TransCanada Reports Record First Quarter Financial Results
Declares Quarterly Dividend of $0.75 per Common Share

CALGARY, Alberta – **May 3, 2019** – TransCanada Corporation (TSX, NYSE: TRP) (TransCanada or the Company) today announced net income attributable to common shares for first quarter 2019 of $1.004 billion or $1.09 per share compared to net income of $734 million or $0.83 per share for the same period in 2018. Comparable earnings for first quarter 2019 were $987 million or $1.07 per common share compared to $864 million or $0.98 per common share for the same period in 2018. TransCanada's Board of Directors also declared a quarterly dividend of $0.75 per common share for the quarter ending June 30, 2019, equivalent to $3.00 per common share on an annualized basis.

"We are very pleased with the performance of our diversified and irreplaceable portfolio of high-quality, long-life energy infrastructure assets which continued to produce record financial results through the first quarter of 2019," said Russ Girling, TransCanada's president and chief executive officer. "Comparable earnings per share increased nine per cent compared to the same period last year while comparable funds generated from operations of $1.8 billion were eleven per cent higher. The increases reflect the strong performance of our legacy assets along with contributions from approximately $5.3 billion of growth projects that were placed into service in first quarter 2019."

"With the demand for our existing assets driving historically high utilization rates and $30 billion of secured growth projects underway, approximately $7 billion of which are expected to be completed by the end of the year, earnings and cash flow are forecast to continue to rise. These projects are supported by regulated or long-term contracted business models that are expected to support annual dividend growth of eight to ten per cent through 2021," added Girling. "We have invested $10 billion in these projects to date and are well positioned to fund the remainder of our secured growth program through significant and growing internally generated cash flow and access to capital markets. We also continue to progress various portfolio management activities, including the announced sale of our Coolidge generating station which is expected to close by mid-year. This will allow us to prudently fund our capital program in a manner that is consistent with achieving targeted leverage metrics, including debt-to-EBITDA in the high four times area, in 2019 and thereafter and deliver ongoing growth as measured on a per-share basis."

"Looking ahead, we continue to methodically advance more than $20 billion of projects under development including Keystone XL and the Bruce Power life extension program. Success in progressing these and other growth initiatives that are expected to emanate from our five operating businesses across North America could extend our growth outlook well into the next decade," concluded Girling.

Highlights

(All financial figures are unaudited and in Canadian dollars unless noted otherwise)

- First quarter 2019 financial results
  - Net income attributable to common shares of $1.004 billion or $1.09 per common share
  - Comparable earnings of $987 million or $1.07 per common share
  - Comparable earnings before interest, taxes, depreciation and amortization of $2.4 billion
  - Net cash provided by operations of $1.9 billion
  - Comparable funds generated from operations of $1.8 billion
  - Comparable distributable cash flow of $1.6 billion or $1.76 per common share
- Declared a quarterly dividend of $0.75 per common share for the quarter ending June 30, 2019
- Placed approximately $5.3 billion of projects in service including Mountaineer XPress, Gulf XPress and certain NGTL System expansions
- Continued pre-construction activities on Coastal GasLink pipeline project
- Received new Presidential Permit for Keystone XL
- Completed commissioning on White Spruce pipeline
- Issued $1.0 billion of 30-year fixed-rate medium-term notes in April 2019.

Net income attributable to common shares increased by $270 million or $0.26 per common share to $1.004 billion or $1.09 per share for the three months ended March 31, 2019 compared to the same period last year. Per share results reflect the dilutive impact of common shares issued under our DRP in 2018 and 2019 and our Corporate ATM program in 2018. First quarter 2019 and 2018 results included an after-tax loss of $12 million and an after-tax gain of $6 million, respectively, related to our U.S. Northeast power marketing contracts. These specific items, as well as unrealized gains and losses from changes in risk management activities, are excluded from comparable earnings.

Comparable EBITDA increased by $320 million for the three months ended March 31, 2019 compared to the same period in 2018 primarily due to the net effect of the following:

- higher contribution from U.S. Natural Gas Pipelines mainly due to increased earnings from Columbia Gas and Columbia Gulf growth projects placed in service
- higher contribution from Liquids Pipelines primarily due to higher volumes on the Keystone Pipeline System and increased earnings from liquids marketing activities
- higher contribution from Canadian Natural Gas Pipelines mainly due to the recovery of increased depreciation in 2019 as a result of higher rates approved in both the Canadian Mainline NEB 2018 Decision and the NGTL 2018-2019 Settlement and higher incentive earnings for the Canadian Mainline
- lower contribution from Power and Storage primarily due to the sale of our interests in the Cartier Wind power facilities in 2018 and costs related to Napanee's delayed in-service
- foreign exchange impact of a stronger U.S. dollar on the Canadian dollar equivalent earnings from our U.S. operations.

Comparable earnings increased by $123 million or $0.09 per common share for the three months ended March 31, 2019 compared to the same period in 2018 and was primarily the net effect of:

- changes in comparable EBITDA described above
- higher depreciation largely in Canadian Natural Gas Pipelines, which is fully recovered in tolls as reflected in the increase in comparable EBITDA described above, therefore having no impact on comparable earnings. In addition, higher depreciation reflects new projects placed in service
- higher interest expense primarily as a result of long-term debt issuances, net of maturities, and the foreign exchange impact on translation of U.S. dollar-denominated interest
- higher income tax expense due to higher comparable earnings before income taxes and lower foreign tax rate differentials

- lower interest income and other due to realized losses in 2019 compared to realized gains in 2018 on derivatives used to manage exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income
- higher AFUDC due to increased capital expenditures for our NGTL System and Mexico projects.

Comparable earnings per common share for the three months ended March 31, 2019 also reflects the dilutive impact of common shares issued under our DRP in 2018 and 2019 and our Corporate ATM program in 2018.

Notable recent developments include:

Canadian Natural Gas Pipelines:

- *Coastal GasLink Pipeline Project:* Following the October 2018 positive Final Investment Decision (FID) by LNG Canada, pre-construction activities continue at many locations along the pipeline route.

  The NEB process considering regulatory jurisdiction continues with all evidence now submitted. A final hearing is scheduled for second quarter 2019 with a decision expected in third quarter 2019.

  TransCanada continues to advance funding plans for the $6.2 billion pipeline project through a combination of the sale of up to 75 per cent ownership interest and potential project financing.

- *NGTL System*: In first quarter 2019, we placed approximately $250 million of projects in service which included the Gordondale Lateral Loop and the Boundary Lake North projects.

  On March 14, 2019, we filed the NGTL System Rate Design and Services Application with the NEB which includes a settlement agreement negotiated between NGTL and members of its Tolls, Tariff, Facilities and Procedures (TTFP) committee, which represents stakeholders. The settlement is supported by a majority of members of the TTFP committee. The Application addresses rate design, terms and conditions of service for the NGTL System and a tolling methodology for the North Montney Mainline. Given the complexity of the issues raised in the Application, the NEB decided to hold a public hearing. Application to participate and comments on the Application were due April 12, 2019 and reply comments were submitted by NGTL on April 18, 2019.

U.S. Natural Gas Pipelines:

- *Mountaineer XPress and Gulf XPress:* The Mountaineer XPress project, a Columbia Gas project designed to transport supply from the Marcellus and Utica shale plays to points along the system and the Leach interconnect with Columbia Gulf, was phased into service over first quarter 2019 along with Gulf XPress, a Columbia Gulf project.

- *Grand Chenier XPress:* In February 2019, we approved the Grand Chenier XPress project, an ANR Pipeline project which will connect supply directly to Gulf Coast LNG export markets through the addition of a mid-point compressor station and incremental compression capability at existing facilities. Subject to a positive customer FID, the anticipated in-service dates are in 2021 and 2022 for Phase I and II, respectively, with estimated project costs of US$0.2 billion.

Mexico Natural Gas Pipelines:

- *Sur de Texas:* The Sur de Texas project has experienced force majeure events that have delayed in-service. Some events are subject to potential dispute and we have taken measures to protect our interests under the contract. Construction and commissioning activities are progressing such that we anticipate mechanical completion in May with an expected June 2019 in-service.

- *Villa de Reyes and Tula:* Construction of the Villa de Reyes project is ongoing with a phased in-service anticipated to commence in the second half of 2019. Commencement of construction of the central segment of the Tula project has been delayed due to a lack of progress by the Secretary of Energy, the governmental department responsible for Indigenous consultations. Project completion has been revised to the end of 2020. We have negotiated separate CFE contracts that would allow certain segments of Tula and Villa de Reyes to be placed in service when facilities are complete and gas is available.

Liquids Pipelines:

- *Keystone Pipeline System:* In January 2019, we entered into an agreement with Motiva Enterprises LLC (Motiva) to construct a pipeline connection between the Keystone Pipeline system and Motiva's 630,000 Bbl/d refinery in Port Arthur, Texas. The connection is targeted to be operational in second quarter 2020.
- *Keystone XL:* A decision from the Nebraska Supreme Court on the appeal of the Nebraska Public Service Commission route approval remains pending. We expect the decision to be issued in second quarter 2019.

  In September 2018, two U.S. Native American communities filed a lawsuit in Montana challenging the Keystone XL Presidential Permit. We, along with the U.S. Government, have filed to have the lawsuit dismissed. In December 2018, we applied to the U.S. District Court in Montana for a stay of its various decisions affecting the issuance of the 2017 Keystone XL Presidential Permit and the extensive environmental assessments made in support of its issuance. The stay application was denied by the U.S. District Court in February 2019. In February 2019, we applied to the Ninth Circuit Court of Appeals (Ninth Circuit) for a stay of the U.S. District Court decisions. On March 16, 2019, the Ninth Circuit denied our stay application and declined to further limit the scope of the preliminary injunction which prevents us from conducting certain pre-construction activities.

  On March 29, 2019, U.S. President Trump issued a new Presidential Permit for the Keystone XL Project, which superseded the 2017 permit. Subsequently, we filed a motion with the Ninth Circuit requesting the court vacate the U.S. District Court decisions, dissolve the injunctions, and direct the U.S. District Court to dismiss the pending cases. A lawsuit was filed challenging the validity of the new Presidential Permit. We are not named in the lawsuit.
- *White Spruce:* Commissioning has been completed on the White Spruce pipeline, which transports crude oil from Canadian Natural Resources Limited's Horizon facility in northeast Alberta to the Grand Rapids pipeline with commercial in-service achieved in May 2019.

Power and Storage (previously Energy):

- *Napanee:* In March 2019, we experienced an equipment failure while progressing commissioning activities at our 900 MW natural gas-fired power plant in Napanee, Ontario. We continue to expect that our total investment in the Napanee facility will be approximately $1.7 billion, however, commencement of commercial operations will be delayed into the second half of 2019 as we repair the damaged equipment.
- *Coolidge Generating Station:* In December 2018, we entered into an agreement to sell our Coolidge generating station in Arizona to SWG Coolidge Holdings, LLC (SWG). Salt River Project Agriculture Improvement and Power District (SRP), the PPA counterparty, subsequently exercised its contractual right of first refusal on a sale to a third party. On March 20, 2019, we terminated the agreement with SWG after entering into an agreement with SRP to sell the Coolidge generating station for approximately US$465 million, subject to timing of the close and related adjustments. The sale will result in an estimated gain of approximately $70 million ($55 million after tax) to be recognized upon closing, which is expected to occur in mid-2019.

Corporate:

- *Common Share Dividend:* Our Board of Directors declared a quarterly dividend of $0.75 per common share for the quarter ending June 30, 2019 on TransCanada's outstanding common shares. The quarterly amount is equivalent to $3.00 per common share on an annualized basis.
- *Issuance of Long-term Debt:* In April 2019, TCPL issued $1.0 billion of Medium Term Notes due in October 2049 bearing interest at a fixed rate of 4.34 per cent. The net proceeds of this debt issuance were used for general corporate purposes and to fund our capital program.

  In first quarter 2019, TCPL repaid $100 million of Debentures bearing interest at a fixed rate of 10.50 per cent, US$750 million of Senior Unsecured Notes bearing interest at a fixed rate of 7.125 per cent and US$400 million of Senior Unsecured Notes bearing interest at a fixed rate of 3.125 per cent.
- *Dividend Reinvestment Plan:* In first quarter 2019, the DRP participation rate amongst common shareholders was approximately 33 per cent, resulting in $226 million reinvested in common equity under the program.

Teleconference and Webcast:

We will hold a teleconference and webcast on Friday, May 3, 2019 to discuss our first quarter 2019 financial results. Russ Girling, President and Chief Executive Officer, and Don Marchand, Executive Vice-President and Chief Financial Officer, along with other members of the executive leadership team, will discuss the financial results and Company developments at 1 p.m. (MT) / 3 p.m. (ET).

Members of the investment community and other interested parties are invited to participate by calling 800.273.9672 or 416.340.2216 (Toronto area). Please dial in 10 minutes prior to the start of the call. No pass code is required. A live webcast of the teleconference will be available at www.transcanada.com or via the following URL: www.gowebcasting.com/9939.

A replay of the teleconference will be available two hours after the conclusion of the call until midnight (ET) on May 10, 2019. Please call 800.408.3053 or 905.694.9451 (Toronto area) and enter pass code 7151952#.

The unaudited interim Condensed consolidated financial statements and Management's Discussion and Analysis (MD&A) are available under TransCanada's profile on SEDAR at www.sedar.com, with the U.S. Securities and Exchange Commission on EDGAR at www.sec.gov/info/edgar.shtml and on our website at www.transcanada.com.

With more than 65 years' experience, TransCanada is a leader in the responsible development and reliable operation of North American energy infrastructure including natural gas and liquids pipelines, power generation and gas storage facilities. We operate one of the largest natural gas transmission networks that extends more than 92,600 kilometres (57,500 miles), connecting major gas supply basins to markets across North America. TransCanada is a leading provider of gas storage and related services with 653 billion cubic feet of storage capacity. A large independent power producer, we currently own or have interests in more than 6,600 megawatts of power generation in Canada and the United States. We are also the developer and operator of one of North America's leading liquids pipeline systems that extends approximately 4,900 kilometres (3,000 miles), connecting growing continental oil supplies to key markets and refineries. TransCanada's common shares trade on the Toronto and New York stock exchanges under the symbol TRP. Visit TransCanada.com to learn more, or connect with us on social media.

Forward Looking Information

This release contains certain information that is forward-looking and is subject to important risks and uncertainties (such statements are usually accompanied by words such as "anticipate", "expect", "believe", "may", "will", "should", "estimate", "intend" or other similar words). Forward-looking statements in this document are intended to provide TransCanada security holders and potential investors with information regarding TransCanada and its subsidiaries, including management's assessment of TransCanada's and its subsidiaries' future plans and financial outlook. All forward-looking statements reflect TransCanada's beliefs and assumptions based on information available at the time the statements were made and as such are not guarantees of future performance. Readers are cautioned not to place undue reliance on this forward-looking information, which is given as of the date it is expressed in this news release, and not to use future-oriented information or financial outlooks for anything other than their intended purpose. TransCanada undertakes no obligation to update or revise any forward-looking information except as required by law. For additional information on the assumptions made, and the risks and uncertainties which could cause actual results to differ from the anticipated results, refer to the Quarterly Report to Shareholders dated May 2, 2019 and the 2018 Annual Report filed under TransCanada's profile on SEDAR at www.sedar.com and with the U.S. Securities and Exchange Commission at www.sec.gov.

Non-GAAP Measures

This news release contains references to non-GAAP measures, including comparable earnings, comparable earnings per common share, comparable EBITDA, comparable distributable cash flow, comparable distributable cash flow per common share and comparable funds generated from operations, that do not have any standardized meaning as prescribed by U.S. GAAP and therefore are unlikely to be comparable to similar measures presented by other companies. These non-GAAP measures are calculated on a consistent basis from period to period and are adjusted for specific items in each period, as applicable except as otherwise described in the Condensed consolidated financial statements and MD&A. For more information on non-GAAP measures, refer to TransCanada's Quarterly Report to Shareholders dated May 2, 2019.

