SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 6-K

Report of Foreign Private Issuer

Pursuant to Rule 13a-16 or 15d-16 of
the Securities Exchange Act of 1934

For the month of February 2018

Commission File No. 1-31690

TransCanada Corporation
(Translation of Registrant's Name into English)

450 – 1 Street S.W., Calgary, Alberta, T2P 5H1, Canada
(Address of Principal Executive Offices)

Indicate by check mark whether the registrant files or will file annual reports under cover of Form 20-F or Form 40-F:

Form 20-F	o	Form 40-F	☑

Indicate by check mark if the registrant is submitting the Form 6-K in paper as permitted by Regulation S-T Rule 101(b)(1): o

Indicate by check mark if the registrant is submitting the Form 6-K in paper as permitted by Regulation S-T Rule 101(b)(7): o

Exhibit 99.1 to this report, furnished on Form 6-K, is furnished, not filed, and will not be incorporated by reference into any registration statement filed by the registrant under the Securities Act of 1933, as amended.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

Date: February 15, 2018	**TRANSCANADA CORPORATION**
	By: /s/ Donald R. Marchand Donald R. Marchand Executive Vice-President and Chief Financial Officer
	By: /s/ G. Glenn Menuz G. Glenn Menuz Vice-President and Controller

EXHIBIT INDEX

99.1	A copy of the registrant’s news release of February 15, 2018.

NewsRelease

TransCanada Reports Record Financial Results for 2017
10.4% Dividend Increase Supported by Strong Outlook for Future Growth

CALGARY, Alberta – **February 15, 2018** – TransCanada Corporation (TSX, NYSE: TRP) (TransCanada or the Company) today announced net income attributable to common shares for fourth quarter 2017 of $861 million or $0.98 per share compared to a net loss of $358 million or $0.43 per share for the same period in 2016. For the year ended December 31, 2017, net income attributable to common shares was $3.0 billion or $3.44 per share compared to net income of $124 million or $0.16 per share in 2016. Comparable earnings for fourth quarter 2017 were $719 million or $0.82 per common share compared to $626 million or $0.75 per share for the same period last year. For the year ended December 31, 2017, comparable earnings were $2.7 billion or $3.09 per common share compared to $2.1 billion or $2.78 per share in 2016. TransCanada's Board of Directors also declared a quarterly dividend of $0.69 per common share for the quarter ending March 31, 2018, equivalent to $2.76 per common share on an annualized basis, an increase of 10.4 per cent. This is the eighteenth consecutive year the Board of Directors has raised the dividend.

"We are pleased that our vision of becoming one of North America’s leading energy infrastructure companies is becoming a reality. In 2017, we advanced a number of strategic initiatives and delivered record financial performance following the successful integration of Columbia into our operations," said Russ Girling, TransCanada’s president and chief executive officer. "Comparable earnings per share increased eleven per cent compared to 2016 while comparable funds generated from operations of $5.6 billion were nine per cent higher than last year. The increases reflect the strong performance of our existing assets and approximately $5 billion of growth projects that were completed and placed into service during 2017. They included expansions of our NGTL and Canadian Mainline systems in our Canadian natural gas pipelines business, the Gibraltar and Rayne XPress projects in U.S. natural gas pipelines and the Grand Rapids and Northern Courier liquids pipelines in Alberta."

"Looking forward, we will continue to advance a $23 billion near-term capital program, including an additional $2.4 billion on NGTL. This program is expected to generate significant additional growth in earnings and cash flow and support continued 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 $8 billion into these projects to date and are well positioned to fund the remainder of this capital program through our strong and growing internally generated cash flow and access to capital markets on compelling terms."

"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. Progress on Keystone XL continues following the Nebraska Public Service Commission approval of a viable route through the state, which we support, and the receipt of commercial commitments for the project. At the same time we expect to secure additional organic growth associated with our extensive North American footprint in natural gas pipelines, liquids pipelines and power generation as evidenced by ongoing expansions of the NGTL System. These initiatives highlight the strong competitive position of our asset base and our proven ability to continuously replenish our growth portfolio with attractive, strategic, low-risk investment opportunities. 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)

- Fourth quarter 2017 financial results:
  - Net income attributable to common shares of $861 million or $0.98 per share
  - Comparable earnings of $719 million or $0.82 per common share
  - Comparable earnings before interest, taxes, depreciation and amortization of $1.9 billion
  - Net cash provided by operations of $1.4 billion
  - Comparable funds generated from operations of $1.5 billion
  - Comparable distributable cash flow of $1.3 billion or $1.45 per common share reflecting only non-recoverable maintenance capital expenditures
- For the year ended December 31, 2017:
  - Net income attributable to common shares of $3.0 billion or $3.44 per share
  - Comparable earnings of $2.7 billion or $3.09 per common share
  - Comparable earnings before interest, taxes, depreciation and amortization of $7.4 billion
  - Net cash provided by operations of $5.2 billion
  - Comparable funds generated from operations of $5.6 billion
  - Comparable distributable cash flow of $5.0 billion or $5.69 per common share reflecting only non-recoverable maintenance capital expenditures
- Fourth quarter highlights:
  - Announced a 10.4 per cent increase in the quarterly common share dividend to $0.69 per common share for the quarter ending March 31, 2018
  - NGTL placed approximately $0.6 billion of facilities in service during the fourth quarter bringing the total to $1.7 billion in 2017
  - Placed Rayne XPress and Gibraltar into service in November, followed by Leach XPress on January 1, 2018
  - Received FERC certificates for the WB XPress, Mountaineer XPress and Gulf XPress projects
  - Completed the sale of our Ontario solar assets for $541 million
  - Announced that we would no longer be pursuing Energy East and related projects
  - Raised US$1.25 billion in 2-year floating and fixed rate senior debt on November 15, 2017
  - Concluded open seasons for the Keystone and Marketlink pipeline systems and secured incremental long-term contractual commitments
  - Received approval for a route through Nebraska for Keystone XL from the Nebraska Public Service Commission
  - In January 2018, announced that we received commercial support for the Keystone XL project
  - In February 2018, announced a new NGTL System expansion for 2021 of $2.4 billion

Net income attributable to common shares increased by $1.2 billion or $1.41 per share to $861 million or $0.98 per share for the three months ended December 31, 2017 compared to the same period last year. Fourth quarter 2017 results included 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 and a $64 million after-tax net gain related to the monetization of our U.S. Northeast power business. These gains were partially offset by 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 and 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. All of these specific items, as well as unrealized gains and losses from changes in risk management activities, are excluded from comparable earnings.

Net income attributable to common shares for the year ended December 31, 2017 was $3.0 billion or $3.44 per share compared to $124 million or $0.16 per share in 2016. Net income per common share includes the dilutive effect of issuing 161 million common shares in 2016 and common shares issued under our DRP and corporate ATM program in 2017. Results in 2017 included an $804 million recovery of deferred income taxes as a result of U.S. Tax Reform, a $307 million after-tax net gain related to the monetization of our U.S. Northeast power business and a $136 million after-tax gain related to the sale of our Ontario solar assets. These items were partially offset by 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 $69 million after-tax charge for integration-related costs associated with the acquisition of Columbia, a $28 million after-tax charge related to the maintenance and liquidation of Keystone XL assets which were expensed pending further advancement of the project and a $7 million income tax recovery in first quarter 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 fourth quarter 2017 were $719 million or $0.82 per share compared to $626 million or $0.75 per share for the same period in 2016, an increase of $93 million or $0.07 per share. The increase in fourth quarter comparable earnings was primarily due to the net effect of a higher contribution from U.S. Natural Gas Pipelines due to lower operating costs including synergies achieved from the Columbia acquisition, a higher contribution from Liquids Pipelines primarily due to higher volumes on Keystone, the commencement of operations on Northern Courier and Grand Rapids and liquids marketing activities, higher earnings from Bruce Power mainly due to higher volumes resulting from fewer outage days, and higher AFUDC on our rate-regulated U.S. natural gas pipelines, partially offset by our decision not to proceed with the Energy East pipeline, a lower contribution from U.S. Power due to the monetization of our U.S. Northeast power generation assets in second quarter 2017 and the continued wind-down of our U.S. power marketing operations and an after-tax impairment charge in 2017 related to obsolete Energy equipment.

Comparable earnings for the year ended December 31, 2017 of $2.7 billion or $3.09 per share were $582 million or $0.31 per common share higher than in 2016 and includes the dilutive effect of issuing 161 million common shares in 2016 and common shares issued under our DRP and corporate ATM program in 2017. The 2017 increase in comparable earnings was primarily the net result of a higher contribution from U.S. Natural Gas Pipelines due to incremental earnings from Columbia following the July 2016 acquisition and higher ANR transportation revenue resulting from a FERC-approved rate settlement, increased earnings from Liquids Pipelines primarily due to higher volumes on the Keystone Pipeline System, liquids marketing activities and the commencement of operations on Grand Rapids and Northern Courier, higher earnings from Bruce Power mainly due to higher volumes resulting from fewer outage days, a higher contribution from Mexico Natural Gas Pipelines due to earnings from Topolobampo beginning in July 2016 and Mazatlán beginning in December 2016, higher AFUDC on our rate-regulated U.S. natural gas pipelines, the NGTL System, Tula and Villa de Reyes, partially offset by the commercial in-service of Topolobampo and completion of Mazatlán construction, and higher interest income and other due to income related to Coastal GasLink project costs and the termination of the PRGT project. These items were partially offset by lower contributions from U.S. Power due to the sales of our U.S. Northeast power generation assets in second quarter 2017 and the wind-down of our U.S. power marketing operations, as well as higher interest expense as a result of debt assumed in the acquisition of Columbia on July 1, 2016 and long-term debt and junior subordinated note issuances in 2017, net of maturities.

