QuarterlyReport to Shareholders

TransCanada
In business to deliver

TransCanada Reports Strong First Quarter 2018 Financial Results
Diversified Portfolio of High Quality Assets Continues to Drive Record Performance

CALGARY, Alberta – **April 27, 2018** – TransCanada Corporation (TSX, NYSE: TRP) (TransCanada or the Company) today announced net income attributable to common shares for first quarter 2018 of $734 million or $0.83 per share compared to net income of $643 million or $0.74 per share for the same period in 2017. Comparable earnings for first quarter 2018 were $870 million or $0.98 per share compared to $698 million or $0.81 per share for the same period in 2017. TransCanada's Board of Directors also declared a quarterly dividend of $0.69 per common share for the quarter ending June 30, 2018, equivalent to $2.76 per common share on an annualized basis.

"During the first quarter of 2018 our diversified portfolio of high-quality energy infrastructure assets continued to perform very well," said Russ Girling, TransCanada's president and chief executive officer. "Comparable earnings per share increased 21 per cent compared to the same period last year despite the sale of our U.S. Northeast power assets, reflecting the strong performance of our legacy assets and contributions from approximately $7 billion of growth projects that were placed into service over the last twelve months. These included expansions of our NGTL and Canadian Mainline systems in our Canadian natural gas pipelines business, the Gibraltar, Rayne XPress, Leach XPress and Cameron Access projects in our U.S. natural gas pipelines business and the Grand Rapids and Northern Courier liquids pipelines in Alberta."

"Looking forward, we continue to advance our $21 billion near-term capital program with approximately $11 billion of projects expected to enter service by the end of 2018. This program is expected to generate significant additional growth in earnings and cash flow and support annual dividend growth at the upper end of an eight to ten per cent range through 2020 and an additional eight to ten per cent in 2021," added Girling. "We have invested approximately $7 billion into these projects to date and, despite recent significant changes to the MLP sector, are well positioned to fund the remainder through our strong and growing internally generated cash flow, along with a broad spectrum of financing levers including access to capital markets on compelling terms and potential portfolio management activities."

"In addition, we continue to advance more than $20 billion of medium to longer-term projects including Keystone XL, Coastal GasLink and the Bruce Power life extension program. At the same time, we expect to secure additional organic growth opportunities associated with our extensive and well-positioned North American footprint. Success in advancing these and other projects into construction and operation could extend our dividend growth outlook beyond 2021," concluded Girling.

Highlights

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

- First quarter 2018 financial results
  - Net income attributable to common shares of $734 million or $0.83 per share
  - Comparable earnings of $870 million or $0.98 per share
  - Comparable earnings before interest, taxes, depreciation and amortization of $2.1 billion
  - Net cash provided by operations of $1.4 billion
  - Comparable funds generated from operations of $1.6 billion
  - Comparable distributable cash flow of $1.4 billion or $1.64 per share reflecting only non-recoverable maintenance capital expenditures

- Declared a quarterly dividend of $0.69 per common share for the quarter ending June 30, 2018
- Placed approximately $160 million of NGTL facilities in service to complete the 2017 Expansion Program as well as the approximate $100 million Sundre Crossover project
- Successfully completed open seasons for NGTL securing contracts for 620 MMcf/d of incremental firm receipt service and 1.5 Bcf/d of existing and expansion export delivery capacity. These facilities are expected to result in an expansion program of approximately $2.5 billion
- Filed an NGTL application with the NEB for approval of a negotiated settlement with customers for 2018 and 2019
- Placed the US$1.6 billion Leach XPress and US$0.3 billion Cameron Access projects in service
- Received FERC approval for Great Lakes and Northern Border rate settlements
- FERC proposed changes related to a number of income tax matters with respect to pipeline ratemaking.

Net income attributable to common shares increased by $91 million to $734 million or $0.83 per share for the three months ended March 31, 2018 compared to the same period last year. Net income per common share in first quarter 2018 includes the effect of common shares issued in 2017 and 2018 under our DRP and corporate ATM program. First quarter 2017 results included a $24 million after-tax charge for integration-related costs associated with the acquisition of Columbia, a $10 million after-tax charge for costs related to the monetization of our U.S. Northeast power generation business, a $7 million after-tax charge related to the maintenance of Keystone XL assets and a $7 million income tax recovery related to the realized loss on a third party sale of Keystone XL project assets. All of these specific items, as well as unrealized gains and losses from changes in risk management activities, are excluded from comparable earnings.

Comparable earnings for first quarter 2018 were $870 million or $0.98 per share compared to $698 million or $0.81 per share for the same period in 2017, an increase of $172 million or $0.17 per share. Comparable earnings per share for the three months ended March 31, 2018 include the effect of common shares issued in 2017 and 2018 under our DRP and corporate ATM program. The increase in first quarter 2018 comparable earnings over the same period in 2017 was primarily due to the net effect of:

- a higher contribution from Liquids Pipelines primarily due to earnings from intra-Alberta pipelines placed in service in the second half of 2017, higher volumes on the Keystone Pipeline System and increased earnings from liquids marketing activities
- a higher contribution from U.S. Natural Gas Pipelines mainly due to increased earnings from Columbia Gas and Columbia Gulf growth projects placed in service, additional contract sales on ANR and Great Lakes and amortization of net regulatory liabilities recognized as a result of U.S. Tax Reform
- lower income tax expense primarily due to lower rates as a result of U.S. Tax Reform and lower flow-through income taxes in Canadian rate-regulated pipelines
- a higher contribution from Mexico Natural Gas Pipelines mainly due to higher revenues
- higher interest income and other due to realized gains in 2018 compared to realized losses in 2017 on derivatives used to manage our net exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income
- lower earnings from U.S. Power mainly due to the monetization of U.S. Northeast power generation assets in second quarter 2017 and the continued wind down of our U.S. power marketing operations
- lower earnings from Bruce Power primarily due to lower volumes resulting from increased outage days
- higher interest expense as a result of long-term debt and junior subordinated notes issuances, net of maturities, partially offset by the repayment of the Columbia acquisition bridge facilities in June 2017.

Notable recent developments include:

Canadian Natural Gas Pipelines:

- ***NGTL System***: On April 9, 2018, we announced that the Sundre Crossover project was placed in service. The approximate $100 million pipeline project increases NGTL capacity at our Alberta / B.C. Export Delivery Point by 245 TJ/d (228 MMcf/d), enhancing connectivity to key downstream markets in the Pacific Northwest and California.

  The NGTL 2017 Expansion Program has also been completed with approximately $160 million of facilities placed in service since December 31, 2017, including the Northwest Mainline Loop-Boundary Lake pipeline on April 2, 2018. The 2017 Expansion Program added approximately 230 km (143 miles) of new pipeline along with additional compression facilities and increased the NGTL System capacity by approximately 535 TJ/d (500 MMcf/d).

  On February 15, 2018, we announced the successful completion of an open season for 260 TJ/d (242 MMcf/d) of existing and 1.1 PJ/d (1.0 Bcf/d) of expansion export capacity at the Empress / McNeill Export Delivery Point, with the expansion service expected to commence in November 2020 and April 2021. The average awarded contract term for the expansion capacity was approximately 29 years. We also announced that we had separately secured contracts for 664 TJ/d (620 MMcf/d) of incremental firm receipt service beginning in April 2021. Together, the incremental receipt and export delivery contracts will drive a $2.4 billion expansion program, bringing NGTL's capital program to a total of $7.2 billion.

  On March 20, 2018, we announced the successful completion of an open season for additional expansion capacity at the Empress / McNeill Export Delivery Point for service expected to commence in November 2021. The offering of 300 TJ/d (280 MMcf/d) was oversubscribed with an average awarded contract term of approximately 22 years. The facilities and capital requirements for the expansion are still being finalized and are currently anticipated to increase NGTL's capital program by a further approximate $120 million.

  On March 23, 2018, we filed an application with the National Energy Board (NEB) for approval of a negotiated settlement with our customers and other interested parties on the annual costs required to operate the NGTL System for 2018 and 2019, along with final 2018 tolls and revised interim 2018 tolls. The settlement fixes return on equity (ROE) at 10.1 per cent on 40 per cent deemed equity. The NEB is reviewing comments from interested parties and we anticipate a decision on the application in second quarter 2018.

U.S. Natural Gas Pipelines:

- ***Leach XPress:*** Leach XPress was placed in service on January 1, 2018. This Columbia Gas project transports approximately 1.6 PJ/d (1.5 Bcf/d) of Marcellus and Utica gas supply to delivery points along the system.
- ***Cameron Access:*** Cameron Access was placed in service on March 13, 2018. This Columbia Gulf project is designed to transport approximately 0.9 PJ/d (0.8 Bcf/d) of gas supply to the Cameron LNG export terminal in Louisiana.
- ***Mountaineer XPress and WB XPress:*** In first quarter 2018, estimated project costs of US$3.0 billion for Mountaineer XPress and US$0.9 billion for WB XPress increased by US$0.4 billion and US$0.1 billion, respectively. These increases primarily reflect the impact of delays of various regulatory approvals from the Federal Energy Regulatory Commission (FERC) and other agencies, increased contractor construction costs due to unusually high demand for construction resources in the region, and modifications to contractor work plans and resources to maintain our projected in-service dates.
- ***Great Lakes and Northern Border Rate Settlements:*** In February 2018, FERC approved the 2017 Great Lakes Rate Settlement and the 2017 Northern Border Rate Settlement, both of which were uncontested.

Mexico Natural Gas Pipelines:

- *Tula and Villa de Reyes:* We continue to work toward finalizing amending agreements for both of these pipelines with the Comisión Federal de Electricidad (CFE) to formalize the schedule and payments resulting from their respective force majeure events. The CFE has commenced payments on both pipelines in accordance with the TSAs.
- *Sur de Texas:* Offshore construction is now approximately 80 per cent complete and the project continues to progress toward an anticipated in-service date of late 2018.

Liquids Pipelines:

- *Keystone XL:* In December 2017, an appeal to Nebraska's Court of Appeals was filed by intervenors after the Nebraska Public Service Commission (PSC) issued an approval of an alternative route for the Keystone XL project in November 2017. On March 14, 2018, the Nebraska Supreme Court, on its own motion, agreed to bypass the Court of Appeals and hear the appeal case against the PSC's alternative route itself. We expect the Nebraska Supreme Court, as the final arbiter, could reach a decision by late 2018 or first quarter 2019.

  The Keystone XL Presidential Permit, issued in March 2017, has been challenged in two separate lawsuits commenced in Montana. Together with the U.S. Department of Justice, we are actively participating in these lawsuits to defend both the issuance of the permit and the exhaustive environmental assessments that support the U.S. President's actions. Legal arguments addressing the merits of these lawsuits are scheduled to be heard in late May 2018 and we believe the court's decisions may be issued by year-end 2018.

  The South Dakota Public Utilities Commission permit for the Keystone XL project was issued in June 2010 and recertified in January 2016. An appeal of that recertification was denied in June 2017 and that decision has been further appealed to the South Dakota Supreme Court. On April 6, 2018, the Supreme Court directed the parties to address whether the Court lacks jurisdiction under the governing statute to consider the appeal. Legal arguments are scheduled for April 2018. A decision from the Supreme Court is expected in second or third quarter 2018.
- *White Spruce:* In February 2018, the Alberta Energy Regulator issued a permit for the construction of the White Spruce pipeline. Construction has commenced with an anticipated in-service date in second quarter 2019.

Energy:

- *Monetization of U.S. Northeast power business:* On March 1, 2018, as part of the continued wind down of our U.S. power marketing operations, we closed the sale of our U.S. power retail contracts for proceeds of approximately US$23 million and recognized income of US$10 million (US$7 million after tax).

Corporate:

- *Common Share Dividend:* Our Board of Directors declared a quarterly dividend of $0.69 per share for the quarter ending June 30, 2018 on TransCanada's outstanding common shares. The quarterly amount is equivalent to $2.76 per common share on an annualized basis.
- *Dividend Reinvestment Plan (DRP):* In first quarter 2018, the participation rate in our DRP was approximately 38 per cent of common share dividends, resulting in $234 million reinvested in common equity under the program.
- *ATM Equity Issuance Program:* In first quarter 2018, 5.8 million common shares were issued through the corporate ATM program at an average price of $56.51 per common share for gross proceeds of $329 million. An additional 1.6 million common shares were issued in April 2018, bringing year-to-date gross proceeds to $415 million at an average price of $55.64 per common share.

- ***U.S. Tax Reform and 2018 FERC Actions:*** In December 2016, FERC issued a Notice of Inquiry (NOI) seeking comment on how to address the issue of whether its existing policies resulted in a 'double recovery' of income taxes in a pass-through entity such as a master limited partnership (MLP). The NOI was in response to a decision by the U.S. Court of Appeals for the District of Columbia Circuit in July 2016, in ***United Airlines, Inc., et al. v. FERC***, directing FERC to address the issue.

  On December 22, 2017, H.R. 1, the Tax Cuts and Jobs Act (U.S. Tax Reform), was signed resulting in significant changes to U.S. tax law including a decrease in the U.S. federal corporate income tax rate from 35 per cent to 21 per cent effective January 1, 2018. As a result of this change, deferred income tax assets and deferred income tax liabilities related to our U.S. businesses, including amounts related to our proportionate share of assets held in TC PipeLines, LP, were remeasured, as at December 31, 2017, to reflect the new lower income tax rate.

  On March 15, 2018, FERC issued (1) a revised Policy Statement to address the treatment of income taxes for ratemaking purposes for MLPs; (2) a Notice of Proposed Rulemaking proposing interstate pipelines file a one-time report to quantify the impact of the federal income tax rate reduction and the impact of the revised Policy Statement on each pipeline's ROE assuming a single-issue adjustment to a pipeline's rates; and (3) a NOI seeking comment on how FERC should address changes related to accumulated deferred income taxes and bonus depreciation (collectively, the 2018 FERC Actions).

  For more information on these developments and their implications for TransCanada and TC PipeLines, LP, please refer to our management's discussion and analysis.

Teleconference and Webcast:

We will hold a teleconference and webcast on Friday, April 27, 2018 to discuss our first quarter 2018 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 TransCanada 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/9259.

A replay of the teleconference will be available two hours after the conclusion of the call until midnight (ET) on May 4, 2018. Please call 800.408.3053 or 905.694.9451 (Toronto area) and enter pass code 3158821#.

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 the TransCanada 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. TransCanada operates one of the largest natural gas transmission networks that extends more than 91,900 kilometres (57,100 miles), tapping into virtually all major gas supply basins in 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, TransCanada owns or has interests in approximately 6,100 megawatts of power generation in Canada and the United States. TransCanada is 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 and 3BL 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 April 26, 2018 and the 2017 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 share, comparable EBITDA, comparable distributable cash flow, comparable distributable cash flow per 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. For more information on non-GAAP measures, refer to TransCanada's Quarterly Report to Shareholders dated April 26, 2018.

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Quarterly report to shareholders

First quarter 2018

Financial highlights

(unaudited - millions of $, except per share amounts)	three months ended March 31 2018	2017
Income		
Revenues	**3,424**	3,407
Net income attributable to common shares	**734**	643
per common share – basic and diluted	**$0.83**	$0.74
Comparable EBITDA[1]	**2,071**	1,977
Comparable earnings[1]	**870**	698
per common share[1]	**$0.98**	$0.81
Cash flows		
Net cash provided by operations	**1,412**	1,302
Comparable funds generated from operations[1]	**1,619**	1,508
Comparable distributable cash flow[1]		
– reflecting all maintenance capital expenditures	**1,223**	1,203
– reflecting only non-recoverable maintenance capital expenditures	**1,447**	1,340
Comparable distributable cash flow per common share[1]		
– reflecting all maintenance capital expenditures	**$1.38**	$1.39
– reflecting only non-recoverable maintenance capital expenditures	**$1.64**	$1.55
Capital spending[2]	**2,096**	1,794
Dividends declared		
Per common share	**$0.69**	$0.625
Basic common shares outstanding (millions)		
– weighted average for the period	**885**	866
– issued and outstanding at end of period	**891**	867

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. See 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

April 26, 2018

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, 2018, and should be read with the accompanying unaudited condensed consolidated financial statements for the three months ended March 31, 2018, which have been prepared in accordance with U.S. GAAP.

