NewsRelease

TransCanada Reports Record Financial Results for 2018
Increases Common Share Dividend for Nineteenth Consecutive Year

CALGARY, Alberta – **February 14, 2019** – TransCanada Corporation (TSX, NYSE: TRP) (TransCanada or the Company) today announced net income attributable to common shares for fourth quarter 2018 of $1.1 billion or $1.19 per share compared to net income of $0.9 billion or $0.98 per share for the same period in 2017. For the year ended December 31, 2018, net income attributable to common shares was $3.5 billion or $3.92 per share compared to net income of $3.0 billion or $3.44 per share in 2017. Comparable earnings for fourth quarter 2018 were $946 million or $1.03 per common share compared to $719 million or $0.82 per share for the same period in 2017. For the year ended December 31, 2018, comparable earnings were $3.5 billion or $3.86 per common share compared to $2.7 billion or $3.09 per share in 2017. TransCanada's Board of Directors also declared a quarterly dividend of $0.75 per common share for the quarter ending March 31, 2019, equivalent to $3.00 per common share on an annualized basis, an increase of 8.7 per cent. This is the nineteenth consecutive year the Board of Directors has raised the dividend.

"We are very pleased with the performance of our diversified portfolio of high-quality, long-life energy infrastructure assets which produced record financial results again in 2018," said Russ Girling, TransCanada's president and chief executive officer. "Comparable earnings per share increased twenty-five per cent compared to 2017 while comparable funds generated from operations of $6.5 billion were sixteen per cent higher than last year. The increases reflect the strong performance of our legacy assets, contributions from approximately $4 billion of growth projects that were placed into service and the positive impact of U.S. Tax Reform."

"With our existing asset base expected to benefit from supportive market fundamentals and $36 billion of secured growth projects currently underway, approximately $9 billion of which is commissioning or nearing completion, earnings and cash flow are forecast to continue to rise. This is expected to support annual dividend growth of eight to ten per cent through 2021," added Girling. "We have invested $13 billion in these projects to date and are well positioned to fund the remainder of our secured growth program through significant and growing internally generated cash flow, access to capital markets and further portfolio management activities. As outlined in the third quarter, we view the issuance of common shares under our At-The-Market equity program as being complete and will continue to evaluate the use of our Dividend Reinvestment Program on a quarterly basis. We also continue to progress various portfolio management activities, including the recently announced sale of our Coolidge generating station which is expected to close by mid-year. This will allow us to prudently fund our capital program in a manner that is consistent with achieving targeted leverage metrics in 2019."

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

Highlights

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

- Fourth quarter 2018 financial results
  - Net income attributable to common shares of $1.1 billion or $1.19 per common share
  - Comparable earnings of $946 million or $1.03 per common share
  - Comparable earnings before interest, taxes, depreciation and amortization of $2.5 billion
  - Net cash provided by operations of $2.0 billion
  - Comparable funds generated from operations of $1.9 billion
  - Comparable distributable cash flow of $1.7 billion or $1.89 per common share
- For the year ended December 31, 2018
  - Net income attributable to common shares of $3.5 billion or $3.92 per common share
  - Comparable earnings of $3.5 billion or $3.86 per common share
  - Comparable earnings before interest, taxes, depreciation and amortization of $8.6 billion
  - Net cash provided by operations of $6.6 billion
  - Comparable funds generated from operations of $6.5 billion
  - Comparable distributable cash flow of $5.9 billion or $6.52 per common share
- Fourth quarter highlights
  - TransCanada's Board approved an 8.7 per cent increase in the quarterly common share dividend to $0.75 per common share for the quarter ending March 31, 2019
  - Announced that we will proceed with construction of the $6.2 billion Coastal GasLink pipeline project
  - Announced $1.5 billion NGTL 2022 Expansion Program
  - Secured transportation contracts for the North Bay Junction Long Term Fixed Price service on the Canadian Mainline
  - Completed the sale of our interests in the Cartier Wind power facilities for approximately $630 million
  - Entered into an agreement to sell our Coolidge generating station for approximately US$465 million with closing expected to occur in mid-2019
  - Reimbursed for $470 million of Coastal GasLink pre-Final Investment Decision costs
  - In January 2019, announced planned name change to TC Energy subject to shareholder and regulatory approval

Net income attributable to common shares increased by $231 million or $0.21 per share to $1.1 billion or $1.19 per share for the three months ended December 31, 2018 compared to the same period last year primarily due to changes in net income described below, as well as the dilutive effect of common shares issued in 2017 and 2018 under our DRP and Corporate ATM program. Fourth quarter 2018 results included a $143 million after-tax gain related to the sale of our interests in the Cartier Wind power facilities; a $115 million deferred income tax recovery from an MLP regulatory liability write-off resulting from the 2018 FERC Actions; a $52 million recovery of deferred income taxes as a result of finalizing the impact of U.S. Tax Reform; a $27 million income tax recovery related to the sale of our U.S. Northeast power generation assets; and $25 million of income after tax and after non-controlling interests recognized on the Bison contract terminations. These items were partially offset by a $140 million impairment charge on Bison after tax and after non-controlling interests; a $15 million goodwill impairment charge on Tuscarora after tax and after non-controlling interests; and an after-tax net loss of $7 million related to our U.S. Northeast power marketing contracts. 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, 2018 was $3.5 billion or $3.92 per share compared to $3.0 billion or $3.44 per share in 2017 due to the changes in net income described below, as well as the dilutive effect of common shares issued in 2017 and 2018 under our DRP and Corporate ATM program. Results in 2018 include the items highlighted for fourth quarter 2018 with a full year after-tax net loss related to our U.S. Northeast power marketing contracts of $4 million. All of these specific items, as well as unrealized gains and losses from changes in risk management activities, are excluded from comparable earnings.