Notable recent developments include:

Canadian Natural Gas Pipelines:

- *NGTL System*: In February 2018, we announced a $2.4 billion NGTL System expansion with expected in-service dates between 2019 and 2021 that includes approximately 375 km (233 miles) of 16-inch to 48-inch pipeline, four compression units and associated facilities. We anticipate incremental firm receipt contracts of 664 TJ/d (620 MMcf/d) and firm delivery contracts to our major border export and intra-basin delivery locations of 1.1 PJ/d (1.0 Bcf/d). With this expansion, NGTL now has a $7.2 billion growth capital program, excluding the $1.9 billion Merrick pipeline project. In 2017, we placed approximately $1.7 billion of facilities in service.

  On December 28, 2017, the NEB approved the Sundre Crossover Project on the NGTL System. The approximate $100 million project will increase delivery of 245 TJ/d (229 MMcf/d) to the Alberta / British Columbia border to connect with TransCanada downstream pipelines. In-service is planned for April 1, 2018.

- *North Montney:* In 2017, we filed an application with the NEB for a variance to the existing approvals for the North Montney Project on the NGTL System to remove the condition that the project could only proceed once a positive final investment decision was made for the Pacific Northwest LNG project. The North Montney project is now underpinned by restructured 20-year commercial contracts and is not dependent on the LNG project proceeding. A hearing on the matter began the week of January 22, 2018 and a decision from the NEB is anticipated in second quarter 2018.

- *NGTL 2018 Revenue Requirement:* NGTL's 2016-2017 Settlement, which established revenue requirements for the system, expired on December 31, 2017. We continue to work with interested parties towards a new revenue requirement arrangement for 2018 and longer. While these discussions are underway, NGTL is operating under interim tolls for 2018 that were approved by the NEB on November 24, 2017.
- *Canadian Mainline Long-Term Fixed-Price Service:* On November 1, 2017, we began offering the new Long-Term Fixed-Price service on the Canadian Mainline. This NEB-approved service enables WCSB producers to transport up to 1.5 PJ/d (1.4 Bcf/d) of natural gas at a simplified toll of $0.77/GJ from the Empress receipt point in Alberta to the Dawn hub in Southern Ontario. The service is underpinned by ten-year contracts that have early termination rights after five years. Any early termination will result in an increased toll for the last two years of the contract.
- *Canadian Mainline 2018-2020 Toll Review:* Tolls for the Canadian Mainline were previously established for 2015 to 2017 in accordance with the terms of the 2015-2030 LDC Settlement. While the settlement specified tolls for 2015 to 2020, the NEB ordered a toll review halfway through the six-year period which must include costs, forecast volumes, contract levels, deferral balances and any other material changes. A Supplemental Agreement for the 2018 to 2020 period was executed on December 8, 2017 and filed for approval with the NEB on December 18, 2017. The Agreement proposes lower tolls, maintains an incentive arrangement that provides the opportunity for a 10.1 per cent or greater return on 40 per cent deemed equity and describes the revenue requirements and billing determinants for the 2018-2020 period. We anticipate the NEB will provide direction and process to adjudicate the application in first quarter 2018. Interim tolls for 2018 were filed at the level established by the agreement and subsequently approved by the NEB on December 19, 2017.

U.S. Natural Gas Pipelines:

- *Gibraltar:* Gibraltar, a Midstream project consisting of a 1,000 TJ/d (934 MMcf/d) dry gas header pipeline in southwest Pennsylvania, was placed in service November 1, 2017.
- *Rayne XPress:* Rayne Xpress was placed in service November 2, 2017. This Columbia Gulf project transports approximately 1.1 PJ/d (1.0 Bcf/d) of supply from an interconnect with the Leach XPress pipeline project, and another interconnect, to markets along the system and to the Gulf Coast.
- *Leach XPress:* Leach XPress was placed in service 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.
- *WB, Mountaineer and Gulf XPress:* The FERC certificate for WB XPress was received in November 2017 and the FERC certificates for Mountaineer XPress and Gulf XPress projects were received on December 29, 2017.

Mexico Natural Gas Pipelines:

- *Tula:* Construction of the Tula pipeline continues with completion revised to late 2019 due to delays experienced by the Secretary of Energy, the governmental department which conducts indigenous consultations in Mexico. Construction of the Tula pipeline was substantially completed in 2017 with the exception of approximately 90 km (56 miles) of the pipeline. The delay has been recognized by the CFE as a force majeure event and we are finalizing amending agreements to formalize the schedule and payment impacts. As a result of the delay and increased costs of land and permitting, estimated project costs have increased by US$0.1 billion from the original estimate.

- *Villa de Reyes:* Construction has commenced, however, delays due to archeological investigations by federal authorities have caused the in-service date of the project to be revised to late 2018. The delay has been recognized as a force majeure event by the CFE and we are finalizing amending agreements to formalize the schedule and payment impacts. As a result of the delay and increased costs of land and permitting, estimated project costs have increased by US$0.2 billion from the original estimate.
- *Sur de Texas:* Construction on the pipeline is progressing toward an anticipated in-service date of late 2018, with approximately 60 per cent of the off-shore construction completed as of the end of 2017.

Liquids Pipelines:

- *Keystone XL:* In February 2017, we filed an application with the Nebraska Public Service Commission (PSC) seeking approval for the Keystone XL pipeline route through that state and received approval for an alternate route on November 20, 2017. On December 27, 2017, opponents of the Keystone XL project, and intervenors in the Keystone XL Nebraska regulatory proceeding, filed an appeal of the November 20, 2017 PSC decision seeking to have that decision overturned. TransCanada supports the decision of the Nebraska PSC and will actively participate in the appeal process to defend that decision.

  In January 2018, TransCanada announced that we secured approximately 500,000 barrels per day of firm, 20-year commitments, following an open season in 2017, positioning the proposed project to proceed. The Company will look to continue to secure additional long-term contracted volumes. We are also continuing an outreach program in the communities where the pipeline will be constructed and are working collaboratively with landowners in an open and transparent way to obtain the necessary easements for the approved route. Construction preparation has commenced and will increase as the permitting process advances throughout 2018. Primary construction is expected to begin in 2019 and will take approximately two years to complete.

- *Keystone Pipeline System:* In fourth quarter 2017, we concluded open seasons for the Keystone and Marketlink pipeline systems and secured incremental long-term contractual support.

  On November 16, 2017, the Keystone pipeline was temporarily shut down after a leak was detected in Marshall County, South Dakota. On November 29, 2017, the pipeline was repaired and returned to service at a reduced pressure in the affected section of the pipeline. Further investigative activities and corrective measures required by the Pipeline and Hazardous Materials Safety Administration (PHMSA) are planned for 2018. This shutdown did not have a significant impact on our 2017 earnings.

- *Northern Courier:* The $1 billion Northern Courier project achieved commercial in-service in November 2017.
- *White Spruce:* In first quarter 2018, we anticipate receiving a decision from the Alberta Energy Regulator on the regulatory permit to construct the $200 million White Spruce pipeline, which will transport crude oil from Canadian Natural Resources Limited's Horizon facility in northeast Alberta into the Grand Rapids pipeline. Due to the delay in the regulatory process, we expect the White Spruce pipeline to be in-service in 2019.

- *Energy East and Related Projects:* In September 2017, we requested the NEB suspend the review of the Energy East and Eastern Mainline project applications for 30 days to provide time for us to conduct a careful review of the NEB's changes, announced on August 23, 2017, regarding the list of issues and environmental assessment factors related to the projects and how these changes impact the projects' costs, schedules and viability. In October 2017, we announced that we would no longer be pursuing these projects. We reviewed the $1.3 billion carrying value of the projects, including AFUDC capitalized since inception, and recorded a $954 million after-tax non-cash charge in fourth quarter 2017. With Energy East's inability to reach a regulatory decision, no recoveries of costs from third parties are forthcoming.

Energy:

- *Napanee:* Construction continues on our 900 MW natural gas-fired power plant. We expect to invest approximately $1.3 billion in the Napanee facility and commercial operations are expected to begin in fourth quarter 2018. Costs have increased due to delays in the construction schedule. Once in service, production from the facility is fully contracted with Ontario's Independent Electricity System Operator for a 20-year period.

- *Ontario Solar:* On October 24, 2017, we entered into an agreement to sell our Ontario solar assets comprised of eight facilities with a total generating capacity of 76 MWs. On December 19, 2017, we closed the sale for $541 million resulting in a pre-tax gain of $127 million ($136 million after-tax).
- *Monetization of U.S. Northeast power business:* On December 22, 2017, we entered into an agreement to sell our U.S. power retail contracts as part of the continued wind down of our U.S. power marketing operations. The transaction is expected to close in the first quarter of 2018 subject to regulatory and other approvals.

Corporate:

- *Common Share Dividend:* Our Board of Directors declared a quarterly dividend of $0.69 per share for the quarter ending March 31, 2018 on TransCanada's outstanding common shares. This represents an increase in the dividend of 10.4 per cent from the previous dividend and is equivalent to $2.76 per common share on an annualized basis.
- *Issuance of Senior Notes:* On November 15, 2017, we raised US$700 million in Senior Unsecured Notes at a fixed interest rate of 2.125 per cent and US$550 million in Senior Unsecured Notes at a floating rate, both due in November 2019.
- *Dividend Reinvestment Plan (DRP):* In 2017, the participation rate in our DRP was approximately 36 per cent of common share dividends, resulting in $790 million of common equity issued under the program.
- *ATM Equity Issuance Program:* In fourth quarter 2017, 3.5 million common shares were issued through the corporate ATM program at an average price of $63.03 per share for gross proceeds of $218 million.
- *U.S. Tax Reform:* As a result of changes to U.S. tax legislation resulting from the enactment of H.R. 1, the Tax Cuts and Jobs Act, in the fourth quarter we recorded an $804 million recovery of deferred income taxes, a $1,686 million increase in net regulatory liabilities and a $2,490 million decrease in net deferred income tax liabilities.

Teleconference and Webcast:

We will hold a teleconference and webcast on Thursday, February 15, 2018 to discuss our fourth quarter 2017 and year-end financial results. Russ Girling, TransCanada 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 2 p.m. (MST) / 4 p.m. (EST).