This MD&A should also be read in conjunction with our December 31, 2017 audited consolidated financial statements and notes and the MD&A in our 2017 Annual Report. Capitalized and abbreviated terms that are used but not otherwise defined herein are identified in our 2017 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. These statements 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:

- planned changes in our business
- our financial and operational performance, including the performance of our subsidiaries
- expectations or projections about strategies and goals for growth and expansion
- expected cash flows and future financing options available to us
- expected dividend growth
- expected costs for planned projects, including projects under construction, permitting and in development
- expected schedules for planned projects (including anticipated construction and completion dates)
- expected regulatory processes and outcomes, including the expected impact of recent FERC policy changes
- expected outcomes with respect to legal proceedings, including arbitration and insurance claims
- expected capital expenditures and contractual obligations
- expected operating and financial results
- expected impact of future accounting changes, commitments and contingent liabilities
- expected impact of U.S. Tax Reform
- 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 is subject to the following risks and uncertainties:

Assumptions

- continued wind down of our U.S. Northeast power marketing business
- inflation rates and commodity prices
- nature and scope of hedging activities
- regulatory decisions and outcomes, including those related to recent FERC policy changes
- interest, tax and foreign exchange rates, including the impact of U.S. Tax Reform
- planned and unplanned outages and the use of our pipeline and energy assets
- integrity and reliability of our assets
- access to capital markets
- anticipated construction costs, schedules and completion dates.

Risks and uncertainties

- our ability to successfully implement our strategic priorities and whether they will yield the expected benefits
- the operating performance of our pipeline and energy assets
- amount of capacity sold and rates achieved in our pipeline businesses
- the availability and price of energy commodities
- the amount of capacity payments and revenues from our energy business
- regulatory decisions and outcomes, including those related to recent FERC policy changes
- outcomes of legal proceedings, including arbitration and insurance claims
- performance and credit risk of our counterparties
- changes in market commodity prices
- changes in the regulatory environment
- changes in the political environment
- changes in environmental and other laws and regulations
- competitive factors in the pipeline and energy sectors
- construction and completion of capital projects
- costs for labour, equipment and materials
- access to capital markets, including the economic benefit of asset drop downs to TC PipeLines, LP
- interest, tax and foreign exchange rates, including the impact of U.S. Tax Reform
- weather
- cyber security
- technological developments
- economic conditions in North America as well as globally.

You can read more about these factors and others in this MD&A and in other disclosure documents we have filed with Canadian securities regulators and the SEC, including the MD&A in our 2017 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 earnings
- comparable earnings per common share
- comparable EBITDA
- comparable EBIT
- 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 similar to measures presented by other entities.

Comparable measures

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. 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 and changes 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 property, plant and equipment, goodwill, investments and other assets including certain ongoing maintenance and liquidation costs
- 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 equivalent GAAP measures.

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

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 and non-controlling interests, adjusted for specific items. See the Consolidated results section for reconciliations to net income attributable to common shares and net income per common share.

Comparable EBIT and comparable EBITDA

Comparable EBIT represents segmented earnings, adjusted for specific items. We use comparable EBIT as a measure of our earnings from ongoing operations as it is a useful measure of our performance and an effective tool for evaluating trends in each segment. Comparable EBITDA is calculated the same way as comparable EBIT but excludes the non-cash charges for depreciation and amortization. See the Reconciliation of non-GAAP measures section for a reconciliation to segmented earnings.

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. See 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 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.

Although we deduct maintenance capital expenditures in determining comparable distributable cash flow, we have the ability to recover the majority of these costs in Canadian Natural Gas Pipelines, U.S. Natural Gas Pipelines and Liquids Pipelines. As such, our presentation of comparable distributable cash flow and comparable distributable cash flow per common share also illustrates the impact of excluding recoverable maintenance capital expenditures from their respective calculations.

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

Consolidated results - first quarter 2018

(unaudited - millions of $, except per share amounts)	three months ended March 31 2018	2017
Canadian Natural Gas Pipelines	**253**	282
U.S. Natural Gas Pipelines	**648**	561
Mexico Natural Gas Pipelines	**137**	118
Liquids Pipelines	**341**	227
Energy	**50**	198
Corporate	**(81)**	(33)
Total segmented earnings	**1,348**	1,353
Interest expense	**(527)**	(500)
Allowance for funds used during construction	**105**	101
Interest income and other	**63**	20
Income before income taxes	**989**	974
Income tax expense	**(121)**	(200)
Net income	**868**	774
Net income attributable to non-controlling interests	**(94)**	(90)
Net income attributable to controlling interests	**774**	684
Preferred share dividends	**(40)**	(41)
Net income attributable to common shares	**734**	643
Net income per common share - basic and diluted	**$0.83**	$0.74

Net income attributable to common shares increased by $91 million or $0.09 per common share for the three months ended March 31, 2018 compared to the same period in 2017. Net income per common share in 2018 reflects the effect of common shares issued in 2017 and 2018 under our DRP and corporate ATM program.

Net income in both periods 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.

2017 results included:

- a $24 million after-tax charge for integration-related costs associated with the acquisition of Columbia
- a $10 million after-tax charge for costs related to the monetization of our U.S. Northeast power generation business
- a $7 million after-tax charge related to the maintenance of Keystone XL assets which was expensed in 2017 pending further advancement of the project. In 2018, Keystone XL expenditures are being capitalized
- a $7 million income tax recovery related to the realized loss on a third-party sale of Keystone XL project assets.

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	
(unaudited - millions of $, except per share amounts)	2018	2017
Net income attributable to common shares	**734**	643
Specific items (net of tax):		
Risk management activities[1]	**136**	21
Integration and acquisition related costs – Columbia	—	24
Loss on sales of U.S. Northeast power generation assets	—	10
Keystone XL asset costs	—	7
Keystone XL income tax recoveries	—	(7)
Comparable earnings	**870**	698
Net income per common share	**$0.83**	$0.74
Specific items (net of tax):		
Risk management activities	**0.15**	0.03
Integration and acquisition related costs – Columbia	—	0.03
Loss on sales of U.S. Northeast power generation assets	—	0.01
Keystone XL asset costs	—	0.01
Keystone XL income tax recoveries	—	(0.01)
Comparable earnings per common share	**$0.98**	$0.81

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Risk management activities	three months ended March 31	
(unaudited - millions of $)	2018	2017
Liquids marketing	**(7)**	—
Canadian Power	**2**	1
U.S. Power	**(101)**	(62)
Natural Gas Storage	**(3)**	5
Foreign exchange	**(79)**	15
Income tax attributable to risk management activities	**52**	20
Total unrealized losses from risk management activities	**(136)**	(21)

Comparable earnings increased by $172 million or $0.17 per common share for the three months ended March 31, 2018 compared to the same period in 2017 and was primarily the net effect of:

- higher contribution from Liquids Pipelines primarily due to earnings from intra-Alberta pipelines placed in service in the second half of 2017, higher volumes on the Keystone Pipeline System and increased earnings from liquids marketing activities
- higher contribution from U.S. Natural Gas Pipelines mainly due to increased earnings from Columbia Gas and Columbia Gulf growth projects placed in service, additional contract sales on ANR and Great Lakes and amortization of net regulatory liabilities recognized as a result of U.S. Tax Reform
- lower income tax expense primarily due to lower income tax rates as a result of U.S. Tax Reform and lower flow-through income taxes in Canadian rate-regulated pipelines
- higher contribution from Mexico Natural Gas Pipelines mainly due to higher revenues
- higher interest income and other due to realized gains in 2018 compared to realized losses in 2017 on derivatives used to manage our net exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income

- lower earnings from U.S. Power mainly due to the monetization of U.S. Northeast power generation assets in second quarter 2017 and the continued wind down of our U.S. power marketing operations
- lower earnings from Bruce Power primarily due to lower volumes resulting from increased outage days
- higher interest expense as a result of long-term debt and junior subordinated notes issuances, net of maturities, partially offset by the repayment of the Columbia acquisition bridge facilities in June 2017.

Comparable earnings per common share for the three months ended March 31, 2018 also reflect the effect of common shares issued in 2017 and 2018 under our DRP and corporate ATM program.

2018 FERC Actions

BACKGROUND

In December 2016, FERC issued a Notice of Inquiry (NOI) seeking comment on how to address the issue of whether its existing policies resulted in a 'double recovery' of income taxes in a pass-through entity such as a master limited partnership (MLP). The NOI was in response to a decision by the U.S. Court of Appeals for the District of Columbia Circuit in July 2016, in ***United Airlines, Inc., et al. v. FERC*** (the United case), directing FERC to address the issue.

On December 22, 2017, H.R. 1, the Tax Cuts and Jobs Act (U.S. Tax Reform), was signed resulting in significant changes to U.S. tax law including a decrease in the U.S. federal corporate income tax rate from 35 per cent to 21 per cent effective January 1, 2018. As a result of this change, deferred income tax assets and deferred income tax liabilities related to our U.S. businesses, including amounts related to our proportionate share of assets held in TC PipeLines, LP, were remeasured as at December 31, 2017 to reflect the new lower U.S. federal corporate income tax rate.

On March 15, 2018, FERC issued (1) a revised Policy Statement to address the treatment of income taxes for ratemaking purposes for MLPs; (2) a Notice of Proposed Rulemaking (NOPR) proposing interstate pipelines file a one-time report to quantify the impact of the federal income tax rate reduction and the impact of the revised Policy Statement on each pipeline's return on equity (ROE) assuming a single-issue adjustment to a pipeline's rates; and (3) a NOI seeking comment on how FERC should address changes related to accumulated deferred income taxes and bonus depreciation (collectively, the 2018 FERC Actions). Each is described below.

FERC Revised Policy Statement on Treatment of Income Taxes in MLPs

FERC changed its long-standing policy on the treatment of income tax amounts to be included in pipeline rates subject to cost of service rate regulation within a MLP. The Policy Statement no longer permits entities organized as MLPs to recover an income tax allowance in their cost of service rates.

On April 16, 2018, we filed a Request for Clarification and If Necessary Rehearing of the FERC Policy Statement addressing concerns over the lack of clarity around entities with non-MLP ownership structures, entities with shared ownership between a MLP and a corporation, as well as entities owned by MLPs that are, in turn, owned partially by corporations. We sought clarification or a rehearing on the basis that FERC erred in not assessing the propriety of income tax allowances for pipelines on a case-by-case basis; overturned applicable legal precedent expressly not affected by the United case; failed to consider the effects of its order on industry; and failed to exhibit reasoned decision making or to support its decision with substantial evidence on the record.

NOPR on Tax Law Changes for Interstate Natural Gas Pipelines

The NOPR proposes a rule that would require interstate pipelines, in certain circumstances, to file a one-time report, called FERC Form No. 501-G, that quantifies the rate impact of U.S. Tax Reform on FERC-regulated pipelines and the revised Policy Statement on pipelines held by MLPs. In addition to filing the one-time report, each pipeline would have four options:

- make a limited Natural Gas Act Section 4 filing to reduce its rates by the percentage reduction in its cost of service shown in its FERC Form No. 501-G
- commit to file either a pre-packaged uncontested rate settlement or a general Section 4 rate case if it believes that using the limited Section 4 option will not result in just and reasonable rates. If the pipeline commits to file either by December 31, 2018, FERC will not initiate a Natural Gas Act Section 5 investigation of its rates prior to that date
- file a statement explaining its rationale for why it does not believe the pipeline's rates must change
- file the one-time report without taking any other action. At that point, FERC would consider whether to initiate a Section 5 investigation of any pipeline that has not submitted a limited Section 4 rate reduction filing or committed to file a general Section 4 rate case.

We submitted comments on the NOPR on April 25, 2018. Following the public comment period, we expect FERC to issue final order(s) in the late summer or early fall of 2018. We are evaluating this NOPR and our next courses of action, however, we do not expect an immediate or a retroactive impact from the NOPR or the revised Policy Statement described above.

NOI Regarding the Effect of U.S. Tax Reform on Commission-Jurisdictional Rates

In the NOI, FERC seeks comment on the effects of U.S. Tax Reform to determine additional action, if any, required by FERC related to accumulated deferred income taxes that were collected from shippers in anticipation of paying the Internal Revenue Service, but which no longer accurately reflect the future income tax liability. The NOI also seeks comment on the elimination of bonus depreciation for regulated natural gas pipelines and other effects of U.S. Tax Reform. We plan to submit comments in response to the NOI, which are due May 21, 2018.

IMPACT OF 2018 FERC ACTIONS ON TRANSCANADA

We own our U.S. natural gas pipelines through a number of different ownership structures. If the 2018 FERC Actions are enacted as proposed, we do not anticipate that the earnings and cash flows from our directly-held U.S. natural gas pipelines, including ANR, Columbia Gas and Columbia Gulf, will be materially impacted by the revised Policy Statement as they are held through wholly-owned taxable corporations and a significant proportion of their revenues are earned under non-recourse rates. Columbia Gas is required under existing settlements to adjust certain of its recourse rates for the decrease in the U.S. federal corporate income tax rate enacted December 22, 2017, with the changes implemented January 1, 2018. As ANR, Columbia Gas and Columbia Gulf and other wholly-owned regulated assets undergo future rate proceedings, some of which may be accelerated by the NOPR issued in March 2018, future rates may be impacted prospectively as a result of U.S. Tax Reform, but the impact is expected to be substantially mitigated by lower corporate income tax rates. Therefore, the impact on earnings and cash flows resulting from the 2018 FERC Actions on our wholly-owned U.S. natural gas pipelines is expected to be limited.

The revised Policy Statement also makes reference to prohibiting an income tax allowance for liquids pipelines held in MLP structures. We do not expect an impact on our liquids pipelines in the U.S. as they are not held in MLP form.

Financing

In the absence of changes to the 2018 FERC Actions or the identification and implementation of appropriate mitigation measures, further drop downs of assets into TC PipeLines, LP are not considered to be a viable funding lever. In addition, the TC PipeLines, LP ATM program is not currently being utilized. It is uncertain whether these will be restored as competitive financing options in the future. We believe we have the financial capacity to fund our existing capital program through predictable and growing cash flow generated from operations, access to capital markets, including through our Corporate ATM program and our DRP, portfolio management, cash on hand and substantial committed credit facilities.

Impact of 2018 FERC Actions on TC PipeLines, LP

U.S. natural gas pipelines owned wholly or in part through TC PipeLines, LP are expected to be adversely impacted by the 2018 FERC Actions, if they are enacted as proposed, particularly as contemplated by the policy change prohibiting the recovery of an income tax allowance for pipelines held through MLPs. While approximately half of TC PipeLines, LP's revenues, including those of equity investments, are earned under non-recourse rates, the remaining revenues under recourse rates are expected to decline as rate adjustments occur without a compensating offset on income taxes paid. Individual pipelines owned by TC PipeLines, LP do not currently have a requirement to file for new rates until 2022, however, that timing may be accelerated by the NOPR, except where moratoria exist. While a number of uncertainties exist with respect to the changes resulting from the 2018 FERC Actions, in the absence of mitigation, TC PipeLines, LP's earnings, cash flows and financial position could be materially adversely impacted. The impact in 2018 is expected to be limited, but as rate adjustments are enacted following proceedings with customers and the FERC, subsequent periods could be more significantly affected. As our ownership interest in TC PipeLines, LP is approximately 25 per cent, the impact of the 2018 FERC Actions related to TC PipeLines, LP is not expected to be significant to our consolidated earnings or cash flows.

We are closely monitoring these developments as they relate to TC PipeLines, LP in order to identify the strategy that best positions us for the long term. As noted above, we do not anticipate further asset drop downs into TC PipeLines, LP as they are not considered to be a viable funding alternative at this time.

Additional Considerations

In addition to the direct impacts of the 2018 FERC Actions, each individual pipeline will be separately evaluated, including all cost of service elements, to ensure rates are deemed to be just and reasonable. In situations where a pipeline is realizing a relatively higher or lower ROE than is viewed to be just and reasonable, there may be additional prospective adjustments to future rates. The impact to our earnings and cash flows as a result of these potential changes is not expected to be significant. As well, the impact of the 2018 FERC Actions on certain pipelines with shared ownership between corporations and MLPs, or under other ownership structures, remains unclear at this time, with FERC expected to address these in future proceedings. We are monitoring developments on this and will assess the impact as more information becomes available.

Impairment Considerations

We review plant, property and equipment and equity investments for impairment whenever events or changes in circumstances indicate the carrying value of the asset may not be recoverable.

Goodwill is tested for impairment on an annual basis or more frequently if events or changes in circumstance indicate that it might be impaired. We can initially make this assessment based on qualitative factors. If we conclude that it is not more likely than not that the fair value of the reporting unit is less than its carrying value, then an impairment test is not performed.

