate for the Series 6 preferred shares is 3.086 per cent for the period starting October 30, 2018 to, but excluding, January 30, 2019. These rates will reset each quarter going forward.

In February 2016, holders of 1,285,739 Series 5 cumulative redeemable first preferred shares exercised their option to convert to Series 6 cumulative redeemable first preferred shares.

In April 2016, the Company completed a public offering of 20 million Series 13 cumulative redeemable minimum rate reset first preferred shares at \$25 per share, resulting in gross proceeds of \$500 million.

In November 2016, the Company completed a public offering of 40 million Series 15 cumulative redeemable minimum rate reset first preferred shares at \$25 per share, resulting in gross proceeds of \$1.0 billion.

The holders of preferred shares are entitled to receive a fixed cumulative quarterly preferential dividend as and when declared by the Board with the exception of Series 2, Series 4 and Series 6 preferred shares. The holders of Series 2, Series 4 and Series 6 preferred shares are entitled to receive quarterly floating rate cumulative preferential dividends as and when declared by the Board. The holders will have the right, subject to certain conditions, to convert their first preferred shares of a specified series into first preferred shares of another specified series on the conversion option date and every fifth anniversary thereafter.

TransCanada may, at its option, redeem all or a portion of the outstanding preferred shares for the redemption price per share, plus all accrued and unpaid dividends on the applicable redemption option date and on every fifth anniversary thereafter. In addition, Series 2, Series 4 and Series 6 preferred shares are redeemable by TransCanada at any time other than on a designated date for \$25.50 per share plus all accrued and unpaid dividends on such redemption date.

22. 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 (millions of Canadian \$) | Amounts Reclassified From AOCI ¹ | | | Affected Line Item in the Consolidated Statement of Income |
|---|--|------|------|---|
| | 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 23, 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.

23. EMPLOYEE POST-RETIREMENT BENEFITS

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

On December 31, 2017, the Columbia DB Plan merged with TransCanada'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 TransCanada'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 TransCanada'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 (millions of Canadian \$) | Pension Benefit Plans | | Other Post-Retirement Benefit Plans | |
|---|--------------------------|-------|--|------|
| | 2018 | 2017 | 2018 | 2017 |
| Change in Benefit Obligation¹ | | | | |
| 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 (millions of Canadian \$) | Pension Benefit Plans | | Other Post-Retirement Benefit Plans | |
|---|-----------------------|-------|-------------------------------------|-------|
| | 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 (millions of Canadian \$) | Pension Benefit Plans | | Other Post-Retirement Benefit Plans | |
|---|-----------------------|--------------|-------------------------------------|--------------|
| | 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:

| at December 31 | Percentage of Plan Assets | | Target Allocations |
|-------------------|---------------------------|------|--------------------|
| | 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 24, Risk management and financial instruments.

| at December 31 (millions of Canadian \$) | Quoted Prices in Active Markets (Level I) | | Significant Other Observable Inputs (Level II) | | Significant Unobservable Inputs (Level III) | | Total | | Percentage of Total Portfolio | |
|---|---|-------|---|-------|--|------|--------------|-------|----------------------------------|------|
| | 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:

| at December 31 | Pension Benefit Plans | | Other Post-Retirement Benefit Plans | |
|-------------------------------|-----------------------|-------|-------------------------------------|-------|
| | 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:

| year ended December 31 | Pension Benefit Plans | | | Other Post-Retirement Benefit Plans | | |
|--|-----------------------|-------|-------|-------------------------------------|-------|-------|
| | 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 (millions of Canadian \$) | Pension Benefit Plans | | | Other Post-Retirement Benefit Plans | | |
|---|-----------------------|------------|------------|-------------------------------------|------------|-----------|
| | 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 (millions of Canadian \$) | 2018 | | 2017 | | 2016 | |
|---|------------------|--------------------------------|------------------|--------------------------------|------------------|--------------------------------|
| | 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 (millions of Canadian \$) | 2018 | | 2017 | | 2016 | |
|--|------------------|--------------------------------|------------------|--------------------------------|------------------|--------------------------------|
| | 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 net income | (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) |

24. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

Risk Management Overview

TransCanada 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 TransCanada'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, TransCanada 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, TransCanada'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, TransCanada enters into pipeline and storage terminal capacity contracts. TransCanada 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

TransCanada utilizes short-term and long-term debt to finance its operations which exposes the Company to interest rate risk. TransCanada 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 TransCanada'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

TransCanada 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 TransCanada'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

TransCanada'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 TransCanada 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.