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

A replay of the teleconference will be available two hours after the conclusion of the call until midnight (EST) on February 22, 2018. Please call 800.408.3053 or 905.694.9451 (Toronto area) and enter pass code 2578190#.

The audited annual 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 currently 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.

Media Enquiries:
Mark Cooper / Grady Semmens
403.920.7859 or 800.608.7859

Investor & Analyst Enquiries:
David Moneta / Stuart Kampel
403.920.7911 or 800.361.6522

Fourth quarter 2017 financial highlights

(unaudited - millions of $, except per share amounts)	three months ended December 31 2017	three months ended December 31 2016	year ended December 31 2017	year ended December 31 2016
Income				
Revenues	**3,617**	3,635	**13,449**	12,547
Net income/(loss) attributable to common shares	**861**	(358)	**2,997**	124
per common share - basic	**$0.98**	($0.43)	**$3.44**	$0.16
- diluted	**$0.98**	($0.43)	**$3.43**	$0.16
Comparable EBITDA[1]	**1,903**	1,890	**7,377**	6,647
Comparable earnings[1]	**719**	626	**2,690**	2,108
per common share[1]	**$0.82**	$0.75	**$3.09**	$2.78
Operating cash flow				
Net cash provided by operations	**1,390**	1,575	**5,230**	5,069
Comparable funds generated from operations[1]	**1,450**	1,425	**5,641**	5,171
Comparable distributable cash flow[1]				
- reflecting all maintenance capital expenditures	**727**	928	**3,599**	3,541
- reflecting only non-recoverable maintenance capital expenditures	**1,268**	1,251	**4,963**	4,482
Comparable distributable cash flow per common share[1]				
- reflecting all maintenance capital expenditures	**$0.83**	$1.12	**$4.13**	$4.67
- reflecting only non-recoverable maintenance capital expenditures	**$1.45**	$1.50	**$5.69**	$5.91
Investing activities				
Capital spending[2]	**2,552**	2,016	**9,210**	6,067
Acquisitions, net of cash acquired	**—**	—	**—**	13,608
Proceeds from sales of assets, net of transaction costs	**1,170**	—	**5,317**	6
Dividends declared				
per common share	**$0.625**	$0.565	**$2.50**	$2.26
Basic common shares outstanding (millions)				
- weighted average	**877**	832	**872**	759
- issued and outstanding	**881**	864	**881**	864

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.

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 news release 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
- expected outcomes with respect to legal proceedings, including arbitration and insurance claims
- expected capital expenditures and contractual obligations
- expected operating and financial results
- the expected impact of future accounting changes, commitments and contingent liabilities
- the 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 news release.

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

Assumptions

- planned wind-down of our U.S. Northeast power marketing business
- inflation rates and commodity prices
- nature and scope of hedging
- regulatory decisions and outcomes
- 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

- outcomes of legal proceedings, including arbitration and insurance claims
- performance and credit risk of our counterparties
- changes in market commodity prices
- 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
- 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 reports we have filed with Canadian securities regulators and the SEC, including the MD&A in our 2016 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 news release 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 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 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/(loss) attributable to common shares
comparable earnings per common share	net income/(loss) per common share
comparable EBITDA	segmented earnings/(losses)
comparable EBIT	segmented earnings/(losses)
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 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 the specific items. See the reconciliation of net income to comparable earnings.

Comparable EBIT and comparable EBITDA

Comparable EBIT represents segmented earnings adjusted for the specific items described above. 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 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 noted above. See the comparable distributable cash flow section for the reconciliation to net cash provided by operations.

Comparable distributable cash flow and comparable distributable cash flow per 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. See the comparable distributable cash flow section for the reconciliation to net cash provided by operations.

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. The majority of our U.S. natural gas pipelines can seek to recover maintenance capital expenditures through rates established in future rate cases or rate settlements. As such, these maintenance capital expenditures are effectively recovered in the same manner as expansion capital expenditures. Tolling arrangements in Liquids Pipelines provide for recovery of maintenance capital.

Effective December 31, 2017, we amended our presentation of comparable distributable cash flow and comparable distributable cash flow per share to illustrate the impact of excluding recoverable maintenance capital expenditures from their respective calculations. We have included comparable distributable cash flow and comparative distributable cash flow per share for 2016 to reflect the amended presentation format which we believe provides better information for readers.

Consolidated results - fourth quarter 2017

We operate in three core businesses - Natural Gas Pipelines, Liquids Pipelines and Energy. In order to provide information that is aligned with how management decisions about our business are made and how performance of our business is assessed, our results are reflected in five operating segments: Canadian Natural Gas Pipelines, U.S. Natural Gas Pipelines, Mexico Natural Gas Pipelines, Liquids Pipelines and Energy. We also have a non-operational Corporate segment consisting of corporate and administrative functions that provide governance and other support to our operational business segments.

Certain costs previously reported in our Corporate segment are now being reported within the business segments to better align with how we measure our financial performance. 2016 results have been adjusted to reflect this change.

	three months ended December 31		year ended December 31	
(unaudited - millions of $, except per share amounts)	**2017**	**2016**	**2017**	**2016**
Canadian Natural Gas Pipelines	**333**	364	**1,236**	1,307
U.S. Natural Gas Pipelines	**461**	403	**1,760**	1,190
Mexico Natural Gas Pipelines	**93**	103	**426**	287
Liquids Pipelines	**(932)**	213	**(251)**	806
Energy	**472**	(574)	**1,552**	(1,157)
Corporate	**63**	(33)	**(39)**	(120)
Total segmented earnings	**490**	476	**4,684**	2,313
Interest expense	**(541)**	(542)	**(2,069)**	(1,998)
Allowance for funds used during construction	**140**	97	**507**	419
Interest income and other	**(9)**	(15)	**184**	103
Income before income taxes	**80**	16	**3,306**	837
Income tax recovery/(expense)	**870**	(274)	**89**	(352)
Net income/(loss)	**950**	(258)	**3,395**	485
Net income attributable to non-controlling interests	**(49)**	(68)	**(238)**	(252)
Net income/(loss) attributable to controlling interests	**901**	(326)	**3,157**	233
Preferred share dividends	**(40)**	(32)	**(160)**	(109)
Net income/(loss) attributable to common shares	**861**	(358)	**2,997**	124
Net income/(loss) per common share				
- basic	**$0.98**	($0.43)	**$3.44**	$0.16
- diluted	**$0.98**	($0.43)	**$3.43**	$0.16

Net income/(loss) attributable to common shares increased by $1,219 million or $1.41 per share for the three months ended December 31, 2017 compared to the same period in 2016 due to the changes in net income described below, as well as the dilutive effect of issuing 60 million common shares in the fourth quarter of 2016 and common shares issued under our DRP and corporate ATM program in 2017.

Fourth quarter 2017 results included:

- 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.

Fourth quarter 2016 results included:

- 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 closing of the acquisition and $23 million of retention, severance and integration costs
- an $18 million after-tax charge related to the maintenance and liquidation of Keystone XL assets which were 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 form part of a restructuring initiative, which commenced in 2015, to maximize the effectiveness and efficiency of our existing operations and reduce overall costs.

Net income in all periods included unrealized gains and losses from changes in risk management activities which we exclude, along with the above-noted items, to arrive at comparable earnings. A reconciliation of net income/(loss) attributable to common shares to comparable earnings is shown in the following table.

RECONCILIATION OF NET INCOME/(LOSS) TO COMPARABLE EARNINGS

	three months ended December 31		year ended December 31	
(unaudited - millions of $, except per share amounts)	2017	2016	2017	2016
Net income/(loss) attributable to common shares	**861**	(358)	**2,997**	124
Specific items (net of tax):				
U.S. Tax Reform adjustment	**(804)**	—	**(804)**	—
Gain on sale of Ontario solar assets	**(136)**	—	**(136)**	—
Net (gain)/loss on sales of U.S. Northeast power assets	**(64)**	870	**(307)**	873
Energy East impairment charge	**954**	—	**954**	—
Keystone XL asset costs	**9**	18	**28**	42
Integration and acquisition related costs – Columbia	**—**	67	**69**	273
Keystone XL income tax recoveries	**—**	—	**(7)**	(28)
Ravenswood goodwill impairment	**—**	—	**—**	656
Alberta PPA terminations and settlement	**—**	68	**—**	244
Restructuring costs	**—**	6	**—**	16
TC Offshore loss on sale	**—**	—	**—**	3
Risk management activities[1]	**(101)**	(45)	**(104)**	(95)
Comparable earnings	**719**	626	**2,690**	2,108
Net income/(loss) per common share	**$0.98**	($0.43)	**$3.44**	$0.16
Specific items (net of tax):				
U.S. Tax Reform adjustment	**(0.92)**	—	**(0.92)**	—
Gain on sale of Ontario solar assets	**(0.16)**	—	**(0.16)**	—
Net loss/(gain) on sales of U.S. Northeast power assets	**(0.08)**	1.05	**(0.34)**	1.15
Energy East impairment charge	**1.09**	—	**1.09**	—
Keystone XL asset costs	**0.01**	0.02	**0.03**	0.06
Integration and acquisition related costs – Columbia	**—**	0.08	**0.08**	0.37
Keystone XL income tax recoveries	**—**	—	**(0.01)**	(0.04)
Ravenswood goodwill impairment	**—**	—	**—**	0.86
Alberta PPA terminations and settlement	**—**	0.08	**—**	0.32
Restructuring costs	**—**	0.01	**—**	0.02
Risk management activities	**(0.10)**	(0.06)	**(0.12)**	(0.12)
Comparable earnings per common share	**$0.82**	$0.75	**$3.09**	$2.78

1

Risk management activities	three months ended December 31		year ended December 31	
(unaudited - millions of $)	2017	2016	2017	2016
Canadian Power	**6**	1	**11**	4
U.S. Power	**136**	97	**39**	113
Liquids marketing	**15**	4	**—**	(2)
Natural Gas Storage	**7**	(1)	**12**	8
Interest rate	**—**	—	**(1)**	—
Foreign exchange	**(1)**	(23)	**88**	26
Income tax attributable to risk management activities	**(62)**	(33)	**(45)**	(54)
Total unrealized gains from risk management activities	**101**	45	**104**	95

Comparable earnings increased by $93 million or $0.07 per share for the three months ended December 31, 2017 compared to the same period in 2016 and was primarily the net effect of:

- increased earnings from Liquids Pipelines primarily due to higher uncontracted volumes on the Keystone Pipeline System, liquids marketing activities, and the commencement of operations on Grand Rapids and Northern Courier
- higher contribution from U.S. Natural Gas Pipelines due to lower operating costs including synergies achieved from the Columbia acquisition
- higher AFUDC on our rate-regulated U.S. natural gas pipelines, partially offset by our decision not to proceed with the Energy East Pipeline
- higher earnings from Bruce Power mainly due to higher volumes resulting from fewer outage days
- lower contribution from U.S. Power due to the monetization of our U.S. Northeast power generation assets in second quarter 2017 and the continued wind-down of our U.S. power marketing operations
- an after-tax impairment charge in 2017 of $16 million related to obsolete Energy equipment.