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Quarterly report to shareholders

First quarter 2019

Financial highlights

(millions of $, except per share amounts)	three months ended March 31 2019	2018
Income		
Revenues	**3,487**	3,424
Net income attributable to common shares	**1,004**	734
per common share – basic and diluted	**$1.09**	$0.83
Comparable EBITDA[1]	**2,383**	2,063
Comparable earnings[1]	**987**	864
per common share[1]	**$1.07**	$0.98
Cash flows		
Net cash provided by operations	**1,949**	1,412
Comparable funds generated from operations[1]	**1,791**	1,611
Comparable distributable cash flow[1]	**1,623**	1,439
per common share[1]	**$1.76**	$1.63
Capital spending[2]	**2,331**	2,096
Dividends declared		
Per common share	**$0.75**	$0.69
Basic common shares outstanding (millions)		
– weighted average for the period	**921**	885
– issued and outstanding at end of period	**924**	891

1 Comparable EBITDA, comparable earnings, comparable earnings per common share, comparable funds generated from operations, comparable distributable cash flow and comparable distributable cash flow per common share are all non-GAAP measures. Refer to the Non-GAAP measures section for more information.

2 Includes capital expenditures, capital projects in development and contributions to equity investments.

Management's discussion and analysis

May 2, 2019

This management's discussion and analysis (MD&A) contains information to help the reader make investment decisions about TransCanada Corporation. It discusses our business, operations, financial position, risks and other factors for the three months ended March 31, 2019, and should be read with the accompanying unaudited Condensed consolidated financial statements for the three months ended March 31, 2019, which have been prepared in accordance with U.S. GAAP.

This MD&A should also be read in conjunction with our December 31, 2018 audited Consolidated financial statements and notes and the MD&A in our 2018 Annual Report. Capitalized and abbreviated terms that are used but not otherwise defined herein are identified in our 2018 Annual Report. Certain comparative figures have been adjusted to reflect the current period's presentation.

FORWARD-LOOKING INFORMATION

We disclose forward-looking information to help current and potential investors understand management's assessment of our future plans and financial outlook, and our future prospects overall.

Statements that are ***forward-looking*** are based on certain assumptions and on what we know and expect today and generally include words like ***anticipate, expect, believe, may, will, should, estimate*** or other similar words.

Forward-looking statements in this MD&A include information about the following, among other things:

- our financial and operational performance, including the performance of our subsidiaries
- expectations about strategies and goals for growth and expansion
- expected cash flows and future financing options available, including portfolio management
- expected dividend growth
- expected access to and cost of capital
- expected costs and schedules for planned projects, including projects under construction and in development
- expected capital expenditures and contractual obligations
- expected regulatory processes and outcomes
- expected outcomes with respect to legal proceedings, including arbitration and insurance claims
- expected impact of future tax and accounting changes, commitments and contingent liabilities
- expected industry, market and economic conditions.

Forward-looking statements do not guarantee future performance. Actual events and results could be significantly different because of assumptions, risks or uncertainties related to our business or events that happen after the date of this MD&A.

Our forward-looking information is based on the following key assumptions, and subject to the following risks and uncertainties:

Assumptions

- regulatory decisions and outcomes
- planned and unplanned outages and the use of our pipeline, power and storage assets
- integrity and reliability of our assets
- anticipated construction costs, schedules and completion dates
- access to capital markets, including portfolio management

- expected industry, market and economic conditions
- inflation rates and commodity prices
- interest, tax and foreign exchange rates
- nature and scope of hedging.

Risks and uncertainties

- our ability to successfully implement our strategic priorities and whether they will yield the expected benefits
- our ability to implement a capital allocation strategy aligned with maximizing shareholder value
- the operating performance of our pipeline, power and storage assets
- amount of capacity sold and rates achieved in our pipeline businesses
- the amount of capacity payments and revenues from our power generation assets due to plant availability
- production levels within supply basins
- construction and completion of capital projects
- costs for labour, equipment and materials
- the availability and market prices of commodities
- access to capital markets on competitive terms
- interest, tax and foreign exchange rates
- performance and credit risk of our counterparties
- regulatory decisions and outcomes of legal proceedings, including arbitration and insurance claims
- changes in environmental and other laws and regulations
- competition in the pipeline, power and storage sectors
- unexpected or unusual weather
- acts of civil disobedience
- cyber security and technological developments
- economic conditions in North America as well as globally
- our ability to effectively anticipate and assess changes to government policies and regulations.

You can read more about these factors and others in this MD&A and in other reports we have filed with Canadian securities regulators and the SEC, including the MD&A in our 2018 Annual Report.

As actual results could vary significantly from the forward-looking information, you should not put undue reliance on forward-looking information and should not use future-oriented information or financial outlooks for anything other than their intended purpose. We do not update our forward-looking statements due to new information or future events, unless we are required to by law.

FOR MORE INFORMATION

You can find more information about TransCanada in our Annual Information Form and other disclosure documents, which are available on SEDAR (www.sedar.com).

NON-GAAP MEASURES

This MD&A references the following non-GAAP measures:

- comparable EBITDA
- comparable EBIT
- comparable earnings
- comparable earnings per common share
- funds generated from operations
- comparable funds generated from operations
- comparable distributable cash flow
- comparable distributable cash flow per common share.

These measures do not have any standardized meaning as prescribed by GAAP and therefore may not be comparable to similar measures presented by other entities.

Comparable measures

We calculate comparable measures by adjusting certain GAAP measures for specific items we believe are significant but not reflective of our underlying operations in the period. Except as otherwise described herein, these comparable measures are calculated on a consistent basis from period to period and are adjusted for specific items in each period, as applicable.

Our decision not to adjust for a specific item is subjective and made after careful consideration. Specific items may include:

- certain fair value adjustments relating to risk management activities
- income tax refunds and adjustments to enacted tax rates
- gains or losses on sales of assets or assets held for sale
- legal, contractual and bankruptcy settlements
- impact of regulatory or arbitration decisions relating to prior year earnings
- restructuring costs
- impairment of goodwill, investments and other assets
- acquisition and integration costs.

We exclude the unrealized gains and losses from changes in the fair value of derivatives used to reduce our exposure to certain financial and commodity price risks. These derivatives generally provide effective economic hedges but do not meet the criteria for hedge accounting. As a result, the changes in fair value are recorded in net income. As these amounts do not accurately reflect the gains and losses that will be realized at settlement, we do not consider them reflective of our underlying operations.

The following table identifies our non-GAAP measures against their most directly comparable GAAP measures.

Comparable measure	GAAP measure
comparable EBITDA	segmented earnings
comparable EBIT	segmented earnings
comparable earnings	net income attributable to common shares
comparable earnings per common share	net income per common share
comparable funds generated from operations	net cash provided by operations
comparable distributable cash flow	net cash provided by operations

Comparable EBITDA and comparable EBIT

Comparable EBITDA represents segmented earnings adjusted for certain specific items, excluding non-cash charges for depreciation and amortization. We use comparable EBITDA as a measure of our earnings from ongoing operations as it is a useful indicator of our performance and is also presented on a consolidated basis. Comparable EBIT represents segmented earnings adjusted for specific items. Comparable EBIT is an effective tool for evaluating trends in each segment.

Comparable earnings and comparable earnings per common share

Comparable earnings represents earnings or loss attributable to common shareholders on a consolidated basis, adjusted for specific items. Comparable earnings is comprised of segmented earnings, Interest expense, AFUDC, Interest income and other, Income taxes, Non-controlling interests and Preferred share dividends, adjusted for specific items. Refer to the Consolidated results section for reconciliations to net income attributable to common shares and net income per common share.

Funds generated from operations and comparable funds generated from operations

Funds generated from operations reflects net cash provided by operations before changes in operating working capital. We believe it is a useful measure of our consolidated operating cash flow because it does not include fluctuations from working capital balances, which do not necessarily reflect underlying operations in the same period, and is used to provide a consistent measure of the cash generating performance of our assets. Comparable funds generated from operations is adjusted for the cash impact of specific items. Refer to the Financial condition section for a reconciliation to net cash provided by operations.

Comparable distributable cash flow and comparable distributable cash flow per common share

We believe comparable distributable cash flow is a useful supplemental measure of performance that defines cash available to common shareholders before capital allocation. Comparable distributable cash flow is defined as comparable funds generated from operations less preferred share dividends, distributions to non-controlling interests and non-recoverable maintenance capital expenditures.

Maintenance capital expenditures are expenditures incurred to maintain our operating capacity, asset integrity and reliability, and include amounts attributable to our proportionate share of maintenance capital expenditures on our equity investments. We have the opportunity to recover effectively all of our pipeline maintenance capital expenditures in Canadian Natural Gas Pipelines, U.S. Natural Gas Pipelines and Liquids Pipelines through tolls. As such, our presentation of comparable distributable cash flow and comparable distributable cash flow per common share only includes a reduction for non-recoverable maintenance capital expenditures in their respective calculations.

Refer to the Financial condition section for a reconciliation to net cash provided by operations.

Consolidated results – first quarter 2019

As of first quarter 2019, the previously disclosed Energy segment has been renamed the Power and Storage segment.

(millions of $, except per share amounts)	three months ended March 31 2019	2018
Canadian Natural Gas Pipelines	**269**	253
U.S. Natural Gas Pipelines	**792**	648
Mexico Natural Gas Pipelines	**116**	137
Liquids Pipelines	**460**	341
Power and Storage	**48**	50
Corporate	**(19)**	(81)
Total segmented earnings	**1,666**	1,348
Interest expense	**(586)**	(527)
Allowance for funds used during construction	**139**	105
Interest income and other	**163**	63
Income before income taxes	**1,382**	989
Income tax expense	**(236)**	(121)
Net income	**1,146**	868
Net income attributable to non-controlling interests	**(101)**	(94)
Net income attributable to controlling interests	**1,045**	774
Preferred share dividends	**(41)**	(40)
Net income attributable to common shares	**1,004**	734
Net income per common share – basic and diluted	**$1.09**	$0.83

Net income attributable to common shares increased by $270 million, or $0.26 per common share, for the three months ended March 31, 2019 compared to the same period in 2018. Net income per common share reflects the dilutive impact of common shares issued under our DRP in 2018 and 2019 and our Corporate ATM program in 2018.

Net income included unrealized gains and losses from changes in risk management activities which we exclude along with other specific items as noted below to arrive at comparable earnings. Results included an after-tax loss of $12 million and an after-tax gain of $6 million for the three months ended March 31, 2019 and 2018, respectively, related to our U.S. Northeast power marketing contracts. These amounts have been excluded from Power and Storage's comparable earnings as we do not consider the wind-down and sales of the remaining contracts part of our underlying operations.

A reconciliation of net income attributable to common shares to comparable earnings is shown in the following table.

RECONCILIATION OF NET INCOME TO COMPARABLE EARNINGS

	three months ended March 31	
(millions of $, except per share amounts)	2019	2018
Net income attributable to common shares	**1,004**	734
Specific items (net of tax):		
U.S. Northeast power marketing contracts	**12**	(6)
Risk management activities[1]	**(29)**	136
Comparable earnings	**987**	864
Net income per common share	**$1.09**	$0.83
Specific items (net of tax):		
U.S. Northeast power marketing contracts	**0.01**	—
Risk management activities	**(0.03)**	0.15
Comparable earnings per common share	**$1.07**	$0.98

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Risk management activities	three months ended March 31	
(millions of $)	2019	2018
Canadian Power	**(1)**	2
U.S. Power	**(60)**	(101)
Liquids marketing	**(15)**	(7)
Natural Gas Storage	**(3)**	(3)
Foreign exchange	**120**	(79)
Income tax attributable to risk management activities	**(12)**	52
Total unrealized gains/(losses) from risk management activities	**29**	(136)

COMPARABLE EBITDA TO COMPARABLE EARNINGS

Comparable EBITDA represents segmented earnings adjusted for certain aspects of the specific items described above and excludes non-cash charges for depreciation and amortization.

(millions of $)	three months ended March 31 2019	2018
Comparable EBITDA		
Canadian Natural Gas Pipelines	**556**	494
U.S. Natural Gas Pipelines	**972**	804
Mexico Natural Gas Pipelines	**146**	160
Liquids Pipelines	**563**	431
Power and Storage	**151**	176
Corporate	**(5)**	(2)
Comparable EBITDA	**2,383**	2,063
Depreciation and amortization	**(608)**	(535)
Interest expense	**(586)**	(527)
Allowance for funds used during construction	**139**	105
Interest income and other included in comparable earnings	**29**	63
Income tax expense included in comparable earnings	**(228)**	(171)
Net income attributable to non-controlling interests	**(101)**	(94)
Preferred share dividends	**(41)**	(40)
Comparable earnings	**987**	864

Comparable EBITDA and comparable earnings – 2019 versus 2018

Comparable EBITDA increased by $320 million for the three months ended March 31, 2019 compared to the same period in 2018 primarily due to the net effect of the following:

- higher contribution from U.S. Natural Gas Pipelines mainly due to increased earnings from Columbia Gas and Columbia Gulf growth projects placed in service
- higher contribution from Liquids Pipelines primarily due to higher volumes on the Keystone Pipeline System and increased earnings from liquids marketing activities
- higher contribution from Canadian Natural Gas Pipelines mainly due to the recovery of increased depreciation in 2019 as a result of higher rates approved in both the Canadian Mainline NEB 2018 Decision and the NGTL 2018-2019 Settlement and higher incentive earnings for the Canadian Mainline
- lower contribution from Power and Storage primarily due to the sale of our interests in the Cartier Wind power facilities in 2018 and costs related to Napanee's delayed in-service
- foreign exchange impact of a stronger U.S. dollar on the Canadian dollar equivalent earnings from our U.S. operations.

Comparable earnings increased by $123 million or $0.09 per common share for the three months ended March 31, 2019 compared to the same period in 2018 and was primarily the net effect of:

- changes in comparable EBITDA described above
- higher depreciation largely in Canadian Natural Gas Pipelines, which is fully recovered in tolls as reflected in the increase in comparable EBITDA described above, therefore having no impact on comparable earnings. In addition, higher depreciation reflects new projects placed in service
- higher interest expense primarily as a result of long-term debt issuances, net of maturities, and the foreign exchange impact on translation of U.S. dollar-denominated interest
- higher income tax expense due to higher comparable earnings before income taxes and lower foreign tax rate differentials
- lower interest income and other due to realized losses in 2019 compared to realized gains in 2018 on derivatives used to manage exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income
- higher AFUDC due to increased capital expenditures for our NGTL System and Mexico projects.

Comparable earnings per common share for the three months ended March 31, 2019 also reflects the dilutive impact of common shares issued under our DRP in 2018 and 2019 and our Corporate ATM program in 2018.

Capital Program

We are developing quality projects under our capital program. These long-life infrastructure assets are supported by long-term commercial arrangements with creditworthy counterparties or regulated business models and are expected to generate significant growth in earnings and cash flows.

Our capital program consists of approximately $30.3 billion of secured projects which include commercially supported, committed projects that are either under construction or are in or preparing to commence the permitting stage but are not yet fully approved. An additional $21.5 billion of projects under development are commercially supported except where noted but have greater uncertainty with respect to timing and estimated project costs and are subject to certain approvals. During first quarter 2019, we placed approximately $5.3 billion of projects in service including Mountaineer XPress, Gulf XPress, and certain NGTL System expansions.

Three years of maintenance capital expenditures for our businesses are included in the secured projects table. Maintenance capital expenditures on our regulated Canadian and U.S. natural gas pipelines businesses are added to rate base on which we have the opportunity to earn a return and recover these expenditures through current or future tolls, which is similar to our capacity capital projects on these pipelines. Tolling arrangements in our liquids pipelines business provide for the recovery of maintenance capital expenditures.

All projects are subject to cost adjustments due to weather, market conditions, route refinement, permitting conditions, scheduling and timing of regulatory permits, among other factors. Amounts presented in the following tables exclude capitalized interest and AFUDC.

Secured projects

(billions of $)	Expected in-service date	Estimated project cost[1]	Carrying value at March 31, 2019
Canadian Natural Gas Pipelines			
Canadian Mainline	2019-2022	0.3	0.1
NGTL System	2019	2.8	2.0
	2020	1.8	0.3
	2021	2.6	—
	2022+	1.4	—
Coastal GasLink[2,3]	2023	6.2	0.2
Regulated maintenance capital expenditures	2019-2021	1.6	0.2
U.S. Natural Gas Pipelines			
Columbia Gas			
Modernization II	2019-2020	US 1.1	US 0.5
Other capacity capital	2019-2021	US 0.5	—
Regulated maintenance capital expenditures	2019-2021	US 1.8	US 0.1
Mexico Natural Gas Pipelines			
Sur de Texas[4]	2019	US 1.5	US 1.4
Villa de Reyes[4]	2019-2020	US 0.8	US 0.7
Tula[4]	2020	US 0.7	US 0.6
Liquids Pipelines			
White Spruce	2019	0.2	0.2
Other capacity capital	2020	0.1	—
Recoverable maintenance capital expenditures	2019-2021	0.1	—
Power and Storage			
Napanee	2019	1.7	1.7
Bruce Power – life extension[5]	2019-2023	2.2	0.7
Other			
Non-recoverable maintenance capital expenditures[6]	2019-2021	0.7	0.1
		28.1	**8.8**
Foreign exchange impact on secured projects[7]		**2.2**	**1.1**
Total secured projects (Cdn$)		**30.3**	**9.9**

1 Amounts reflect our proportionate share of joint venture costs where applicable and 100 per cent of costs related to wholly-owned assets and assets held through TC PipeLines, LP.