TransCanada 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, 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 Instruments¹ |
|--|-----------------------------|------------------------------|--------------------------------------|-----------------------------|---|
| 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 (millions of Canadian \$) | Carrying amount | | Fair value hedging adjustments¹ | |
|--|------------------------|-------------|---|-------------|
| | 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 trading¹ | | | |
| 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 22) related to derivatives in cash flow hedging relationships including the portion attributable to non-controlling interests are as follows:

| year ended December 31 | | | |
|---|-------------|-------------|-------------|
| (millions of Canadian \$, pre-tax) | 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 | (2,265) | (2,069) | (1,998) |
| 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 22, 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. TransCanada 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 Offset¹ | 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 Offset¹ | 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 | <p>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.</p> <p>Inputs include published exchange rates, interest rates, interest rate swap curves, yield curves and broker quotes from external data service providers.</p> <p>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.</p> <p>Transfers between Level I and Level II would occur when there is a change in market circumstances.</p> |
| Level III | <p>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.</p> <p>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.</p> |

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 | Quoted Prices in Active Markets (Level I)¹ | Significant Other Observable Inputs (Level II)¹ | Significant Unobservable Inputs (Level III)¹ | Total |
|------------------------------------|--|---|--|--------------|
| (millions of Canadian \$) | | | | |
| 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 | Quoted Prices in Active Markets (Level I)¹ | Significant Other Observable Inputs (Level II)¹ | Significant Unobservable Inputs (Level III)¹ | Total |
|------------------------------------|--|---|--|--------------|
| (millions of Canadian \$) | | | | |
| 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 year¹ | (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.

25. CHANGES IN OPERATING WORKING CAPITAL

| year ended December 31 (millions of Canadian \$) | 2018 | 2017 | 2016 |
|--|--------------|--------------|------------|
| Increase in Accounts receivable | (69) | (576) | (482) |
| 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 | (70) | 151 | 424 |
| 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 | (102) | (273) | 248 |

26. ACQUISITIONS AND DISPOSITIONS

U.S. Natural Gas Pipelines

Iroquois Gas Transmission System and Portland Natural Gas Transmission System

On June 1, 2017, TransCanada 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, TransCanada 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, TransCanada 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, TransCanada acquired a 4.87 per cent interest in Iroquois for an aggregate purchase price of US\$54 million, increasing TransCanada'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 TransCanada's interest in Iroquois to 50 per cent.

Acquisition of Columbia

On July 1, 2016, TransCanada 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 proceeds of approximately \$4.4 billion from the sale of subscription receipts, draws on acquisition bridge facilities in the aggregate amount of US\$6.9 billion and existing cash on hand. The sale of the subscription receipts was completed on April 1, 2016 through a public offering and, upon closing of the acquisition, were exchanged into approximately 96.6 million common shares of TransCanada. Refer to Note 20, Common shares for further information on the subscription receipts.

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. TransCanada 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 TransCanada.

| (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, TransCanada 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 TransCanada'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) | 627 | (820) |
| Net Income/(Loss) Attributable to Common Shares | 234 | (971) |

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, TransCanada 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, TransCanada 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.

27. COMMITMENTS, CONTINGENCIES AND GUARANTEES

Commitments

Operating leases

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

| year ended December 31 (millions of Canadian \$) | Minimum Lease Payments | Amounts Recoverable under Subleases | Net Payments |
|---|------------------------------|--|-----------------|
| 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

TransCanada 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, TransCanada 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

TransCanada 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.

TransCanada 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

TransCanada 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.

TransCanada 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 TransCanada 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:

| at December 31 (millions of Canadian \$) | | 2018 | | 2017 | |
|---|-----------------|---------------------------------|----------------|---------------------------------|----------------|
| | | 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 TransCanada's share of the potential estimated current or contingent exposure.

28. CORPORATE RESTRUCTURING COSTS

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

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 |