U.S. TAX REFORM

On December 22, 2017, H.R. 1, the Tax Cuts and Jobs Act (U.S. Tax Reform or the Act) 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, we have remeasured existing deferred income tax assets and deferred income tax liabilities related to our U.S. businesses to reflect the new lower income tax rate as at December 31, 2017.

For our businesses in the U.S. not subject to rate-regulated accounting (RRA), the reduction in enacted tax rates has been recorded as a decrease in net deferred income tax liabilities and income tax expense, resulting in an increase in net income attributable to common shares in the fourth quarter and for the year ended December 31, 2017 in the amount of $816 million.

For our businesses in the U.S. subject to RRA, we expect the lower income tax rates to impact future rate setting processes and have therefore recognized a net regulatory liability with a corresponding reduction in net deferred income tax liabilities in the amount of $1,686 million. These regulatory liabilities will be amortized to earnings over time.

Net deferred income tax liabilities related to the cumulative remeasurements of employee post-retirement benefits included in accumulated other comprehensive income have also been adjusted with a corresponding increase in deferred income tax expense of $12 million.

Given the significance of the legislation, the Securities and Exchange Commission (SEC) issued guidance which allows registrants to record provisional amounts which may be adjusted as information becomes available, prepared or analyzed during a measurement period not to exceed one year.

The SEC guidance summarizes a three-step process to be applied at each reporting period to identify: (1) where the accounting is complete; (2) provisional amounts where the accounting is not yet complete, but a reasonable estimate has been determined; and (3) where a reasonable estimate cannot yet be determined and therefore income taxes are reflected in accordance with law prior to the enactment of the Act.

At December 31, 2017, we consider all amounts recorded related to U.S. Tax Reform to be reasonable estimates. Amounts related to businesses subject to RRA are provisional as our interpretation, assessment and presentation of the impact of the tax law change 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, we will review the provisional amounts and adjust as appropriate.

As a result of the lower U.S. income tax rates included as part of the Act, we expect a modest increase to 2018 earnings. In addition to the reduction in statutory rates, longer-term there are several other provisions in the new legislation which may impact us prospectively, including changes to the expensing of depreciable property, limitations to interest deductions, the creation of Base Erosion Anti-Abuse Tax along with certain exemptions for rate-regulated businesses. We continue to evaluate the impact of these and other provisions of the Act.

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 $23 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 $)	Expected in-service date	Estimated project cost	Carrying value at December 31, 2017
Canadian Natural Gas Pipelines			
Canadian Mainline	2018-2021	0.2	—
NGTL System	2018	0.6	0.2
	2019	2.3	0.3
	2020	1.6	0.1
	2021	2.7	—
U.S. Natural Gas Pipelines			
Columbia Gas			
Leach XPress[1]	2018	US 1.6	US 1.5
WB XPress	2018	US 0.8	US 0.4
Mountaineer XPress	2018	US 2.6	US 0.5
Modernization II	2018-2020	US 1.1	US 0.1
Buckeye XPress	2020	US 0.2	—
Columbia Gulf			
Cameron Access	2018	US 0.3	US 0.3
Gulf XPress	2018	US 0.6	US 0.2
Other[2]	2018-2020	US 0.3	—
Mexico Natural Gas Pipelines			
Sur de Texas[3]	2018	US 1.3	US 1.0
Villa de Reyes	2018	US 0.8	US 0.5
Tula	2019	US 0.7	US 0.5
Liquids Pipelines			
White Spruce	2019	0.2	—
Energy			
Napanee	2018	1.3	0.9
Bruce Power – life extension[4]	up to 2020	0.9	0.3
		20.1	**6.8**
Foreign exchange impact on near-term projects[5]		**2.6**	**1.3**
Total near-term projects (billions of Cdn$)		**22.7**	**8.1**

1 Leach XPress was placed in service in January 2018.
2 Reflects our proportionate share of costs related to Portland Xpress and various expansion projects.
3 Our proportionate share.

4 Amount 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.
5 Reflects U.S./Canada foreign exchange rate of 1.25 at December 31, 2017.

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 applicable 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 $)	**Segment**	**Estimated project cost**	**Carrying value at December 31, 2017**
Heartland and TC Terminals[1]	Liquids Pipelines	0.9	0.1
Grand Rapids Phase 2[2]	Liquids Pipelines	0.7	—
Bruce Power – life extension[2]	Energy	5.3	—
Keystone projects			
Keystone XL[3]	Liquids Pipelines	US 8.0	US 0.3
Keystone Hardisty Terminal[1,3]	Liquids Pipelines	0.3	0.1
BC west coast LNG-related projects			
Coastal GasLink	Canadian Natural Gas Pipelines	4.8	0.4
NGTL System – Merrick	Canadian Natural Gas Pipelines	1.9	—
		21.9	0.9
Foreign exchange impact on medium to longer-term projects[4]		2.0	0.1
Total medium to longer-term projects (billions of Cdn$)		**23.9**	**1.0**

1 Regulatory approvals have been obtained, additional commercial support is being pursued.
2 Our proportionate share.
3 Carrying value reflects amount remaining after impairment charge recorded in 2015.
4 Reflects U.S./Canada foreign exchange rate of 1.25 at December 31, 2017.

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). Certain costs previously reported in our Corporate segment are now being reported within the business segments to better align with how we measure our financial performance. 2016 results have been adjusted to reflect this change.

	three months ended December 31		year ended December 31	
(unaudited - millions of $)	**2017**	**2016**	**2017**	**2016**
NGTL System	**274**	255	**996**	968
Canadian Mainline	**269**	305	**1,043**	1,105
Other Canadian pipelines[1]	**29**	27	**110**	116
Business development	**(3)**	(3)	**(5)**	(7)
Comparable EBITDA	**569**	584	**2,144**	2,182
Depreciation and amortization	**(236)**	(220)	**(908)**	(875)
Comparable EBIT and segmented earnings	**333**	364	**1,236**	1,307

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

Canadian Natural Gas Pipelines segmented earnings decreased by $31 million for the three months ended December 31, 2017 compared to the same period in 2016 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. Changes in depreciation, financial charges and income taxes also impact comparable EBITDA but do not have a significant impact on net income as they are almost entirely recovered in revenue on a flow-through basis.

NET INCOME - NGTL SYSTEM AND CANADIAN MAINLINE

	three months ended December 31		year ended December 31	
(unaudited - millions of $)	**2017**	**2016**	**2017**	**2016**
NGTL System	**91**	85	**352**	318
Canadian Mainline	**50**	54	**199**	208

Net income for the NGTL System increased by $6 million for the three months ended December 31, 2017 compared to the same period in 2016 mainly due to a higher average investment base, partially offset by lower OM&A incentive earnings. The NGTL System operated under the two-year 2016-2017 Revenue Requirement Settlement which included an ROE of 10.1 per cent on 40 per cent deemed equity and a mechanism for sharing variances between actual and a fixed OM&A amount.

Canadian Mainline's net income decreased by $4 million for the three months ended December 31, 2017 compared to the same period in 2016 primarily due to a lower average investment base and lower incentive earnings. The Canadian Mainline is operating under the NEB 2014 Decision which includes an approved ROE of 10.1 per cent on a 40 per cent deemed equity with a possible range of achieved outcomes between 8.7 per cent and 11.5 per cent. The decision also includes an incentive mechanism that has both upside and downside risk and a $20 million annual after-tax contribution from TransCanada.

DEPRECIATION AND AMORTIZATION

Depreciation and amortization increased by $16 million for the three months ended December 31, 2017 compared to the same period in 2016 mainly due to facilities that were placed in service for the NGTL System and Canadian Mainline.

OPERATING STATISTICS - NGTL SYSTEM AND CANADIAN MAINLINE

year ended December 31	NGTL System[1]		Canadian Mainline[2]	
(unaudited)	**2017**	**2016**	**2017**	**2016**
Average investment base (millions of $)	**8,385**	7,451	**4,184**	4,441
Delivery volumes (Bcf):				
Total	**4,153**	4,055	**1,620**	1,634
Average per day	**11.4**	11.1	**4.4**	4.5

1 Field receipt volumes for the NGTL System for the year ended December 31, 2017 were 4,224 Bcf (2016 – 4,117 Bcf). Average per day was 11.6 Bcf (2016 – 11.3 Bcf).

2 Canadian Mainline's throughput volumes represent physical deliveries to domestic and export markets. Physical receipts originating at the Alberta border and in Saskatchewan for the year ended December 31, 2017 were 1,019 Bcf (2016 – 1,055 Bcf). Average per day was 2.8 Bcf (2016 – 2.9 Bcf).