2 Represents 100 per cent of required capital prior to potential joint venture partners or project financing.

3 Carrying value is net of the fourth quarter 2018 receipts from the LNG Canada participants for the reimbursement of approximately $0.5 billion of pre-FID costs pursuant to project agreements.

4 The CFE has recognized force majeure events for these pipelines and approved the payment of fixed capacity charges in accordance with their respective TSAs. Payments will be recognized as revenue over the contract service term commencing once the pipelines are placed in service.

5 Reflects our proportionate share of the Unit 6 Major Component Replacement program costs, expected to be in service in 2023, and amounts to be invested under the Asset Management program through 2023.

6 Includes non-recoverable maintenance capital expenditures from all segments and is primarily comprised of our proportionate share of maintenance capital expenditures for Bruce Power and other Power and Storage assets.

7 Reflects U.S./Canada foreign exchange rate of 1.34 at March 31, 2019.

Projects under development

The costs provided in the table below reflect the most recent estimates for each project as filed with the various regulatory authorities or otherwise determined by management.

(billions of $)	Estimated project cost[1]	Carrying value at March 31, 2019
Canadian Natural Gas Pipelines		
NGTL System – Merrick	1.9	—
U.S. Natural Gas Pipelines		
Other capacity capital[2]	US 0.7	—
Liquids Pipelines		
Keystone XL[3]	US 8.0	US 0.7
Heartland and TC Terminals[4]	0.9	0.1
Grand Rapids Phase 2[4]	0.7	—
Keystone Hardisty Terminal[4]	0.3	0.1
Power and Storage		
Bruce Power – life extension[5]	6.0	—
	18.5	0.9
Foreign exchange impact on projects under development[6]	3.0	0.2
Total projects under development (Cdn$)	**21.5**	**1.1**

1 Amounts reflect our proportionate share of joint venture costs where applicable and 100 per cent of costs related to wholly-owned assets and assets held through TC PipeLines, LP.
2 Includes projects subject to a positive customer FID.
3 Carrying value reflects amount remaining after impairment charge recorded in 2015 along with additional amounts capitalized from January 1, 2018. A portion of these costs are recoverable from shippers under certain conditions.
4 Regulatory approvals have been obtained and additional commercial support is being pursued.
5 Reflects our proportionate share of Major Component Replacement program costs for Units 3, 4, 5, 7 and 8, and the remaining Asset Management program costs beyond 2023.
6 Reflects U.S./Canada foreign exchange rate of 1.34 at March 31, 2019.

Outlook

Consolidated comparable earnings

Our overall comparable earnings outlook for 2019 remains consistent with the disclosure in the 2018 Annual Report.

Consolidated capital spending

Our expected total capital expenditures as outlined in the 2018 Annual Report remain materially unchanged.

Canadian Natural Gas Pipelines

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented earnings (the most directly comparable GAAP measure).

(millions of $)	three months ended March 31 2019	2018
NGTL System	**292**	271
Canadian Mainline	**237**	193
Other Canadian pipelines[1]	**27**	30
Comparable EBITDA	**556**	494
Depreciation and amortization	**(287)**	(241)
Comparable EBIT and segmented earnings	**269**	253

1 Includes results from Foothills, Ventures LP, Great Lakes Canada and our share of equity income from our investment in TQM as well as general and administrative and business development costs related to our Canadian Natural Gas Pipelines.

Canadian Natural Gas Pipelines comparable EBIT and segmented earnings increased by $16 million for the three months ended March 31, 2019 compared to the same period in 2018.

Net income and comparable EBITDA for our rate-regulated Canadian natural gas pipelines are primarily affected by our approved ROE, our investment base, the level of deemed common equity and incentive earnings. Changes in depreciation, financial charges and income taxes also impact comparable EBITDA but do not have a significant impact on net income as they are almost entirely recovered in revenue on a flow-through basis.

NET INCOME AND AVERAGE INVESTMENT BASE

(millions of $)	three months ended March 31 2019	2018
Net Income		
NGTL System	**113**	92
Canadian Mainline	**44**	37
Average investment base		
NGTL System	**11,096**	9,091
Canadian Mainline	**3,665**	3,817

Net income for the NGTL System increased by $21 million for the three months ended March 31, 2019 compared to the same period in 2018 mainly due to a higher average investment base resulting from continued system expansions. The NGTL System is operating under the 2018-2019 Settlement which includes an ROE of 10.1 per cent on 40 per cent deemed common equity, a mechanism for sharing variances above and below a fixed annual OM&A amount and flow-through treatment of all other costs.

Net income for the Canadian Mainline increased by $7 million for the three months ended March 31, 2019 compared to the same period in 2018 mainly due to higher incentive earnings. We did not record incentive earnings in first quarter 2018 pending the outcome of the 2018-2020 toll review. The NEB 2018 Decision, received in December 2018, preserved the incentive arrangement from the NEB 2014 Decision along with an approved ROE of 10.1 per cent on 40 per cent deemed equity.

COMPARABLE EBITDA

Comparable EBITDA increased by $62 million for the three months ended March 31, 2019 compared to the same period in 2018 mainly due to the recovery of increased depreciation as a result of higher rates approved in both the Canadian Mainline NEB 2018 Decision and the NGTL 2018-2019 Settlement, as well as higher pre-tax rate base earnings for the NGTL System and higher incentive earnings and flow-through income taxes for the Canadian Mainline.

DEPRECIATION AND AMORTIZATION

Depreciation and amortization increased by $46 million for the three months ended March 31, 2019 compared to the same period in 2018 mainly due to the increase in composite depreciation rates approved in the Mainline NEB 2018 Decision and the NGTL 2018-2019 Settlement as well as additional NGTL System facilities that were placed in service in 2018 and first quarter 2019.

U.S. Natural Gas Pipelines

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented earnings (the most directly comparable GAAP measure).

	three months ended March 31	
(millions of US$, unless otherwise noted)	**2019**	**2018**
Columbia Gas	**308**	231
ANR	**153**	141
TC PipeLines, LP[1,2]	**36**	39
Great Lakes[3]	**30**	35
Midstream	**37**	30
Columbia Gulf	**35**	26
Other U.S. pipelines[4]	**19**	15
Non-controlling interests[5]	**112**	118
Comparable EBITDA	**730**	635
Depreciation and amortization	**(135)**	(122)
Comparable EBIT	**595**	513
Foreign exchange impact	**197**	135
Comparable EBIT and segmented earnings (Cdn$)	**792**	648

1 Reflects our earnings from TC PipeLines, LP's ownership interests in eight natural gas pipelines as well as general and administrative costs related to TC PipeLines, LP.

2 For the three months ended March 31, 2019, our ownership interest in TC PipeLines, LP was 25.5 per cent, which is unchanged from the same period in 2018.

3 Reflects our 53.55 per cent direct interest in Great Lakes. The remaining 46.45 per cent is held by TC PipeLines, LP.

4 Reflects earnings from our effective ownership in Millennium and Hardy Storage, as well as general and administrative and business development costs related to our U.S. natural gas pipelines.

5 Reflects earnings attributable to portions of TC PipeLines, LP, that we do not own.

U.S. Natural Gas Pipelines comparable EBIT and segmented earnings increased by $144 million for the three months ended March 31, 2019 compared to the same period in 2018. In addition to the net increases in comparable EBITDA noted below, a stronger U.S. dollar in 2019 had a positive impact on the Canadian dollar equivalent segmented earnings from our U.S. operations compared to the same period in 2018.

Comparable EBITDA for U.S. Natural Gas Pipelines increased by US$95 million for the three months ended March 31, 2019 compared to the same period in 2018. This was primarily the net effect of:

- increased earnings from Columbia Gas and Columbia Gulf growth projects placed in service
- decreased earnings from Bison due to 2018 customer agreements to pay out their future contracted revenues and terminate their contracts.

DEPRECIATION AND AMORTIZATION

Depreciation and amortization increased by US$13 million for the three months ended March 31, 2019 compared to the same period in 2018 mainly due to new projects placed in service.

Mexico Natural Gas Pipelines

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented earnings (the most directly comparable GAAP measure).

	three months ended March 31	
(millions of US$, unless otherwise noted)	**2019**	**2018**
Topolobampo	**40**	44
Tamazunchale	**31**	31
Mazatlán	**18**	20
Guadalajara	**16**	19
Sur de Texas[1]	**5**	9
Other	**—**	4
Comparable EBITDA	**110**	127
Depreciation and amortization	**(23)**	(19)
Comparable EBIT	**87**	108
Foreign exchange impact	**29**	29
Comparable EBIT and segmented earnings (Cdn$)	**116**	137

1 Represents equity income from our 60 per cent interest.

Mexico Natural Gas Pipelines comparable EBIT and segmented earnings decreased by $21 million for the three months ended March 31, 2019 compared to the same period in 2018. Lower EBITDA as described below was partially offset by a stronger U.S. dollar in 2019 which had a positive impact on Canadian dollar equivalent earnings.

Comparable EBITDA for Mexico Natural Gas Pipelines decreased by US$17 million for the three months ended March 31, 2019 compared to the same period in 2018 mainly due to the net effect of:

- lower revenues from operations as a result of changes in timing of revenue recognition in 2018
- lower equity earnings from our investment in the Sur de Texas pipeline which records AFUDC during construction, net of interest expense on an inter-affiliate loan from TransCanada. The inter-affiliate loan amount is fully offset in Interest income and other in the Corporate segment
- a TransGas distribution received and recorded as income in 2018, recorded in Other above.

DEPRECIATION AND AMORTIZATION

Depreciation and amortization was higher for the three months ended March 31, 2019 compared to the same period in 2018 reflecting new assets in service and other adjustments.

Liquids Pipelines

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented earnings (the most directly comparable GAAP measure).

	three months ended March 31	
(millions of $)	**2019**	**2018**
Keystone Pipeline System	**424**	340
Intra-Alberta pipelines	**39**	39
Liquids marketing and other	**100**	52
Comparable EBITDA	**563**	431
Depreciation and amortization	**(88)**	(83)
Comparable EBIT	**475**	348
Specific item:		
Risk management activities	**(15)**	(7)
Segmented earnings	**460**	341
Comparable EBIT denominated as follows:		
Canadian dollars	**89**	93
U.S. dollars	**290**	202
Foreign exchange impact	**96**	53
Comparable EBIT	**475**	348

Liquids Pipelines segmented earnings increased by $119 million for the three months ended March 31, 2019 compared to the same period in 2018 and include unrealized losses from changes in the fair value of derivatives related to our liquids marketing business which have been excluded from our calculation of comparable EBIT.

Comparable EBITDA for Liquids Pipelines increased by $132 million for the three months ended March 31, 2019 compared to the same period in 2018 and was due to:

- higher volumes on the Keystone Pipeline System
- higher contribution from liquids marketing activities due to improved margins and volumes
- positive foreign exchange impact on the Canadian dollar equivalent earnings from our U.S. operations.

DEPRECIATION AND AMORTIZATION

Depreciation and amortization increased by $5 million for the three months ended March 31, 2019 compared to the same period in 2018 as a result of new facilities being placed in service and the effect of a stronger U.S. dollar.

Power and Storage

As of first quarter 2019, the previously disclosed Energy segment has been renamed the Power and Storage segment.

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented earnings (the most directly comparable GAAP measure).

(millions of $)	three months ended March 31 2019	2018
Western and Eastern Power[1]	**77**	119
Bruce Power[1]	**60**	54
Natural Gas Storage and other	**17**	7
Business development	**(3)**	(4)
Comparable EBITDA	**151**	176
Depreciation and amortization	**(23)**	(32)
Comparable EBIT	**128**	144
Specific items:		
U.S. Northeast power marketing contracts	**(16)**	8
Risk management activities	**(64)**	(102)
Segmented earnings	**48**	50

1 Includes our share of equity income from our investments in Portlands Energy and Bruce Power.

Power and Storage segmented earnings decreased by $2 million for the three months ended March 31, 2019 compared to the same period in 2018 and included the following specific items:

- a loss of $16 million for the three months ended March 31, 2019 (2018 – gain of $8 million) related to our U.S. Northeast power marketing contracts. These amounts have been excluded from Power and Storage's comparable earnings as we do not consider the wind-down and sales of the remaining contracts part of our underlying operations
- unrealized losses from changes in the fair value of derivatives used to reduce our exposure to certain commodity price risks, primarily related to the remaining U.S. Northeast power marketing contracts.

Comparable EBITDA for Power and Storage decreased by $25 million for the three months ended March 31, 2019 compared to the same period in 2018 primarily due to the net effect of:

- decreased Western and Eastern Power results largely due to the sale of our interests in the Cartier Wind power facilities in October 2018 and costs related to Napanee's delayed in-service. Refer to the Recent developments section for more information
- increased Natural Gas Storage results due to higher realized natural gas storage price spreads
- increased Bruce Power results primarily due to higher income on funds invested for future retirement benefits, partially offset by lower volumes resulting from higher outage days. Additional financial and operating information on Bruce Power is provided below.

DEPRECIATION AND AMORTIZATION

Depreciation and amortization decreased by $9 million for the three months ended March 31, 2019 compared to the same period in 2018 primarily due to the sale of our interests in the Cartier Wind power facilities in October 2018 and the cessation of depreciation on our Coolidge generating station upon classification as held for sale at December 31, 2018.

BRUCE POWER

The following reflects our proportionate share of the components of comparable EBITDA and comparable EBIT.

	three months ended March 31	
(millions of $, unless otherwise noted)	**2019**	**2018**
Equity income included in comparable EBITDA and EBIT comprised of:		
Revenues[1]	**361**	371
Operating expenses	**(227)**	(227)
Depreciation and other	**(74)**	(90)
Comparable EBITDA and EBIT[2]	**60**	54
Bruce Power – other information		
Plant availability[3]	**79%**	85%
Planned outage days	**141**	74
Unplanned outage days	**7**	31
Sales volumes (GWh)[2]	**5,260**	5,696
Realized sales price per MWh[4]	**$68**	$67

1 Net of amounts recorded to reflect operating cost efficiencies shared with the IESO.

2 Represents our 48.3 per cent (2018 – 48.4 per cent) ownership interest in Bruce Power. Sales volumes include deemed generation.

3 The percentage of time the plant was available to generate power, regardless of whether it was running.

4 Calculation based on actual and deemed generation. Realized sales prices per MWh includes realized gains and losses from contracting activities and cost flow-through items. Excludes unrealized gains and losses on contracting activities and non-electricity revenues.

Planned maintenance on Unit 3 began in fourth quarter 2018 and on Unit 7 in February 2019, with both units expected to be back in service in second quarter 2019. Planned maintenance is expected to occur on Unit 2 in second quarter 2019 and on Unit 5 in the second half of 2019. The overall average plant availability percentage in 2019 is expected to be in the mid-80 per cent range.

On April 1, 2019, Bruce Power's contract price increased from approximately $68 per MWh to approximately $75 per MWh reflecting capital to be invested under the Unit 6 Major Component Replacement program and the Asset Management program as well as normal annual inflation adjustments.

Corporate

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented losses (the most directly comparable GAAP measure).

	three months ended March 31	
(millions of $)	**2019**	**2018**
Comparable EBITDA and EBIT	**(5)**	(2)
Specific item:		
Foreign exchange loss – inter-affiliate loan[1]	**(14)**	(79)
Segmented losses	**(19)**	(81)

1 Reported in Income from equity investments on the Condensed consolidated statement of income.

Corporate segmented losses decreased by $62 million for the three months ended March 31, 2019 compared to the same period in 2018. Segmented losses include foreign exchange losses on a peso-denominated inter-affiliate loan to the Sur de Texas project for our proportionate share of the project's financing which are fully offset by corresponding foreign exchange gains included in Interest income and other on the inter-affiliate loan receivable. These amounts have been excluded from our calculation of comparable EBIT.