Comparable EBITDA for fourth quarter 2018 increased by $550 million to $2.5 billion compared to the same period in 2017 primarily due to the net effect of the following:

- higher contribution from Canadian Natural Gas Pipelines primarily due to the recovery of increased depreciation approved in both the Mainline NEB 2018 Decision and the NGTL 2018-2019 Settlement, as well as higher flow-through taxes and incentive earnings
- higher contribution from U.S. Natural Gas Pipelines mainly due to increased earnings from Columbia Gas and Columbia Gulf growth projects placed in service, additional contract sales on ANR and Great Lakes, and amortization of net regulatory liabilities recognized as a result of U.S. Tax Reform
- higher contribution from Liquids Pipelines primarily due to higher volumes on the Keystone Pipeline System, increased earnings from liquids marketing activities and earnings from intra-Alberta pipelines placed in service in the second half of 2017
- higher revenues from Mexico Natural Gas Pipelines as a result of changes in timing of revenue recognition
- lower earnings from Bruce Power primarily due to lower volumes resulting from higher outage days.

Comparable earnings for fourth quarter 2018 were $946 million or $1.03 per common share compared to $719 million or $0.82 per share for the same period in 2017, an increase of $227 million or $0.21 per share which was primarily the net result of the following:

- changes in comparable EBITDA described above
- higher depreciation primarily in Canadian Natural Gas Pipelines due to increased depreciation rates approved in the Mainline NEB 2018 Decision and the NGTL 2018-2019 Settlement (these amounts are fully recovered as reflected in the increase in comparable EBITDA described above, having no net impact on comparable earnings) as well as higher depreciation related to new projects placed in service in 2017 and 2018
- higher interest expense primarily as a result of long-term debt and junior subordinated notes issuances, net of maturities
- lower interest income and other as a result of realized losses in 2018 compared to realized gains in 2017 on derivatives used to manage net exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income.

Comparable EBITDA in 2018 increased by $1.2 billion to $8.6 billion compared to 2017 primarily due to the net effect of the following:

- higher contribution from U.S. Natural Gas Pipelines mainly due to increased earnings from Columbia Gas and Columbia Gulf growth projects placed in service, additional contract sales on ANR and Great Lakes, and amortization of net regulatory liabilities recognized as a result of U.S. Tax Reform
- higher contribution from Liquids Pipelines primarily due to higher volumes on the Keystone Pipeline System, increased earnings from liquids marketing activities and earnings from intra-Alberta pipelines placed in service in the second half of 2017
- higher contribution from Canadian Natural Gas Pipelines primarily due to the recovery of increased depreciation as a result of higher rates approved in both the Mainline NEB 2018 Decision and the NGTL 2018-2019 Settlement, as well as higher overall pre-tax rate base earnings, partially offset by lower incentive earnings and flow-through income taxes
- lower earnings from U.S. Power mainly due to the sales of our U.S. Northeast power generation assets in second quarter 2017
- lower earnings from Bruce Power primarily due to lower volumes resulting from higher outage days and lower results from contracting activities.

Comparable earnings in 2018 of $3.5 billion or $3.86 per common share were $790 million or $0.77 per share higher than in 2017. The 2018 increase was primarily the net result of the following:

- changes in comparable EBITDA described above
- higher depreciation primarily in Canadian Natural Gas Pipelines due to increased depreciation rates approved in the Mainline NEB 2018 Decision and the NGTL 2018-2019 Settlement (these amounts are fully recovered as reflected in the increase in comparable EBITDA described above, having no net impact on comparable earnings) as well as higher depreciation related to new projects placed in service in 2017 and 2018
- higher interest expense primarily as a result of additional long-term debt issuances in 2018 and the full year impact of long-term debt and junior subordinated notes issuances in 2017, net of maturities, as well as lower capitalized interest, partially offset by the repayment of the Columbia acquisition bridge facilities in June 2017
- lower income tax expense primarily due to reduced income tax rates resulting from U.S. Tax Reform and lower flow-through income taxes in Canadian rate-regulated pipelines.

Notable recent developments include:

Canadian Natural Gas Pipelines:

- *Coastal GasLink Pipeline Project:* In October 2018, we announced that we are proceeding with construction of the Coastal GasLink pipeline project following the LNG Canada joint venture participants' announcement that they had reached a positive Final Investment Decision (FID) to build the LNG Canada natural gas liquefaction facility in Kitimat, B.C. Coastal GasLink will provide the natural gas supply to the LNG Canada facility and is underpinned by 25-year TSAs (with additional renewal provisions) with each of the five LNG Canada participants. Coastal GasLink will be a 670 km (416 miles) pipeline with an initial capacity of approximately 2.2 PJ/d (2.1 Bcf/d) with potential expansion capacity up to 5.4 PJ/d (5.0 Bcf/d). All necessary regulatory permits have been received to allow us to proceed with construction activities which began in December 2018, with a planned in-service date in 2023. Coastal GasLink has signed project and community agreements with all 20 elected Indigenous bands along the pipeline route, confirming strong support from Indigenous communities across the province of B.C.