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). Certain costs previously reported in our Corporate segment are now being reported within the business segments to better align with how we measure our financial performance. 2016 results have been adjusted to reflect this change.

	three months ended December 31		year ended December 31	
(unaudited - millions of US$, unless otherwise noted)	**2017**	**2016**	**2017**	**2016**
Columbia Gas[1]	**177**	146	**623**	269
ANR	**99**	88	**400**	321
TC PipeLines, LP[2,3]	**27**	28	**110**	118
Midstream[1]	**23**	14	**93**	40
Columbia Gulf[1]	**21**	14	**76**	25
Great Lakes[3,4]	**15**	12	**64**	60
Other U.S. pipelines[1,2,3,5]	**30**	28	**108**	74
Non-controlling interests[6]	**84**	101	**341**	365
Business development	**(1)**	(1)	**(2)**	(3)
Comparable EBITDA	**475**	430	**1,813**	1,269
Depreciation and amortization	**(113)**	(118)	**(453)**	(322)
Comparable EBIT	**362**	312	**1,360**	947
Foreign exchange impact	**99**	102	**410**	310
Comparable EBIT (Cdn$)	**461**	414	**1,770**	1,257
Specific items:				
Integration and acquisition related costs – Columbia	**—**	(11)	**(10)**	(63)
TC Offshore loss on sale	**—**	—	**—**	(4)
Segmented earnings (Cdn$)	**461**	403	**1,760**	1,190

1 We completed the acquisition of Columbia on July 1, 2016. Results reflect our effective ownership in these assets from that date.

2 Results from Northern Border and Iroquois reflect our share of equity income from these investments. We acquired additional interests in Iroquois of 4.87 per cent on March 31, 2016 and 0.65 per cent on May 1, 2016. TC PipeLines, LP acquired 49.34 per cent of our 50 per cent interest in Iroquois on June 1, 2017. On January 1, 2016, we sold a 49.9 per cent direct interest in PNGTS to TC PipeLines, LP and its remaining 11.81 per cent interest to TC PipeLines, LP on June 1, 2017.

3 TC PipeLines, LP periodically conducts at-the-market equity issuances which decrease our ownership in TC PipeLines, LP. The following shows our ownership interest in TC PipeLines, LP and our effective ownership interest of Great Lakes and PNGTS through our ownership interest in TC PipeLines, LP at the date presented.

	Effective ownership percentage as of	
	December 31, 2017	**December 31, 2016**
TC PipeLines, LP	25.7	26.8
Effective ownership through TC PipeLines, LP:		
Great Lakes	11.9	12.5
PNGTS	15.9	13.4

4 Represents our 53.6 per cent direct interest in Great Lakes. The remaining 46.4 per cent is held by TC PipeLines, LP.

5 Includes our direct ownership in Iroquois and PNGTS (until June 1, 2017), our effective ownership in Millennium and Hardy Storage, and general and administrative costs related to U.S. natural gas assets.

6 Comparable EBITDA for the portions of TC PipeLines, LP, PNGTS (until June 1, 2017) and CPPL that we do not own. Effective February 17, 2017, we acquired the remaining publicly held units of CPPL.

U.S. Natural Gas Pipelines segmented earnings increased by $58 million for the three months ended December 31, 2017 compared to the same period in 2016. Segmented earnings for the three months ended December 31, 2016 included pre-tax costs of $11 million mainly related to retention and severance expenses resulting from the Columbia acquisition. These amounts have been excluded from our calculation of comparable EBIT.

Earnings from our U.S. Natural Gas Pipelines operations, which include Columbia effective July 1, 2016, 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$45 million for the three months ended December 31, 2017 compared to the same period in 2016. This was primarily due to lower operating costs including synergies achieved from the Columbia acquisition.

DEPRECIATION AND AMORTIZATION

Depreciation and amortization decreased by US$5 million for the three months ended December 31, 2017 compared to the same period in 2016 primarily due to fair value adjustments related to our Midstream assets recorded in fourth quarter 2016.

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). Certain costs previously reported in our Corporate segment are now being reported within the business segments to better align with how we measure our financial performance. 2016 results have been adjusted to reflect this change.

	three months ended December 31		year ended December 31	
(unaudited - millions of US$, unless otherwise noted)	**2017**	2016	**2017**	2016
Topolobampo	**38**	41	**157**	81
Tamazunchale	**27**	26	**112**	105
Guadalajara	**17**	18	**68**	67
Mazatlán	**16**	5	**65**	5
Sur de Texas[1]	**(6)**	—	**8**	—
Other	**(1)**	(3)	**(11)**	(3)
Business development	**—**	(1)	**—**	(5)
Comparable EBITDA	**91**	86	**399**	250
Depreciation and amortization	**(18)**	(12)	**(72)**	(35)
Comparable EBIT	**73**	74	**327**	215
Foreign exchange impact	**20**	29	**99**	72
Comparable EBIT and segmented earnings (Cdn$)	**93**	103	**426**	287

1 Represents our 60 per cent equity interest in a joint venture with IEnova to build, own and operate the Sur de Texas pipeline.

Mexico Natural Gas Pipelines segmented earnings decreased by $10 million for the three months ended December 31, 2017 compared to the same period in 2016 and are equivalent to comparable EBIT. Aside from the commercial factors outlined below, a weaker U.S. dollar had a negative impact on the Canadian dollar equivalent segmented earnings from our Mexico operations.

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.

Comparable EBITDA for Mexico Natural Gas Pipelines increased by US$5 million for the three months December 31, 2017 compared to the same period in 2016 and was the net effect of:

- incremental earnings from Mazatlán beginning December 2016
- 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 interest is fully offset in interest income and other in the Corporate segment.

DEPRECIATION AND AMORTIZATION

Depreciation and amortization increased by US$6 million for the three months ended December 31, 2017 compared to the same period in 2016 primarily due to the commencement of depreciation on Mazatlán.

Liquids Pipelines

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented earnings (the equivalent GAAP measure). Certain costs previously reported in our Corporate segment are now being reported within the business segments to better align with how we measure our financial performance. 2016 results have been adjusted to reflect this change.

	three months ended December 31		year ended December 31	
(unaudited - millions of $)	**2017**	**2016**	**2017**	**2016**
Keystone Pipeline System	**346**	296	**1,283**	1,155
Intra-Alberta pipelines	**29**	—	**33**	—
Other services[1]	**26**	6	**32**	(3)
Comparable EBITDA	**401**	302	**1,348**	1,152
Depreciation and amortization	**(81)**	(78)	**(309)**	(292)
Comparable EBIT	**320**	224	**1,039**	860
Specific items:				
Energy East impairment charge	**(1,256)**	—	**(1,256)**	—
Keystone XL asset costs	**(11)**	(15)	**(34)**	(52)
Risk management activities	**15**	4	**—**	(2)
Segmented (losses)/earnings	**(932)**	213	**(251)**	806

Comparable EBIT denominated as follows:				
Canadian dollars	**80**	63	**255**	223
U.S. dollars	**188**	122	**604**	482
Foreign exchange impact	**52**	39	**180**	155
	320	224	**1,039**	860

1 Includes primarily liquids marketing and business development activities.

Liquids Pipelines segmented earnings decreased by $1,145 million for the three months ended December 31, 2017 compared to the same period in 2016. This was primarily the net effect of a $1,256 million pre-tax impairment charge for the Energy East pipeline and related projects, $11 million (2016 - $15 million) of pre-tax costs related to Keystone XL for the maintenance and liquidation of project assets which were expensed pending further advancement of the project, and unrealized gains from changes in the fair value of derivatives related to our liquids marketing business. These amounts have been excluded from our calculation of comparable EBIT.

Keystone Pipeline System earnings are generated primarily by providing pipeline capacity to shippers for fixed monthly payments that are not linked to actual throughput volumes. Uncontracted capacity is offered to the market on a spot basis and provides opportunities to generate incremental earnings.

Comparable EBITDA for Liquids Pipelines increased by $99 million for the three months ended December 31, 2017 compared to the same period in 2016 and was the net effect of:

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

DEPRECIATION AND AMORTIZATION

Depreciation and amortization increased by $3 million for the three months ended December 31, 2017 compared to the same period in 2016 as a result of the 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). Certain costs previously reported in our Corporate segment are now being reported within the business segments to better align with how we measure our financial performance. 2016 results have been adjusted to reflect this change.

	three months ended December 31		year ended December 31	
(unaudited - millions of $)	**2017**	**2016**	**2017**	**2016**
Canadian Power				
Western Power[1]	**23**	26	**100**	74
Eastern Power	**92**	82	**344**	349
Bruce Power	**120**	83	**434**	293
Canadian Power - comparable EBITDA[1,2]	**235**	191	**878**	716
Depreciation and amortization	**(30)**	(26)	**(138)**	(145)
Canadian Power - comparable EBIT[1,2]	**205**	165	**740**	571
U.S. Power - comparable EBITDA[3] (US$)	**(8)**	73	**100**	394
Depreciation and amortization[4]	**—**	(11)	**—**	(109)
U.S. Power - comparable EBIT	**(8)**	62	**100**	285
Foreign exchange impact	**(4)**	20	**30**	92
U.S. Power - comparable EBIT (Cdn$)	**(12)**	82	**130**	377
Natural Gas Storage and other operations - comparable EBITDA	**15**	20	**55**	58
Depreciation and amortization	**(3)**	(3)	**(13)**	(12)
Natural Gas Storage and other operations - comparable EBIT	**12**	17	**42**	46
Business Development and other costs - comparable EBITDA and EBIT[5]	**(24)**	(4)	**(33)**	(15)
Energy - comparable EBIT	**181**	260	**879**	979
Specific items:				
Gain on sale of Ontario solar assets	**127**	—	**127**	—
Gain/(loss) on sales of U.S. Northeast power assets	**15**	(839)	**484**	(844)
Ravenswood goodwill impairment	**—**	—	**—**	(1,085)
Alberta PPA terminations and settlement	**—**	(92)	**—**	(332)
Risk management activities	**149**	97	**62**	125
Segmented earnings/(losses)	**472**	(574)	**1,552**	(1,157)

1 Included losses from the Alberta PPAs up to March 2016 when the PPAs were terminated.
2 Includes our share of equity income from our investments in Portlands Energy and Bruce Power.
3 TC Hydro earnings included up to April 19, 2017 sale date; Ravenswood, Ironwood, Ocean State Power and Kibby Wind earnings included up to June 2, 2017 sale date.
4 Depreciation of U.S. Northeast power assets ceased effective November 2016 when classified as assets held for sale.
5 Includes a $21 million impairment charge in fourth quarter 2017 of obsolete equipment.