Until the proposed 2018 FERC Actions are finalized, implementation requirements are clarified, including the applicability to assets partially-owned by a MLP or held in non-MLP structures, and we and TC PipeLines, LP have fully evaluated our respective alternatives to minimize the impact of the 2018 FERC Actions, we believe that it is not more likely than not that the fair value of any of the reporting units is less than its respective carrying value. Therefore, a goodwill impairment test was not performed. Also, we have determined there is no indication that the carrying values of plant, property and equipment and equity investments potentially impacted by FERC's proposals are not recoverable. We will continue to monitor developments and assess our goodwill for impairment. We will also review our property, plant and equipment and equity investments for recoverability as new information becomes available.

At December 31, 2017, the estimated fair value of Great Lakes exceeded its carrying value by less than 10 per cent. There is a risk that the 2018 FERC Actions, once finalized, could result in a goodwill impairment charge. The goodwill balance for Great Lakes is US$573 million at March 31, 2018 (December 31, 2017 - US$573 million). There is also a risk that the goodwill balance of US$82 million at March 31, 2018 (December 31, 2017 - US$82 million) related to Tuscarora could be negatively impacted by the 2018 FERC Actions.

U.S. Tax Reform

Pursuant to the enactment of U.S. Tax Reform, we recorded net regulatory liabilities and a corresponding reduction in net deferred income tax liabilities in the amount of $1,686 million at December 31, 2017 related to our U.S. natural gas pipelines subject to rate-regulated accounting (RRA). Such amounts remain provisional as our interpretation, assessment and presentation of the impact of U.S. Tax Reform may be further clarified with additional guidance from regulatory, tax and accounting authorities. Should additional guidance be provided by these authorities or other sources during the one-year measurement period permitted by the SEC, we will review the provisional amounts and adjust as appropriate. Other than the amortizations discussed below, no adjustments were made to these amounts during first quarter 2018. There may be prospective adjustments to regulatory liabilities related to natural gas pipelines subject to RRA once the 2018 FERC Actions are finalized and take effect.

Commencing January 1, 2018, the regulatory liabilities are being amortized using the Reverse South Georgia methodology. Under this methodology, rate-regulated entities determine amortization based on their composite depreciation rate and immediately begin recording amortization. Amortization of the net regulatory liability in the amount of $9 million was recorded in first quarter 2018 and included in Revenues.

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 flow.

Our capital program consists of approximately $21 billion of near-term projects and approximately $24 billion of commercially-supported medium to longer-term projects. Amounts presented exclude maintenance capital expenditures, capitalized interest and AFUDC.

All projects are subject to cost adjustments due to market conditions, route refinement, permitting conditions, scheduling and timing of regulatory permits.

Near-term projects

(unaudited - billions of $)	Expected in-service date	Estimated project cost	Carrying value at March 31, 2018
Canadian Natural Gas Pipelines			
Canadian Mainline	2018-2021	0.2	—
NGTL System	2018	0.6	0.4
	2019	2.4	0.4
	2020	1.7	0.1
	2021+	2.5	—
U.S. Natural Gas Pipelines			
Columbia Gas			
Mountaineer XPress	2018	US 3.0	US 0.7
WB XPress	2018	US 0.9	US 0.5
Modernization II	2018-2020	US 1.1	US 0.2
Buckeye XPress	2020	US 0.2	—
Columbia Gulf			
Gulf XPress	2018	US 0.6	US 0.3
Other[1]	2018-2020	US 0.3	US 0.1
Mexico Natural Gas Pipelines			
Sur de Texas[2]	2018	US 1.3	US 1.1
Villa de Reyes	2018	US 0.8	US 0.5
Tula	2019	US 0.7	US 0.5
Liquids Pipelines			
White Spruce	2019	0.2	—
Energy			
Napanee	2018	1.3	1.1
Bruce Power – life extension[3]	up to 2020	0.9	0.3
		18.7	**6.2**
Foreign exchange impact on near-term projects[4]		**2.6**	**1.1**
Total near-term projects (Cdn$)		**21.3**	**7.3**

1 Reflects our proportionate share of costs related to Portland XPress and various expansion projects.
2 Reflects our proportionate share.
3 Reflects our proportionate share of the remaining capital costs that Bruce Power expects to incur on its life extension investment programs in advance of the Unit 6 major refurbishment outage which is expected to begin in 2020.
4 Reflects U.S./Canada foreign exchange rate of 1.29 at March 31, 2018.

Medium to longer-term projects

The medium to longer-term projects have greater uncertainty with respect to timing and estimated project costs. The expected in-service dates of these projects are post-2020, and costs provided in the schedule below reflect the most recent costs for each project as filed with the various regulatory authorities or otherwise determined. These projects are subject to approvals that include FID and/or complex regulatory processes, however, each project has commercial support except where noted.

(unaudited - billions of $)	Estimated project cost	Carrying value at March 31, 2018
Canadian Natural Gas Pipelines		
Canadian west coast LNG-related projects		
Coastal GasLink	4.8	0.4
NGTL System – Merrick	1.9	—
Liquids Pipelines		
Heartland and TC Terminals[1]	0.9	0.1
Grand Rapids Phase 2[2]	0.7	—
Keystone XL[3]	US 8.0	US 0.3
Keystone Hardisty Terminal[1,3]	0.3	0.1
Energy		
Bruce Power – life extension[2]	5.3	—
	21.9	0.9
Foreign exchange impact on medium to longer-term projects[4]	2.3	0.1
Total medium to longer-term projects (Cdn$)	**24.2**	**1.0**

1 Regulatory approvals have been obtained, additional commercial support is being pursued.
2 Reflects our proportionate share.
3 Carrying value reflects amount remaining after impairment charge recorded in 2015, along with additional amounts capitalized from January 1, 2018.
4 Reflects U.S./Canada foreign exchange rate of 1.29 at March 31, 2018.

Outlook

Consolidated comparable earnings

Our overall comparable earnings outlook for 2018 has increased compared to what was included in the 2017 Annual Report primarily as a result of higher volumes on the Keystone Pipeline System and higher contribution from liquids marketing activities in first quarter 2018. We do not anticipate the 2018 FERC Actions will have a material impact on our earnings or cash flows in 2018. See the 2018 FERC Actions section for further information.

Consolidated capital spending

We expect to spend approximately $10 billion in 2018 on growth projects, maintenance capital and contributions to equity investments for 2018. The increase in capital spending from the amount included in the 2017 Annual Report primarily reflects incremental spending required to complete construction of our near-term capital program in 2018, including Columbia Gas projects, as well as the capitalization of costs to further advance our medium to longer-term projects.

Canadian Natural Gas Pipelines

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

	three months ended March 31	
(unaudited - millions of $)	**2018**	**2017**
NGTL System	**271**	230
Canadian Mainline	**193**	247
Other[1]	**30**	27
Comparable EBITDA	**494**	504
Depreciation and amortization	**(241)**	(222)
Comparable EBIT and segmented earnings	**253**	282

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

Canadian Natural Gas Pipelines segmented earnings decreased by $29 million for the three months ended March 31, 2018 compared to the same period in 2017 and are equivalent to comparable EBIT.

Net income and comparable EBITDA for our rate-regulated Canadian Natural Gas Pipelines are generally affected by our approved ROE, our investment base, our level of deemed common equity and incentive earnings or losses. 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 revenues on a flow-through basis.

three months ended March 31	NGTL System		Canadian Mainline	
(unaudited - millions of $)	**2018**	**2017**	**2018**	**2017**
Net Income	**92**	82	**37**	52
Average investment base	**9,091**	7,853	**3,817**	4,103

Net income for the NGTL System increased by $10 million for the three months ended March 31, 2018 compared to the same period in 2017 mainly due to a higher average investment base reflecting continued expansion of the system. Pending a NEB decision on the 2018 and 2019 Revenue Requirement Settlement Application, NGTL System earnings reflect the last approved ROE of 10.1 per cent on 40 per cent deemed equity and no incentive earnings have been recorded in 2018.

Net income for the Canadian Mainline decreased by $15 million for the three months ended March 31, 2018 compared to the same period in 2017 primarily because no incentive earnings have been recorded in 2018 pending a NEB decision on the 2018 - 2020 Tolls Review. As directed by the NEB, the Canadian Mainline filed an application for approval of 2018 - 2020 tolls on December 18, 2017.

DEPRECIATION AND AMORTIZATION

Depreciation and amortization increased by $19 million for the three months ended March 31, 2018 compared to the same period in 2017 mainly due to facilities that were placed in service for the NGTL System.

U.S. Natural Gas Pipelines

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

(unaudited - millions of US$, unless noted otherwise)	three months ended March 31 2018	2017
Columbia Gas	**231**	185
ANR	**141**	122
TC PipeLines, LP[1,2,3]	**39**	32
Great Lakes[4]	**35**	27
Midstream	**30**	23
Columbia Gulf	**26**	18
Other U.S. pipelines[3,5]	**15**	28
Non-controlling interests[6]	**118**	108
Comparable EBITDA	**635**	543
Depreciation and amortization	**(122)**	(112)
Comparable EBIT	**513**	431
Foreign exchange impact	**135**	140
Comparable EBIT (Cdn$)	**648**	571
Specific items:		
Integration and acquisition related costs – Columbia	**—**	(10)
Segmented earnings (Cdn$)	**648**	561

1 Results reflect our earnings from TC PipeLines, LP's ownership interests in GTN, Great Lakes, Iroquois, Northern Border, Bison, PNGTS, North Baja and Tuscarora, as well as general and administrative costs related to TC PipeLines, LP.

2 TC PipeLines, LP periodically conducts ATM equity issuances which decrease our ownership in TC PipeLines, LP. For the three months ended March 31, 2018, our ownership interest in TC PipeLines, LP ranged between 25.7 per cent and 25.5 per cent compared to a range of 26.8 per cent and 26.4 per cent for the same period in 2017.

3 TC PipeLines, LP acquired 49.34 per cent of our 50 per cent interest in Iroquois and our remaining 11.81 per cent interest in PNGTS on June 1, 2017.

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

5 Results reflect earnings from our direct ownership interests in Iroquois, Crossroads and PNGTS (until June 1, 2017) and 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.

6 Results reflect earnings attributable to portions of TC PipeLines, LP, PNGTS (until June 1, 2017) and CPPL (until February 17, 2017) that we do not own.

U.S. Natural Gas Pipelines segmented earnings increased by $87 million for the three months ended March 31, 2018 compared to the same period in 2017.

Segmented earnings for the three months ended March 31, 2017 included a $10 million pre-tax charge for integration and acquisition related costs associated with the Columbia acquisition. This amount has been excluded from our calculation of comparable EBIT. As well, a weaker U.S. dollar had a negative impact on the Canadian dollar equivalent segmented earnings from our U.S. operations.

Earnings from our U.S. Natural Gas Pipelines operations are generally affected by contracted volume levels, volumes delivered and the rates charged as well as by the cost of providing services. Columbia and ANR results are also affected by the contracting and pricing of their storage capacity and commodity sales. Transmission and storage revenues are generally higher in winter months due to increased seasonal demand for our services.

Comparable EBITDA for U.S. Natural Gas Pipelines increased by US$92 million for the three months ended March 31, 2018 compared to the same period in 2017. This was primarily the net effect of:

- increased earnings from Columbia Gas and Columbia Gulf growth projects placed in service, additional contract sales on ANR and Great Lakes and favourable commodity prices in Midstream
- increased earnings due to the amortization of the net regulatory liability recognized in 2017 as a result of U.S. Tax Reform.

DEPRECIATION AND AMORTIZATION

Depreciation and amortization increased by US$10 million for the three months ended March 31, 2018 compared to the same period in 2017 mainly due to projects placed in service on Columbia Gas.

Mexico Natural Gas Pipelines

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

	three months ended March 31	
(unaudited - millions of US$, unless noted otherwise)	**2018**	**2017**
Topolobampo	**44**	40
Tamazunchale	**31**	29
Mazatlán	**20**	16
Guadalajara	**19**	17
Sur de Texas[1]	**9**	4
Other	**4**	—
Comparable EBITDA	**127**	106
Depreciation and amortization	**(19)**	(17)
Comparable EBIT	**108**	89
Foreign exchange impact	**29**	29
Comparable EBIT and segmented earnings (Cdn$)	**137**	118

1 Represents our 60 per cent equity interest.

Mexico Natural Gas Pipelines segmented earnings increased by $19 million for the three months ended March 31, 2018 compared to the same period in 2017 and are equivalent to comparable EBIT. Earnings from our Mexico operations are underpinned by long-term, stable, primarily U.S. dollar-denominated revenue contracts, and are affected by the cost of providing service. A weaker U.S. dollar had a negative impact on the Canadian dollar equivalent segmented earnings from our Mexico operations.

Comparable EBITDA for Mexico Natural Gas Pipelines increased by US$21 million for the three months ended March 31, 2018 compared to the same period in 2017 primarily due to:

- higher revenues from operations
- 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 is fully offset in interest income and other in the Corporate segment.

DEPRECIATION AND AMORTIZATION

Depreciation and amortization remained largely consistent for the three months ended March 31, 2018 compared to the same period in 2017.

Liquids Pipelines

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

	three months ended March 31	
(unaudited - millions of $)	**2018**	**2017**
Keystone Pipeline System	**340**	306
Intra-Alberta pipelines	**39**	—
Other[1]	**52**	6
Comparable EBITDA	**431**	312
Depreciation and amortization	**(83)**	(77)
Comparable EBIT	**348**	235
Specific items:		
Risk management activities	**(7)**	—
Keystone XL asset costs	**—**	(8)
Segmented earnings	**341**	227
Comparable EBIT denominated as follows:		
Canadian dollars	**93**	55
U.S. dollars	**202**	135
Foreign exchange impact	**53**	45
	348	235

1 Includes primarily liquids marketing and business development activities.

Liquids Pipelines segmented earnings increased by $114 million for the three months ended March 31, 2018 compared to the same period in 2017 and included:

- unrealized losses in 2018 from changes in the fair value of derivatives related to our liquids marketing business
- in 2017, an $8 million charge related to the maintenance of Keystone XL assets which was expensed pending further advancement of the project. In 2018, Keystone XL expenditures are being capitalized.

Liquids Pipelines earnings are generated primarily by providing pipeline capacity to shippers for fixed monthly payments that are not linked to actual throughput volumes. The Keystone Pipeline System offers uncontracted capacity to the market on a spot basis which provides opportunities to generate incremental earnings.

Comparable EBITDA for Liquids Pipelines increased by $119 million for the three months ended March 31, 2018 compared to the same period in 2017 and was the net effect of:

- contributions from intra-Alberta pipelines, Grand Rapids and Northern Courier, which began operations in the second half of 2017
- higher volumes on the Keystone Pipeline System
- a higher contribution from liquids marketing activities
- a weaker U.S. dollar which had a negative impact on the Canadian dollar equivalent earnings from our U.S. operations.

DEPRECIATION AND AMORTIZATION

Depreciation and amortization increased by $6 million for the three months ended March 31, 2018 compared to the same period in 2017 as a result of the timing of new facilities being placed in service, partially offset by the effect of a weaker U.S. dollar.

Energy

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

(unaudited - millions of Canadian $, unless noted otherwise)	three months ended March 31 2018	2017
Canadian Power		
Western Power	**37**	30
Eastern Power[1]	**82**	94
Bruce Power[1]	**54**	91
U.S. Power (US$)[2]	**6**	54
Foreign exchange impact on U.S. Power	**2**	18
Natural Gas Storage and other	**7**	21
Business Development	**(4)**	(3)
Comparable EBITDA	**184**	305
Depreciation and amortization	**(32)**	(40)
Comparable EBIT	**152**	265
Specific items:		
Risk management activities	**(102)**	(56)
Loss on sales of U.S. Northeast power generation assets	**—**	(11)
Segmented earnings	**50**	198

1 Includes our share of equity income from our investments in Portlands Energy and Bruce Power.
2 In second quarter 2017, we completed the sales of our U.S. Northeast power generation assets.

Energy segmented earnings decreased by $148 million for the three months ended March 31, 2018 compared to the same period in 2017 and included the following specific items:

- unrealized gains and losses from changes in the fair value of derivatives used to reduce our exposure to certain commodity price risks, as noted in the table below
- in 2017, $11 million of pre-tax costs related to the monetization of our U.S. Northeast power generation business.

Risk management activities (unaudited - millions of $, pre-tax)	three months ended March 31 2018	2017
Canadian Power	**2**	1
U.S. Power	**(101)**	(62)
Natural Gas Storage	**(3)**	5
Total unrealized losses from risk management activities	**(102)**	(56)

The variances in these unrealized gains and losses reflect the impact of changes in forward natural gas and power prices and the volume of our positions for these derivatives over a certain period of time, however, they do not accurately reflect the gains and losses that will be realized on settlement, or the offsetting impacts of other derivative and non-derivative transactions that make up our business as a whole. As a result, we do not consider them reflective of our underlying operations.