  In July 2018, an individual asked the National Energy Board (NEB) to consider whether the Coastal GasLink pipeline should be federally regulated by the NEB. In October 2018, the NEB advised that it would consider the question of jurisdiction, granted Coastal GasLink standing in the matter, and reserved the right to decide on the participation of all other potentially interested parties, including the individual who raised the question. In December 2018, the NEB issued a process letter addressing participation and set the schedule which is expected to conclude in the second half of 2019, with a decision to follow.

  The Coastal GasLink capital cost estimate is $6.2 billion with the majority of the construction spend occurring in 2020 and 2021. Subject to terms and conditions, differences between the estimated capital cost and final cost of the project will be recovered in future pipeline tolls. As part of the Coastal GasLink funding plan, we are exploring joint venture partners and project financing.

  The total capital cost includes pre-FID costs incurred of $470 million. In accordance with provisions in the agreements with the LNG Canada joint venture participants, all five parties elected to reimburse us for their share of pre-FID costs, totaling $470 million, in November 2018. In addition, in January 2019, all five partners elected to make cash payments throughout the construction period with respect to carrying charges on costs incurred.

- *NGTL System*: In October 2018, we announced the NGTL System 2022 Expansion Program to meet capacity requirements for incremental firm receipt and intra-basin delivery services to commence in November 2021 and April 2022. This $1.5 billion expansion of the NGTL System consists of approximately 197 km (122 miles) of new pipeline, three compressor units, meter stations and associated facilities. Applications for approvals to construct and operate the facilities are expected to be filed with the NEB in second quarter 2019 and, pending receipt of regulatory approvals, construction would start as early as third quarter 2020. The NGTL capital program, excluding maintenance capital expenditures, is now approximately $8.6 billion.

- *Canadian Mainline:* In December 2018, we announced the North Bay Junction Long Term Fixed Price service (NBJ LTFP) which includes 670 TJ/d (625 MMcf/d) of new natural gas transportation contracts from the Western Canadian Sedimentary Basin (WCSB) on the Canadian Mainline. Upon NEB approval of the NBJ LTFP service, incremental volumes under these long-term, fixed-priced contracts will reach markets in Ontario, Québec, New Brunswick, Nova Scotia and the Northeastern U.S. using existing capacity on the Canadian Mainline as well as new compression facilities. Customers have executed 15-year precedent agreements to proceed with the project with an estimated capital cost of $96 million. We filed an application for approval of the NBJ LTFP with the NEB in January 2019 and expect a decision in third quarter 2019.

  In October 2018, we concluded the written hearing process for the Canadian Mainline 2018-2020 toll review with the filing of our reply evidence to the NEB. In December 2018, the NEB 2018 Decision was issued approving all elements of the application, including our cost and volume forecasts, higher depreciation rates and continuation of pricing discretion, with the exception of the amortization period for the Long Term Adjustment Account (LTAA), which is now to be amortized over 2018 to 2020. The impact of the decision was reflected in lower tolls effective February 1, 2019. As directed by the NEB, we filed a compliance filing in January 2019, the outcome of which is expected in first quarter 2019.

U.S. Natural Gas Pipelines:

- *WB XPress:* The WB XPress project, a Columbia Gas project designed to transport approximately 1.4 PJ/d (1.3 Bcf/d) of Marcellus gas supply westbound to the Gulf Coast and eastbound to Mid-Atlantic Markets, was placed in service in October 2018 and November 2018 for the Western Build and Eastern Build, respectively.
- *Mountaineer XPress and Gulf XPress:* Mountaineer XPress (MXP), a Columbia Gas project, is designed to transport supply from the Marcellus and Utica shale plays to points along the system and to the Leach interconnect with Columbia Gulf. Approximately 45 per cent of this project was placed in service on January 18, 2019, with the remainder to be placed in service in February and March 2019, along with Gulf XPress, a Columbia Gulf project. Total estimated MXP project costs have been revised upwards to US$3.2 billion reflecting the impact of delays of various regulatory approvals from FERC and other agencies, increased contractor construction costs due to unusually high demand for construction resources in the region, unusually high instances of inclement weather throughout construction, and modifications to contractor work plans to mitigate construction delays associated with these impacts.
- *Louisiana XPress:* In November 2018, we sanctioned the Louisiana XPress project which will connect supply directly to Gulf Coast LNG export markets with the addition of three greenfield mid-point compressor stations along Columbia Gulf. The anticipated in-service date is in 2022 and estimated project costs are US$0.4 billion.
- *Bison contract terminations and asset impairment:* In the second half of 2018, two customers on Bison elected to pay out the remainder of their future contracted revenues and terminate their associated TSAs. The termination of these agreements was agreed to following the receipt of US$97 million in 2018, which was recorded in Revenues, as the terminations released us from providing any future services. This development, coupled with the persistence of unfavourable market conditions which have inhibited system flows on the pipeline, led us to determine that the asset's remaining carrying value was no longer recoverable and a non-cash impairment charge of US$537 million was recorded in our U.S. Natural Gas Pipelines segment. As Bison is a TC PipeLines, LP asset, in which we have a 25.5 per cent interest, this impairment charge impacts our net income by $140 million after tax and non-controlling interests, but is excluded from comparable earnings. We continue to explore alternative transportation-related options for Bison.