Energy segmented earnings increased by $1,046 million for the three months ended December 31, 2017 compared to the same period in 2016 and included the following specific items:

- a gain in 2017 of $127 million before tax related to the sale of our Ontario solar assets
- a net gain in 2017 of $15 million before tax related to the monetization of our U.S. Northeast power assets which consisted primarily of insurance recoveries for a portion of repair costs incurred during an unplanned outage at Ravenswood prior to its sale
- in 2016, a loss of $839 million before tax related to the sale of the U.S. Northeast power assets which included an $829 million pre-tax loss on the thermal and wind package and $10 million of pre-tax disposition costs
- in 2016, a $92 million before tax loss on the transfer of environmental credits to the Balancing Pool upon final settlement of the Alberta PPA terminations
- unrealized gains and losses in both years from changes in the fair value of derivatives used to reduce our exposure to certain commodity price risks

The remainder of the Energy segmented earnings are equivalent to comparable EBIT along with comparable EBITDA.

CANADIAN POWER

Western Power

Western Power comparable EBITDA was consistent for the three months ended December 31, 2017 compared to the same period in 2016.

Eastern Power

Eastern Power comparable EBITDA increased by $10 million for the three months ended December 31, 2017 compared to the same period in 2016 mainly due to higher earnings from our wind facilities.

DEPRECIATION AND AMORTIZATION

Depreciation and amortization increased by $4 million primarily due to a 2016 adjustment related to the expected useful life of our cogeneration assets, partially offset by the cessation of depreciation on our Ontario solar assets upon classification as held for sale in October 2017.

Bruce Power

Bruce Power results reflect our proportionate share. The following is our proportionate share of the components of comparable EBITDA and comparable EBIT.

	three months ended December 31		year ended December 31	
(unaudited - millions of $, unless otherwise noted)	**2017**	**2016**	**2017**	**2016**
Equity income included in comparable EBITDA and EBIT comprised of:				
Revenues	**414**	382	**1,626**	1,491
Operating expenses	**(208)**	(212)	**(846)**	(870)
Depreciation and other	**(86)**	(87)	**(346)**	(328)
Comparable EBITDA and comparable EBIT[1]	**120**	83	**434**	293
Bruce Power – other information				
Plant availability[2]	**92%**	85%	**90%**	83%
Planned outage days	**43**	80	**221**	415
Unplanned outage days	**10**	27	**49**	76
Sales volumes (GWh)[1]	**6,275**	5,758	**24,368**	22,178
Realized sales price per MWh[3]	**$67**	$69	**$67**	$68

1 Represents our 48.4 per cent (2016 - 48.5 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.

Bruce Power comparable EBITDA increased by $37 million for the three months ended December 31, 2017 compared to the same period in 2016 mainly due to higher volumes resulting from fewer outage days.

U.S. POWER

In second quarter 2017, we completed the sales of our U.S. Power generation assets and initiated the wind down of our U.S. power marketing operations.

NATURAL GAS STORAGE AND OTHER OPERATING

Natural Gas Storage comparable EBITDA decreased by $5 million for the three months ended December 31, 2017 compared to the same period in 2016 mainly due to lower realized natural gas storage price spreads.

Corporate

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented earnings/(losses) (the equivalent GAAP measure). Certain costs previously reported in our Corporate segment are now being reported within the business segments to better align with how we measure our financial performance. 2016 results have been adjusted to reflect this change.

	three months ended December 31		year ended December 31	
(unaudited - millions of $)	2017	2016	2017	2016
Comparable EBITDA and EBIT	**(1)**	11	**(21)**	18
Specific items:				
Integration and acquisition related costs – Columbia	**—**	(36)	**(81)**	(116)
Foreign exchange gain – inter-affiliate loan[1]	**64**	—	**63**	—
Restructuring costs	**—**	(8)	**—**	(22)
Segmented earnings/(losses)	**63**	(33)	**(39)**	(120)

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

Corporate segmented earnings were $63 million for the three months ended December 31, 2017 compared to a loss of $33 million for the same period in 2016 and included the following specific items that have been excluded from comparable EBIT:

- in 2017, a foreign exchange gain 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 loss included in interest income and other on the inter-affiliate loan receivable which fully offsets this gain
- in 2016, pre-tax integration and acquisition costs associated with the acquisition of Columbia and restructuring costs.

Comparable EBITDA decreased by $12 million for the three months ended December 31, 2017 compared to the same period in 2016 primarily due to increased general and administrative costs.

OTHER INCOME STATEMENT ITEMS

Interest expense

(unaudited - millions of $)	three months ended December 31 2017	2016	year ended December 31 2017	2016
Interest on long-term debt and junior subordinated notes				
Canadian dollar-denominated	**(138)**	(109)	**(494)**	(452)
U.S. dollar-denominated	**(315)**	(316)	**(1,269)**	(1,127)
Foreign exchange impact	**(86)**	(106)	**(379)**	(366)
	(539)	(531)	**(2,142)**	(1,945)
Other interest and amortization expense	**(25)**	(54)	**(99)**	(114)
Capitalized interest	**23**	43	**173**	176
Interest expense included in comparable earnings	**(541)**	(542)	**(2,068)**	(1,883)
Specific items:				
Integration and acquisition related costs – Columbia	**—**	—	**—**	(115)
Risk management activities	**—**	—	**(1)**	—
Interest expense	**(541)**	(542)	**(2,069)**	(1,998)

Interest expense was consistent for the three months ended December 31, 2017 compared to the same period in 2016 and reflects the net effect of:

- Canadian and U.S. dollar-denominated long-term debt and junior subordinated note issuances in 2017, net of maturities
- retirement of the Columbia acquisition bridge facilities in June 2017
- the impact of a weaker U.S. dollar in translating U.S. dollar-denominated interest
- lower capitalized interest on Liquids Pipelines projects placed in-service in 2017.

Allowance for funds used during construction

(unaudited - millions of $)	three months ended December 31 2017	2016	year ended December 31 2017	2016
Canadian dollar-denominated	**25**	48	**174**	181
U.S. dollar-denominated	**91**	32	**259**	181
Foreign exchange impact	**24**	17	**74**	57
Allowance for funds used during construction	**140**	97	**507**	419

AFUDC increased by $43 million for the three months ended December 31, 2017 compared to the same period in 2016 primarily due to to continued investment in and higher rates on projects acquired as part of the 2016 Columbia acquisition, as well as continued investment in Mexico projects, partially offset by the commercial in-service of Topolobampo, the completion of Mazatlán construction and our decision not to proceed with the Energy East Pipeline.

Interest income and other

	three months ended December 31		year ended December 31	
(unaudited - millions of $)	**2017**	**2016**	**2017**	**2016**
Interest income and other included in comparable earnings	**56**	8	**159**	71
Specific items:				
Integration and acquisition related costs – Columbia	**—**	—	**—**	6
Foreign exchange loss – inter-affiliate loan	**(64)**	—	**(63)**	—
Risk management activities	**(1)**	(23)	**88**	26
Interest income and other	**(9)**	(15)	**184**	103

Interest income and other increased by $6 million for the three months ended December 31, 2017 compared to the same period in 2016 due to the net effect of:

- higher interest income along with a $64 million foreign exchange loss related to an inter-affiliate loan receivable from the Sur de Texas joint venture. The corresponding interest expense and foreign exchange gain 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
- lower unrealized losses on risk management activities in 2017 compared to 2016. These amounts have been excluded from comparable earnings
- foreign exchange impact on the translation of foreign currency denominated working capital balances.

Income tax expense

	three months ended December 31		year ended December 31	
(unaudited - millions of $)	**2017**	**2016**	**2017**	**2016**
Income tax expense included in comparable earnings	**(234)**	(211)	**(839)**	(841)
Specific items:				
U.S. Tax Reform adjustment	**804**	—	**804**	—
Energy East impairment charge	**302**	—	**302**	—
Net loss/(gain) on sales of U.S. Northeast power assets	**49**	(31)	**(177)**	(29)
Gain on sale of Ontario solar assets	**9**	—	**9**	—
Keystone XL asset costs	**2**	(3)	**6**	10
Integration and acquisition related costs – Columbia	**—**	(22)	**22**	10
Keystone XL income tax recoveries	**—**	—	**7**	28
Ravenswood goodwill impairment	**—**	—	**—**	429
Alberta PPA terminations	**—**	24	**—**	88
Restructuring costs	**—**	2	**—**	6
TC Offshore loss on sale	**—**	—	**—**	1
Risk management activities	**(62)**	(33)	**(45)**	(54)
Income tax recovery/(expense)	**870**	(274)	**89**	(352)

Income tax expense included in comparable earnings increased by $23 million for the three months ended December 31, 2017 compared to the same period in 2016 primarily due to an increase in comparable earnings, changes in the proportion of income earned between Canadian and foreign jurisdictions and changes in flow-through taxes in regulatory operations.

Net income attributable to non-controlling interests

(unaudited - millions of $)	three months ended December 31 2017	three months ended December 31 2016	year ended December 31 2017	year ended December 31 2016
Net income attributable to non-controlling interests included in comparable earnings	**(49)**	(70)	**(238)**	(257)
Specific items:				
Acquisition related costs – Columbia	**—**	2	**—**	5
Net income attributable to non-controlling interests	**(49)**	(68)	**(238)**	(252)

Net income attributable to non-controlling interests decreased by $19 million, and $21 million as included in comparable earnings, for the three months ended December 31, 2017 compared to the same period in 2016 primarily due to the acquisition of the remaining outstanding publicly held common units of CPPL in February 2017.