Comparable EBITDA for Energy decreased by $121 million for the three months ended March 31, 2018 compared to the same period in 2017 mainly due to the net effect of:

- lower contribution from U.S. Power due to the sales of our generation assets in second quarter 2017 and the continued wind down of our U.S. Power marketing operations, partially offset by income recognized on the sale of our retail contracts in the first quarter of 2018
- decreased Bruce Power earnings primarily due to lower volumes resulting from increased outage days. Additional financial and operating information on Bruce Power is provided below
- decreased Natural Gas Storage results mainly due to lower realized natural gas storage price spreads
- lower Eastern Power results mainly due to the sale of our Ontario solar assets in December 2017
- increased Western Power results due to higher realized prices on higher generation volumes.

DEPRECIATION AND AMORTIZATION

Depreciation and amortization decreased by $8 million for the three months ended March 31, 2018 compared to the same period in 2017 following the sale of our Ontario solar assets in December 2017.

BRUCE POWER

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

	three months ended March 31	
(unaudited - millions of $, unless noted otherwise)	**2018**	**2017**
Equity income included in comparable EBITDA and EBIT comprised of:		
Revenues	**371**	401
Operating expenses	**(227)**	(224)
Depreciation and other	**(90)**	(86)
Comparable EBITDA and EBIT[1]	**54**	91
Bruce Power – other information		
Plant availability[2]	**85%**	89%
Planned outage days	**74**	56
Unplanned outage days	**31**	17
Sales volumes (GWh)[1]	**5,696**	5,983
Realized sales price per MWh[3]	**$67**	$67

1 Represents our 48.4 per cent (2017 - 48.4 per cent) ownership interest in Bruce Power. Sales volumes include deemed generation.
2 The percentage of time the plant was available to generate power, regardless of whether it was running.
3 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 outage work on Unit 1 was completed in first quarter 2018. Planned outage work commenced on Unit 4 in March 2018 and is scheduled to be completed in second quarter 2018. Planned maintenance is expected to occur on Bruce Units 3 and 8 in the second half of 2018. The overall average plant availability percentage in 2018 is expected to be in the high 80 per cent range.

Corporate

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

(unaudited - millions of $)	three months ended March 31 2018	2017
Comparable EBITDA and EBIT	**(2)**	(4)
Specific items:		
Foreign exchange loss – inter-affiliate loan[1]	**(79)**	—
Integration and acquisition related costs – Columbia	**—**	(29)
Segmented loss	**(81)**	(33)

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

Corporate segmented loss increased by $48 million for the three months ended March 31, 2018 compared to the same period in 2017 and included the following specific items that have been excluded from comparable EBIT:

- in 2018, foreign exchange loss on a peso-denominated inter-affiliate loan to the Sur de Texas project for our proportionate share of the project's financing. There is a corresponding foreign exchange gain included in Interest income and other on the inter-affiliate loan receivable which fully offsets this loss
- in 2017, pre-tax integration and acquisition costs associated with the acquisition of Columbia.

OTHER INCOME STATEMENT ITEMS

Interest expense

(unaudited - millions of $)	three months ended March 31 2018	2017
Interest on long-term debt and junior subordinated notes		
Canadian dollar-denominated	**(134)**	(108)
U.S. dollar-denominated	**(314)**	(317)
Foreign exchange impact	**(83)**	(103)
	(531)	(528)
Other interest and amortization expense	**(22)**	(17)
Capitalized interest	**26**	45
Interest expense	**(527)**	(500)

Interest expense increased by $27 million in the three months ended March 31, 2018 compared to the same period in 2017 and primarily reflects the net effect of:

- long-term debt and junior subordinated notes issuances, net of maturities
- final repayment of the Columbia acquisition bridge facilities in June 2017, resulting in lower interest expense and debt amortization expense
- the positive impact of a weaker U.S. dollar in translating U.S. dollar denominated interest
- lower capitalized interest primarily due to completion of construction of Grand Rapids and Northern Courier in 2017.

Allowance for funds used during construction

(unaudited - millions of $)	three months ended March 31 2018	2017
Canadian dollar-denominated	**20**	50
U.S. dollar-denominated	**67**	38
Foreign exchange impact	**18**	13
Allowance for funds used during construction	**105**	101

AFUDC increased by $4 million for the three months ended March 31, 2018 compared to the same period in 2017.

The decrease in Canadian dollar-denominated AFUDC is primarily due to the October 2017 decision not to proceed with the Energy East pipeline project.

The increase in U.S. dollar-denominated AFUDC is primarily due to additional investment in and higher rates on Columbia Gas and Columbia Gulf growth projects, as well as continued investment in Mexico projects.

Interest income and other

(unaudited - millions of $)	three months ended March 31 2018	2017
Interest income and other included in comparable earnings	**63**	5
Specific items:		
Foreign exchange gain – inter-affiliate loan	**79**	—
Risk management activities	**(79)**	15
Interest income and other	**63**	20

Interest income and other increased by $43 million for the three months ended March 31, 2018 compared to the same period in 2017 and was primarily the net effect of:

- interest income along with the $79 million 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 are reflected in Income from equity investments in the Mexico Natural Gas Pipelines and Corporate segments, respectively. Both currency-related amounts are excluded from comparable earnings
- unrealized losses on risk management activities in 2018 compared to unrealized gains in 2017. These amounts have been excluded from comparable earnings
- realized gains in 2018 compared to realized losses in 2017 on derivatives used to manage our net exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income.

Income tax expense

(unaudited - millions of $)	three months ended March 31 2018	2017
Income tax expense included in comparable earnings	**(173)**	(244)
Specific items:		
Risk management activities	**52**	20
Integration and acquisition related costs – Columbia	**—**	15
Keystone XL income tax recoveries	**—**	7
Loss on sales of U.S. Northeast power generation assets	**—**	1
Keystone XL asset costs	**—**	1
Income tax expense	**(121)**	(200)

Income tax expense included in comparable earnings decreased by $71 million for the three months ended March 31, 2018 compared to the same period in 2017 mainly due to lower income tax rates as a result of U.S. Tax Reform and lower flow-through income taxes in Canadian rate-regulated pipelines.

Net income attributable to non-controlling interests

(unaudited - millions of $)	three months ended March 31 2018	2017
Net income attributable to non-controlling interests	**(94)**	(90)

Net income attributable to non-controlling interests increased by $4 million for the three months ended March 31, 2018 compared to the same period in 2017 primarily due to higher earnings, partially offset by our acquisition of the remaining outstanding publicly held common units of CPPL in February 2017.

Preferred share dividends

(unaudited - millions of $)	three months ended March 31 2018	2017
Preferred share dividends	**(40)**	(41)

Recent developments

CANADIAN NATURAL GAS PIPELINES

NGTL System

The NGTL 2017 Expansion Program is now complete and approximately $160 million of facilities have been placed in service since December 31, 2017, including the Northwest Mainline Loop-Boundary Lake pipeline on April 2, 2018. The 2017 Expansion Program added approximately 230 km (143 miles) of new pipeline along with additional compression facilities and increased the NGTL System capacity by approximately 535 TJ/d (500 MMcf/d).

On March 20, 2018, we announced the successful completion of an open season for additional expansion capacity at the Empress / McNeill Export Delivery Point for service expected to commence in November 2021. The offering of 300 TJ/d (280 MMcf/d) was oversubscribed, with an average awarded contract term of approximately 22 years. The facilities and capital requirements for the expansion are still being finalized and are currently anticipated to increase NGTL's $7.2 billion capital program by approximately $120 million.

Sundre Crossover Project

On April 9, 2018, we announced that the Sundre Crossover project was placed in service. The approximate $100 million pipeline project increases NGTL System capacity at our Alberta / B.C. export delivery point by 245 TJ/d (228 MMcf/d), enhancing connectivity to key downstream markets in the Pacific Northwest and California.

NGTL 2018 - 2019 Revenue Requirement Settlement

On March 23, 2018, we filed an application with the NEB for approval of a negotiated settlement with our customers and other interested parties on the annual costs required to operate the NGTL System for 2018 and 2019, along with final 2018 tolls and revised interim 2018 tolls. The settlement fixes ROE at 10.1 per cent on 40 per cent deemed equity and increases the composite depreciation rate from 3.18 per cent to 3.45 per cent. OM&A costs are fixed at $225 million for 2018 and $230 million for 2019 with a 50/50 sharing mechanism for any variances between the fixed amounts and actual OM&A costs. All other costs, including pipeline integrity expenses and emissions costs, are treated as flow-through expenses. The NEB is reviewing comments from interested parties and we anticipate a decision on the application in second quarter 2018.

Canadian Mainline

Canadian Mainline 2018 - 2020 Toll Review

On March 16, 2018, the NEB provided its Notice of Public Hearing for our Supplemental Agreement with the Eastern LDCs filed on December 18, 2017. Our reply evidence is due September 18, 2018. The NEB will provide further details regarding an oral or written hearing process to consider the written submissions of the interested parties.

Maple Compressor Expansion Project

We continue to await an NEB decision on our application seeking project approval and are reviewing project plans to continue to meet our in-service timelines.

U.S. NATURAL GAS PIPELINES

Cameron Access

The Cameron Access project was placed in service on March 13, 2018 and is a Columbia Gulf project designed to transport approximately 0.9 PJ/d (0.8 Bcf/d) of gas supply to the Cameron LNG export terminal in Louisiana.

Mountaineer XPress and WB XPress

In first quarter 2018, estimated project costs of US$3.0 billion for Mountaineer XPress and US$0.9 billion for WB XPress have increased by US$0.4 billion and US$0.1 billion, respectively. These increases primarily reflect the impact of delays of various regulatory approvals from FERC and other agencies, increased contractor construction costs due to unusually high demand for construction resources in the region, and modifications to contractor work plans and resources to maintain our projected in-service dates.

Great Lakes and Norther Border Rate Settlements

In February 2018, FERC approved the 2017 Great Lakes Rate Settlement and the 2017 Northern Border Rate Settlement, both of which were uncontested.

MEXICO NATURAL GAS PIPELINES

Tula and Villa de Reyes

We continue to work toward finalizing amending agreements for both of these pipelines with the CFE to formalize the schedule and payments resulting from their respective force majeure events. The CFE has commenced payments on both pipelines in accordance with the TSAs.

Sur de Texas

Offshore construction is now approximately 80 per cent complete and the project continues to progress toward an anticipated in-service date of late 2018.

LIQUIDS PIPELINES

Keystone XL

In December 2017, an appeal to Nebraska's Court of Appeals was filed by intervenors after the Nebraska Public Service Commission (PSC) issued an approval of an alternative route for the Keystone XL project in November 2017. On March 14, 2018, the Nebraska Supreme Court, on its own motion, agreed to bypass the Court of Appeals and hear the appeal case against the PSC's alternative route itself. We expect the Nebraska Supreme Court, as the final arbiter, could reach a decision by late 2018 or first quarter 2019.

The Keystone XL Presidential Permit, issued in March 2017, has been challenged in two separate lawsuits commenced in Montana. Together with the U.S. Department of Justice, we are actively participating in these lawsuits to defend both the issuance of the permit and the exhaustive environmental assessments that support the U.S. President's actions. Legal arguments addressing the merits of these lawsuits are scheduled to be heard in late May 2018 and we believe the court's decisions may be issued by year-end 2018.

The South Dakota Public Utilities Commission permit for the Keystone XL project was issued in June 2010 and recertified in January 2016. An appeal of that recertification was denied in June 2017 and that decision has been further appealed to the South Dakota Supreme Court. On April 6, 2018 the Supreme Court directed the parties to address whether the Court lacks jurisdiction under the governing statute to consider the appeal. Legal arguments are scheduled for April 2018. A decision from the Supreme Court is expected in second quarter or third quarter 2018.

White Spruce

In February 2018, the AER issued a permit for the construction of the White Spruce pipeline. Construction has commenced with an anticipated in-service date in second quarter 2019.

ENERGY

Monetization of U.S. Northeast power business

On March 1, 2018, as part of the continued wind down of our U.S. power marketing operations, we closed the sale of our U.S. power retail contracts for proceeds of approximately US$23 million and recognized income of US$10 million (US$7 million after tax).

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 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 our predictable and growing cash flow from operations, access to capital markets, including through our corporate ATM program and our Dividend Reinvestment Plan, portfolio management, cash on hand and substantial committed credit facilities. In light of the 2018 FERC Actions, further drop downs of assets into TC PipeLines, LP are not considered to be a viable funding lever. In addition, the TC PipeLines, LP ATM program is not currently being utilized. It is uncertain whether these will be restored as competitive financing options in the future. See the 2018 FERC Actions section for further information.

At March 31, 2018, our current assets totaled $4.6 billion and current liabilities amounted to $11.9 billion, leaving us with a working capital deficit of $7.3 billion compared to a deficit of $5.2 billion at December 31, 2017. Our working capital deficiency is considered to be in the normal course of business and is managed through:

- our ability to generate cash flow from operations
- our access to capital markets
- approximately $9.1 billion of unutilized, unsecured credit facilities.

CASH PROVIDED BY OPERATING ACTIVITIES

	three months ended March 31	
(unaudited - millions of $, except per share amounts)	**2018**	**2017**
Net cash provided by operations	**1,412**	1,302
Increase in operating working capital	**207**	155
Funds generated from operations[1]	**1,619**	1,457
Specific items:		
Integration and acquisition related costs – Columbia	**—**	32
Keystone XL asset costs	**—**	8
Net loss on sales of U.S. Northeast power generation assets	**—**	11
Comparable funds generated from operations[1]	**1,619**	1,508
Dividends on preferred shares	**(39)**	(39)
Distributions paid to non-controlling interests	**(69)**	(80)
Maintenance capital expenditures		
– recoverable in future tolls	**(224)**	(137)
– other	**(64)**	(49)
Comparable distributable cash flow[1]		
– reflecting all maintenance capital expenditures	**1,223**	1,203
– reflecting only non-recoverable maintenance capital expenditures	**1,447**	1,340
Comparable distributable cash flow per common share[1]		
– reflecting all maintenance capital expenditures	**$1.38**	$1.39
– reflecting only non-recoverable maintenance capital expenditures	**$1.64**	$1.55

1 See the Non-GAAP measures section of this MD&A for further discussion of funds generated from operations, comparable funds generated from operations, comparable distributable cash flow and comparable distributable cash flow per common share.

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.

Despite the sales of our U.S. power generation assets in second quarter 2017 and the continued wind down of our U.S. Power marketing operations, comparable funds generated from operations increased by $111 million for the three months ended March 31, 2018 compared to the same period in 2017. This increase is primarily due to higher comparable EBITDA (excluding income from equity investments) and higher interest income and other, partially offset by higher interest expense.

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, 2018 compared to the same period in 2017 primarily reflects higher comparable funds generated from operations, as described above, partially offset by higher recoverable maintenance capital expenditures on Canadian and U.S. natural gas pipelines. Comparable distributable cash flow per common share for the three months ended March 31, 2018 also reflects the effect of common shares issued in 2017 and 2018.

Although we deduct maintenance capital expenditures in determining comparable distributable cash flow, we have the ability to recover the majority of these costs in Canadian Natural Gas Pipelines, U.S. Natural Gas Pipelines and Liquids Pipelines. Canadian natural gas pipelines maintenance capital expenditures are reflected in rate bases, on which we earn a regulated return and subsequently recover in tolls. Almost all of our U.S. natural gas pipelines can recover maintenance capital through tolls under current rate settlements, or have the ability to recover such expenditures through tolls established in future rate cases or settlements. Tolling arrangements in Liquids Pipelines provide for recovery of maintenance capital.

The following provides a breakdown of maintenance capital expenditures:

	three months ended March 31	
(unaudited - millions of $)	**2018**	**2017**
Canadian Natural Gas Pipelines	**119**	48
U.S. Natural Gas Pipelines	**103**	86
Liquids Pipelines	**3**	3
Other[1]	**63**	49
Maintenance capital expenditures	**288**	186

1 Includes contributions to Bruce Power to fund our proportionate share of maintenance capital expenditures.

CASH USED IN INVESTING ACTIVITIES

(unaudited - millions of $)	three months ended March 31 2018	2017
Capital spending		
Capital expenditures	**(1,702)**	(1,560)
Capital projects in development	**(36)**	(42)
Contributions to equity investments	**(358)**	(192)
	(2,096)	(1,794)
Other distributions from equity investments	**121**	363
Deferred amounts and other	**110**	(85)
Net cash used in investing activities	**(1,865)**	(1,516)

Capital expenditures in 2018 were incurred primarily for the expansion of the Columbia Gas, Columbia Gulf and NGTL System natural gas pipelines, the construction of Mexico natural gas pipelines and the Napanee power generating facility, as well as capital additions to, and maintenance of, our ANR pipeline.