- *Tuscarora goodwill impairment:* In fourth quarter 2018, Tuscarora finalized its regulatory approach in response to the 2018 FERC Actions, resulting in a reduction in its recourse rates. In connection with its annual goodwill impairment analysis, we evaluated Tuscarora's future revenues as well as changes to other assumptions responsive to Tuscarora's commercial environment. In doing so, we incorporated the outcome of a settlement-in-principle reached with its customers in January 2019. As a result of these developments, we determined that the fair value of Tuscarora did not exceed its carrying value, including goodwill, and recorded a goodwill impairment charge of US$59 million within the U.S. Natural Gas Pipelines segment. The remaining goodwill balance related to Tuscarora at December 31, 2018 was US$23 million. As Tuscarora is a TC PipeLines, LP asset, in which we have a 25.5 per cent interest, this impairment charge impacts our net income by $15 million after tax and non-controlling interests, but is excluded from comparable earnings.

Mexico Natural Gas Pipelines:

- *Sur de Texas:* Offshore construction was completed in May 2018 and the project continues to progress toward an anticipated in-service date in early second quarter 2019. An amending agreement was signed with the CFE that recognizes force majeure events and the commencement of payments of fixed capacity charges began on October 31, 2018.

Liquids Pipelines:

- *Keystone XL:* We have secured commercial support for all available Keystone XL project capacity and commenced certain pre-construction activities. We continue to address outstanding legal challenges regarding the project. The South Dakota Supreme Court dismissed an appeal against the certification of the project. We expect the Nebraska Supreme Court to reach a decision in the first quarter of 2019 regarding a challenge to the Nebraska Public Service Commission's route approval. We continue to participate, together with the U.S. Department of Justice, in lawsuits commenced in Montana to defend legal challenges to the U.S. Presidential Permit and the exhaustive environmental assessments that support the U.S. President's actions.

Energy:

- *Cartier Wind:* In October 2018, we completed the sale of our interests in the Cartier Wind power facilities in Québec to Innergex Renewable Energy Inc. for gross proceeds of approximately $630 million before closing adjustments, resulting in a gain of $170 million ($143 million after tax).
- *Coolidge Generating Station:* On December 14, 2018, we entered into an agreement to sell our Coolidge generating station in Arizona to SWG Coolidge Holdings, LLC, for approximately US$465 million, subject to timing of the close and related adjustments. Salt River Project Agriculture Improvement and Power District, the PPA counterparty, exercised its contractual right of first refusal on a sale to a third party in January 2019. The sale will result in an estimated gain of approximately $65 million ($50 million after tax) to be recognized upon closing of the sale transaction which is expected to occur mid-2019.
- *Napanee:* Construction is substantially complete and commissioning activities are continuing at our 900 MW natural gas-fired power plant in eastern Ontario in the town of Greater Napanee. We expect our total investment in the Napanee facility will be approximately $1.7 billion with commercial operations expected to begin in second quarter 2019.

Corporate:

- *Common Share Dividend:* Our Board of Directors declared a quarterly dividend of $0.75 per share for the quarter ending March 31, 2019 on TransCanada's outstanding common shares. This represents an increase in the dividend of 8.7 per cent from the previous dividend and is equivalent to $3.00 per common share on an annualized basis.

- *Issuance of Long-term Debt:* In fourth quarter 2018, TCPL issued US$1.0 billion of Senior Unsecured Notes due in March 2049 bearing interest at a fixed rate of 5.10 per cent and US$400 million of Senior Unsecured Notes due in May 2028 bearing interest at a fixed rate of 4.25 per cent.

  The net proceeds of the debt issuances were used for general corporate purposes, to fund our capital program and to pre-fund early 2019 senior note maturities.

- *Dividend Reinvestment Plan:* In 2018, the DRP participation rate by common shareholders was approximately 35 per cent, resulting in $870 million reinvested in common equity under the program.
- *ATM Equity Program:* In 2018, 20 million common shares were issued under the Corporate ATM program at an average price of $56.13 per common share for proceeds of $1.1 billion, net of approximately $10 million of related commissions and fees. We view the issuance of common shares under this program as being complete.
- *Proposed Name Change:* On January 9, 2019, we announced our intention to change our name to TC Energy to better reflect the scope of the company's operations as a leading North American energy infrastructure company. The name change is subject to shareholder and regulatory approval and would be effective immediately following the Annual and Special Meeting of Shareholders in the second quarter of 2019.
- *Management Changes:* Karl Johannson and Kristine Delkus will be retiring from the Company in the first and second quarters of 2019, respectively. Effective January 1, 2019, Tracy Robinson was appointed Executive Vice-President and President, Canadian Natural Gas Pipelines and Francois Poirier was appointed to the expanded role of President of the Energy and Mexico Natural Gas Pipelines business units in addition to his role as Executive Vice-President, Strategy and Corporate Development.