Preferred share dividends

(unaudited - millions of $)	three months ended December 31 2017	three months ended December 31 2016	year ended December 31 2017	year ended December 31 2016
Preferred share dividends	**(40)**	(32)	**(160)**	(109)

Preferred share dividends increased by $8 million for the three months ended December 31, 2017 compared to the same period in 2016 primarily due to the issuance of Series 15 preferred shares in November 2016.

COMPARABLE DISTRIBUTABLE CASH FLOW

(unaudited - millions of $, except per share amounts)	three months ended December 31		year ended December 31	
	2017	**2016**	**2017**	**2016**
Net cash provided by operations	**1,390**	1,575	**5,230**	5,069
Increase/(decrease) in operating working capital	**49**	(220)	**273**	(248)
Funds generated from operations[1]	**1,439**	1,355	**5,503**	4,821
Specific items:				
Integration and acquisition related costs – Columbia	**—**	45	**84**	283
Keystone XL asset costs	**11**	15	**34**	52
U.S. Northeast power disposition costs	**—**	10	**20**	15
Comparable funds generated from operations[1]	**1,450**	1,425	**5,641**	5,171
Dividends on preferred shares	**(39)**	(26)	**(155)**	(100)
Distributions paid to non-controlling interests	**(68)**	(78)	**(283)**	(279)
Maintenance capital expenditures including equity investments				
- Recoverable in future tolls	**(541)**	(323)	**(1,364)**	(941)
- Other	**(75)**	(70)	**(240)**	(310)
Comparable distributable cash flow[1]				
- Reflecting all maintenance capital expenditures	**727**	928	**3,599**	3,541
- Reflecting only non-recoverable maintenance capital expenditures	**1,268**	1,251	**4,963**	4,482
Comparable distributable cash flow per common share[1]				
- Reflecting all maintenance capital expenditures	**$0.83**	$1.12	**$4.13**	$4.67
- Reflecting only non-recoverable maintenance capital expenditures	**$1.45**	$1.50	**$5.69**	$5.91

1 See the non-GAAP measures section in 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, increased $25 million for the three months ended December 31, 2017 compared to the same period in 2016 primarily due to higher comparable earnings.

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 decrease in comparable distributable cash flow reflecting all maintenance capital expenditures for the three months ended December 31, 2017 compared to the same period in 2016 was primarily driven by the increase in recoverable maintenance capital expenditures in Canadian and U.S. natural gas pipelines. Comparable distributable cash flow reflecting only non-recoverable maintenance capital expenditures is consistent with fourth quarter 2016. Comparable distributable cash flow per common share for the three months ended December 31, 2017 also includes the dilutive effect of common shares issued in fourth quarter 2016 and 2017.

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. The majority of our U.S. natural gas pipelines can recover maintenance capital through tolls under current rate settlements, or have the ability to recover maintenance capital 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 December 31		year ended December 31	
(unaudited - millions of $)	**2017**	**2016**	**2017**	**2016**
Canadian Natural Gas Pipelines	**301**	133	**601**	323
U.S. Natural Gas Pipelines	**237**	182	**749**	586
Liquids Pipelines	**8**	8	**19**	32
Other	**70**	70	**235**	310
Maintenance capital expenditures including equity investments	**616**	393	**1,604**	1,251

Reconciliation of non-GAAP measures

(unaudited - millions of $)	three months ended December 31 2017	2016	year ended December 31 2017	2016
Comparable EBITDA				
Canadian Natural Gas Pipelines	**569**	584	**2,144**	2,182
U.S. Natural Gas Pipelines	**604**	570	**2,357**	1,682
Mexico Natural Gas Pipelines	**116**	119	**519**	332
Liquids Pipelines	**401**	302	**1,348**	1,152
Energy	**214**	304	**1,030**	1,281
Corporate	**(1)**	11	**(21)**	18
Comparable EBITDA	**1,903**	1,890	**7,377**	6,647
Depreciation and amortization	**(516)**	(514)	**(2,048)**	(1,939)
Comparable EBIT	**1,387**	1,376	**5,329**	4,708
Specific items:				
Energy East impairment charge	**(1,256)**	—	**(1,256)**	—
Integration and acquisition related costs – Columbia	**—**	(47)	**(91)**	(179)
Keystone XL asset costs	**(11)**	(15)	**(34)**	(52)
Net gain/(loss) on sales of U.S. Northeast power assets	**15**	(839)	**484**	(844)
Gain on sale of Ontario solar assets	**127**	—	**127**	—
Foreign exchange gain – inter-affiliate loan	**64**	—	**63**	—
Ravenswood goodwill impairment	**—**	—	**—**	(1,085)
Alberta PPA terminations and settlement	**—**	(92)	**—**	(332)
Restructuring costs	**—**	(8)	**—**	(22)
TC Offshore loss on sale	**—**	—	**—**	(4)
Risk management activities	**164**	101	**62**	123
Segmented earnings	**490**	476	**4,684**	2,313

Condensed consolidated statement of income

	three months ended December 31		year ended December 31	
(unaudited - millions of Canadian $, except per share amounts)	**2017**	**2016**	**2017**	**2016**
Revenues				
Canadian Natural Gas Pipelines	**968**	1,005	**3,693**	3,682
U.S. Natural Gas Pipelines	**900**	941	**3,584**	2,526
Mexico Natural Gas Pipelines	**138**	129	**570**	378
Liquids Pipelines	**599**	463	**2,009**	1,755
Energy	**1,012**	1,097	**3,593**	4,206
	3,617	3,635	**13,449**	12,547
Income from Equity Investments	**246**	159	**773**	514
Operating and Other Expenses				
Plant operating costs and other	**944**	1,189	**3,906**	3,861
Commodity purchases resold	**671**	544	**2,382**	2,172
Property taxes	**127**	150	**569**	555
Depreciation and amortization	**516**	514	**2,055**	1,939
Goodwill and other asset impairment charges	**1,257**	92	**1,257**	1,388
	3,515	2,489	**10,169**	9,915
Gain/(Loss) on Assets Held for Sale/Sold	**142**	(829)	**631**	(833)
Financial Charges				
Interest expense	**541**	542	**2,069**	1,998
Allowance for funds used during construction	**(140)**	(97)	**(507)**	(419)
Interest income and other	**9**	15	**(184)**	(103)
	410	460	**1,378**	1,476
Income before Income Taxes	**80**	16	**3,306**	837
Income Tax (Recovery)/Expense				
Current	**21**	53	**149**	156
Deferred	**(87)**	221	**566**	196
Deferred - U.S. Tax Reform	**(804)**	—	**(804)**	—
	(870)	274	**(89)**	352
Net Income/(Loss)	**950**	(258)	**3,395**	485
Net income attributable to non-controlling interests	**49**	68	**238**	252
Net Income/(Loss)Attributable to Controlling Interests	**901**	(326)	**3,157**	233
Preferred share dividends	**40**	32	**160**	109
Net Income/(Loss) Attributable to Common Shares	**861**	(358)	**2,997**	124
Net Income/(Loss) per Common Share				
Basic	**$0.98**	($0.43)	**$3.44**	$0.16
Diluted	**$0.98**	($0.43)	**$3.43**	$0.16
Dividends Declared per Common Share	**$0.625**	$0.565	**$2.50**	$2.26
Weighted Average Number of Common Shares (millions)				
Basic	**877**	832	**872**	759
Diluted	**879**	833	**874**	760

Condensed consolidated statement of cash flows

	three months ended December 31		year ended December 31	
(unaudited - millions of Canadian $)	**2017**	**2016**	**2017**	**2016**
Cash Generated from Operations				
Net income/(loss)	**950**	(258)	**3,395**	485
Depreciation and amortization	**516**	514	**2,055**	1,939
Goodwill and other asset impairment charges	**1,257**	92	**1,257**	1,388
Deferred income taxes	**(87)**	221	**566**	196
Deferred income taxes - U.S. Tax Reform	**(804)**	—	**(804)**	—
Income from equity investments	**(246)**	(159)	**(773)**	(514)
Distributions received from operating activities of equity investments	**227**	219	**970**	844
Employee post-retirement benefits funding, net of expense	**—**	2	**(64)**	(3)
(Gain)/loss on assets held for sale/sold	**(142)**	829	**(631)**	833
Equity allowance for funds used during construction	**(113)**	(58)	**(362)**	(253)
Unrealized gains on financial instruments	**(163)**	(78)	**(149)**	(149)
Other	**44**	31	**43**	55
(Increase)/decrease in operating working capital	**(49)**	220	**(273)**	248
Net cash provided by operations	**1,390**	1,575	**5,230**	5,069
Investing Activities				
Capital expenditures	**(2,000)**	(1,745)	**(7,383)**	(5,007)
Capital projects in development	**(11)**	(76)	**(146)**	(295)
Contributions to equity investments	**(541)**	(195)	**(1,681)**	(765)
Acquisitions, net of cash acquired	**—**	—	**—**	(13,608)
Proceeds from sales of assets, net of transaction costs	**1,170**	—	**5,317**	6
Other distributions from equity investments	**—**	2	**362**	727
Deferred amounts and other	**(81)**	141	**(168)**	159
Net cash used in investing activities	**(1,463)**	(1,873)	**(3,699)**	(18,783)
Financing Activities				
Notes payable (repaid)/issued, net	**(194)**	(229)	**1,038**	(329)
Long-term debt issued, net of issue costs	**1,675**	—	**3,643**	12,333
Long-term debt repaid	**(1,570)**	(4,810)	**(7,085)**	(7,153)
Junior subordinated notes issued, net of issue costs	**—**	(2)	**3,468**	1,549
Dividends on common shares	**(357)**	(277)	**(1,339)**	(1,436)
Dividends on preferred shares	**(39)**	(26)	**(155)**	(100)
Distributions paid to non-controlling interests	**(68)**	(78)	**(283)**	(279)
Common shares issued, net of issue costs	**232**	3,410	**274**	7,747
Common shares repurchased	**—**	—	**—**	(14)
Preferred shares issued, net of issue costs	**—**	982	**—**	1,474
Partnership units of TC PipeLines, LP issued, net of issue costs	**63**	64	**225**	215
Common units of Columbia Pipeline Partners LP acquired	**—**	—	**(1,205)**	—
Net cash (used in)/provided by financing activities	**(258)**	(966)	**(1,419)**	14,007
Effect of Foreign Exchange Rate Changes on Cash and Cash Equivalents	**(4)**	—	**(39)**	(127)
(Decrease)/Increase in Cash and Cash Equivalents	**(335)**	(1,264)	**73**	166
Cash and Cash Equivalents				
Beginning of period	**1,424**	2,280	**1,016**	850
Cash and Cash Equivalents				
End of period	**1,089**	1,016	**1,089**	1,016