Costs incurred on capital projects in development were predominantly related to spending on Keystone XL.

Contributions to equity investments increased in 2018 compared to 2017 primarily due to our investments in Bruce Power, Sur de Texas and Millenium, partially offset by decreased contributions to Grand Rapids which went into service in August 2017. Contributions to equity investments also includes our proportionate share of Sur de Texas debt financing.

Other distributions from equity investments primarily reflects our proportionate share of Bruce Power financings undertaken to fund its capital program and make distributions to its partners. In 2018, Bruce Power issued senior notes in capital markets which resulted in distributions totaling $121 million being received by us.

CASH PROVIDED BY FINANCING ACTIVITIES

(unaudited - millions of $)	three months ended March 31 2018	2017
Notes payable issued, net	**1,812**	670
Long-term debt issued, net of issue costs[1]	**93**	—
Long-term debt repaid[1]	**(1,226)**	(1,051)
Junior subordinated notes issued, net of issue costs	**—**	1,982
Dividends and distributions paid	**(466)**	(419)
Common shares issued, net of issue costs	**340**	18
Partnership units of TC PipeLines, LP issued, net of issue costs	**49**	92
Common units of Columbia Pipeline Partners LP acquired	**—**	(1,205)
Net cash provided by financing activities	**602**	87

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

LONG-TERM DEBT REPAID

In first quarter 2018, long-term debt repaid included retirements by TCPL of US$500 million of Senior Unsecured Notes bearing interest at a fixed rate of 1.875 per cent, US$250 million of Senior Unsecured Notes bearing interest at a floating rate and $150 million of Debentures bearing interest at a fixed rate of 9.45 per cent.

DIVIDEND REINVESTMENT PLAN

With respect to dividends declared on February 15, 2018, the DRP participation rate amongst common shareholders was approximately 38 per cent, resulting in $234 million reinvested in common equity under the program.

TRANSCANADA CORPORATION ATM EQUITY ISSUANCE PROGRAM

In the three months ended March 31, 2018, 5.8 million common shares were issued under the TransCanada ATM program at an average price of $56.51 per common share for gross proceeds of $329 million. Related commissions and fees totaled approximately $3 million, resulting in net proceeds of $326 million. An additional 1.6 million common shares were issued in April 2018, bringing year-to-date gross proceeds to $415 million at an average price of $55.64 per common share.

TC PIPELINES, LP ATM EQUITY ISSUANCE PROGRAM

In the three months ended March 31, 2018, 0.7 million common units were issued under the TC PipeLines, LP ATM program generating net proceeds of approximately US$39 million. At March 31, 2018, our ownership interest in TC PipeLines, LP was 25.5 per cent as a result of issuances under the ATM program and resulting dilution.

The TC PipeLines, LP ATM is not currently being utilized, with future issuances under the program uncertain at this time as a result of the 2018 FERC Actions.

DIVIDENDS

On April 26, 2018, we declared quarterly dividends as follows:

Quarterly dividend on our common shares
$0.69 per share
Payable on July 31, 2018 to shareholders of record at the close of business on June 29, 2018.

Quarterly dividends on our preferred shares	
Series 1	$0.204125
Series 2	$0.19477534
Series 3	$0.1345
Series 4	$0.15444658
Payable on June 29, 2018 to shareholders of record at the close of business on May 31, 2018.	
Series 5	$0.1414375
Series 6	$0.16367534
Series 7	$0.25
Series 9	$0.265625
Payable on July 30, 2018 to shareholders of record at the close of business on July 3, 2018.	
Series 11	$0.2375
Series 13	$0.34375
Series 15	$0.30625
Payable on May 31, 2018 to shareholders of record at the close of business on May 15, 2018.	

SHARE INFORMATION

as at April 23, 2018		
Common shares	**Issued and outstanding**	
	893 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	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	8 million

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 23, 2018, we had a total of $11.3 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 for general corporate purposes	December 2022
US$2.0 billion	US$2.0 billion	TCPL	Supports TCPL's U.S. dollar commercial paper program and for general corporate purposes	December 2018
US$1.0 billion	US$0.9 billion	TCPL USA	Used for TCPL USA general corporate purposes, guaranteed by TCPL	December 2018
US$1.0 billion	US$0.4 billion	Columbia	Used for Columbia general corporate purposes, guaranteed by TCPL	December 2018
US$0.5 billion	US$0.5 billion	TAIL	Supports TAIL's U.S. dollar commercial paper program and for general corporate purposes, guaranteed by TCPL	December 2018
Demand senior unsecured revolving credit facilities				
$2.1 billion	$0.6 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$4.9 billion	Mexican subsidiary	Used for Mexico general corporate purposes, guaranteed by TCPL	Demand

At April 23, 2018, our operated affiliates had an additional $0.4 billion of undrawn capacity on committed credit facilities.

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

CONTRACTUAL OBLIGATIONS

Our capital expenditure commitments have increased by approximately $1.5 billion since December 31, 2017. Increased commitments for Columbia Gas growth projects, as well as our proportionate share of commitments for the ongoing construction of the Sur de Texas natural gas pipeline and the Bruce Power six-unit life extension program, were partially offset by decreased commitments for the Napanee power generating facility.

There were no other material changes to our contractual obligations in first quarter 2018 or to payments due in the next five years or after. See the MD&A in our 2017 Annual Report for more information about our contractual obligations.

Financial risks and financial instruments

We are exposed to liquidity risk, counterparty credit risk and market risk, and have strategies, policies and limits in place to mitigate their impact on our earnings, cash flow and, ultimately, shareholder value. These are designed to ensure our risks and related exposures are in line with our business objectives and risk tolerance.

See our 2017 Annual Report for more information about the risks we face in our business. Our risks have not changed substantially since December 31, 2017, other than as described below.

On March 1, 2018, as part of the continued wind down of our U.S. power marketing operations, we closed the sale of our U.S. power retail contracts for proceeds of approximately US$23 million and recognized income of US$10 million (US$7 million after tax). We expect to realize the value of the remaining marketing contracts and working capital over time. As a result, our exposure to commodity risk has been reduced.

LIQUIDITY RISK

We manage our liquidity risk by continuously forecasting our cash flow for a 12-month period to ensure 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.

COUNTERPARTY CREDIT RISK

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

- accounts receivable
- the fair value of derivative assets
- cash and cash equivalents
- loans receivable.

We review our accounts receivable regularly and record allowances for doubtful accounts using the specific identification method. At March 31, 2018, 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.

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 the joint venture as an equity investment.

In April 2017, we entered into a MXN$13.6 billion unsecured revolving credit facility with the joint venture, which bears interest at a floating rate and matures in March 2022. In December 2017, an amended agreement was entered into to increase the credit facility to MXN$21.3 billion. Draws on the credit facility result in a loan receivable from the joint venture representing our proportionate share of the debt financing requirements advanced to the joint venture. At March 31, 2018, the balance of our loan receivable from the joint venture totaled $1.2 billion (December 31, 2017 - $919 million) and Interest income and other of $27 million for the three months ended March 31, 2018 (2017 - nil). Interest income and other is offset by a corresponding proportionate share of interest expense recorded in Income from equity investments.

FOREIGN EXCHANGE

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. The majority of this risk is offset by interest expense on U.S. dollar-denominated debt and by using foreign exchange derivatives.

INTEREST RATE RISK

We utilize short-term and long-term debt to finance our operations which subjects 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, TransCanada is exposed to interest rate risk on financial instruments and contractual obligations containing variable interest rate components. We mitigate our interest rate risk using a combination of interest rate swaps and option derivatives.

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, 2018	**1.27**
three months ended March 31, 2017	1.32

The impact of changes in the value of the U.S. dollar on our U.S. operations is partially offset by interest on U.S. dollar-denominated long-term debt, as set out in the table below. Comparable EBIT is a non-GAAP measure. See our Reconciliation of non-GAAP measures section for more information.

Significant U.S. dollar-denominated amounts

	three months ended March 31	
(unaudited - millions of US$)	**2018**	**2017**
U.S. Natural Gas Pipelines comparable EBIT	**513**	431
Mexico Natural Gas Pipelines comparable EBIT[1]	**130**	89
U.S. Liquids Pipelines comparable EBIT	**202**	135
U.S. Power comparable EBIT	**6**	54
AFUDC on U.S. dollar-denominated projects	**67**	38
Interest on U.S. dollar-denominated long-term debt	**(314)**	(317)
Capitalized interest on U.S. dollar-denominated capital expenditures	**3**	—
U.S. dollar non-controlling interests and other	**(80)**	(70)
	527	360

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

Net investment hedge

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

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

	March 31, 2018		December 31, 2017	
(unaudited - millions of Canadian $, unless noted otherwise)	Fair value[1,2]	Notional amount	Fair value[1,2]	Notional amount
U.S. dollar cross-currency interest rate swaps (maturing 2018 to 2019)[3]	**(132)**	**US 800**	(199)	US 1,200
U.S. dollar foreign exchange options (maturing 2018)	**(2)**	**US 300**	5	US 500
	(134)	**US 1,100**	(194)	US 1,700

1 Fair values equal carrying values.
2 No amounts have been excluded from the assessment of hedge effectiveness.
3 In the three months ended March 31, 2018, Net income includes net realized gains of $1 million (2017 - $1 million) related to the interest component of cross-currency swap settlements which are reported within interest expense.

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

(unaudited - millions of Canadian $, unless noted otherwise)	March 31, 2018	December 31, 2017
Notional amount	**26,200 (US 20,300)**	25,400 (US 20,200)
Fair value	**29,000 (US 22,500)**	28,900 (US 23,100)

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. We apply hedge accounting to derivative instruments that qualify and are designated for hedge accounting treatment.

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 (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 classification of the fair value of derivative instruments is as follows:

(unaudited - millions of $)	March 31, 2018	December 31, 2017
Other current assets	**132**	332
Intangible and other assets	**72**	73
Accounts payable and other	**(301)**	(387)
Other long-term liabilities	**(80)**	(72)
	(177)	(54)

Unrealized and realized (losses)/gains of derivative instruments

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

	three months ended March 31	
(unaudited - millions of $)	**2018**	**2017**
Derivative instruments held for trading[1]		
Amount of unrealized (losses)/gains in the period		
Commodities[2]	**(109)**	(56)
Foreign exchange	**(79)**	15
Interest rate	**—**	1
Amount of realized gains/(losses) in the period		
Commodities	**110**	(48)
Foreign exchange	**15**	(4)
Derivative instruments in hedging relationships		
Amount of realized gains in the period		
Commodities	**3**	6
Foreign exchange	**—**	5
Interest rate	**1**	1

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

2 In the three months ended March 31, 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 (2017 - nil).

Derivatives in cash flow hedging relationships

The components of the Condensed consolidated statement of OCI related to derivatives in cash flow hedging relationships including the portion attributable to non-controlling interests is as follows:

	three months ended March 31	
(unaudited - millions of $)	**2018**	**2017**
Change in fair value of derivative instruments recognized in OCI (effective portion)[1]		
Commodities	**(3)**	5
Interest rate	**9**	1
	6	6
Reclassification of (losses)/gains on derivative instruments from AOCI to net income[1]		
Commodities[2]	**(1)**	(4)
Interest rate[3]	**5**	4
	4	—

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

2 Reported within Revenues on the Condensed consolidated statement of income.

3 Reported within Interest expense on the Condensed consolidated statement of income.

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, 2018, the aggregate fair value of all derivative contracts with credit-risk-related contingent features that were in a net liability position was $2 million (December 31, 2017 - $2 million), with no collateral provided in the normal course of business at March 31, 2018 and December 31, 2017. If the credit-risk-related contingent features in these agreements were triggered on March 31, 2018, we would have been required to provide collateral of $2 million (December 31, 2017 - $2 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, 2018, 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 2018 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 2017 Annual Report.

Our significant accounting policies have remained unchanged since December 31, 2017 other than described below. A summary of our significant accounting policies is included in our 2017 Annual Report.

Changes in accounting policies for 2018

Revenue from contracts with customers

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

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

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

- pattern of revenue recognition, whether the performance obligation is satisfied at a point in time versus over time within a contract
- term of the contract
- amount of variable consideration associated with a contract and timing of the associated revenue recognition.

The new guidance was effective January 1, 2018, was applied using the modified retrospective transition method, and did not result in any material differences in the amount and timing of revenue recognition.

Financial instruments

In January 2016, the FASB issued new guidance on the accounting for equity investments and financial liabilities. The new guidance changes the income statement effect of equity investments and the recognition of changes in the fair value of financial liabilities when the fair value option is elected. The new guidance also requires us to assess valuation allowances for deferred tax assets related to available for sale debt securities in combination with their other deferred tax assets. This new guidance was effective January 1, 2018 and did not have a material impact on our consolidated financial statements.

Income taxes

In October 2016, the FASB issued new guidance on the income tax effects of intra-entity transfers of assets other than inventory. The new guidance requires the recognition of deferred and current income taxes for an intra-entity asset transfer when the transfer occurs. The new guidance was effective January 1, 2018, was applied using a modified retrospective approach, and did not have a material impact on our consolidated financial statements.

Restricted cash

In November 2016, the FASB issued new guidance on restricted cash and cash equivalents on the statement of cash flows. The new guidance requires that the statement of cash flows explain the change during the period in the total cash and cash equivalents balance, and amounts generally described as restricted cash or restricted cash equivalents. Restricted cash and cash equivalents will be included with cash and cash equivalents when reconciling the beginning of year and end of year total amounts on the statement of cash flows. This new guidance was effective January 1, 2018, was applied retrospectively, and did not have an impact on our consolidated financial statements.

Employee post-retirement benefits

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

Hedge accounting

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

Future accounting changes

Leases

In February 2016, the FASB issued new guidance on the accounting for leases. The new guidance amends the definition of a lease such that, in order for an arrangement to qualify as a lease, the lessor is required to have both (1) the right to obtain substantially all of the economic benefits from the use of the asset and (2) the right to direct the use of the asset. The new guidance also establishes a right-of-use (ROU) model that requires a lessee to recognize a ROU asset and corresponding lease liability on the balance sheet for all leases with a term longer than 12 months. 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.

In January, 2018, the FASB issued an optional practical expedient, to be applied upon transition, to omit the evaluation of land easements not previously accounted for as leases that existed or expired prior to the entity's adoption of the new lease guidance. An entity that elects this practical expedient is required to apply the practical expedient consistently to all of its existing or expired land easements not previously accounted for as leases. We continue to monitor and analyze additional guidance and clarifications provided by the FASB.

The new guidance is effective January 1, 2019, with early adoption permitted. A modified retrospective transition approach is required for leases existing at, or entered into after, the beginning of the earliest comparative period presented in the financial statements, with certain practical expedients available. We are continuing to identify and analyze existing lease agreements to determine the effect of application of the new guidance on our consolidated financial statements. We have also selected a system solution and continue to assess process changes necessary to compile the information to meet the recognition and disclosure requirements of the new guidance.

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.

Goodwill impairment

In January 2017, the FASB issued new guidance on simplifying the test for goodwill impairment by eliminating Step 2 of the impairment test, which is the requirement to calculate the implied fair value of goodwill to measure the impairment charge. Instead, entities will record an impairment charge based on the excess of a reporting unit’s carrying amount over its fair value. This new guidance is effective January 1, 2020 and will be applied prospectively, however, early adoption is permitted. We are currently evaluating the timing and impact of the adoption of this guidance.

Amortization on purchased callable debt securities

In March 2017, the FASB issued new guidance that shortens the amortization period for the premium on certain purchased callable debt securities by requiring entities to amortize the premium to the earliest call date. This new guidance is effective January 1, 2019 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.

Income Taxes

In February 2018, the FASB issued new guidance that allows a reclassification from AOCI to retained earnings for stranded tax effects resulting from the U.S. Tax Cuts and Jobs Act. This new guidance is effective January 1, 2019, however, early adoption is permitted. This guidance can be applied either in the period of adoption or retrospectively to each period (or periods) in which the effect of the change is recognized. We are currently evaluating this guidance.