Teleconference and Webcast:

We will hold a teleconference and webcast on Thursday, February 14, 2019 to discuss our fourth quarter 2018 and year-end financial results. Russ Girling, President and Chief Executive Officer, and Don Marchand, Executive Vice-President and Chief Financial Officer, along with other members of the TransCanada executive leadership team, will discuss the financial results and Company developments at 2 p.m. (MT) / 4 p.m. (ET).

Members of the investment community and other interested parties are invited to participate by calling 800.273.9672 or 416.340.2216 (Toronto area). Please dial in 10 minutes prior to the start of the call. No pass code is required. A live webcast of the teleconference will be available at www.transcanada.com or via the following URL: www.gowebcasting.com/9855.

A replay of the teleconference will be available two hours after the conclusion of the call until midnight (ET) on February 21, 2019. Please call 800.408.3053 or 905.694.9451 (Toronto area) and enter pass code 4856336#.

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 92,600 kilometres (57,500 miles), connecting major gas supply basins to markets across North America. TransCanada is a leading provider of gas storage and related services with 653 billion cubic feet of storage capacity. A large independent power producer, TransCanada currently owns or has interests in more than 6,600 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 www.transcanada.com to learn more, or connect with us on social media.

Forward Looking Information:

This release contains certain information that is forward-looking and is subject to important risks and uncertainties (such statements are usually accompanied by words such as "anticipate", "expect", "believe", "may", "will", "should", "estimate", "intend" or other similar words). Forward-looking statements in this document are intended to provide TransCanada security holders and potential investors with information regarding TransCanada and its subsidiaries, including management's assessment of TransCanada's and its subsidiaries' future plans and financial outlook. All forward-looking statements reflect TransCanada's beliefs and assumptions based on information available at the time the statements were made and as such are not guarantees of future performance. Readers are cautioned not to place undue reliance on this forward-looking information, which is given as of the date it is expressed in this news release, and not to use future-oriented information or financial outlooks for anything other than their intended purpose. TransCanada undertakes no obligation to update or revise any forward-looking information except as required by law. For additional information on the assumptions made, and the risks and uncertainties which could cause actual results to differ from the anticipated results, refer to the Quarterly Report to Shareholders dated February 13, 2019 and the 2018 Annual Report filed under TransCanada's profile on SEDAR at www.sedar.com and with the U.S. Securities and Exchange Commission at www.sec.gov.

Non-GAAP Measures:

This news release contains references to non-GAAP measures, including comparable earnings, comparable earnings per common share, comparable EBITDA, comparable distributable cash flow, comparable distributable cash flow per common share and comparable funds generated from operations, that do not have any standardized meaning as prescribed by U.S. GAAP and therefore are unlikely to be comparable to similar measures presented by other companies. These non-GAAP measures are calculated on a consistent basis from period to period except as otherwise described in the MD&A included in our Quarterly Report to Shareholders dated February 13, 2019 and are adjusted for specific items in each period, as applicable. For more information on non-GAAP measures, refer to TransCanada's Quarterly Report to Shareholders dated February 13, 2019.

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Fourth quarter 2018

Financial highlights

(millions of $, except per share amounts)	three months ended December 31		year ended December 31	
	2018	**2017**	**2018**	**2017**
Income				
Revenues	**3,904**	3,617	**13,679**	13,449
Net income attributable to common shares	**1,092**	861	**3,539**	2,997
per common share – basic	**$1.19**	$0.98	**$3.92**	$3.44
– diluted	**$1.19**	$0.98	**$3.92**	$3.43
Comparable EBITDA	**2,453**	1,903	**8,563**	7,377
Comparable earnings	**946**	719	**3,480**	2,690
per common share	**$1.03**	$0.82	**$3.86**	$3.09
Cash flows				
Net cash provided by operations	**2,039**	1,390	**6,555**	5,230
Comparable funds generated from operations	**1,881**	1,450	**6,522**	5,641
Comparable distributable cash flow	**1,727**	1,272	**5,885**	4,963
per common share	**$1.89**	$1.45	**$6.52**	$5.69
Capital spending[1]	**3,438**	2,552	**10,929**	9,210
Proceeds from sales of assets, net of transaction costs	**614**	536	**614**	4,683
Reimbursement of costs related to capital projects in development	**470**	634	**470**	634
Dividends declared				
Per common share	**$0.69**	$0.625	**$2.76**	$2.50
Basic common shares (millions)				
– weighted average for the period	**915**	877	**902**	872
– issued and outstanding at end of period	**918**	881	**918**	881

1 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 and 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:

- our financial and operational performance, including the performance of our subsidiaries
- expectations about strategies and goals for growth and expansion
- expected cash flows and future financing options available, including portfolio management
- expected dividend growth
- expected future credit ratings
- expected costs and schedules for planned projects, including projects under construction and in development
- expected capital expenditures and contractual obligations
- expected regulatory processes and outcomes, including the impact of the 2018 FERC Actions
- expected outcomes with respect to legal proceedings, including arbitration and insurance claims
- the expected impact of future accounting changes, commitments and contingent liabilities
- expected industry, market and economic conditions.