Condensed consolidated balance sheet

(unaudited - millions of Canadian $)		December 31, 2017	December 31, 2016
ASSETS			
Current Assets			
Cash and cash equivalents		**1,089**	1,016
Accounts receivable		**2,522**	2,075
Inventories		**378**	368
Assets held for sale		**—**	3,717
Other		**691**	908
		4,680	8,084
Plant, Property and Equipment	net of accumulated depreciation of $23,734 and $22,288, respectively	**57,277**	54,475
Equity Investments		**6,366**	6,544
Regulatory Assets		**1,376**	1,322
Goodwill		**13,084**	13,958
Loan Receivable from Affiliate		**919**	—
Intangible and Other Assets		**1,484**	3,026
Restricted Investments		**915**	642
		86,101	88,051
LIABILITIES			
Current Liabilities			
Notes payable		**1,763**	774
Accounts payable and other		**4,057**	3,861
Dividends payable		**586**	526
Accrued interest		**605**	595
Liabilities related to assets held for sale		**—**	86
Current portion of long-term debt		**2,866**	1,838
		9,877	7,680
Regulatory Liabilities		**4,321**	2,121
Other Long-Term Liabilities		**727**	1,183
Deferred Income Tax Liabilities		**5,403**	7,662
Long-Term Debt		**31,875**	38,312
Junior Subordinated Notes		**7,007**	3,931
		59,210	60,889
Common Units Subject to Rescission or Redemption		**—**	1,179
EQUITY			
Common shares, no par value		**21,167**	20,099
Issued and outstanding:	December 31, 2017 - 881 million shares		
	December 31, 2016 - 864 million shares		
Preferred shares		**3,980**	3,980
Additional paid-in capital		**—**	—
Retained earnings		**1,623**	1,138
Accumulated other comprehensive loss		**(1,731)**	(960)
Controlling Interests		**25,039**	24,257
Non-controlling interests		**1,852**	1,726
		26,891	25,983
		86,101	88,051

Segmented information

three months ended December 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	968	900	138	599	1,012	—	3,617
Intersegment revenues	—	20	—	—	—	(20)	—
	968	920	138	599	1,012	(20)	3,617
Income (loss) from equity investments	2	65	(9)	(6)	130	64 [2]	246
Plant operating costs and other	(342)	(336)	(13)	(186)	(86)	19	(944)
Commodity purchases resold	—	—	—	—	(671)	—	(671)
Property taxes	(59)	(45)	—	(22)	(1)	—	(127)
Depreciation and amortization	(236)	(143)	(23)	(81)	(33)	—	(516)
Goodwill and other asset impairment charges	—	—	—	(1,236)	(21)	—	(1,257)
Gain on sale of assets	—	—	—	—	142	—	142
Segmented earnings/(losses)	333	461	93	(932)	472	63	490
Interest expense							(541)
Allowance for funds used during construction							140
Interest income and other							(9)
Income before income taxes							80
Income tax recovery							870
Net income							950
Net income attributable to non-controlling interests							(49)
Net income attributable to controlling interests							901
Preferred share dividends							(40)
Net income attributable to common shares							861

1 The Company records intersegment sales at contracted rates. For segmented reporting, these transactions are included as revenues in the segment providing the service, as expenses in the segment receiving the service and are eliminated on consolidation within the Corporate segment. Intersegment profit is recognized when the product or service has been provided to third parties.

2 This income from equity investments relates to foreign exchange gains 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 December 31, 2016 (unaudited - millions of Canadian $)	Canadian Natural Gas Pipelines	U.S. Natural Gas Pipelines	Mexico Natural Gas Pipelines	Liquids Pipelines	Energy	Corporate[1]	Total
Revenues	1,005	941	129	463	1,097	—	3,635
Intersegment revenue	—	11	—	—	—	(11)	—
	1,005	952	129	463	1,097	(11)	3,635
Income/(loss) from equity investments	3	64	(1)	—	93	—	159
Plant operating costs and other	(359)	(415)	(9)	(151)	(233)	(22)	(1,189)
Commodity purchases resold	—	—	—	—	(544)	—	(544)
Property taxes	(65)	(42)	—	(21)	(22)	—	(150)
Depreciation and amortization	(220)	(156)	(16)	(78)	(44)	—	(514)
Asset impairment charges	—	—	—	—	(92)	—	(92)
Loss on sale of assets	—	—	—	—	(829)	—	(829)
Segmented earnings/(losses)	364	403	103	213	(574)	(33)	476
Interest expense							(542)
Allowance for funds used during construction							97
Interest income and other							(15)
Loss before income taxes							16
Income tax recovery							(274)
Net loss							(258)
Net income attributable to non-controlling interests							(68)
Net loss attributable to controlling interests							(326)
Preferred share dividends							(32)
Net loss attributable to common shares							(358)

1 The Company records intersegment sales at contracted rates. For segmented reporting, these transactions are included as revenues in the segment providing the service, as expenses in the segment receiving the service and are eliminated on consolidation within the Corporate segment. Intersegment profit is recognized when the product or service has been provided to third parties.

year ended December 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	**3,693**	**3,584**	**570**	**2,009**	**3,593**	**—**	**13,449**
Intersegment revenues	**—**	**51**	**—**	**—**	**—**	**(51)**	**—**
	3,693	**3,635**	**570**	**2,009**	**3,593**	**(51)**	**13,449**
Income/(loss) from equity investments	**11**	**240**	**(9)**	**(3)**	**471**	**63** [2]	**773**
Plant operating costs and other	**(1,300)**	**(1,340)**	**(42)**	**(623)**	**(550)**	**(51)**	**(3,906)**
Commodity purchases resold	**—**	**—**	**—**	**—**	**(2,382)**	**—**	**(2,382)**
Property taxes	**(260)**	**(181)**	**—**	**(89)**	**(39)**	**—**	**(569)**
Depreciation and amortization	**(908)**	**(594)**	**(93)**	**(309)**	**(151)**	**—**	**(2,055)**
Goodwill and other asset impairment charges	**—**	**—**	**—**	**(1,236)**	**(21)**	**—**	**(1,257)**
Gain on assets held for sale/sold	**—**	**—**	**—**	**—**	**631**	**—**	**631**
Segmented earnings/(losses)	**1,236**	**1,760**	**426**	**(251)**	**1,552**	**(39)**	**4,684**
Interest expense							**(2,069)**
Allowance for funds used during construction							**507**
Interest income and other							**184**
Income before income taxes							**3,306**
Income tax recovery							**89**
Net income							**3,395**
Net income attributable to non-controlling interests							**(238)**
Net income attributable to controlling interests							**3,157**
Preferred share dividends							**(160)**
Net income attributable to common shares							**2,997**

1 The Company records intersegment sales at contracted rates. For segmented reporting, these transactions are included as revenues in the segment providing the service, as expenses in the segment receiving the service and are eliminated on consolidation within the Corporate segment. Intersegment profit is recognized when the product or service has been provided to third parties.

2 This income from equity investments relates to foreign exchange gains 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.

year ended December 31, 2016 (unaudited - millions of Canadian $)	**Canadian Natural Gas Pipelines**	**U.S. Natural Gas Pipelines**	**Mexico Natural Gas Pipelines**	**Liquids Pipelines**	**Energy**	**Corporate[1]**	**Total**
Revenues	3,682	2,526	378	1,755	4,206	—	12,547
Intersegment revenues	—	56	—	—	—	(56)	—
	3,682	2,582	378	1,755	4,206	(56)	12,547
Income/(loss) from equity investments	12	214	(3)	(1)	292	—	514
Plant operating costs and other	(1,245)	(1,057)	(43)	(568)	(884)	(64)	(3,861)
Commodity purchases resold	—	—	—	—	(2,172)	—	(2,172)
Property taxes	(267)	(120)	—	(88)	(80)	—	(555)
Depreciation and amortization	(875)	(425)	(45)	(292)	(302)	—	(1,939)
Asset impairment charges	—	—	—	—	(1,388)	—	(1,388)
Loss on sale of assets	—	(4)	—	—	(829)	—	(833)
Segmented earnings/(losses)	1,307	1,190	287	806	(1,157)	(120)	2,313
Interest expense							(1,998)
Allowance for funds used during construction							419
Interest income and other							103
Income before income taxes							837
Income tax expense							(352)
Net Income							485
Net income attributable to non-controlling interests							(252)
Net Income attributable to controlling interests							233
Preferred share dividends							(109)
Net Income attributable to common shares							124

1 The Company records intersegment sales at contracted rates. For segmented reporting, these transactions are included as revenues in the segment providing the service, as expenses in the segment receiving the service and are eliminated on consolidation within the Corporate segment. Intersegment profit is recognized when the product or service has been provided to third parties.

TOTAL ASSETS

(unaudited - millions of Canadian $)	**December 31, 2017**	**December 31, 2016**
Canadian Natural Gas Pipelines	**16,904**	15,816
U.S. Natural Gas Pipelines	**35,898**	34,422
Mexico Natural Gas Pipelines	**5,716**	5,013
Liquids Pipelines	**15,438**	16,896
Energy	**8,503**	13,169
Corporate	**3,642**	2,735
	86,101	88,051