OTHER INCOME STATEMENT ITEMS

Interest Expense

	three months ended March 31	
(millions of $)	**2019**	**2018**
Interest on long-term debt and junior subordinated notes		
Canadian dollar-denominated	**(140)**	(134)
U.S. dollar-denominated	**(331)**	(314)
Foreign exchange impact	**(109)**	(83)
	(580)	(531)
Other interest and amortization expense	**(43)**	(22)
Capitalized interest	**37**	26
Interest expense	**(586)**	(527)

Interest expense increased by $59 million for the three months ended March 31, 2019 compared to the same period in 2018 and primarily reflects the net effect of:

- long-term debt issuances, net of maturities
- foreign exchange impact from a stronger U.S. dollar on translation of U.S. dollar-denominated interest
- higher levels of short-term borrowing
- higher capitalized interest primarily related to Napanee and Keystone XL.

Allowance for funds used during construction

(millions of $)	three months ended March 31 2019	2018
Canadian dollar-denominated	**43**	20
U.S. dollar-denominated	**72**	67
Foreign exchange impact	**24**	18
Allowance for funds used during construction	**139**	105

AFUDC increased by $34 million for the three months ended March 31, 2019 compared to the same period in 2018. The increase in Canadian dollar-denominated AFUDC is primarily due to capital expenditures in our NGTL System expansion projects. The increase in U.S. dollar-denominated AFUDC is primarily due to continued investment in Mexico projects.

Interest income and other

(millions of $)	three months ended March 31 2019	2018
Interest income and other included in comparable earnings	**29**	63
Specific items:		
Foreign exchange gain – inter-affiliate loan	**14**	79
Risk management activities	**120**	(79)
Interest income and other	**163**	63

Interest income and other increased by $100 million for the three months ended March 31, 2019 compared to the same period in 2018 and was primarily the net effect of:

- unrealized gains on risk management activities in 2019 compared to unrealized losses in 2018. These amounts have been excluded from comparable earnings
- higher interest income combined with a lower foreign exchange gain related to an inter-affiliate loan receivable from the Sur de Texas joint venture. The corresponding interest expense and foreign exchange loss in Sur de Texas are reflected in Income from equity investments in the Mexico Natural Gas Pipelines and Corporate segments, respectively, resulting in no impact on net income. The offsetting currency-related gain and loss amounts are excluded from comparable earnings
- realized losses in 2019 compared to realized gains in 2018 on derivatives used to manage our net exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income.

Income tax expense

(millions of $)	three months ended March 31 2019	2018
Income tax expense included in comparable earnings	**(228)**	(171)
Specific items:		
U.S. Northeast power marketing contracts	**4**	(2)
Risk management activities	**(12)**	52
Income tax expense	**(236)**	(121)

Income tax expense included in comparable earnings increased by $57 million for the three months ended March 31, 2019 compared to the same period in 2018. This was primarily due to higher comparable earnings before income taxes and lower foreign tax rate differentials.

Net income attributable to non-controlling interests

(millions of $)	three months ended March 31 2019	2018
Net income attributable to non-controlling interests	**(101)**	(94)

Net income attributable to non-controlling interests increased by $7 million for the three months ended March 31, 2019 compared to the same period in 2018 primarily due to higher earnings in TC PipeLines, LP and the impact of a stronger U.S. dollar in 2019 on the Canadian dollar equivalent earnings.

Preferred share dividends

(millions of $)	three months ended March 31 2019	2018
Preferred share dividends	**(41)**	(40)

Recent developments

CANADIAN NATURAL GAS PIPELINES

Coastal GasLink Pipeline Project
Following the October 2018 positive FID by LNG Canada, pre-construction activities continue at many locations along the pipeline route including the area south of Houston, B.C. which required a B.C. Supreme Court injunction for access.

The NEB process considering regulatory jurisdiction continues with all evidence now submitted. A final hearing is scheduled for second quarter 2019 with a decision expected in third quarter 2019.

TransCanada continues to advance funding plans for the $6.2 billion pipeline project through a combination of the sale of up to 75 per cent ownership interest and potential project financing.

NGTL System
On March 14, 2019, we filed the NGTL System Rate Design and Services Application with the NEB which includes a settlement agreement negotiated between NGTL and members of its Tolls, Tariff, Facilities and Procedures (TTFP) committee, which represents stakeholders. The settlement is supported by a majority of members of the TTFP committee. The Application addresses rate design, terms and conditions of service for the NGTL System and a tolling methodology for the North Montney Mainline. Given the complexity of the issues raised in the Application, the NEB decided to hold a public hearing. Application to participate and comments on the Application were due April 12, 2019 and reply comments were submitted by NGTL on April 18, 2019.

In first quarter 2019, we placed approximately $250 million of projects in service which included the Gordondale Lateral Loop and the Boundary Lake North projects.

Canadian Mainline 2018-2020 Toll Review
On March 13, 2019, the NEB approved Canadian Mainline tolls as filed in the January 2019 compliance filing.

U.S. NATURAL GAS PIPELINES

Mountaineer XPress and Gulf XPress
The Mountaineer XPress project, a Columbia Gas project designed to transport supply from the Marcellus and Utica shale plays to points along the system and the Leach interconnect with Columbia Gulf, was phased into service over first quarter 2019 along with Gulf XPress, a Columbia Gulf project.

Grand Chenier XPress
In February 2019, we approved the Grand Chenier XPress project, an ANR Pipeline project which will connect supply directly to Gulf Coast LNG export markets through the addition of a mid-point compressor station and incremental compression capability at existing facilities. Subject to a positive customer FID, the anticipated in-service dates are in 2021 and 2022 for Phase I and II, respectively, with estimated project costs of US$0.2 billion.

MEXICO NATURAL GAS PIPELINES

Sur de Texas
The Sur de Texas project has experienced force majeure events that have delayed in-service. Some events are subject to potential dispute and we have taken measures to protect our interests under the contract. Construction and commissioning activities are progressing such that we anticipate mechanical completion in May with an expected June 2019 in-service.

Villa de Reyes and Tula

Construction of the Villa de Reyes project is ongoing with a phased in-service anticipated to commence in the second half of 2019. Commencement of construction for the central segment of the Tula project has been delayed due to a lack of progress by the Secretary of Energy, the governmental department responsible for Indigenous consultations. Project completion has been revised to the end of 2020. We have negotiated separate CFE contracts that would allow certain segments of Tula and Villa de Reyes to be placed in service when facilities are complete and gas is available.

LIQUIDS PIPELINES

Keystone Pipeline System

In January 2019, we entered into an agreement with Motiva Enterprises LLC (Motiva) to construct a pipeline connection between the Keystone Pipeline system and Motiva's 630,000 Bbl/d refinery in Port Arthur, Texas. The connection is targeted to be operational in second quarter 2020.

On February 6, 2019, the Keystone Pipeline system was temporarily shut down after a leak was detected near St. Charles, Missouri. The pipeline system was restarted the same day while the segment between Steele City, Nebraska to Patoka, Illinois was restarted on February 18, 2019. This shutdown is not expected to have a significant impact on our 2019 earnings.

Keystone XL

A decision from the Nebraska Supreme Court on the appeal of the Nebraska Public Service Commission route approval remains pending. We expect the decision to be issued in second quarter 2019.

In September 2018, two U.S. Native American communities filed a lawsuit in Montana challenging the Keystone XL Presidential Permit. We, along with the U.S. Government, have filed to have the lawsuit dismissed. In December 2018, we applied to the U.S. District Court in Montana for a stay of its various decisions affecting the issuance of the 2017 Keystone XL Presidential Permit and the extensive environmental assessments made in support of its issuance. The stay application was denied by the U.S. District Court in February 2019. In February 2019, we applied to the Ninth Circuit Court of Appeals (Ninth Circuit) for a stay of the U.S. District Court decisions. On March 16, 2019, the Ninth Circuit denied our stay application and declined to further limit the scope of the preliminary injunction which prevents us from conducting certain pre-construction activities.

On March 29, 2019, U.S. President Trump issued a new Presidential Permit for the Keystone XL Project, which superseded the 2017 permit. Subsequently, we filed a motion with the Ninth Circuit requesting the court vacate the U.S. District Court decisions, dissolve the injunctions, and direct the U.S. District Court to dismiss the pending cases. A lawsuit was filed challenging the validity of the new Presidential Permit. We are not named in the lawsuit.

White Spruce

Commissioning has been completed on the White Spruce pipeline, which transports crude oil from Canadian Natural Resources Limited's Horizon facility in northeast Alberta to the Grand Rapids pipeline with commercial in-service achieved in May 2019.

POWER AND STORAGE (Previously ENERGY)

Napanee

In March 2019, we experienced an equipment failure while progressing commissioning activities at our 900 MW natural gas-fired power plant in Napanee, Ontario. We continue to expect that our total investment in the Napanee facility will be approximately $1.7 billion, however, commencement of commercial operations will be delayed into the second half of 2019 as we repair the damaged equipment.

Coolidge Generating Station

In December 2018, we entered into an agreement to sell our Coolidge generating station in Arizona to SWG Coolidge Holdings, LLC (SWG). Salt River Project Agriculture Improvement and Power District (SRP), the PPA counterparty, subsequently exercised its contractual right of first refusal on a sale to a third party. On March 20, 2019, we terminated the agreement with SWG after entering into an agreement with SRP to sell the Coolidge generating station for approximately US$465 million, subject to timing of the close and related adjustments. The sale will result in an estimated gain of approximately $70 million ($55 million after tax) to be recognized upon closing, which is expected to occur in mid-2019.

Financial condition

We strive to maintain strong financial capacity and flexibility in all parts of the economic cycle. We rely on our operating cash flow to sustain our business, pay dividends and fund a portion of our growth. In addition, we access capital markets and engage in portfolio management to meet our financing needs, manage our capital structure and to preserve our credit ratings.

We believe we have the financial capacity to fund our existing capital program through predictable and growing cash flow from operations, access to capital markets, portfolio management, cash on hand, substantial committed credit facilities, and if deemed appropriate, our Corporate ATM program and DRP. Annually, in fourth quarter, we renew and extend our credit facilities as required.

At March 31, 2019, our current assets totaled $4.9 billion and current liabilities amounted to $13.4 billion, leaving us with a working capital deficit of $8.5 billion compared to $7.8 billion at December 31, 2018. Our working capital deficiency is considered to be in the normal course of business and is managed through:

- our ability to generate predictable and growing cash flow from operations
- approximately $11.7 billion of unutilized, unsecured credit facilities
- our access to capital markets, including through our DRP and Corporate ATM programs, if deemed appropriate.

CASH PROVIDED BY OPERATING ACTIVITIES

	three months ended March 31	
(millions of $, except per share amounts)	**2019**	**2018**
Net cash provided by operations	**1,949**	1,412
(Decrease)/increase in operating working capital	**(142)**	207
Funds generated from operations	**1,807**	1,619
Specific items:		
U.S. Northeast power marketing contracts	**(16)**	(8)
Comparable funds generated from operations	**1,791**	1,611
Dividends on preferred shares	**(40)**	(39)
Distributions to non-controlling interests	**(56)**	(69)
Non-recoverable maintenance capital expenditures[1]	**(72)**	(64)
Comparable distributable cash flow	**1,623**	1,439
Comparable distributable cash flow per common share	**$1.76**	$1.63

1 Includes non-recoverable maintenance capital expenditures from all segments including cash contributions to fund our proportionate share of maintenance capital expenditures for our equity investments which are primarily related to contributions to Bruce Power.

NET CASH PROVIDED BY OPERATIONS

Net cash provided by operations increased by $537 million for the three months ended March 31, 2019 compared to the same period in 2018, primarily due to higher earnings, the recovery of increased depreciation on Canadian regulated pipelines as well as the amount and timing of working capital changes.

COMPARABLE FUNDS GENERATED FROM OPERATIONS

Comparable funds generated from operations, a non-GAAP measure, helps us assess the cash generating ability of our operations by excluding the timing effects of working capital changes as well as the cash impact of our specific items.

Comparable funds generated from operations increased by $180 million for the three months ended March 31, 2019 compared to the same period in 2018 primarily due to higher comparable earnings adjusted for non-cash items and the cash impact of specific items as well as the recovery of higher depreciation for both the Canadian Mainline and the NGTL System.

COMPARABLE DISTRIBUTABLE CASH FLOW

Comparable distributable cash flow, a non-GAAP measure, helps us assess the cash available to common shareholders before capital allocation.

The increase in comparable distributable cash flow for the three months ended March 31, 2019 compared to the same period in 2018 reflects higher comparable funds generated from operations as described above. Comparable distributable cash flow per common share for the three months ended March 31, 2019 also reflects the dilutive impact of common shares issued under our DRP in 2018 and 2019 and our Corporate ATM program in 2018.

CASH USED IN INVESTING ACTIVITIES

	three months ended March 31	
(millions of $)	**2019**	**2018**
Capital spending		
Capital expenditures	**(2,022)**	(1,702)
Capital projects in development	**(164)**	(36)
Contributions to equity investments	**(145)**	(358)
	(2,331)	(2,096)
Other distributions from equity investments	**120**	121
Deferred amounts and other	**(26)**	110
Net cash used in investing activities	**(2,237)**	(1,865)

Capital expenditures in first quarter 2019 were incurred primarily for the expansion of the NGTL System and Columbia Gas projects along with construction of the Coastal GasLink pipeline and Napanee power generating facility.

Costs incurred on capital projects in development in 2019 and 2018 were mostly attributed to spending on Keystone XL.

Contributions to equity investments decreased in 2019 compared to 2018 mainly due to lower contributions to Sur de Texas which include our proportionate share of debt financing requirements.

Other distributions from equity investments in 2019 and 2018 reflect our proportionate share of Bruce Power financings undertaken to fund its capital program and to make distributions to its partners. In first quarter 2019, we received distributions of $120 million (2018 – $121 million) from Bruce Power in connection with their issuance of senior notes in capital markets.

CASH PROVIDED BY FINANCING ACTIVITIES

(millions of $)	three months ended March 31 2019	2018
Notes payable issued, net	**2,852**	1,812
Long-term debt issued, net of issue costs[1]	**24**	93
Long-term debt repaid[1]	**(1,708)**	(1,226)
Dividends and distributions paid	**(515)**	(466)
Common shares issued, net of issue costs	**68**	340
Partnership units of TC PipeLines, LP issued, net of issue costs	**—**	49
Net cash provided by financing activities	**721**	602

1 Includes draws and repayments on an unsecured loan facility by TC PipeLines, LP.

LONG-TERM DEBT ISSUED

The following table outlines significant debt issuances in 2019:

(millions of Canadian $, unless otherwise noted)

Company	Issue date	Type	Maturity Date	Amount	Interest rate
TRANSCANADA PIPELINES LIMITED					
	April 2019	Medium Term Notes	October 2049	1,000	4.34%

The net proceeds of the above debt issuance were used for general corporate purposes and to fund our capital program.

LONG-TERM DEBT REPAID

The following table outlines significant debt retired in 2019:

(millions of Canadian $, unless otherwise noted)

Company	Retirement date	Type	Amount	Interest rate
TRANSCANADA PIPELINES LIMITED				
	March 2019	Debentures	100	10.50%
	January 2019	Senior Unsecured Notes	US 750	7.125%
	January 2019	Senior Unsecured Notes	US 400	3.125%

DIVIDEND REINVESTMENT PLAN

With respect to dividends declared on February 14, 2019, the DRP participation rate amongst common shareholders was approximately 33 per cent, resulting in $226 million reinvested in common equity under the program.

DIVIDENDS

On May 2, 2019, we declared quarterly dividends as follows:

Quarterly dividend on our common shares
$0.75 per share
Payable on July 31, 2019 to shareholders of record at the close of business on June 28, 2019.