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

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

Assumptions

- regulatory decisions and outcomes, including final outcomes of the 2018 FERC Actions
- planned and unplanned outages and the use of our pipeline and energy assets
- integrity and reliability of our assets
- anticipated construction costs, schedules and completion dates
- access to capital markets, including portfolio management
- expected industry, market and economic conditions
- inflation rates and commodity prices
- interest, tax and foreign exchange rates
- nature and scope of hedging.

Risks and uncertainties

- our ability to successfully implement our strategic priorities and whether they will yield the expected benefits
- our ability to implement a capital allocation strategy aligned with maximizing shareholder value
- the operating performance of our pipeline and energy assets
- amount of capacity sold and rates achieved in our pipeline businesses
- the amount of capacity payments and revenues from our energy business due to plant availability
- production levels within supply basins
- construction and completion of capital projects
- costs for labour, equipment and materials
- the availability and market prices of commodities
- access to capital markets on competitive terms

- interest, tax and foreign exchange rates
- performance and credit risk of our counterparties
- regulatory decisions and outcomes of legal proceedings, including arbitration and insurance claims
- changes in environmental and other laws and regulations
- competition in the pipeline and energy sectors
- unexpected or unusual weather
- acts of civil disobedience
- cyber security and technological developments
- economic conditions in North America as well as globally
- our ability to effectively anticipate and assess changes to government policies and regulations.

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

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

FOR MORE INFORMATION

You can also find more information about TransCanada in our Annual Information Form (AIF) 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 EBITDA
- comparable EBIT
- comparable earnings
- comparable earnings per common share
- funds generated from operations
- comparable funds generated from operations
- comparable distributable cash flow
- comparable distributable cash flow per common share.

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

Comparable measures

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

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

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

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

Comparable EBITDA and comparable EBIT

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

Comparable earnings and comparable earnings per common share

Comparable earnings represents earnings or losses attributable to common shareholders on a consolidated basis adjusted for specific items. Comparable earnings is comprised of segmented earnings, interest expense, AFUDC, interest income and other, income taxes, non-controlling interests and preferred share dividends adjusted for specific items. Refer to the Reconciliation of net income to comparable earnings section.

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. Refer to the Cash provided by operating activities section for a reconciliation to net cash provided by operations.

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

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

Maintenance capital expenditures are expenditures incurred to maintain our operating capacity, asset integrity and reliability, and include amounts attributable to our proportionate share of maintenance capital expenditures on our equity investments. We have the opportunity to recover effectively all of our pipeline maintenance capital expenditures in Canadian Natural Gas Pipelines, U.S. Natural Gas Pipelines and Liquids Pipelines through tolls. Canadian natural gas pipelines maintenance capital expenditures are included in rate bases, on which we earn a regulated return and subsequently recover in tolls. Our U.S. natural gas pipelines can recover maintenance capital expenditures through tolls under current rate settlements, or have the ability to recover such expenditures through tolls established in future rate cases or settlements. Tolling arrangements in our liquids pipelines provide for the recovery of maintenance capital expenditures. As such, in 2018 our presentation of comparable distributable cash flow and comparable distributable cash flow per common share only includes a reduction for non-recoverable maintenance capital expenditures in their respective calculations. We have adjusted our comparable distributable cash flow and comparable distributable cash flow per common share for 2017 to reflect the amended presentation format which we believe provides better information for readers.

Consolidated results - fourth quarter 2018

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 businesses are made and how performance of our businesses 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 Corporate segment, consisting of corporate and administrative functions that provide governance and other support to our operational business segments.

	three months ended December 31		year ended December 31	
(millions of $, except per share amounts)	**2018**	**2017**	**2018**	**2017**
Segmented earnings/(losses)				
Canadian Natural Gas Pipelines	**450**	333	**1,250**	1,236
U.S. Natural Gas Pipelines	**(34)**	461	**1,700**	1,760
Mexico Natural Gas Pipelines	**128**	93	**510**	426
Liquids Pipelines	**532**	(932)	**1,579**	(251)
Energy	**315**	472	**779**	1,552
Corporate	**23**	63	**(54)**	(39)
Total segmented earnings	**1,414**	490	**5,764**	4,684
Interest expense	**(603)**	(541)	**(2,265)**	(2,069)
Allowance for funds used during construction	**161**	140	**526**	507
Interest income and other	**(215)**	(9)	**(76)**	184
Income before income taxes	**757**	80	**3,949**	3,306
Income tax (expense)/recovery	**(38)**	870	**(432)**	89
Net income	**719**	950	**3,517**	3,395
Net loss/(income) attributable to non-controlling interests	**414**	(49)	**185**	(238)
Net income attributable to controlling interests	**1,133**	901	**3,702**	3,157
Preferred share dividends	**(41)**	(40)	**(163)**	(160)
Net income attributable to common shares	**1,092**	861	**3,539**	2,997
Net income per common share — basic	**$1.19**	$0.98	**$3.92**	$3.44
— diluted	**$1.19**	$0.98	**$3.92**	$3.43

Net income attributable to common shares increased by $231 million or $0.21 per common share for the three months ended December 31, 2018 compared to the same period in 2017 primarily due to changes in net income described below, as well as the dilutive impact of common shares issued in 2017 and 2018 under our DRP and Corporate ATM program.