Reconciliation of non-GAAP measures

(unaudited - millions of $)	three months ended March 31 2018	2017
Comparable EBITDA		
Canadian Natural Gas Pipelines	**494**	504
U.S. Natural Gas Pipelines	**804**	720
Mexico Natural Gas Pipelines	**160**	140
Liquids Pipelines	**431**	312
Energy	**184**	305
Corporate	**(2)**	(4)
Comparable EBITDA	**2,071**	1,977
Depreciation and amortization	**(535)**	(510)
Comparable EBIT	**1,536**	1,467
Specific items:		
Risk management activities[1]	**(109)**	(56)
Foreign exchange loss – inter-affiliate loan	**(79)**	—
Integration and acquisition related costs – Columbia	**—**	(39)
Loss on sales of U.S. Northeast power generation assets	**—**	(11)
Keystone XL asset costs	**—**	(8)
Segmented earnings	**1,348**	1,353

1

Risk management activities (unaudited - millions of $)	three months ended March 31 2018	2017
Liquids marketing	**(7)**	—
Canadian Power	**2**	1
U.S. Power	**(101)**	(62)
Natural Gas Storage	**(3)**	5
Total unrealized losses from risk management activities	**(109)**	(56)

Quarterly results

SELECTED QUARTERLY CONSOLIDATED FINANCIAL DATA

	2018	2017			2016		
(unaudited - millions of $, except per share amounts)	First	Fourth	Third	Second	First	Fourth	Third	Second
Revenues	**3,424**	3,617	3,195	3,230	3,407	3,635	3,642	2,756
Net income/(loss) attributable to common shares	**734**	861	612	881	643	(358)	(135)	365
Comparable earnings	**870**	719	614	659	698	626	622	366
Per share statistics								
Net income/(loss) per common share - basic and diluted	**$0.83**	$0.98	$0.70	$1.01	$0.74	($0.43)	($0.17)	$0.52
Comparable earnings per common share	**$0.98**	$0.82	$0.70	$0.76	$0.81	$0.75	$0.78	$0.52
Dividends declared per common share	**$0.69**	$0.625	$0.625	$0.625	$0.625	$0.565	$0.565	$0.565

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
- acquisitions and divestitures
- developments outside of the normal course of operations
- newly constructed assets being placed in service.

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

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

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

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 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 business, which included an incremental after-tax loss of $7 million recorded on the sale of the thermal and wind package, $23 million of after-tax third-party insurance proceeds related to a 2017 Ravenswood outage and income tax adjustments
- 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 which were expensed pending further advancement of the project.

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 business which included an incremental loss of $7 million after tax on the sale of the thermal and wind package and $14 million of after-tax disposition costs and income tax adjustments
- 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 which were being expensed pending further advancement of the project.

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 business which included a $441 million after-tax gain on the sale of TC Hydro and an additional 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 which were being expensed pending further advancement of the project.

In first quarter 2017, comparable earnings also excluded:

- a charge of $24 million after tax for integration-related costs associated with the acquisition of Columbia
- a charge of $10 million after tax for costs related to the monetization of our U.S. Northeast power generation business
- a charge of $7 million after tax related to the maintenance of Keystone XL assets which were being expensed pending further advancement of the project
- a $7 million income tax recovery related to the realized loss on a third-party sale of Keystone XL project assets. A provision for the expected pre-tax loss on these assets was included in our 2015 impairment charge but the related income tax recoveries could not be recorded until realized.

In fourth quarter 2016, comparable earnings also excluded:

- an $870 million after-tax charge related to the loss on U.S. Northeast power assets held for sale which included an $863 million after-tax loss on the thermal and wind package held for sale and $7 million of after-tax costs related to the monetization
- an additional $68 million after-tax loss on the transfer of environmental credits to the Balancing Pool upon final settlement of the Alberta PPA terminations
- an after-tax charge of $67 million for costs associated with the acquisition of Columbia which included a $44 million deferred tax adjustment upon acquisition and $23 million of retention, severance and integration costs
- an after-tax charge of $18 million related to Keystone XL costs for the maintenance and liquidation of project assets which were being expensed pending further advancement of the project
- an after-tax restructuring charge of $6 million for additional expected future losses under lease commitments. These charges formed part of a restructuring initiative, which commenced in 2015, to maximize the effectiveness and efficiency of our existing operations and reduce overall costs.

In third quarter 2016, comparable earnings also excluded:

- a $656 million after-tax impairment on the Ravenswood goodwill. As a result of information received during the process to monetize our U.S. Northeast power business in third quarter 2016, it was determined that the fair value of Ravenswood no longer exceeded its carrying value
- costs associated with the acquisition of Columbia including a charge of $67 million after tax primarily relating to retention, severance and integration expenses
- $28 million of income tax recoveries related to the realized loss on a third-party sale of Keystone XL plant and equipment. A provision for the expected loss on these assets was included in our fourth quarter 2015 impairment charge but the related tax recoveries could not be recorded until realized
- a charge of $9 million after tax related to Keystone XL costs for the maintenance and liquidation of project assets which were being expensed pending further advancement of the project
- a $3 million after-tax charge related to the monetization of our U.S. Northeast power business.

In second quarter 2016, comparable earnings also excluded:

- a charge of $113 million related to costs associated with the acquisition of Columbia which included $109 million related to dividend equivalent payments on the subscription receipts issued to partially fund the acquisition
- a charge of $9 million after tax related to Keystone XL costs for the maintenance and liquidation of project assets which were being expensed pending further advancement of the project
- a charge of $10 million after tax for restructuring charges mainly related to expected future losses under lease commitments.

Condensed consolidated statement of income

	three months ended March 31	
(unaudited - millions of Canadian $, except per share amounts)	**2018**	**2017**
Revenues		
Canadian Natural Gas Pipelines	**884**	882
U.S. Natural Gas Pipelines	**1,091**	994
Mexico Natural Gas Pipelines	**151**	143
Liquids Pipelines	**623**	472
Energy	**675**	916
	3,424	3,407
Income from Equity Investments	**80**	174
Operating and Other Expenses		
Plant operating costs and other	**874**	1,006
Commodity purchases resold	**597**	543
Property taxes	**150**	162
Depreciation and amortization	**535**	517
	2,156	2,228
Financial Charges		
Interest expense	**527**	500
Allowance for funds used during construction	**(105)**	(101)
Interest income and other	**(63)**	(20)
	359	379
Income before Income Taxes	**989**	974
Income Tax Expense		
Current	**50**	67
Deferred	**71**	133
	121	200
Net Income	**868**	774
Net income attributable to non-controlling interests	**94**	90
Net Income Attributable to Controlling Interests	**774**	684
Preferred share dividends	**40**	41
Net Income Attributable to Common Shares	**734**	643
Net Income per Common Share		
Basic and diluted	**$0.83**	$0.74
Dividends Declared per Common Share	**$0.69**	$0.625
Weighted Average Number of Common Shares (millions)		
Basic	**885**	866
Diluted	**886**	868

See accompanying notes to the condensed consolidated financial statements.

Condensed consolidated statement of comprehensive income

(unaudited - millions of Canadian $)	three months ended March 31 2018	2017
Net Income	**868**	774
Other Comprehensive Income/(Loss), Net of Income Taxes		
Foreign currency translation gains and losses on net investment in foreign operations	**432**	(82)
Change in fair value of net investment hedges	**(2)**	(1)
Change in fair value of cash flow hedges	**7**	5
Reclassification to net income of gains and losses on cash flow hedges	**3**	—
Reclassification of actuarial gains and losses on pension and other post-retirement benefit plans	**(2)**	3
Other comprehensive income on equity investments	**6**	3
Other comprehensive income/(loss)	**444**	(72)
Comprehensive Income	**1,312**	702
Comprehensive income attributable to non-controlling interests	**160**	50
Comprehensive Income Attributable to Controlling Interests	**1,152**	652
Preferred share dividends	**40**	41
Comprehensive Income Attributable to Common Shares	**1,112**	611

See accompanying notes to the condensed consolidated financial statements.

Condensed consolidated statement of cash flows

	three months ended March 31	
(unaudited - millions of Canadian $)	**2018**	**2017**
Cash Generated from Operations		
Net income	**868**	774
Depreciation and amortization	**535**	517
Deferred income taxes	**71**	133
Income from equity investments	**(80)**	(174)
Distributions received from operating activities of equity investments	**234**	219
Employee post-retirement benefits funding, net of expense	**3**	3
Equity allowance for funds used during construction	**(78)**	(64)
Unrealized losses on financial instruments	**188**	41
Other	**(122)**	8
Increase in operating working capital	**(207)**	(155)
Net cash provided by operations	**1,412**	1,302
Investing Activities		
Capital expenditures	**(1,702)**	(1,560)
Capital projects in development	**(36)**	(42)
Contributions to equity investments	**(358)**	(192)
Other distributions from equity investments	**121**	363
Deferred amounts and other	**110**	(85)
Net cash used in investing activities	**(1,865)**	(1,516)
Financing Activities		
Notes payable issued, net	**1,812**	670
Long-term debt issued, net of issue costs	**93**	—
Long-term debt repaid	**(1,226)**	(1,051)
Junior subordinated notes issued, net of issue costs	**—**	1,982
Dividends on common shares	**(358)**	(300)
Dividends on preferred shares	**(39)**	(39)
Distributions paid to non-controlling interests	**(69)**	(80)
Common shares issued, net of issue costs	**340**	18
Partnership units of TC PipeLines, LP issued, net of issue costs	**49**	92
Common units of Columbia Pipeline Partners LP acquired	**—**	(1,205)
Net cash provided by financing activities	**602**	87
Effect of Foreign Exchange Rate Changes on Cash and Cash Equivalents	**29**	5
Increase/(Decrease) in Cash and Cash Equivalents	**178**	(122)
Cash and Cash Equivalents		
Beginning of period	**1,089**	1,016
Cash and Cash Equivalents		
End of period	**1,267**	894

See accompanying notes to the condensed consolidated financial statements.

Condensed consolidated balance sheet

(unaudited - millions of Canadian $)		March 31, 2018	December 31, 2017
ASSETS			
Current Assets			
Cash and cash equivalents		**1,267**	1,089
Accounts receivable		**2,208**	2,522
Inventories		**384**	378
Other		**718**	691
		4,577	4,680
Plant, Property and Equipment	net of accumulated depreciation of $24,416 and $23,734, respectively	**59,313**	57,277
Equity Investments		**6,362**	6,366
Regulatory Assets		**1,334**	1,376
Goodwill		**13,483**	13,084
Loan Receivable from Affiliate		**1,211**	919
Intangible and Other Assets		**1,725**	1,484
Restricted Investments		**1,005**	915
		89,010	86,101
LIABILITIES			
Current Liabilities			
Notes payable		**3,658**	1,763
Accounts payable and other		**3,697**	4,057
Dividends payable		**631**	586
Accrued interest		**552**	605
Current portion of long-term debt		**3,406**	2,866
		11,944	9,877
Regulatory Liabilities		**4,473**	4,321
Other Long-Term Liabilities		**712**	727
Deferred Income Tax Liabilities		**5,529**	5,403
Long-Term Debt		**30,995**	31,875
Junior Subordinated Notes		**7,177**	7,007
		60,830	59,210
EQUITY			
Common shares, no par value		**21,703**	21,167
Issued and outstanding:	March 31, 2018 - 891 million shares		
	December 31, 2017 - 881 million shares		
Preferred shares		**3,980**	3,980
Additional paid-in capital		**10**	—
Retained earnings		**1,859**	1,623
Accumulated other comprehensive loss		**(1,353)**	(1,731)
Controlling Interests		**26,199**	25,039
Non-controlling interests		**1,981**	1,852
		28,180	26,891
		89,010	86,101

Contingencies and Guarantees (Note 12)

Variable Interest Entities (Note 13)

See accompanying notes to the condensed consolidated financial statements.

Condensed consolidated statement of equity

	three months ended March 31	
(unaudited - millions of Canadian $)	**2018**	**2017**
Common Shares		
Balance at beginning of period	**21,167**	20,099
Shares issued:		
Under at-the-market equity issuance program, net of issue costs	**327**	—
Under dividend reinvestment and share purchase plan	**195**	190
On exercise of stock options	**14**	19
Balance at end of period	**21,703**	20,308
Preferred Shares		
Balance at beginning and end of period	**3,980**	3,980
Additional Paid-In Capital		
Balance at beginning of period	**—**	—
Issuance of stock options, net of exercises	**3**	2
Dilution from TC PipeLines, LP units issued	**7**	10
Columbia Pipeline Partners LP acquisition	**—**	(171)
Reclassification of additional paid-in capital deficit to retained earnings	**—**	159
Balance at end of period	**10**	—
Retained Earnings		
Balance at beginning of period	**1,623**	1,138
Net income attributable to controlling interests	**774**	684
Common share dividends	**(614)**	(542)
Preferred share dividends	**(19)**	(18)
Adjustment related to income tax effects of asset drop downs to TC PipeLines, LP	**95**	—
Adjustment related to employee share-based payments	**—**	12
Reclassification of additional paid-in capital deficit to retained earnings	**—**	(159)
Balance at end of period	**1,859**	1,115
Accumulated Other Comprehensive Loss		
Balance at beginning of period	**(1,731)**	(960)
Other comprehensive income/(loss)	**378**	(32)
Balance at end of period	**(1,353)**	(992)
Equity Attributable to Controlling Interests	**26,199**	24,411
Equity Attributable to Non-Controlling Interests		
Balance at beginning of period	**1,852**	1,726
Net income attributable to non-controlling interests	**94**	90
Other comprehensive income/(loss) attributable to non-controlling interests	**66**	(40)
Issuance of TC PipeLines, LP units		
Proceeds, net of issue costs	**49**	92
Decrease in TransCanada's ownership of TC PipeLines, LP	**(9)**	(17)
Distributions declared to non-controlling interests	**(71)**	(80)
Reclassification from common units of TC PipeLines, LP subject to rescission	**—**	24
Impact of Columbia Pipeline Partners LP acquisition	**—**	33
Balance at end of period	**1,981**	1,828
Total Equity	**28,180**	26,239

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, 2017, except as described in Note 2, Accounting changes. Capitalized and abbreviated terms that are used but not otherwise defined herein are identified in TransCanada's 2017 Annual Report.

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 2017 audited consolidated financial statements included in TransCanada's 2017 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 Energy 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 JUDGEMENTS

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 judgement 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, 2017, except as described in Note 2, Accounting changes.

2. Accounting changes

CHANGES IN ACCOUNTING POLICIES FOR 2018

Revenue from contracts with customers

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

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

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

- pattern of revenue recognition, whether the performance obligation is satisfied at a point in time versus over time within a contract
- term of the contract
- amount of variable consideration associated with a contract and timing of the associated revenue recognition.

The new guidance was effective January 1, 2018, was applied using the modified retrospective transition method, and did not result in any material differences in the amount and timing of revenue recognition. Refer to Note 4, Revenues, for further information related to the impact of adopting the new guidance and the Company's updated accounting policies related to revenue recognition from contracts with customers.

Financial instruments

In January 2016, the FASB issued new guidance on the accounting for equity investments and financial liabilities. The new guidance changes the income statement effect of equity investments and the recognition of changes in the fair value of financial liabilities when the fair value option is elected. The new guidance also requires the Company to assess valuation allowances for deferred tax assets related to available for sale debt securities in combination with their other deferred tax assets. This new guidance was effective January 1, 2018, and did not have a material impact on the Company's consolidated financial statements.

Income taxes

In October 2016, the FASB issued new guidance on the income tax effects of intra-entity transfers of assets other than inventory. The new guidance requires the recognition of deferred and current income taxes for an intra-entity asset transfer when the transfer occurs. The new guidance was effective January 1, 2018, was applied using a modified retrospective approach, and did not have a material impact on the Company's consolidated financial statements.

Restricted cash

In November 2016, the FASB issued new guidance on restricted cash and cash equivalents on the statement of cash flows. The new guidance requires that the statement of cash flows explain the change during the period in the total cash and cash equivalents balance, and amounts generally described as restricted cash or restricted cash equivalents. Restricted cash and cash equivalents will be included with cash and cash equivalents when reconciling the beginning of year and end of year total amounts on the statement of cash flows. This new guidance was effective January 1, 2018, was applied retrospectively, and did not have an impact on the Company's consolidated financial statements.

Employee post-retirement benefits

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

Hedge accounting

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

FUTURE ACCOUNTING CHANGES

Leases

In February 2016, the FASB issued new guidance on the accounting for leases. The new guidance amends the definition of a lease such that, in order for an arrangement to qualify as a lease, the lessor is required to have both (1) the right to obtain substantially all of the economic benefits from the use of the asset and (2) the right to direct the use of the asset. The new guidance also establishes a right-of-use (ROU) model that requires a lessee to recognize a ROU asset and corresponding lease liability on the balance sheet for all leases with a term longer than 12 months. 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.