Quarterly dividends on our preferred shares	
Payable on June 28, 2019 to shareholders of record at the close of business on May 31, 2019:	
Series 1	$0.204125
Series 2	$0.22450822
Series 3	$0.1345
Series 4	$0.18461781
Payable on July 30, 2019 to shareholders of record at the close of business on July 2, 2019:	
Series 5	$0.14143750
Series 6	$0.19895342
Series 7	$0.243938
Series 9	$0.265625
Payable on May 31, 2019 to shareholders of record at the close of business on May 15, 2019:	
Series 11	$0.2375
Series 13	$0.34375
Series 15	$0.30625

SHARE INFORMATION

as at April 30, 2019		
Common shares	**Issued and outstanding**	
	927 million	
Preferred shares	**Issued and outstanding**	**Convertible to**
Series 1	9.5 million	Series 2 preferred shares
Series 2	12.5 million	Series 1 preferred shares
Series 3	8.5 million	Series 4 preferred shares
Series 4	5.5 million	Series 3 preferred shares
Series 5	12.7 million	Series 6 preferred shares
Series 6	1.3 million	Series 5 preferred shares
Series 7[1]	24 million	Series 8 preferred shares
Series 9	18 million	Series 10 preferred shares
Series 11	10 million	Series 12 preferred shares
Series 13	20 million	Series 14 preferred shares
Series 15	40 million	Series 16 preferred shares
Options to buy common shares	**Outstanding**	**Exercisable**
	13 million	9 million

1 As the total number of Series 7 preferred shares tendered for conversion did not meet the threshold for conversion, no Series 7 preferred shares were converted into Series 8 preferred shares on April 30, 2019.

CREDIT FACILITIES

We have several committed credit facilities that support our commercial paper programs and provide short-term liquidity for general corporate purposes. In addition, we have demand credit facilities that are also used for general corporate purposes, including issuing letters of credit and providing additional liquidity.

At April 30, 2019, we had a total of $12.8 billion of committed revolving and demand credit facilities, including:

Amount	Unused capacity	Borrower	Description	Matures
Committed, syndicated, revolving, extendible senior unsecured credit facilities:				
$3.0 billion	$3.0 billion	TCPL	Supports TCPL's Canadian dollar commercial paper program and is used for general corporate purposes	December 2023
US$4.5 billion	US$4.5 billion	TCPL/TCPL USA/ Columbia/TAIL	Supports TCPL and TCPL USA's U.S. dollar commercial paper programs and is used for general corporate purposes of the borrowers, guaranteed by TCPL	December 2019
US$1.0 billion	US$1.0 billion	TCPL/TCPL USA/ Columbia/TAIL	Used for general corporate purposes of the borrowers, guaranteed by TCPL	December 2021
Demand senior unsecured revolving credit facilities:				
$2.1 billion	$1.0 billion	TCPL/TCPL USA	Supports the issuance of letters of credit and provides additional liquidity, TCPL USA facility guaranteed by TCPL	Demand
MXN$5.0 billion	MXN$5.0 billion	Mexican subsidiary	Used for Mexico general corporate purposes, guaranteed by TCPL	Demand

At April 30, 2019, our operated affiliates had an additional $0.8 billion of undrawn capacity on committed credit facilities.

Refer to Financial risks and financial instruments for more information about liquidity, market and other risks.

CONTRACTUAL OBLIGATIONS

Our capital expenditure commitments have risen by approximately $0.2 billion since December 31, 2018. This increase is primarily due to increased commitments related to the construction of Coastal GasLink, Columbia growth projects and advancement of Keystone XL, partially offset by decreased commitments for the NGTL System and the White Spruce pipeline.

There were no other material changes to our contractual obligations in first quarter 2019 or to payments due in the next five years or after. Refer to the MD&A in our 2018 Annual Report for more information about our contractual obligations.

Financial risks and financial instruments

We are exposed to market risk and counterparty credit risk and have strategies, policies and limits in place to manage the impact of these risks on our earnings, cash flow and, ultimately, shareholder value. Risk management strategies, policies and limits are designed to ensure our risks and related exposures are in line with our business objectives and risk tolerance.

Refer to our 2018 Annual Report for more information about the risks we face in our business. Our risks have not changed substantially since December 31, 2018.

INTEREST RATE RISK

We utilize short-term and long-term debt to finance our operations which exposes us to interest rate risk. We typically pay fixed rates of interest on our long-term debt and floating rates on our commercial paper programs and amounts drawn on our credit facilities. A small portion of our long-term debt is at floating interest rates. In addition, we are exposed to interest rate risk on financial instruments and contractual obligations containing variable interest rate components. We manage our interest rate risk using a combination of interest rate swaps and option derivatives.

FOREIGN EXCHANGE RISK

We generate revenues and incur expenses that are denominated in currencies other than Canadian dollars. As a result, our earnings and cash flows are exposed to currency fluctuations.

A portion of our businesses generate earnings in U.S. dollars, but since we report our financial results in Canadian dollars, changes in the value of the U.S. dollar against the Canadian dollar can affect our net income. As our 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 actively managed on a rolling one-year basis using foreign exchange derivatives, however the natural exposure beyond that period remains.

Average exchange rate – U.S. to Canadian dollars

The average exchange rate for one U.S. dollar converted into Canadian dollars was as follows:

three months ended March 31, 2019	**1.33**
three months ended March 31, 2018	1.27

The impact of changes in the value of the U.S. dollar on our U.S. and Mexico operations is partially offset by interest on U.S. dollar-denominated debt as set out in the table below. Comparable EBIT is a non-GAAP measure.

Significant U.S. dollar-denominated amounts

	three months ended March 31	
(millions of US$)	**2019**	**2018**
U.S. Natural Gas Pipelines comparable EBIT	**595**	513
Mexico Natural Gas Pipelines comparable EBIT[1]	**113**	130
U.S. Liquids Pipelines comparable EBIT	**290**	202
Interest on U.S. dollar-denominated long-term debt and junior subordinated notes	**(331)**	(314)
Capitalized interest on U.S. dollar-denominated capital expenditures	**6**	3
U.S. dollar-denominated allowance for funds used during construction	**72**	67
U.S. dollar comparable non-controlling interests and other	**(81)**	(80)
	664	521

1 Excludes interest expense on our inter-affiliate loan with Sur de Texas which is offset in Interest income and other.

Net investment hedges

We hedge our net investment in foreign operations (on an after-tax basis) with U.S. dollar-denominated debt, cross-currency swaps and foreign exchange options.

COUNTERPARTY CREDIT RISK

We have exposure to counterparty credit risk in the following areas:

- cash and cash equivalents
- accounts receivable
- available-for-sale assets
- the fair value of derivative assets
- a loan receivable.

We monitor counterparties and review our accounts receivable regularly. We record allowances for doubtful accounts using the specific identification method. At March 31, 2019, we had no significant credit losses, no significant credit risk concentration and no significant amounts past due or impaired.

We have significant credit and performance exposure to financial institutions because they hold cash deposits and provide committed credit lines and letters of credit that help manage our exposure to counterparties and provide liquidity in commodity, foreign exchange and interest rate derivative markets.

LIQUIDITY RISK

We manage our liquidity risk by continuously forecasting our cash flow and making sure we have adequate cash balances, cash flow from operations, committed and demand credit facilities and access to capital markets to meet our operating, financing and capital expenditure obligations under both normal and stressed economic conditions.

LOAN RECEIVABLE FROM AFFILIATE

We hold a 60 per cent equity interest in a joint venture with IEnova to build, own and operate the Sur de Texas pipeline. We account for our interest in the joint venture as an equity investment. In 2017, we 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 March 31, 2019, our Condensed consolidated balance sheet included a MXN$19.4 billion or $1.3 billion (December 31, 2018 – MXN$18.9 billion or $1.3 billion) loan receivable from the Sur de Texas joint venture which represents our proportionate share of long-term debt financing requirements related to the joint venture. Interest income and other included interest income of $35 million for the three months ended March 31, 2019 (2018 – $27 million) from this joint venture with a corresponding proportionate share of interest expense recorded in Income from equity investments.

FINANCIAL INSTRUMENTS

With the exception of Long-term debt and Junior subordinated notes, our derivative and non-derivative financial instruments are recorded on the balance sheet at fair value unless they were entered into and continue to be held for the purpose of receipt or delivery in accordance with our normal purchase and sales exemptions and are documented as such. In addition, fair value accounting is not required for other financial instruments that qualify for certain accounting exemptions.

Derivative instruments

We use derivative instruments to reduce volatility associated with fluctuations in commodity prices, interest rates and foreign exchange rates. Derivative instruments, including those that qualify and are designated for hedge accounting treatment, are recorded at fair value.

The majority of derivative instruments that are not designated or do not qualify for hedge accounting treatment have been entered into as economic hedges to manage our exposure to market risk and are classified as held for trading. Changes in the fair value of held-for-trading derivative instruments are recorded in net income in the period of change. This may expose us to increased variability in reported operating results since the fair value of the held-for-trading derivative instruments can fluctuate significantly from period to period.

Balance sheet presentation of derivative instruments

The balance sheet presentation of the fair value of derivative instruments is as follows:

(millions of $)	March 31, 2019	December 31, 2018
Other current assets	**313**	737
Intangible and other assets	**35**	61
Accounts payable and other	**(389)**	(922)
Other long-term liabilities	**(49)**	(42)
	(90)	(166)

Unrealized and realized (losses)/gains on derivative instruments

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

	three months ended March 31	
(millions of $)	2019	2018
Derivative instruments held for trading[1]		
Amount of unrealized (losses)/gains in the period		
Commodities[2]	**(88)**	(109)
Foreign exchange	**120**	(79)
Amount of realized gains/(losses) in the period		
Commodities	**107**	110
Foreign exchange	**(29)**	15
Derivative instruments in hedging relationships		
Amount of realized (losses)/gains in the period		
Commodities	**(7)**	3
Interest rate	**—**	1

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 the three months ended March 31, 2019 and 2018, 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.

Effect of fair value and cash flow hedging relationships

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

	three months ended March 31			
	Revenues (Power and Storage)		Interest Expense	
(millions of $)	2019	2018	2019	2018
Total Amount Presented in the Condensed Consolidated Statement of Income	**336**	675	**(586)**	(527)
Fair Value Hedges				
Interest rate contracts				
Hedged items	**—**	—	**(6)**	(20)
Derivatives designated as hedging instruments	**—**	—	**(1)**	—
Cash Flow Hedges				
Reclassification of gains/(losses) on derivative instruments from AOCI to net income[1,2]				
Interest rate contracts	**—**	—	**4**	5
Commodity contracts	**—**	(1)	**—**	—

1 Refer to our Condensed consolidated financial statements 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.

Credit-risk-related contingent features of derivative instruments

Derivatives often contain financial assurance provisions that may require us to provide collateral if a credit-risk-related contingent event occurs (for example, if our credit rating is downgraded to non-investment grade). We may also need to provide collateral if the fair value of our derivative financial instruments exceeds pre-defined exposure limits.

Based on contracts in place and market prices at March 31, 2019, the aggregate fair value of all derivative contracts with credit-risk-related contingent features that were in a net liability position was $4 million (December 31, 2018 – $6 million), with no collateral provided in the normal course of business. If the credit-risk-related contingent features in these agreements were triggered on March 31, 2019, we would have been required to provide collateral of $4 million (December 31, 2018 – $6 million) to our counterparties. Collateral may also need to be provided should the fair value of derivative instruments exceed pre-defined contractual exposure limit thresholds.

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

Other information

CONTROLS AND PROCEDURES

Management, including our President and CEO and our CFO, evaluated the effectiveness of our disclosure controls and procedures as at March 31, 2019, as required by the Canadian securities regulatory authorities and by the SEC, and concluded that our disclosure controls and procedures are effective at a reasonable assurance level.

There were no changes in first quarter 2019 that had or are likely to have a material impact on our internal control over financial reporting.

CRITICAL ACCOUNTING ESTIMATES AND ACCOUNTING POLICY CHANGES

When we prepare financial statements that conform with U.S. GAAP, we are required to make estimates and assumptions that affect the timing and amounts we record for our assets, liabilities, revenues and expenses because these items may be affected by future events. We base the estimates and assumptions on the most current information available, using our best judgement. We also regularly assess the assets and liabilities themselves. A summary of our critical accounting estimates is included in our 2018 Annual Report.

Our significant accounting policies have remained unchanged since December 31, 2018 other than described below. A summary of our significant accounting policies is included in our 2018 Annual Report.

Changes in accounting policies for 2019

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 twelve months. Leases will be classified as finance or operating, with classification affecting the pattern of expense recognition in the consolidated statement of income. The new guidance does not make extensive changes to lessor accounting.

The new guidance was effective January 1, 2019 and was applied using optional transition relief which allowed entities to initially apply the new lease standard at adoption (January 1, 2019) and recognize a cumulative-effect adjustment to the opening balance of retained earnings in the period of adoption. This transition option allowed us to not apply the new guidance, including disclosure requirements, to the comparative periods presented.

We elected available practical expedients and exemptions upon adoption which allowed us:

- not to reassess prior conclusions on existing leases regarding lease identification, lease classification and initial direct costs under the new standard
- to carry forward the historical lease classification and our accounting treatment for land easements on existing agreements
- to not recognize ROU assets or lease liabilities for leases that qualify for the short-term lease recognition exemption
- to not separate lease and non-lease components for all leases for which we are the lessee and for facility and liquids tank terminals for which we are the lessor
- to use hindsight in determining the lease term and assessing ROU assets for impairment.

The new guidance had a significant impact on our Condensed consolidated balance sheet, but did not have an impact on our Condensed consolidated statements of income and cash flows. The most significant impact was the recognition of ROU assets and lease liabilities for operating leases and providing significant new disclosures about our leasing activities. Refer to our Condensed consolidated financial statements for further information related to the impact of adopting the new guidance and our updated accounting policies related to leases.

In the application of the new guidance, significant assumptions and judgments are used to determine the following:

- whether a contract contains a lease
- the duration of the lease term including exercising lease renewal options. The lease term for all of our leases includes the noncancellable period of the lease plus any additional periods covered by either our option to extend (or not to terminate) the lease that we are reasonably certain to exercise, or an option to extend (or not to terminate) the lease controlled by the lessor
- the discount rate for the lease.

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. We elected to adopt this guidance effective first quarter 2019. The guidance was applied retrospectively and did not have a material impact on our consolidated financial statements.

Future accounting changes

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. We are currently evaluating the impact of the adoption of this guidance and have not yet determined the effect on our consolidated financial statements.

Defined benefit plans

In August 2018, the FASB issued new guidance which amends and clarifies disclosure requirements related to defined benefit 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. We are currently evaluating the timing and impact of the adoption of this guidance and have not yet determined the effect on our 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. We are currently evaluating the timing and impact of adoption of this guidance and have not yet determined the effect on our 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. We are currently evaluating the timing and impact of the adoption of this guidance and have not yet determined the effect on our consolidated financial statements.

Quarterly results

SELECTED QUARTERLY CONSOLIDATED FINANCIAL DATA

	2019	2018				2017		
(millions of $, except per share amounts)	**First**	**Fourth**	**Third**	**Second**	**First**	**Fourth**	**Third**	**Second**
Revenues	**3,487**	3,904	3,156	3,195	3,424	3,617	3,195	3,230
Net income attributable to common shares	**1,004**	1,092	928	785	734	861	612	881
Comparable earnings	**987**	946	902	768	864	719	614	659
Share statistics								
Net income per common share – basic and diluted	**$1.09**	$1.19	$1.02	$0.88	$0.83	$0.98	$0.70	$1.01
Comparable earnings per common share	**$1.07**	$1.03	$1.00	$0.86	$0.98	$0.82	$0.70	$0.76
Dividends declared per common share	**$0.75**	$0.69	$0.69	$0.69	$0.69	$0.625	$0.625	$0.625

FACTORS AFFECTING QUARTERLY FINANCIAL INFORMATION BY BUSINESS SEGMENT

Quarter-over-quarter revenues and net income fluctuate for reasons that vary across our business segments.

In our Canadian Natural Gas Pipelines, U.S. Natural Gas Pipelines and Mexico Natural Gas Pipelines segments, except for seasonal fluctuations in short-term throughput volumes on U.S. pipelines, quarter-over-quarter revenues and net income generally remain relatively stable during any fiscal year. Over the long term, however, they fluctuate because of:

- regulators' decisions
- negotiated settlements with shippers
- newly constructed assets being placed in service
- acquisitions and divestitures
- developments outside of the normal course of operations.

In Liquids Pipelines, annual revenues and net income are based on contracted and uncommitted spot transportation and liquids marketing activities. Quarter-over-quarter revenues and net income are affected by:

- regulatory decisions
- newly constructed assets being placed in service
- acquisitions and divestitures
- demand for uncontracted transportation services
- liquids marketing activities
- developments outside of the normal course of operations
- certain fair value adjustments.

In Power and Storage, quarter-over-quarter revenues and net income are affected by:

- weather
- customer demand
- newly constructed assets being placed in service
- acquisitions and divestitures
- market prices for natural gas and power
- capacity prices and payments
- planned and unplanned plant outages
- developments outside of the normal course of operations
- certain fair value adjustments.