Fourth quarter 2018 results included:

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

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 generation assets
- a $954 million after-tax impairment charge for the Energy East pipeline and related projects as a result of our decision not to proceed with the project applications
- a $9 million after-tax charge related to the maintenance and liquidation of Keystone XL assets.

Net income in both 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 attributable to common shares to comparable earnings is shown in the following table.

RECONCILIATION OF NET INCOME TO COMPARABLE EARNINGS

	three months ended December 31		year ended December 31	
(millions of $, except per share amounts)	**2018**	**2017**	**2018**	**2017**
Net income attributable to common shares	**1,092**	861	**3,539**	2,997
Specific items (net of tax):				
Gain on sale of Cartier Wind power facilities	**(143)**	—	**(143)**	—
MLP regulatory liability write-off	**(115)**	—	**(115)**	—
U.S. Tax Reform	**(52)**	(804)	**(52)**	(804)
Net gain on sales of U.S. Northeast power generation assets	**(27)**	(64)	**(27)**	(307)
Bison contract terminations	**(25)**	—	**(25)**	—
Bison asset impairment	**140**	—	**140**	—
Tuscarora goodwill impairment	**15**	—	**15**	—
U.S. Northeast power marketing contracts	**7**	—	**4**	—
Gain on sale of Ontario solar assets	**—**	(136)	**—**	(136)
Energy East impairment charge	**—**	954	**—**	954
Keystone XL asset costs	**—**	9	**—**	28
Keystone XL income tax recoveries	**—**	—	**—**	(7)
Integration and acquisition related costs – Columbia	**—**	—	**—**	69
Risk management activities[1]	**54**	(101)	**144**	(104)
Comparable earnings	**946**	719	**3,480**	2,690
Net income per common share	**$1.19**	$0.98	**$3.92**	$3.44
Specific items (net of tax):				
Gain on sale of Cartier Wind power facilities	**(0.16)**	—	**(0.16)**	—
MLP regulatory liability write-off	**(0.13)**	—	**(0.13)**	—
U.S. Tax Reform	**(0.06)**	(0.92)	**(0.06)**	(0.92)
Net gain on sales of U.S. Northeast power generation assets	**(0.03)**	(0.08)	**(0.03)**	(0.34)
Bison contract terminations	**(0.03)**	—	**(0.03)**	—
Bison asset impairment	**0.16**	—	**0.16**	—
Tuscarora goodwill impairment	**0.02**	—	**0.02**	—
U.S. Northeast power marketing contracts	**0.01**	—	**0.01**	—
Gain on sale of Ontario solar assets	**—**	(0.16)	**—**	(0.16)
Energy East impairment charge	**—**	1.09	**—**	1.09
Keystone XL asset costs	**—**	0.01	**—**	0.03
Keystone XL income tax recoveries	**—**	—	**—**	(0.01)
Integration and acquisition related costs – Columbia	**—**	—	**—**	0.08
Risk management activities[1]	**0.06**	(0.10)	**0.16**	(0.12)
Comparable earnings per common share	**$1.03**	$0.82	**$3.86**	$3.09

1

Risk management activities	three months ended December 31		year ended December 31	
(millions of $)	**2018**	**2017**	**2018**	**2017**
Liquids marketing	**81**	15	**71**	—
Canadian Power	**—**	6	**3**	11
U.S. Power	**20**	136	**(11)**	39
Natural Gas Storage	**(5)**	7	**(11)**	12
Interest rate	**—**	—	**—**	(1)
Foreign exchange	**(169)**	(1)	**(248)**	88
Income tax attributable to risk management activities	**19**	(62)	**52**	(45)
Total unrealized (losses)/gains from risk management activities	**(54)**	101	**(144)**	104

COMPARABLE EBITDA TO COMPARABLE EARNINGS

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

	three months ended December 31		year ended December 31	
(millions of $)	**2018**	**2017**	**2018**	**2017**
Comparable EBITDA	**2,453**	1,903	**8,563**	7,377
Adjustments:				
Depreciation and amortization	**(681)**	(516)	**(2,350)**	(2,048)
Interest expense included in comparable earnings	**(603)**	(541)	**(2,265)**	(2,068)
Allowance for funds used during construction	**161**	140	**526**	507
Interest income and other included in comparable earnings	**11**	56	**177**	159
Income tax expense included in comparable earnings	**(268)**	(234)	**(693)**	(839)
Net income attributable to non-controlling interests included in comparable earnings	**(86)**	(49)	**(315)**	(238)
Preferred share dividends	**(41)**	(40)	**(163)**	(160)
Comparable earnings	**946**	719	**3,480**	2,690

Comparable EBITDA and comparable earnings – 2018 versus 2017

Comparable EBITDA increased by $550 million for the three months ended December 31, 2018 compared to the same period in 2017 primarily due to the net effect of the following:

- higher contribution from Canadian Natural Gas Pipelines primarily due to the recovery of increased depreciation as a result of higher rates approved in both the Mainline NEB 2018 Decision and the NGTL 2018-2019 Settlement, as well as higher flow-through taxes and incentive earnings
- higher contribution from U.S. Natural Gas Pipelines mainly due to increased earnings from Columbia Gas and Columbia Gulf growth projects placed in service, additional contract sales on ANR and Great Lakes, and amortization of net regulatory liabilities recognized as a result of U.S. Tax Reform
- higher contribution from Liquids Pipelines primarily due to higher volumes on the Keystone Pipeline System, increased earnings from liquids marketing activities and earnings from intra-Alberta pipelines placed in service in the second half of 2017
- higher revenues from Mexico Natural Gas Pipelines as a result of changes in timing of revenue recognition
- lower earnings from Bruce Power primarily due to lower volumes resulting from higher outage days.