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

The new guidance is effective January 1, 2019, with early adoption permitted. A modified retrospective transition approach is required for leases existing at, or entered into after, the beginning of the earliest comparative period presented in the financial statements, with certain practical expedients available. The Company is continuing to identify and analyze existing lease agreements to determine the effect of application of the new guidance on its consolidated financial statements. The Company has also selected a system solution and continues to assess process changes necessary to compile the information to meet the recognition and disclosure requirements of the new guidance.

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.

Goodwill impairment

In January 2017, the FASB issued new guidance on simplifying the test for goodwill impairment by eliminating Step 2 of the impairment test, which is the requirement to calculate the implied fair value of goodwill to measure the impairment charge. Instead, entities will record an impairment charge based on the excess of a reporting unit’s carrying amount over its fair value. This new guidance is effective January 1, 2020 and will be applied prospectively, however, early adoption is permitted. The Company is currently evaluating the timing and impact of the adoption of this guidance.

Amortization on purchased callable debt securities

In March 2017, the FASB issued new guidance that shortens the amortization period for the premium on certain purchased callable debt securities by requiring entities to amortize the premium to the earliest call date. This new guidance is effective January 1, 2019 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.

Income Taxes

In February 2018, the FASB issued new guidance that allows a reclassification from AOCI to retained earnings for stranded tax effects resulting from the U.S. Tax Cuts and Jobs Act. This new guidance is effective January 1, 2019, however, early adoption is permitted. This guidance can be applied either in the period of adoption or retrospectively to each period (or periods) in which the effect of the change is recognized. The Company is currently evaluating this guidance.

3. Segmented information

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**	**Energy**	**Corporate**[1]	**Total**
Revenues	**884**	**1,091**	**151**	**623**	**675**	**—**	**3,424**
Intersegment revenues	**—**	**25**	**—**	**—**	**42**	**(67)** [2]	**—**
	884	**1,116**	**151**	**623**	**717**	**(67)**	**3,424**
Income/(loss) from equity investments	**3**	**67**	**11**	**15**	**63**	**(79)** [3]	**80**
Plant operating costs and other	**(323)**	**(324)**	**(2)**	**(191)**	**(99)**	**65** [2]	**(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							**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 Includes intersegment eliminations.

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

3 Income/(loss) from equity investments includes foreign exchange losses on the Company's inter-affiliate loan with Sur de Texas. The peso-denominated loan to the Sur de Texas joint venture represents the Company's proportionate share of debt financing for this joint venture.

three months ended March 31, 2017 (unaudited - millions of Canadian $)	**Canadian Natural Gas Pipelines**	**U.S. Natural Gas Pipelines**	**Mexico Natural Gas Pipelines**	**Liquids Pipelines**	**Energy**	**Corporate**[1]	**Total**
Revenues	882	994	143	472	916	—	3,407
Intersegment revenues	—	11	—	—	—	(11) [2]	—
	882	1,005	143	472	916	(11)	3,407
Income from equity investments	3	65	6	—	100	—	174
Plant operating costs and other	(312)	(306)	(9)	(145)	(212)	(22) [2]	(1,006)
Commodity purchases resold	—	—	—	—	(543)	—	(543)
Property taxes	(69)	(47)	—	(23)	(23)	—	(162)
Depreciation and amortization	(222)	(156)	(22)	(77)	(40)	—	(517)
Segmented Earnings/(Loss)	282	561	118	227	198	(33)	1,353
Interest expense							(500)
Allowance for funds used during construction							101
Interest income and other							20
Income before income taxes							974
Income tax expense							(200)
Net Income							774
Net income attributable to non-controlling interests							(90)
Net Income Attributable to Controlling Interests							684
Preferred share dividends							(41)
Net Income Attributable to Common Shares							643

1 Includes intersegment eliminations.

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

TOTAL ASSETS

(unaudited - millions of Canadian $)	**March 31, 2018**	**December 31, 2017**
Canadian Natural Gas Pipelines	**17,171**	16,904
U.S. Natural Gas Pipelines	**37,586**	35,898
Mexico Natural Gas Pipelines	**5,931**	5,716
Liquids Pipelines	**15,916**	15,438
Energy	**8,376**	8,503
Corporate	**4,030**	3,642
	89,010	86,101

4. Revenues

In 2014, the FASB issued new guidance on revenue from contracts with customers. The Company adopted the new guidance on January 1, 2018 using the modified retrospective transition method for all contracts that were in effect on the date of adoption. Results reported for 2018 reflect the application of the new guidance, while the 2017 comparative results were prepared and reported under previous revenue recognition guidance which is referred to herein as "legacy U.S. GAAP."

DISAGGREGATION OF REVENUES

The following table summarizes total Revenues for the three months ended March 31, 2018:

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**	**Energy**	**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[1,2]	**—**	**15**	**—**	**88**	**55**	**158**
	884	**1,091**	**151**	**623**	**675**	**3,424**

1 Other revenues includes income from the Company's financial instruments and lease arrangements within each operating segment. Income from lease arrangements includes certain long term PPAs, as well as certain liquids pipelines capacity and transportation arrangements. These arrangements are not in the scope of the new guidance, therefore, revenues related to these contracts are excluded from revenues from contracts with customers. Refer to Note 11, Risk management and financial instruments, for further information on income from financial instruments.

2 Other revenues from U.S. Natural Gas Pipelines includes the amortization of the regulatory liability resulting from U.S. Tax Reform. Refer to Note 6, Income taxes, for further information.

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

Canadian Natural Gas Pipelines

Capacity Arrangements and Transportation

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

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

U.S. Natural Gas Pipelines

Capacity Arrangements and Transportation

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

The Company's U.S. natural gas pipelines are subject to FERC regulations and, as a result, a portion of revenues collected may be subject to refund if invoiced during an interim period when a rate proceeding is ongoing. Allowances for these potential refunds are recognized using management's best estimate based on the facts and circumstances of the proceeding. Any allowances that are recognized during the proceeding process are refunded or retained at the time a regulatory decision becomes final. U.S. natural gas pipelines' revenues are invoiced and received on a monthly basis. The Company does not take ownership of the natural gas that it transports for customers.

Natural Gas Storage and Other

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

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

Mexico Natural Gas Pipelines

Capacity Arrangements and Transportation

Revenues from the Company's Mexico natural gas pipelines are primarily collected based on CRE-approved negotiated firm capacity contracts and are generally recognized ratably over the term of the contract. For certain firm capacity arrangements, the Company has elected to utilize the practical expedient to recognize revenues as invoiced. Transportation revenues related to interruptible or volumetric-based services are recognized when the service is performed. Other volumes shipped on these pipelines are subject to CRE-approved tariffs and revenues are recognized when the Company has performed the transportation services. Mexico natural gas pipelines' revenues are invoiced and received on a monthly basis. The Company does not take ownership of the natural gas that it transports for customers.

Liquids Pipelines

Capacity Arrangements and Transportation

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

Energy

Power Generation

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

Natural Gas Storage and Other

Non-regulated natural gas storage contracts include park, loan and term storage arrangements. Park and loan contracts allow for fixed injection or withdrawal volumes on specified dates for a specified price. Term storage contracts allow for a maximum amount of gas to be stored over a set period of time. Revenues from park and loan contracts are recognized and invoiced as the injection and withdrawal services are provided and revenues from term storage contracts are recognized ratably over the term of the contract. Term storage revenues are invoiced and received on a monthly basis. Revenues earned from the sale of proprietary natural gas are recognized in the month of delivery. Revenues from ancillary services are recognized as the service is provided. The Company does not take ownership of the natural gas that it stores for customers.

FINANCIAL STATEMENT IMPACT OF ADOPTING REVENUE FROM CONTRACTS WITH CUSTOMERS

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

Capacity Arrangements and Transportation

For certain natural gas pipelines capacity contracts, amounts are invoiced to the customer in accordance with the terms of the contract, however, the related revenues are recognized when the Company satisfies its performance obligation to provide committed capacity ratably over the term of the contract. This difference in timing between revenue recognition and amounts invoiced creates a contract asset or contract liability under the new revenue recognition guidance. Under legacy U.S. GAAP, this difference was recorded as Accounts receivable.

Impact of New Revenue Recognition Guidance on Date of Adoption

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

(unaudited - millions of Canadian $)	As reported December 31, 2017	Adjustment	January 1, 2018
Current Assets			
Accounts receivable	2,522	(62)	2,460
Other[1]	691	79	770
Current Liabilities			
Accounts payable and other[2]	4,057	17	4,074

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

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

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

As required by the new revenue recognition guidance, the following tables illustrate the pro-forma impact on the affected line items on the Condensed consolidated balance sheet, as at March 31, 2018, had legacy U.S. GAAP been applied:

	March 31, 2018	
(unaudited - millions of Canadian $)	As reported	Pro-forma using Legacy U.S. GAAP
Current Assets		
Accounts receivable	**2,208**	**2,358**
Other	**718**	**568**

CONTRACT BALANCES

(unaudited - millions of Canadian $)	March 31, 2018	January 1, 2018
Receivables from contracts with customers	**1,344**	1,736
Contract assets[1]	**150**	79
Contract liabilities[2]	**6**	17
Long-term contract liabilities[3]	**7**	—

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

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 the rights become unconditional and the customer is invoiced as well as the recognition of additional revenues that remains to be invoiced.

FUTURE REVENUES FROM REMAINING PERFORMANCE OBLIGATIONS

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

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

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

Capacity Arrangements and Transportation

As at March 31, 2018, future revenues from long-term capacity arrangements and transportation contracts extending through 2043 are approximately $30.5 billion, of which approximately $4.2 billion is expected to be recognized during the remainder of 2018.

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

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

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

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

Power Generation

The Company has long-term power generation contracts extending through 2032. Revenues from power generation have a variable component related to market prices that are subject to factors outside the Company’s influence. These revenues are considered to be fully constrained and are recognized on a monthly basis when the Company satisfies the performance obligation. The Company applies the practical expedient related to variable revenues to these contracts. As a result, future revenues from these contracts are excluded from the disclosures.

Natural Gas Storage and Other

As at March 31, 2018, future revenues from long-term natural gas storage and other contracts extending through 2033, are approximately $1.4 billion, of which approximately $378 million is expected to be recognized during the remainder of 2018. The Company applies the practical expedients related to contracts that are for a duration of one year or less and where we have variable consideration, and therefore excludes the related revenues from the future revenues disclosure. As a result, this amount is lower than the potential total future revenues from these contracts.

5. Plant, Property and Equipment, Equity Investments and Goodwill

The Company reviews plant, property and equipment and equity investments for impairment whenever events or changes in circumstances indicate the carrying value of the asset may not be recoverable.

Goodwill is tested for impairment on an annual basis or more frequently if events or changes in circumstance indicate that it might be impaired. The Company can initially make this assessment based on qualitative factors. If the Company concludes that it is not more likely than not that the fair value of the reporting unit is less than its carrying value, then an impairment test is not performed.

On March 15, 2018, FERC proposed changes related to U.S. Tax Reform and income taxes for ratemaking purposes in a master limited partnership (MLP) that may have an impact on the future earnings and cash flows of FERC-regulated pipelines. Until these pronouncements are finalized and implementation requirements are clarified, including the applicability to assets partially-owned by a MLP or held in non-MLP structures, and the Company and TC PipeLines, LP have fully evaluated their respective alternatives to minimize the impact of the proposed FERC changes, the Company believes that it is not more likely than not that the fair value of any of its reporting units is less than its respective carrying value. Therefore, a goodwill impairment test was not performed. Also, the Company has determined there is no indication that the carrying values of plant, property and equipment and equity investments potentially impacted by FERC's proposals are not recoverable. The Company will continue to monitor developments and assess its goodwill for impairment. The Company will also review its plant, property and equipment and equity investments for recoverability as new information becomes available.

At December 31, 2017, the estimated fair value of Great Lakes exceeded its carrying value by less than 10 per cent. There is a risk that the recent FERC developments, once finalized, could result in a goodwill impairment charge. The goodwill balance related to Great Lakes is US$573 million at March 31, 2018 (December 31, 2017 – US$573 million). There is also a risk that the goodwill balance related to Tuscarora of US$82 million at March 31, 2018 (December 31, 2017 – US$82 million) could be negatively impacted by the recent FERC developments.

6. Income taxes

U.S. Tax Reform

Pursuant to the enactment of U.S. Tax Reform, we recorded net regulatory liabilities and a corresponding reduction in net deferred income tax liabilities in the amount of $1,686 million at December 31, 2017 related to the Company's U.S. natural gas pipelines subject to rate-regulated accounting. Such amounts remain provisional as the Company's interpretation, assessment and presentation of the impact of U.S. Tax Reform may be further clarified with additional guidance from regulatory, tax and accounting authorities. Should additional guidance be provided by these authorities or other sources during the one-year measurement period permitted by the SEC, the Company will review the provisional amounts and adjust as appropriate. Other than the amortizations discussed below, no adjustments were made to these amounts during first quarter 2018. On March 15, 2018, FERC proposed changes related to U.S. Tax Reform and income taxes for ratemaking purposes in MLPs. There may be prospective adjustments to regulatory liabilities once these proposed changes are finalized and take effect.

Commencing January 1, 2018, the regulatory liabilities are being amortized using the Reverse South Georgia methodology. Under this methodology, rate-regulated entities determine amortization based on their composite depreciation rate and immediately begin recording amortization. Amortization of the net regulatory liability in the amount of $9 million was recorded in the three months ended March 31, 2018 and included in Revenues in the Condensed consolidated statement of income.

Effective Tax Rates

The effective tax rates for the three-month periods ended March 31, 2018 and 2017 were 12 per cent and 21 per cent, respectively. The lower effective tax rate in 2018 was primarily the result of the rate change resulting from U.S. Tax Reform and lower flow-through tax in Canadian rate-regulated pipelines.

7. Long-term debt

LONG-TERM DEBT RETIRED

The Company retired long-term debt in the three months ended March 31, 2018 as follows:

(unaudited - millions of Canadian $, unless noted otherwise) Company	Retirement date	Type	Amount	Interest rate
TRANSCANADA PIPELINES LIMITED				
	March 2018	Debentures	150	9.45%
	January 2018	Senior Unsecured Notes	US 500	1.875%
	January 2018	Senior Unsecured Notes	US 250	Floating
GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP				
	March 2018	Senior Unsecured Notes	US 9	6.73%

In the three months ended March 31, 2018, TransCanada capitalized interest related to capital projects of $26 million (2017 – $45 million).

8. Common shares

TRANSCANADA CORPORATION ATM EQUITY ISSUANCE PROGRAM

In the three months ended March 31, 2018, the Company issued 5.8 million common shares under the TransCanada ATM program at an average price of $56.51 per common share, for gross proceeds of $329 million. Related commissions and fees totaled approximately $3 million, resulting in net proceeds of $326 million. Subsequent to March 31, 2018, the Company issued an additional 1.6 million common shares at an average price of $52.52 per common share, for gross proceeds of $86 million.

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

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

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**

three months ended March 31, 2017 (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	(88)	6	(82)
Change in fair value of net investment hedges	(2)	1	(1)
Change in fair value of cash flow hedges	6	(1)	5
Reclassification of actuarial gains and losses on pension and other post-retirement benefit plans	5	(2)	3
Other comprehensive income on equity investments	4	(1)	3
Other comprehensive loss	(75)	3	(72)

The changes in AOCI by component are as follows:

three months ended March 31, 2018 (unaudited - millions of Canadian $)	**Currency Translation Adjustments**	**Cash Flow Hedges**	**Pension and OPEB Plan Adjustments**	**Equity Investments**	**Total**[1]
AOCI balance at January 1, 2018	**(1,043)**	**(31)**	**(203)**	**(454)**	**(1,731)**
Other comprehensive income/(loss) before reclassifications[2,3]	**373**	**(2)**	**—**	**—**	**371**
Amounts reclassified from accumulated other comprehensive loss	**—**	**3**	**(2)**	**6**	**7**
Net current period other comprehensive income/(loss)	**373**	**1**	**(2)**	**6**	**378**
AOCI balance at March 31, 2018	**(670)**	**(30)**	**(205)**	**(448)**	**(1,353)**

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

2 Other comprehensive income/(loss) before reclassifications on currency translation adjustments and cash flow hedges is net of non-controlling interest gains of $57 million and $9 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 $22 million ($16 million, net of tax) at March 31, 2018. These estimates assume constant commodity prices, interest rates and foreign exchange rates over time, however, the amounts reclassified will vary based on the actual value of these factors at the date of settlement.