FACTORS AFFECTING FINANCIAL INFORMATION BY QUARTER

We calculate comparable measures by adjusting certain GAAP and non-GAAP measures for specific items we believe are significant but not reflective of our underlying operations in the period.

Comparable earnings exclude the unrealized gains and losses from changes in the fair value of certain derivatives used to reduce our exposure to certain financial and commodity price risks. These derivatives generally provide effective economic hedges, but do not meet the criteria for hedge accounting. As a result, the changes in fair value are recorded in net income. As these amounts do not accurately reflect the gains and losses that will be realized at settlement, we do not consider them part of our underlying operations.

In the first quarter 2019, comparable earnings also excluded:

- an after-tax loss of $12 million related to our U.S. Northeast power marketing contracts.

In fourth quarter 2018, comparable earnings also excluded:

- a $143 million after-tax gain related to the sale of our interests in the Cartier Wind power facilities
- a $115 million deferred income tax recovery from an MLP regulatory liability write-off resulting from the 2018 FERC Actions
- a $52 million recovery of deferred income taxes as a result of finalizing the impact of U.S. Tax Reform
- a $27 million income tax recovery related to the sale of our U.S. Northeast power generation assets
- $25 million of after-tax income recognized on the Bison contract terminations
- a $140 million after-tax impairment charge on Bison
- a $15 million after-tax goodwill impairment charge on Tuscarora
- an after-tax net loss of $7 million related to our U.S. Northeast power marketing contracts.

In third quarter 2018, comparable earnings also excluded:

- after-tax gain of $8 million related to our U.S. Northeast power marketing contracts.

In second quarter 2018, comparable earnings also excluded:

- an after-tax loss of $11 million related to our U.S. Northeast power marketing contracts.

In the first quarter 2018, comparable earnings also excluded:

- after-tax gain of $6 million related to our U.S. Northeast power marketing contracts, primarily due to income recognized on the sale of our retail contracts.

In fourth quarter 2017, comparable earnings also excluded:

- an $804 million recovery of deferred income taxes as a result of U.S. Tax Reform
- a $136 million after-tax gain related to the sale of our Ontario solar assets
- a $64 million net after-tax gain related to the monetization of our U.S. Northeast power generation assets
- a $954 million after-tax impairment charge for the Energy East pipeline and related projects as a result of our decision not to proceed with the project applications
- a $9 million after-tax charge related to the maintenance and liquidation of Keystone XL assets.

In third quarter 2017, comparable earnings also excluded:

- an incremental net loss of $12 million related to the monetization of our U.S. Northeast power generation assets
- an after-tax charge of $30 million for integration-related costs associated with the acquisition of Columbia
- an after-tax charge of $8 million related to the maintenance of Keystone XL assets.

In second quarter 2017, comparable earnings also excluded:

- a $265 million net after-tax gain related to the monetization of our U.S. Northeast power generation assets which included a $441 million after-tax gain on the sale of TC Hydro and a loss of $176 million after tax on the sale of the thermal and wind package
- an after-tax charge of $15 million for integration-related costs associated with the acquisition of Columbia
- an after-tax charge of $4 million related to the maintenance of Keystone XL assets.

Condensed consolidated statement of income

	three months ended March 31	
(unaudited - millions of Canadian $, except per share amounts)	**2019**	**2018**
Revenues		
Canadian Natural Gas Pipelines	**967**	884
U.S. Natural Gas Pipelines	**1,304**	1,091
Mexico Natural Gas Pipelines	**152**	151
Liquids Pipelines	**728**	623
Power and Storage	**336**	675
	3,487	3,424
Income from Equity Investments	**155**	80
Operating and Other Expenses		
Plant operating costs and other	**929**	874
Commodity purchases resold	**252**	597
Property taxes	**187**	150
Depreciation and amortization	**608**	535
	1,976	2,156
Financial Charges		
Interest expense	**586**	527
Allowance for funds used during construction	**(139)**	(105)
Interest income and other	**(163)**	(63)
	284	359
Income before Income Taxes	**1,382**	989
Income Tax Expense		
Current	**160**	50
Deferred	**76**	71
	236	121
Net Income	**1,146**	868
Net income attributable to non-controlling interests	**101**	94
Net Income Attributable to Controlling Interests	**1,045**	774
Preferred share dividends	**41**	40
Net Income Attributable to Common Shares	**1,004**	734
Net Income per Common Share		
Basic and diluted	**$1.09**	$0.83
Dividends Declared per Common Share	**$0.75**	$0.69
Weighted Average Number of Common Shares (millions)		
Basic	**921**	885
Diluted	**922**	886

See accompanying notes to the Condensed consolidated financial statements.

Condensed consolidated statement of comprehensive income

	three months ended March 31	
(unaudited - millions of Canadian $)	**2019**	**2018**
Net Income	**1,146**	868
Other Comprehensive (Loss)/Income, Net of Income Taxes		
Foreign currency translation losses and gains on net investment in foreign operations	**(370)**	432
Change in fair value of net investment hedges	**20**	(2)
Change in fair value of cash flow hedges	**(17)**	7
Reclassification to net income of gains and losses on cash flow hedges	**3**	3
Reclassification of actuarial gains and losses on pension and other post-retirement benefit plans	**3**	(2)
Other comprehensive income on equity investments	**1**	6
Other comprehensive (loss)/income	**(360)**	444
Comprehensive Income	**786**	1,312
Comprehensive income attributable to non-controlling interests	**61**	160
Comprehensive Income Attributable to Controlling Interests	**725**	1,152
Preferred share dividends	**41**	40
Comprehensive Income Attributable to Common Shares	**684**	1,112

See accompanying notes to the Condensed consolidated financial statements.

Condensed consolidated statement of cash flows

	three months ended March 31	
(unaudited - millions of Canadian $)	**2019**	**2018**
Cash Generated from Operations		
Net income	**1,146**	868
Depreciation and amortization	**608**	535
Deferred income taxes	**76**	71
Income from equity investments	**(155)**	(80)
Distributions received from operating activities of equity investments	**277**	234
Employee post-retirement benefits funding, net of expense	**3**	3
Equity allowance for funds used during construction	**(94)**	(78)
Unrealized (gains)/losses on financial instruments	**(32)**	188
Other	**(22)**	(122)
Decrease/(increase) in operating working capital	**142**	(207)
Net cash provided by operations	**1,949**	1,412
Investing Activities		
Capital expenditures	**(2,022)**	(1,702)
Capital projects in development	**(164)**	(36)
Contributions to equity investments	**(145)**	(358)
Other distributions from equity investments	**120**	121
Deferred amounts and other	**(26)**	110
Net cash used in investing activities	**(2,237)**	(1,865)
Financing Activities		
Notes payable issued, net	**2,852**	1,812
Long-term debt issued, net of issue costs	**24**	93
Long-term debt repaid	**(1,708)**	(1,226)
Dividends on common shares	**(419)**	(358)
Dividends on preferred shares	**(40)**	(39)
Distributions to non-controlling interests	**(56)**	(69)
Common shares issued, net of issue costs	**68**	340
Partnership units of TC PipeLines, LP issued, net of issue costs	**—**	49
Net cash provided by financing activities	**721**	602
Effect of Foreign Exchange Rate Changes on Cash and Cash Equivalents	**(7)**	29
Increase in Cash and Cash Equivalents	**426**	178
Cash and Cash Equivalents		
Beginning of period	**446**	1,089
Cash and Cash Equivalents		
End of period	**872**	1,267

See accompanying notes to the Condensed consolidated financial statements.

Condensed consolidated balance sheet

(unaudited - millions of Canadian $)		March 31, 2019	December 31, 2018
ASSETS			
Current Assets			
Cash and cash equivalents		**872**	446
Accounts receivable		**2,214**	2,535
Inventories		**407**	431
Assets held for sale		**533**	543
Other		**879**	1,180
		4,905	5,135
Plant, Property and Equipment	net of accumulated depreciation of $26,181 and $25,834, respectively	**67,520**	66,503
Equity Investments		**6,966**	7,113
Regulatory Assets		**1,557**	1,548
Goodwill		**13,881**	14,178
Loan Receivable from Affiliate		**1,336**	1,315
Intangible and Other Assets		**1,867**	1,921
Restricted Investments		**1,315**	1,207
		99,347	98,920
LIABILITIES			
Current Liabilities			
Notes payable		**5,587**	2,762
Accounts payable and other		**4,693**	5,408
Dividends payable		**705**	668
Accrued interest		**613**	646
Current portion of long-term debt		**1,757**	3,462
		13,355	12,946
Regulatory Liabilities		**3,971**	3,930
Other Long-Term Liabilities		**1,492**	1,008
Deferred Income Tax Liabilities		**5,995**	6,026
Long-Term Debt		**35,857**	36,509
Junior Subordinated Notes		**7,380**	7,508
		68,050	67,927
EQUITY			
Common shares, no par value		**23,466**	23,174
Issued and outstanding:	March 31, 2019 – 924 million shares		
	December 31, 2018 – 918 million shares		
Preferred shares		**3,980**	3,980
Additional paid-in capital		**11**	17
Retained earnings		**3,106**	2,773
Accumulated other comprehensive loss		**(926)**	(606)
Controlling Interests		**29,637**	29,338
Non-controlling interests		**1,660**	1,655
		31,297	30,993
		99,347	98,920

Contingencies and Guarantees (Note 12)
Variable Interest Entities (Note 13)
Subsequent Event (Note 14)

See accompanying notes to the Condensed consolidated financial statements.

Condensed consolidated statement of equity

	three months ended March 31	
(unaudited - millions of Canadian $)	2019	2018
Common Shares		
Balance at beginning of period	**23,174**	21,167
Shares issued:		
Under at-the-market equity issuance program, net of issue costs	**—**	327
Under dividend reinvestment and share purchase plan	**216**	195
On exercise of stock options	**76**	14
Balance at end of period	**23,466**	21,703
Preferred Shares		
Balance at beginning and end of period	**3,980**	3,980
Additional Paid-In Capital		
Balance at beginning of period	**17**	—
Issuance of stock options, net of exercises	**(6)**	3
Dilution from TC PipeLines, LP units issued	**—**	7
Balance at end of period	**11**	10
Retained Earnings		
Balance at beginning of period	**2,773**	1,623
Net income attributable to controlling interests	**1,045**	774
Common share dividends	**(693)**	(614)
Preferred share dividends	**(19)**	(19)
Adjustment related to income tax effects of asset drop-downs to TC PipeLines, LP	**—**	95
Balance at end of period	**3,106**	1,859
Accumulated Other Comprehensive Loss		
Balance at beginning of period	**(606)**	(1,731)
Other comprehensive (loss)/income attributable to controlling interests	**(320)**	378
Balance at end of period	**(926)**	(1,353)
Equity Attributable to Controlling Interests	**29,637**	26,199
Equity Attributable to Non-Controlling Interests		
Balance at beginning of period	**1,655**	1,852
Net income attributable to non-controlling interests	**101**	94
Other comprehensive (loss)/income attributable to non-controlling interests	**(40)**	66
Issuance of TC PipeLines, LP units		
Proceeds, net of issue costs	**—**	49
Decrease in TransCanada's ownership of TC PipeLines, LP	**—**	(9)
Distributions declared to non-controlling interests	**(56)**	(71)
Balance at end of period	**1,660**	1,981
Total Equity	**31,297**	28,180

See accompanying notes to the Condensed consolidated financial statements.

Notes to Condensed consolidated financial statements (unaudited)

1. Basis of presentation

These Condensed consolidated financial statements of TransCanada Corporation (TransCanada or the Company) have been prepared by management in accordance with U.S. GAAP. The accounting policies applied are consistent with those outlined in TransCanada's annual audited Consolidated financial statements for the year ended December 31, 2018, except as described in Note 2, Accounting changes. Capitalized and abbreviated terms that are used but not otherwise defined herein are identified in the 2018 audited Consolidated financial statements included in TransCanada's 2018 Annual Report. As of first quarter 2019, the previously disclosed Energy segment has been renamed the Power and Storage segment.

These Condensed consolidated financial statements reflect adjustments, all of which are normal recurring adjustments that are, in the opinion of management, necessary to reflect fairly the financial position and results of operations for the respective periods. These Condensed consolidated financial statements do not include all disclosures required in the annual financial statements and should be read in conjunction with the 2018 audited Consolidated financial statements included in TransCanada's 2018 Annual Report. Certain comparative figures have been reclassified to conform with the current period's presentation.

Earnings for interim periods may not be indicative of results for the fiscal year in the Company's natural gas pipelines segments due to the timing of regulatory decisions and seasonal fluctuations in short-term throughput volumes on U.S. pipelines. Earnings for interim periods may also not be indicative of results for the fiscal year in the Company's Power and Storage segment due to the impact of seasonal weather conditions on customer demand and market pricing in certain of the Company's investments in electrical power generation plants and non-regulated gas storage facilities.

USE OF ESTIMATES AND JUDGMENTS

In preparing these 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. In the opinion of management, these Condensed consolidated financial statements have been properly prepared within reasonable limits of materiality and within the framework of the Company's significant accounting policies included in the annual audited Consolidated financial statements for the year ended December 31, 2018, except as described in Note 2, Accounting changes.

2. Accounting changes

CHANGES IN ACCOUNTING POLICIES FOR 2019

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 twelve months. Leases will be classified as finance or operating, with classification affecting the pattern of expense recognition in the consolidated statement of income. The new guidance does not make extensive changes to lessor accounting.

The new guidance was effective January 1, 2019 and was applied using optional transition relief which allowed entities to initially apply the new lease standard at adoption (January 1, 2019) and recognize a cumulative-effect adjustment to the opening balance of retained earnings in the period of adoption. This transition option allowed the Company to not apply the new guidance, including disclosure requirements, to the comparative periods presented.

The Company elected available practical expedients and exemptions upon adoption which allowed the Company:

- not to reassess prior conclusions on existing leases regarding lease identification, lease classification and initial direct costs under the new standard
- to carry forward the historical lease classification and its accounting treatment for land easements on existing agreements
- to not recognize ROU assets or lease liabilities for leases that qualify for the short-term lease recognition exemption
- 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
- to use hindsight in determining the lease term and assessing ROU assets for impairment.

The new guidance had a significant impact on the Company's Condensed consolidated balance sheet, but did not have an impact on the Company's Condensed consolidated statements of income and cash flows. The most significant impact was the recognition of ROU assets and lease liabilities for operating leases and providing significant new disclosures about the Company's leasing activities. Refer to Note 7, Leases, for further information related to the impact of adopting the new guidance and the Company's updated accounting policies related to leases.

In the application of the new guidance, significant assumptions and judgments are used to determine the following:

- whether a contract contains a lease
- the duration of the lease term including exercising lease renewal options. The lease term for all of the Company’s leases includes the noncancellable period of the lease plus any additional periods covered by either a Company option to extend (or not to terminate) the lease that the Company is reasonably certain to exercise, or an option to extend (or not to terminate) the lease controlled by the lessor
- the discount rate for the lease.

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 elected to adopt this guidance effective first quarter 2019. The guidance was applied retrospectively and did not have a material impact on the Company's consolidated financial statements.

FUTURE ACCOUNTING CHANGES

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.

Defined benefit plans

In August 2018, the FASB issued new guidance which amends and clarifies disclosure requirements related to defined benefit 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.

3. Segmented information

three months ended March 31, 2019 (unaudited - millions of Canadian $)	Canadian Natural Gas Pipelines	U.S. Natural Gas Pipelines	Mexico Natural Gas Pipelines	Liquids Pipelines	Power and Storage[1]	Corporate[2]	Total
Revenues	**967**	**1,304**	**152**	**728**	**336**	**—**	**3,487**
Intersegment revenues	**—**	**42**	**—**	**—**	**5**	**(47)** [3]	**—**
	967	**1,346**	**152**	**728**	**341**	**(47)**	**3,487**
Income/(loss) from equity investments	**1**	**76**	**6**	**14**	**72**	**(14)** [4]	**155**
Plant operating costs and other	**(343)**	**(362)**	**(12)**	**(166)**	**(88)**	**42** [3]	**(929)**
Commodity purchases resold	**—**	**—**	**—**	**—**	**(252)**	**—**	**(252)**
Property taxes	**(69)**	**(88)**	**—**	**(28)**	**(2)**	**—**	**(187)**
Depreciation and amortization	**(287)**	**(180)**	**(30)**	**(88)**	**(23)**	**—**	**(608)**
Segmented Earnings/(Loss)	**269**	**792**	**116**	**460**	**48**	**(19)**	**1,666**
Interest expense							**(586)**
Allowance for funds used during construction							**139**
Interest income and other[4]							**163**
Income before income taxes							**1,382**
Income tax expense							**(236)**
Net Income							**1,146**
Net income attributable to non-controlling interests							**(101)**
Net Income Attributable to Controlling Interests							**1,045**
Preferred share dividends							**(41)**
Net Income Attributable to Common Shares							**1,004**

1 Previously referred to as Energy.

2 Includes intersegment eliminations.

3 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.

4 Income/(loss) from equity investments includes foreign exchange losses on the Company's inter-affiliate loan with Sur de Texas. The offsetting foreign exchange gains 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.

three months ended March 31, 2018 (unaudited - millions of Canadian $)	Canadian Natural Gas Pipelines	U.S. Natural Gas Pipelines	Mexico Natural Gas Pipelines	Liquids Pipelines	Power and Storage[1]	Corporate[2]	Total
Revenues	884	1,091	151	623	675	—	3,424
Intersegment revenues	—	25	—	—	42	(67) [3]	—
	884	1,116	151	623	717	(67)	3,424
Income/(loss) from equity investments	3	67	11	15	63	(79) [4]	80
Plant operating costs and other	(323)	(324)	(2)	(191)	(99)	65 [3]	(874)
Commodity purchases resold	—	—	—	—	(597)	—	(597)
Property taxes	(70)	(55)	—	(23)	(2)	—	(150)
Depreciation and amortization	(241)	(156)	(23)	(83)	(32)	—	(535)
Segmented Earnings/(Loss)	253	648	137	341	50	(81)	1,348
Interest expense							(527)
Allowance for funds used during construction							105
Interest income and other[4]							63
Income before income taxes							989
Income tax expense							(121)
Net Income							868
Net income attributable to non-controlling interests							(94)
Net Income Attributable to Controlling Interests							774
Preferred share dividends							(40)
Net Income Attributable to Common Shares							734

1 Previously referred to as Energy.

2 Includes intersegment eliminations.

3 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.

4 Income/(loss) from equity investments includes foreign exchange losses on the Company's inter-affiliate loan with Sur de Texas. The offsetting foreign exchange gains 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.

TOTAL ASSETS BY SEGMENT

(unaudited - millions of Canadian $)	March 31, 2019	December 31, 2018
Canadian Natural Gas Pipelines	**19,287**	18,407
U.S. Natural Gas Pipelines	**43,532**	44,115
Mexico Natural Gas Pipelines	**6,858**	7,058
Liquids Pipelines	**17,025**	17,352
Power and Storage	**8,331**	8,475
Corporate	**4,314**	3,513
	99,347	98,920

4. Revenues

DISAGGREGATION OF REVENUES

The following tables summarize total Revenues for the three months ended March 31, 2019 and 2018:

three months ended March 31, 2019 (unaudited - millions of Canadian $)	**Canadian Natural Gas Pipelines**	**U.S. Natural Gas Pipelines**	**Mexico Natural Gas Pipelines**	**Liquids Pipelines**	**Power and Storage**	**Total**
Revenues from contracts with customers						
Capacity arrangements and transportation	**967**	**1,100**	**151**	**593**	**—**	**2,811**
Power generation	**—**	**—**	**—**	**—**	**343**	**343**
Natural gas storage and other	**—**	**180**	**1**	**1**	**28**	**210**
	967	**1,280**	**152**	**594**	**371**	**3,364**
Other revenues[1]	**—**	**24**	**—**	**134**	**(35)**	**123**
	967	**1,304**	**152**	**728**	**336**	**3,487**

1 Other revenues include income from the Company's marketing activities, financial instruments and lease arrangements. These arrangements are not in the scope of the revenue guidance. Refer to Note 7, Leases, and Note 11, Risk management and financial instruments, for further information on income from lease arrangements and financial instruments, respectively.

three months ended March 31, 2018 (unaudited - millions of Canadian $)	**Canadian Natural Gas Pipelines**	**U.S. Natural Gas Pipelines**	**Mexico Natural Gas Pipelines**	**Liquids Pipelines**	**Power and Storage**	**Total**
Revenues from contracts with customers						
Capacity arrangements and transportation	884	884	150	534	—	2,452
Power generation	—	—	—	—	590	590
Natural gas storage and other	—	192	1	1	30	224
	884	1,076	151	535	620	3,266
Other revenues[1]	—	15	—	88	55	158
	884	1,091	151	623	675	3,424

1 Other revenues include income from the Company's marketing activities, financial instruments and lease arrangements. These arrangements are not in the scope of the revenue guidance. Refer to Note 11, Risk management and financial instruments, for further information on income from financial instruments.

CONTRACT BALANCES

(unaudited - millions of Canadian $)	**March 31, 2019**	**December 31, 2018**
Receivables from contracts with customers	**1,382**	1,684
Contract assets[1]	**249**	159
Long-term contract assets[2]	**11**	21
Contract liabilities[3]	**39**	11
Long-term contract liabilities[4]	**119**	121

1 Recorded as part of Other current assets on the Condensed consolidated balance sheet.

2 Recorded as part of Intangibles and other assets on the Condensed consolidated balance sheet.

3 Comprised of deferred revenue recorded in Accounts payable and other on the Condensed consolidated balance sheet. During the three months ended March 31, 2019, $6 million of revenue was recognized that was included in contract liabilities at the beginning of the period.

4 Comprised of deferred revenue recorded in Other long-term liabilities on the Condensed 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

Capacity Arrangements and Transportation

As at March 31, 2019, future revenues from long-term pipeline capacity arrangements and transportation contracts extending through 2045 are approximately $32.3 billion, of which approximately $5.4 billion is expected to be recognized during the remainder of 2019.

Power Generation

The Company has long-term power generation contracts extending through 2030. Revenues from power generation contracts 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.

Natural Gas Storage and Other

As at March 31, 2019, future revenues from long-term natural gas storage and other contracts extending through 2033 are approximately $1.7 billion, of which approximately $366 million is expected to be recognized during the remainder of 2019.

5. Income taxes

Effective Tax Rates

The effective income tax rates for the three-month periods ended March 31, 2019 and 2018 were 17 per cent and 12 per cent, respectively. The higher effective tax rate in 2019 was primarily the result of lower foreign tax rate differentials partially offset by lower flow-through tax in Canadian rate-regulated pipelines.

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. The proposed regulations are complex and comprehensive, and considerable uncertainty continues to exist pending release of the final regulations which is expected to occur later in 2019. As these proposed regulations have not been enacted as at March 31, 2019, their impact has not been reflected in income tax expense. If the proposed regulations are enacted as currently drafted, the resulting income tax expense should not have a material impact on the Company's financial statements.

6. Assets held for sale

Coolidge Generating Station

In December 2018, TransCanada entered into an agreement to sell its Coolidge generating station in Arizona to SWG Coolidge Holdings, LLC (SWG). Salt River Project Agriculture Improvement and Power District (SRP), the PPA counterparty, subsequently exercised its contractual right of first refusal on a sale to a third party. On March 20, 2019, TransCanada terminated the agreement with SWG after entering into an agreement with SRP to sell the Coolidge generating station for approximately US$465 million, subject to timing of the close and related adjustments.

The sale will result in an estimated gain of approximately $70 million ($55 million after tax) including the release of an estimated $10 million of foreign currency translation gains. The gain will be recognized upon closing of the sale transaction, which is expected to occur mid-2019.

At March 31, 2019, the related assets and liabilities in the Power and Storage segment were classified as held for sale as follows:

(unaudited - millions of Canadian $)	
Assets held for sale	
Accounts receivable	**6**
Other current assets	**1**
Plant, property and equipment	**526**
Total assets held for sale	**533**
Liabilities related to assets held for sale	
Other long-term liabilities	**(3)**
Total liabilities related to assets held for sale[1]	**(3)**

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

7. Leases

In 2016, the FASB issued new guidance on leases. The Company adopted the new guidance on January 1, 2019 using optional transition relief. Results reported for 2019 reflect the application of the new guidance, while the 2018 comparative results were prepared and reported under previous leases guidance.

Lessee Accounting Policy

The Company determines if an arrangement is a lease at inception of the contract. Operating leases are recognized as ROU assets and included in Plant, property and equipment while corresponding liabilities are included in Accounts payable and other, and Other long-term liabilities on the Condensed consolidated balance sheet.

Operating lease ROU assets and operating lease liabilities are recognized based on the present value of the future minimum lease payments over the lease term at the commencement date of the lease agreement. As the Company's lease contracts do not provide an implicit interest rate, the Company uses its incremental borrowing rate based on the information available at commencement date in determining the present value of future payments. The operating lease ROU asset also includes any lease payments made and initial direct costs incurred and excludes lease incentives. Lease terms may include options to extend or terminate the lease when it is reasonably certain that the Company will exercise that option. Operating lease expense is recognized on a straight-line basis over the lease term and included in Plant operating costs and other in the Condensed consolidated statement of income.

Lessor Accounting Policy

The Company is the lessor for certain contracts and these contracts are accounted for as operating leases. The Company recognizes lease payments as income over the lease term on a straight-line basis. Variable lease payments are recognized as income in the period in which the changes in facts and circumstances on which these payments are based occur.

Impact of New Lease Guidance on Date of Adoption

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

(unaudited - millions of Canadian $)	As reported December 31, 2018	Adjustment	January 1, 2019
Plant, property and equipment	66,503	585	67,088
Accounts payable and other	5,408	57	5,465
Other long-term liabilities	1,008	528	1,536

As a Lessee

The Company has operating leases for corporate offices, other various premises, equipment and land. Some leases have an option to renew for periods of one to 25 years, and some may include options to terminate the lease within one year. Payments due under lease contracts include fixed payments plus, for many of the Company's leases, variable payments such as proportionate share of the buildings' property taxes, insurance and common area maintenance. The Company subleases some of the leased premises.

Operating lease cost is as follows:

(unaudited - millions of Canadian $)	three months ended March 31, 2019
Operating lease cost[1]	28
Sublease income	(2)
Net operating lease cost	26

1 Includes short-term leases and variable lease costs.

Other information related to operating leases is noted in the following table:

(unaudited - millions of Canadian $)	three months ended March 31, 2019
Cash paid for amounts included in the measurement of operating lease liabilities	19
Weighted average remaining lease term	10.8 years
Weighted average discount rate	3.56%

Maturities of operating lease liabilities on a prospective 12-month basis and where they are disclosed on the Condensed consolidated balance sheet as at March 31, 2019 are as follows:

(unaudited - millions of Canadian $)	
2020	72
2021	69
2022	64
2023	58
2024	57
Thereafter	355
Total operating lease payments	675
Imputed interest	(110)
Operating lease liabilities recorded on the Condensed consolidated balance sheet	565
Reported as follows:	
Accounts payable and other	55
Other long-term liabilities	510
	565

Future payments reported under previous lease guidance for the Company's operating leases as at December 31, 2018 were as follows:

(unaudited - millions of Canadian $)	**Minimum operating lease payments**
2019	81
2020	78
2021	76
2022	69
2023	67
Thereafter	390
	761

As at March 31, 2019, the carrying value of the ROU assets recorded under operating leases was $570 million and is included in Plant, property and equipment on the Condensed consolidated balance sheet.

As a Lessor

Coolidge, Grandview and Bécancour power plants in the Power and Storage segment and the Northern Courier pipeline in the Liquids Pipelines segment are accounted for as operating leases. As Coolidge is classified as Assets held for sale, it is not included in the following lease disclosures. The Company has long-term PPAs for the sale of power for the Power and Storage lease assets which expire between 2024 and 2026. Northern Courier pipeline transports bitumen and diluent between the Fort Hills mine site and Suncor Energy's terminal, with a contract expiring in 2042.

Some leases contain variable lease payments that are based on operating hours and the reimbursement of variable costs, options to purchase the underlying asset at fair value or based on a formula considering the remaining fixed payments, and options to extend a lease up to five years. Lessees have rights under some leases to terminate under certain circumstances.

The Company also leases liquids tanks which are accounted for as operating leases.

Operating lease income recorded by the Company for the three months ended March 31, 2019 was $55 million.

Future lease payments to be received under operating leases as at March 31, 2019 are as follows:

(unaudited - millions of Canadian $)	Future lease payments
Remainder of 2019	183
2020	226
2021	223
2022	218
2023	224
Thereafter	1,940
	3,014

The cost and accumulated depreciation for facilities accounted for as operating leases was $2,023 million and $338 million, respectively, at March 31, 2019 (December 31, 2018 – $2,007 million and $324 million, respectively).

8. Long-term debt

LONG-TERM DEBT REPAID

The Company retired long-term debt in the three months ended March 31, 2019 as follows:

(unaudited - millions of Canadian $, unless otherwise noted) **Company**	**Retirement date**	**Type**	**Amount**	**Interest rate**
TRANSCANADA PIPELINES LIMITED				
	March 2019	Debentures	100	10.50%
	January 2019	Senior Unsecured Notes	US 750	7.125%
	January 2019	Senior Unsecured Notes	US 400	3.125%

CAPITALIZED INTEREST

In the three months ended March 31, 2019, TransCanada capitalized interest related to capital projects of $37 million (2018 – $26 million).

9. Other comprehensive (loss)/income and accumulated other comprehensive loss

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

three months ended March 31, 2019 (unaudited - millions of Canadian $)	**Before Tax Amount**	**Income Tax Recovery/ (Expense)**	**Net of Tax Amount**
Foreign currency translation losses on net investment in foreign operations	**(364)**	**(6)**	**(370)**
Change in fair value of net investment hedges	**27**	**(7)**	**20**
Change in fair value of cash flow hedges	**(22)**	**5**	**(17)**
Reclassification to net income of gains and losses on cash flow hedges	**4**	**(1)**	**3**
Reclassification of actuarial gains and losses on pension and other post-retirement benefit plans	**4**	**(1)**	**3**
Other comprehensive income on equity investments	**1**	**—**	**1**
Other Comprehensive Loss	**(350)**	**(10)**	**(360)**

three months ended March 31, 2018 (unaudited - millions of Canadian $)	Before Tax Amount	Income Tax Recovery/ (Expense)	Net of Tax Amount
Foreign currency translation gains on net investment in foreign operations	416	16	432
Change in fair value of net investment hedges	(3)	1	(2)
Change in fair value of cash flow hedges	6	1	7
Reclassification to net income of gains and losses on cash flow hedges	4	(1)	3
Reclassification of actuarial gains and losses on pension and other post-retirement benefit plans	4	(6)	(2)
Other comprehensive income on equity investments	7	(1)	6
Other Comprehensive Income	434	10	444

The changes in AOCI by component are as follows:

three months ended March 31, 2019 (unaudited - millions of Canadian $)	Currency Translation Adjustments	Cash Flow Hedges	Pension and OPEB Plan Adjustments	Equity Investments	Total[1]
AOCI balance at January 1, 2019	**107**	**(23)**	**(314)**	**(376)**	**(606)**
Other comprehensive loss before reclassifications[2]	**(315)**	**(12)**	**—**	**(1)**	**(328)**
Amounts reclassified from AOCI[3,4]	**—**	**2**	**3**	**3**	**8**
Net current period other comprehensive (loss)/ income	**(315)**	**(10)**	**3**	**2**	**(320)**
AOCI balance at March 31, 2019	**(208)**	**(33)**	**(311)**	**(374)**	**(926)**

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

2 Other comprehensive loss before reclassifications on currency translation adjustments and cash flow hedges are net of non-controlling interests losses of $35 million and $5 million, respectively.

3 Losses related to cash flow hedges reported in AOCI and expected to be reclassified to net income in the next 12 months are estimated to be $16 million ($12 million, net of tax) at March 31, 2019. 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.

4 Amounts reclassified from AOCI on cash flow hedges and equity investments are net of non-controlling interests gains of $1 million and nil, respectively.

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

(unaudited - millions of Canadian $)	Amounts Reclassified From AOCI three months ended March 31 2019	2018	Affected line item in the Condensed consolidated statement of income
Cash flow hedges			
Commodities	—	1	Revenues (Power and Storage)
Interest	**(3)**	(5)	Interest expense
	(3)	(4)	Total before tax
	1	1	Income tax expense
	(2)	(3)	Net of tax[1,3]
Pension and other post-retirement benefit plan adjustments			
Amortization of actuarial losses	**(4)**	(4)	Plant operating costs and other[2]
	1	6	Income tax expense
	(3)	2	Net of tax[1]
Equity investments			
Equity income	**(3)**	(7)	Income from equity investments
	—	1	Income tax expense
	(3)	(6)	Net of tax[1,3]

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

2 These AOCI components are included in the computation of net benefit cost. Refer to Note 10, Employee post-retirement benefits, for further information.