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

(unaudited - millions of Canadian $)	Amounts Reclassified From AOCI[1] three months ended March 31 2018	2017	Affected Line Item in the Condensed Consolidated Statement of Income
Cash flow hedges			
Commodities	**1**	4	Revenues (Energy)
Interest	**(5)**	(4)	Interest expense
	(4)	—	Total before tax
	1	—	Income tax expense
	(3)	—	Net of tax
Pension and other post-retirement benefit plan adjustments			
Amortization of actuarial gains and losses	**(4)**	(4)	Plant operating costs and other[2]
	6	2	Income tax expense
	2	(2)	Net of tax
Equity investments			
Equity income	**(7)**	(4)	Income from equity investments
	1	1	Income tax expense
	(6)	(3)	Net of tax

1 All amounts in parentheses indicate expenses to the Condensed consolidated statement of income.
2 These accumulated other comprehensive loss components are included in the computation of net benefit cost. Refer to Note 10, Employee post-retirement benefits, for further information.

10. Employee post-retirement benefits

The net benefit cost recognized for the Company's defined benefit pension 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 $)	2018	2017	2018	2017
Service cost[1]	**30**	29	**1**	1
Other components of net benefit cost[1]				
Interest cost	**33**	34	**3**	4
Expected return on plan assets	**(55)**	(50)	**(4)**	(5)
Amortization of actuarial loss	**4**	4	**—**	—
Amortization of regulatory asset	**5**	6	**—**	—
	(13)	(6)	**(1)**	(1)
Net Benefit Cost	**17**	23	**—**	—

1 Service cost and other components of net benefit cost are included in Plant operating costs and other on 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 and cash flow.

COUNTERPARTY CREDIT RISK

TransCanada's maximum counterparty credit exposure with respect to financial instruments at March 31, 2018, without taking into account security held, consisted of cash and cash equivalents, accounts receivable, available for sale assets, derivative assets and loans receivable. The Company regularly reviews its accounts receivable and records an allowance for doubtful accounts as necessary using the specific identification method. At March 31, 2018, there were no significant amounts past due or impaired, no significant credit risk concentration and no significant credit losses during the period.

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 the joint venture as an equity investment. On April 21, 2017, the Company entered into a MXN$13.6 billion unsecured revolving credit facility with the joint venture, which bears interest at a floating rate and matures in March 2022. On December 6, 2017, an amended agreement was entered into to increase the credit facility to MXN$21.3 billion. Draws on the credit facility result in a loan receivable from the joint venture representing the Company's proportionate share of the debt financing requirements advanced to the joint venture. At March 31, 2018, the balance of the Company's loan receivable from the joint venture totaled $1.2 billion (December 31, 2017 – $919 million) and Interest income and other included of $27 million for the three months ended March 31, 2018 (2017 – nil). Interest income and other is offset by 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 interest rate swaps and foreign exchange forward contracts and options.

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

	March 31, 2018		December 31, 2017	
(unaudited - millions of Canadian $, unless noted otherwise)	**Fair value[1,2]**	**Notional amount**	**Fair value[1,2]**	**Notional amount**
U.S. dollar cross-currency interest rate swaps (maturing 2018 to 2019)[3]	**(132)**	**US 800**	(199)	US 1,200
U.S. dollar foreign exchange options (maturing 2018)	**(2)**	**US 300**	5	US 500
	(134)	**US 1,100**	(194)	US 1,700

1 Fair values equal carrying values.

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

3 In the three months ended March 31, 2018, Net income includes net realized gains of $1 million (2017 – $1 million) related to the interest component of cross-currency swap settlements which are reported within Interest expense.

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

(unaudited - millions of Canadian $, unless noted otherwise)	March 31, 2018	December 31, 2017
Notional amount	**26,200 (US 20,300)**	25,400 (US 20,200)
Fair value	**29,000 (US 22,500)**	28,900 (US 23,100)

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, 2018		December 31, 2017	
(unaudited - millions of Canadian $)	Carrying amount	Fair value	Carrying amount	Fair value
Long-term debt including current portion[1,2]	**(34,401)**	**(38,789)**	(34,741)	(40,180)
Junior subordinated notes	**(7,177)**	**(7,264)**	(7,007)	(7,233)
	(41,578)	**(46,053)**	(41,748)	(47,413)

1 Long-term debt is recorded at amortized cost except for US$1.2 billion (December 31, 2017 – US$1.1 billion) that is attributed to hedged risk and recorded at fair value.

2 Net income for the three months ended March 31, 2018 included unrealized gains of $5 million (2017 – $2 million) for fair value adjustments attributable to the hedged interest rate risk associated with interest rate swap fair value hedging relationships on US$1.2 billion of long-term debt at March 31, 2018 (December 31, 2017 – US$1.1 billion). There were no other unrealized gains or losses from fair value adjustments to the non-derivative financial instruments.

Available for sale assets summary

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

(unaudited - millions of Canadian $)	March 31, 2018		December 31, 2017	
	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	**—**	**25**	—	23
Maturing within 1-5 years	**—**	**123**	—	107
Maturing within 5-10 years	**71**	**—**	14	—
Maturing after 10 years	**801**	**—**	790	—
	872	**148**	804	130

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

2 Available for sale assets are recorded at fair value and included in Other current assets and Restricted investments on the Condensed consolidated balance sheet.

(unaudited - millions of Canadian $)	March 31, 2018		March 31, 2017	
	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	**2**	**1**	2	—

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 Unrealized gains and losses on other restricted investments are included in Interest income and other.

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.

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, 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]	—	—	—	103	103
Foreign exchange	—	—	4	20	24
Interest rate	5	—	—	—	5
	5	—	4	123	132
Intangible and other assets					
Commodities[2]	—	—	—	59	59
Foreign exchange	—	—	2	—	2
Interest rate	11	—	—	—	11
	11	—	2	59	72
Total Derivative Assets	16	—	6	182	204
Accounts payable and other					
Commodities[2]	(9)	—	—	(120)	(129)
Foreign exchange	—	—	(126)	(38)	(164)
Interest rate	—	(8)	—	—	(8)
	(9)	(8)	(126)	(158)	(301)
Other long-term liabilities					
Commodities[2]	(2)	—	—	(62)	(64)
Foreign exchange	—	—	(14)	—	(14)
Interest rate	—	(2)	—	—	(2)
	(2)	(2)	(14)	(62)	(80)
Total Derivative Liabilities	(11)	(10)	(140)	(220)	(381)
Total Derivatives	5	(10)	(134)	(38)	(177)

1 Fair value equals carrying value.

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

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

1 Fair value equals carrying value.

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

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

Derivatives in fair value hedging relationships

The following table details amounts recorded on the 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, 2018**	**December 31, 2017**	**March 31, 2018**	**December 31, 2017**
Current portion of long-term debt	**(1,091)**	(688)	**6**	1
Long-term debt	**(448)**	(685)	**4**	4
	(1,539)	(1,373)	**10**	5

1 At March 31, 2018, the balance includes adjustments for discontinued hedging relationships of nil (December 31, 2017 – nil).

Notional and Maturity Summary

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

at March 31, 2018 (unaudited)	**Power**	**Natural Gas**	**Liquids**	**Foreign Exchange**	**Interest**
Purchases[1]	**46,005**	**101**	**11**	**—**	**—**
Sales[1]	**31,648**	**107**	**14**	**—**	**—**
Millions of U.S. dollars	**—**	**—**	**—**	**US 3,137**	**US 2,400**
Maturity dates	**2018-2022**	**2018-2021**	**2018**	**2018-2019**	**2018-2028**

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

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

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

Unrealized and realized (losses)/gains on derivative instruments

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

(unaudited - millions of Canadian $)	three months ended March 31	
	2018	**2017**
Derivative Instruments Held for Trading[1]		
Amount of unrealized (losses)/gains in the period		
Commodities[2]	**(109)**	(56)
Foreign exchange	**(79)**	15
Interest rate	**—**	1
Amount of realized gains/(losses) in the period		
Commodities	**110**	(48)
Foreign exchange	**15**	(4)
Derivative Instruments in Hedging Relationships		
Amount of realized gains in the period		
Commodities	**3**	6
Foreign exchange	**—**	5
Interest rate	**1**	1

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

2 In the three months ended March 31, 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 (2017 – nil).

Derivatives in cash flow hedging relationships

The components of OCI related to the change in fair value of derivatives in cash flow hedging relationships including the portion attributable to non-controlling interests are as follows:

(unaudited - millions of Canadian $)	three months ended March 31	
	2018	**2017**
Change in fair value of derivative instruments recognized in OCI[1]		
Commodities	**(3)**	5
Interest rate	**9**	1
	6	6

1 Amounts presented are pre-tax. 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 (Energy)		Interest Expense	
(unaudited - millions of Canadian $)	2018	2017	2018	2017
Total Amount Presented in the Condensed Consolidated Statement of Income	**675**	916	**(527)**	(500)
Fair Value Hedges				
Interest rate contracts				
Hedged items	**—**	—	**(20)**	(19)
Derivatives designated as hedging instruments	**—**	—	**—**	1
Cash Flow Hedges				
Reclassification of gains/(losses) on derivative instruments from AOCI to net income				
Interest rate contracts[1]	**—**	—	**1**	—
Commodity contracts[2]	**(1)**	(4)	**—**	—
Reclassification of gains on derivative instruments from AOCI to net income as a result of forecasted transactions that are no longer probable of occurring				
Interest rate contracts[1]	**—**	—	**4**	4

1 Refer to Note 9, Other comprehensive income/(loss) and accumulated other comprehensive loss, for the components of OCI related to derivatives in cash flow hedging relationships including the portion attributable to non-controlling interests.
2 There are no amounts recognized in earnings that were excluded from effectiveness testing.

Offsetting of derivative instruments

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

at March 31, 2018 (unaudited - millions of Canadian $)	Gross derivative instruments	Amounts available for offset[1]	Net amounts
Derivative instrument assets			
Commodities	**162**	**(94)**	**68**
Foreign exchange	**26**	**(22)**	**4**
Interest rate	**16**	**(2)**	**14**
	204	**(118)**	**86**
Derivative instrument liabilities			
Commodities	**(193)**	**94**	**(99)**
Foreign exchange	**(178)**	**22**	**(156)**
Interest rate	**(10)**	**2**	**(8)**
	(381)	**118**	**(263)**

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

at December 31, 2017 (unaudited - millions of Canadian $)	Gross derivative instruments	Amounts available for offset[1]	Net amounts
Derivative instrument assets			
Commodities	319	(198)	121
Foreign exchange	78	(56)	22
Interest rate	8	(1)	7
	405	(255)	150
Derivative instrument liabilities			
Commodities	(242)	198	(44)
Foreign exchange	(212)	56	(156)
Interest rate	(5)	1	(4)
	(459)	255	(204)

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

With respect to the derivative instruments presented above as at March 31, 2018, the Company provided cash collateral of $198 million (December 31, 2017 – $165 million) and letters of credit of $12 million (December 31, 2017 – $30 million) to its counterparties. The Company held nil (December 31, 2017 – nil) in cash collateral and $1 million (December 31, 2017 – $3 million) in letters of credit from counterparties on asset exposures at March 31, 2018.

Credit risk related contingent features of derivative instruments

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

Based on contracts in place and market prices at March 31, 2018, the aggregate fair value of all derivative instruments with credit-risk-related contingent features that were in a net liability position was $2 million (December 31, 2017 – $2 million), for which the Company did not provide collateral in the normal course of business at March 31, 2018 or December 31, 2017. If the credit-risk-related contingent features in these agreements were triggered on March 31, 2018, the Company would have been required to provide collateral of $2 million (December 31, 2017 – $2 million) to its counterparties. Collateral may also need to be provided should the fair value of derivative instruments exceed pre-defined contractual exposure limit thresholds.

The Company has sufficient liquidity in the form of cash and undrawn committed revolving 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	Valuation based on the extrapolation of inputs, other than quoted prices included within Level I, for which all significant inputs are observable directly or indirectly. Inputs include published exchange rates, interest rates, interest rate swap curves, yield curves and broker quotes from external data service providers. This category includes interest rate and foreign exchange derivative assets and liabilities where fair value is determined using the income approach and commodity derivatives where fair value is determined using the market approach. Transfers between Level I and Level II would occur when there is a change in market circumstances.
Level III	Valuation of assets and liabilities are measured using a market approach based on extrapolation of inputs that are unobservable or where observable data does not support a significant portion of the derivative's fair value. This category mainly includes long-dated commodity transactions in certain markets where liquidity is low and the Company uses the most observable inputs available or, if not available, long-term broker quotes to estimate the fair value for these transactions. Valuation of options is based on the Black-Scholes pricing model. Assets and liabilities measured at fair value can fluctuate between Level II and Level III depending on the proportion of the value of the contract that extends beyond the time frame for which significant inputs are considered to be observable. As contracts near maturity and observable market data become available, they are transferred out of Level III and into Level II.

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

at March 31, 2018 (unaudited - millions of Canadian $)	**Quoted prices in active markets (Level I)**[1]	**Significant other observable inputs (Level II)**[1]	**Significant unobservable inputs (Level III)**[1]	**Total**
Derivative instrument assets				
Commodities	**20**	**137**	**5**	**162**
Foreign exchange	**—**	**26**	**—**	**26**
Interest rate	**—**	**16**	**—**	**16**
Derivative instrument liabilities				
Commodities	**(26)**	**(144)**	**(23)**	**(193)**
Foreign exchange	**—**	**(178)**	**—**	**(178)**
Interest rate	**—**	**(10)**	**—**	**(10)**
	(6)	**(153)**	**(18)**	**(177)**

1 There were no transfers from Level I to Level II or from Level II to Level III for the three months ended March 31, 2018.

at December 31, 2017 (unaudited - millions of Canadian $)	Quoted prices in active markets (Level I)[1]	Significant other observable inputs (Level II)[1]	Significant unobservable inputs (Level III)[1]	Total
Derivative instrument assets				
Commodities	21	283	15	319
Foreign exchange	—	78	—	78
Interest rate	—	8	—	8
Derivative instrument liabilities				
Commodities	(27)	(193)	(22)	(242)
Foreign exchange	—	(212)	—	(212)
Interest rate	—	(5)	—	(5)
	(6)	(41)	(7)	(54)

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

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

	three months ended March 31	
(unaudited - millions of Canadian $)	**2018**	**2017**
Balance at beginning of period	**(7)**	16
Total losses included in Net income	**(2)**	—
Settlements	**(9)**	—
Sales	**—**	(2)
Transfers out of Level III	**—**	(4)
Balance at end of period[1]	**(18)**	10

1 For the three months ended March 31, 2018, revenues include unrealized losses of $11 million attributed to derivatives in the Level III category that were still held at March 31, 2018 (2017 – unrealized losses of less than $1 million).

A 10 per cent increase or decrease in commodity prices, with all other variables held constant, would result in a $1 million increase or decrease, respectively, in the fair value of outstanding derivative instruments included in Level III as at March 31, 2018.

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 obligations for construction services during the construction of the pipeline.

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, 2018		at December 31, 2017	
(unaudited - millions of Canadian $)	Term	Potential exposure[1]	Carrying value	Potential exposure[1]	Carrying value
Sur de Texas	ranging to 2020	**199**	**1**	315	2
Bruce Power	ranging to 2019	**88**	**—**	88	1
Other jointly-owned entities	ranging to 2059	**105**	**12**	104	13
		392	**13**	507	16

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, 2018	December 31, 2017
ASSETS		
Current Assets		
Cash and cash equivalents	**88**	41
Accounts receivable	**61**	63
Inventories	**24**	23
Other	**15**	11
	188	138
Plant, Property and Equipment	**3,617**	3,535
Equity Investments	**944**	917
Goodwill	**482**	490
Intangible and Other Assets	**11**	3
	5,242	5,083
LIABILITIES		
Current Liabilities		
Accounts payable and other	**128**	137
Dividends payable	**3**	1
Accrued interest	**31**	23
Current portion of long-term debt	**86**	88
	248	249
Regulatory Liabilities	**36**	34
Other Long-Term Liabilities	**3**	3
Deferred Income Tax Liabilities	**13**	13
Long-Term Debt	**3,304**	3,244
	3,604	3,543

Non-Consolidated VIEs

The Company's non-consolidated VIEs consist of legal entities where the Company does not have the power to direct the activities that most significantly impact the economic performance of these entities 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, 2018	December 31, 2017
Balance sheet		
Equity investments	**4,306**	4,372
Off-balance sheet		
Potential exposure to guarantees	**172**	171
Maximum exposure to loss	**4,478**	4,543