3 Amounts reclassified from AOCI on cash flow hedges and equity investments are net of non-controlling interests gains of $1 million and nil, respectively, for the three months ended March 31, 2019 (2018 – nil and nil).

10. Employee post-retirement benefits

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

	three months ended March 31			
	Pension benefit plans		Other post-retirement benefit plans	
(unaudited - millions of Canadian $)	2019	2018	2019	2018
Service cost[1]	**33**	30	**1**	1
Other components of net benefit cost[1]				
Interest cost	**35**	33	**4**	3
Expected return on plan assets	**(58)**	(55)	**(4)**	(4)
Amortization of actuarial losses	**3**	4	**1**	—
Amortization of regulatory asset	**3**	5	**—**	—
	(17)	(13)	**1**	(1)
Net Benefit Cost	**16**	17	**2**	—

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

11. 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.

COUNTERPARTY CREDIT RISK

TransCanada's maximum counterparty credit exposure with respect to financial instruments at March 31, 2019, without taking into account security held, consisted of cash and cash equivalents, accounts receivable, available-for-sale assets, derivative assets and a loan receivable.

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 March 31, 2019, there were no significant credit losses, no significant credit risk concentration and no significant amounts past due or impaired.

LOAN RECEIVABLE FROM AFFILIATE

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

The Company holds a 60 per cent equity interest in a joint venture with IEnova to build, own and operate the Sur de Texas pipeline. The Company accounts for its interest in the joint venture as an equity investment. In 2017, the Company 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 March 31, 2019, the Company's Condensed consolidated balance sheet included a MXN$19.4 billion or $1.3 billion (December 31, 2018 – MXN$18.9 billion or $1.3 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 $35 million for the three months ended March 31, 2019 (2018 – $27 million) from this joint venture with a corresponding proportionate share of interest expense recorded in Income from equity investments.

NET INVESTMENT IN FOREIGN OPERATIONS

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

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

	March 31, 2019		December 31, 2018	
(unaudited - millions of Canadian $, unless otherwise noted)	**Fair value[1,2]**	**Notional amount**	**Fair value[1,2]**	**Notional amount**
U.S. dollar cross-currency swaps (maturing 2019)[3]	**(12)**	**US 100**	(43)	US 300
U.S. dollar foreign exchange options (maturing 2019 to 2020)	**(13)**	**US 2,500**	(47)	US 2,500
	(25)	**US 2,600**	(90)	US 2,800

1 Fair value equals carrying value.

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

3 In the three months ended March 31, 2019, Net income includes net realized gains of nil (2018 – $1 million) related to the interest component of cross-currency swap settlements which are reported within Interest expense on the Company's Condensed consolidated statement of income.

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

(unaudited - millions of Canadian $, unless otherwise noted)	March 31, 2019	December 31, 2018
Notional amount	**30,800 (US 23,100)**	31,000 (US 22,700)
Fair value	**32,900 (US 24,600)**	31,700 (US 23,200)

FINANCIAL INSTRUMENTS

Non-derivative financial instruments

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. Each of these instruments are classified in Level II of the fair value hierarchy.

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

Balance sheet presentation of non-derivative financial instruments

The following table details the fair value of the Company's non-derivative financial instruments, excluding those where carrying amounts approximate fair value, which are classified in Level II of the fair value hierarchy:

	March 31, 2019		December 31, 2018	
(unaudited - millions of Canadian $)	Carrying amount	Fair value	Carrying amount	Fair value
Long-term debt including current portion[1,2]	**(37,614)**	**(41,737)**	(39,971)	(42,284)
Junior subordinated notes	**(7,380)**	**(7,006)**	(7,508)	(6,665)
	(44,994)	**(48,743)**	(47,479)	(48,949)

1 Long-term debt is recorded at amortized cost except for US$450 million (December 31, 2018 – US$750 million) that is attributed to hedged risk and recorded at fair value.

2 Net income for the three months ended March 31, 2019 includes unrealized losses of $3 million (2018 – gains of $5 million) for fair value adjustments attributable to the hedged interest rate risk associated with interest rate swap fair value hedging relationships on US$450 million of long-term debt at March 31, 2019 (December 31, 2018 – US$750 million). There were no other unrealized gains or losses from fair value adjustments to the non-derivative financial instruments.

Available-for-sale assets summary

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

(unaudited - millions of Canadian $)	March 31, 2019		December 31, 2018	
	LMCI restricted investments	Other restricted investments[1]	LMCI restricted investments	Other restricted investments[1]
Fair values of fixed income securities[2]				
Maturing within 1 year	**—**	**24**	—	22
Maturing within 1-5 years	**—**	**94**	—	110
Maturing within 5-10 years	**156**	**—**	140	—
Maturing after 10 years	**1,053**	**—**	952	—
	1,209	**118**	1,092	132

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 Condensed consolidated balance sheet.

(unaudited - millions of Canadian $)	March 31, 2019		March 31, 2018	
	LMCI restricted investments[1]	Other restricted investments[2]	LMCI restricted investments[1]	Other restricted investments[2]
Net unrealized gains in the period				
three months ended	**51**	**1**	2	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 Gains and losses on other restricted investments are included in Interest income and other on the Condensed consolidated statement of income.

Derivative instruments

Fair value of derivative instruments

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

Balance sheet presentation of derivative instruments

The balance sheet classification of the fair value of derivative instruments is as follows:

at March 31, 2019 (unaudited - 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					
Commodities[2]	—	—	—	**294**	**294**
Foreign exchange	—	—	**14**	**3**	**17**
Interest rate	**2**	—	—	—	**2**
	2	—	**14**	**297**	**313**
Intangible and other assets					
Commodities[2]	—	—	—	**28**	**28**
Foreign exchange	—	—	**1**	—	**1**
Interest rate	**4**	**2**	—	—	**6**
	4	**2**	**1**	**28**	**35**
Total Derivative Assets	**6**	**2**	**15**	**325**	**348**
Accounts payable and other					
Commodities[2]	**(4)**	—	—	**(273)**	**(277)**
Foreign exchange	—	—	**(39)**	**(71)**	**(110)**
Interest rate	—	**(2)**	—	—	**(2)**
	(4)	**(2)**	**(39)**	**(344)**	**(389)**
Other long-term liabilities					
Commodities[2]	**(1)**	—	—	**(23)**	**(24)**
Foreign exchange	—	—	**(1)**	—	**(1)**
Interest rate	**(24)**	—	—	—	**(24)**
	(25)	—	**(1)**	**(23)**	**(49)**
Total Derivative Liabilities	**(29)**	**(2)**	**(40)**	**(367)**	**(438)**
Total Derivatives	**(23)**	—	**(25)**	**(42)**	**(90)**

1 Fair value equals carrying value.

2 Includes purchases and sales of power, natural gas and liquids.

at December 31, 2018 (unaudited - 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					
Commodities[2]	1	—	—	716	717
Foreign exchange	—	—	16	1	17
Interest rate	3	—	—	—	3
	4	—	16	717	737
Intangible and other assets					
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					
Commodities[2]	(4)	—	—	(622)	(626)
Foreign exchange	—	—	(105)	(188)	(293)
Interest rate	—	(3)	—	—	(3)
	(4)	(3)	(105)	(810)	(922)
Other long-term liabilities					
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 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 Condensed consolidated balance sheet in relation to cumulative adjustments for fair value hedges included in the carrying amount of the hedged liabilities:

	Carrying amount		**Fair value hedging adjustments**[1]	
(unaudited - millions of Canadian $)	**March 31, 2019**	**December 31, 2018**	**March 31, 2019**	**December 31, 2018**
Current portion of long-term debt	**(332)**	(748)	**2**	3
Long-term debt	**(269)**	(273)	**(2)**	—
	(601)	(1,021)	**—**	3

1 At March 31, 2019 and December 31, 2018, 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 March 31, 2019 (unaudited)	Power	Natural Gas	Liquids	Foreign Exchange	Interest Rate
Purchases[1]	**17,374**	**34**	**63**	**—**	**—**
Sales[1]	**14,243**	**43**	**82**	**—**	**—**
Millions of U.S. dollars	**—**	**—**	**—**	**3,900**	**1,400**
Maturity dates	**2019-2024**	**2019-2027**	**2019-2020**	**2019-2020**	**2019-2030**

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

at December 31, 2018 (unaudited)	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.

Unrealized and realized (losses)/gains on derivative instruments

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

	three months ended March 31	
(unaudited - millions of Canadian $)	2019	2018
Derivative Instruments Held for Trading[1]		
Amount of unrealized (losses)/gains in the period		
Commodities[2]	**(88)**	(109)
Foreign exchange	**120**	(79)
Amount of realized gains/(losses) in the period		
Commodities	**107**	110
Foreign exchange	**(29)**	15
Derivative Instruments in Hedging Relationships		
Amount of realized (losses)/gains in the period		
Commodities	**(7)**	3
Interest rate	**—**	1

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 the three months ended March 31, 2019 and 2018, there were no gains or losses included in Net income relating to discontinued cash flow hedges where it was probable that the anticipated transaction would not occur.

Derivatives in cash flow hedging relationships

The components of OCI (Note 9) related to the change in fair value of derivatives in cash flow hedging relationships before tax and including the portion attributable to non-controlling interests are as follows:

	three months ended March 31	
(unaudited - millions of Canadian $)	**2019**	**2018**
Change in fair value of derivative instruments recognized in OCI (effective portion)[1]		
Commodities	**(3)**	(3)
Interest rate	**(19)**	9
	(22)	6

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 Condensed consolidated statement of income in which the effects of fair value or cash flow hedging relationships are recorded.

	three months ended March 31			
	Revenues (Power and Storage)		Interest Expense	
(unaudited - millions of Canadian $)	**2019**	**2018**	**2019**	**2018**
Total Amount Presented in the Condensed Consolidated Statement of Income	**336**	675	**(586)**	(527)
Fair Value Hedges				
Interest rate contracts				
Hedged items	**—**	—	**(6)**	(20)
Derivatives designated as hedging instruments	**—**	—	**(1)**	—
Cash Flow Hedges				
Reclassification of gains/(losses) on derivative instruments from AOCI to net income[1,2]				
Interest rate contracts	**—**	—	**4**	5
Commodity contracts	**—**	(1)	**—**	—

1 Refer to Note 9, Other comprehensive (loss)/income 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 Condensed consolidated balance sheet. The following table shows the impact on the presentation of the fair value of derivative instrument assets and liabilities had the Company elected to present these contracts on a net basis:

at March 31, 2019 (unaudited - millions of Canadian $)	**Gross derivative instruments**	**Amounts available for offset**[1]	**Net amounts**
Derivative instrument assets			
Commodities	**322**	**(267)**	**55**
Foreign exchange	**18**	**(18)**	**—**
Interest rate	**8**	**(3)**	**5**
	348	**(288)**	**60**
Derivative instrument liabilities			
Commodities	**(301)**	**267**	**(34)**
Foreign exchange	**(111)**	**18**	**(93)**
Interest rate	**(26)**	**3**	**(23)**
	(438)	**288**	**(150)**

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

at December 31, 2018 (unaudited - millions of Canadian $)	**Gross derivative instruments**	**Amounts available for offset**[1]	**Net amounts**
Derivative instrument assets			
Commodities	768	(626)	142
Foreign exchange	18	(18)	—
Interest rate	12	(4)	8
	798	(648)	150
Derivative instrument liabilities			
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.

With respect to the derivative instruments presented above, the Company provided cash collateral of $118 million and letters of credit of $37 million as at March 31, 2019 (December 31, 2018 – $143 million and $22 million) to its counterparties. At March 31, 2019, the Company held no cash collateral and $1 million in letters of credit (December 31, 2018 – nil and $1 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 March 31, 2019, the aggregate fair value of all derivative instruments with credit-risk-related contingent features that were in a net liability position was $4 million (December 31, 2018 – $6 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 March 31, 2019, the Company would have been required to provide collateral of $4 million (December 31, 2018 – $6 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 credit facilities 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	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. Inputs include published exchange rates, interest rates, interest rate swap curves, yield curves and broker quotes from external data service providers.
Level III	This category mainly includes long-dated commodity transactions in certain markets where liquidity is low and the Company uses the most observable inputs available or, if not available, long-term broker quotes to estimate the fair value for these transactions. There is uncertainty caused by using unobservable market data which may not accurately reflect possible future changes in fair value.

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

at March 31, 2019 (unaudited - millions of Canadian $)	**Quoted prices in active markets (Level I)**	**Significant other observable inputs (Level II)**[1]	**Significant unobservable inputs (Level III)**[1]	**Total**
Derivative instrument assets				
Commodities	**235**	**86**	**1**	**322**
Foreign exchange	**—**	**18**	**—**	**18**
Interest rate	**—**	**8**	**—**	**8**
Derivative instrument liabilities				
Commodities	**(229)**	**(67)**	**(5)**	**(301)**
Foreign exchange	**—**	**(111)**	**—**	**(111)**
Interest rate	**—**	**(26)**	**—**	**(26)**
	6	**(92)**	**(4)**	**(90)**

1 There were no transfers from Level II to Level III for the three months ended March 31, 2019.

at December 31, 2018 (unaudited - millions of Canadian $)	**Quoted prices in active markets (Level I)**	**Significant other observable inputs (Level II)**[1]	**Significant unobservable inputs (Level III)**[1]	**Total**
Derivative instrument assets				
Commodities	581	187	—	768
Foreign exchange	—	18	—	18
Interest rate	—	12	—	12
Derivative instrument liabilities				
Commodities	(555)	(95)	(4)	(654)
Foreign exchange	—	(295)	—	(295)
Interest rate	—	(15)	—	(15)
	26	(188)	(4)	(166)

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

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

	three months ended March 31	
(unaudited - millions of Canadian $)	**2019**	**2018**
Balance at beginning of period	**(4)**	(7)
Total losses included in Net income	**—**	(2)
Settlements	**—**	(9)
Balance at end of period[1]	**(4)**	(18)

1 For the three months ended March 31, 2019, Revenues included unrealized gains of less than $1 million attributed to derivatives in the Level III category that were still held at March 31, 2019 (2018 – unrealized losses of $11 million).

12. Contingencies and guarantees

CONTINGENCIES

TransCanada and its subsidiaries are subject to various legal proceedings, arbitrations and actions arising in the normal course of business. While the final outcome of such legal proceedings and actions cannot be predicted with certainty, it is the opinion of management that the resolution of such proceedings and actions 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 included in Other long-term liabilities on the Condensed consolidated balance sheet. Information regarding the Company's guarantees is as follows:

		at March 31, 2019		at December 31, 2018	
(unaudited - millions of Canadian $)	Term	Potential exposure[1]	Carrying value	Potential exposure[1]	Carrying value
Sur de Texas	ranging to 2020	**174**	**1**	183	1
Bruce Power	ranging to 2021	**88**	**—**	88	—
Other jointly-owned entities	ranging to 2059	**102**	**11**	104	11
		364	**12**	375	12

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

13. 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 considered non-consolidated VIEs and 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 the settlement of the VIE’s obligations are as follows:

(unaudited - millions of Canadian $)	March 31, 2019	December 31, 2018
ASSETS		
Current Assets		
Cash and cash equivalents	**69**	45
Accounts receivable	**69**	79
Inventories	**26**	24
Other	**9**	13
	173	161
Plant, Property and Equipment	**2,949**	3,026
Equity Investments	**847**	965
Goodwill	**444**	453
Intangible and Other Assets	**3**	8
	4,416	4,613
LIABILITIES		
Current Liabilities		
Accounts payable and other	**79**	88
Accrued interest	**31**	24
Current portion of long-term debt	**76**	79
	186	191
Regulatory Liabilities	**42**	43
Other Long-Term Liabilities	**4**	3
Deferred Income Tax Liabilities	**12**	13
Long-Term Debt	**3,003**	3,125
	3,247	3,375

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:

(unaudited - millions of Canadian $)	March 31, 2019	December 31, 2018
Balance sheet		
Equity investments	**4,487**	4,575
Off-balance sheet		
Potential exposure to guarantees	**168**	170
Maximum exposure to loss	**4,655**	4,745

14. Subsequent Event

Long-term debt issuance

On April 10, 2019, TCPL issued $1.0 billion of Medium Term Notes, due in October 2049, bearing interest at a fixed rate of 4.34 per cent.