Comparable earnings increased by $227 million or $0.21 per common share for the three months ended December 31, 2018 compared to the same period in 2017 and was primarily the net effect of:

- changes in comparable EBITDA described above
- higher depreciation primarily in Canadian Natural Gas Pipelines due to increased depreciation rates approved in the Mainline NEB 2018 Decision and the NGTL 2018-2019 Settlement (these amounts are fully recovered as reflected in the increase in comparable EBITDA described above, having no net impact on comparable earnings) as well as higher depreciation related to new projects placed in service in 2017 and 2018
- higher interest expense primarily as a result of long-term debt and junior subordinated notes issuances, net of maturities
- lower interest income and other as a result of realized losses in 2018 compared to realized gains in 2017 on derivatives used to manage net exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income.

Comparable earnings per common share for the three months ended December 31, 2018 also reflect the dilutive impact of common shares issued in 2017 and 2018 under our DRP and our Corporate ATM program.

2018 FERC Actions and U.S. Tax Reform

In fourth quarter 2018, the following significant developments with respect to 2018 FERC Actions and U.S. Tax Reform took place:

- On November 15, 2018, FERC issued a Policy Statement on the Accounting and Ratemaking Treatment of Accumulated Deferred Income Taxes (ADIT) and Treatment Following the Sale or Retirement of an Asset, a policy statement (Excess ADIT Policy Statement) addressing certain issues raised in the Notice of Inquiry (NOI) issued on March 15, 2018. The Excess ADIT Policy Statement clarifies FERC accounts in which pipelines should record amortization of excess and/or deficient ADIT for FERC reporting and ratemaking purposes. The Excess ADIT Policy Statement also addresses how to disclose reversals of ADIT account balances in FERC's annual financial report filings
- In accordance with the Form 501-G filings and settlements reached with customers in response to the 2018 FERC Actions, the ADIT balances for all pipelines held wholly or in part by TC PipeLines, LP were eliminated from their respective rate bases. Therefore, regulatory liabilities recorded for these assets pursuant to U.S. Tax Reform were written off, resulting in a deferred income tax recovery of $115 million in fourth quarter 2018
- All of our FERC-regulated natural gas pipelines and storage assets have now either filed a Form 501-G or an uncontested rate settlement with FERC as directed. There has been no significant incremental impact from our third quarter 2018 disclosures regarding the effect of 2018 FERC Actions on future earnings and cash flows
- Upon finalizing the 2017 annual tax returns for our U.S. businesses and clarifying the impact of U.S. Tax Reform on our deferred income tax liability at December 31, 2017, and as permitted by the SEC during the one-year measurement period, it was determined that an adjustment was required to the estimate originally recorded. Accordingly, a deferred income tax recovery of $52 million was recognized in fourth quarter 2018 to adjust our net regulatory liability and ADIT balances.

Capital Program

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

Our $57 billion capital program consists of approximately $36.6 billion of secured projects and approximately $20.7 billion of projects under development. Our secured projects include commercially supported, committed projects that are either under construction or are in or preparing to commence the permitting stage, but are not yet fully approved. Our projects under development are commercially supported except where noted, but have greater uncertainty with respect to timing and estimated project costs and are subject to certain approvals.

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

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

Secured projects

(billions of $)	Expected in-service date	Estimated project cost[1]	Carrying value at December 31, 2018
Canadian Natural Gas Pipelines			
Canadian Mainline	2019-2021	0.3	—
NGTL System	2019	2.8	1.4
	2020	1.7	0.2
	2021	2.8	—
	2022	1.3	—
Coastal GasLink[2,3]	2023	6.2	0.1
Regulated maintenance capital expenditures	2019-2021	1.8	—
U.S. Natural Gas Pipelines			
Columbia Gas			
Mountaineer XPress	2019	US 3.2	US 2.9
Modernization II	2019-2020	US 1.1	US 0.5
Columbia Gulf			
Gulf XPress	2019	US 0.6	US 0.5
Other capacity capital	2019-2022	US 0.9	US 0.1
Regulated maintenance capital expenditures	2019-2021	US 2.0	—
Mexico Natural Gas Pipelines			
Sur de Texas[4]	2019	US 1.5	US 1.4
Villa de Reyes[4]	2019	US 0.8	US 0.6
Tula[4]	2020	US 0.7	US 0.6
Liquids Pipelines			
White Spruce	2019	0.2	0.1
Other capacity capital	2020	0.1	—
Recoverable maintenance capital expenditures	2019-2021	0.1	—
Energy			
Napanee	2019	1.7	1.6
Bruce Power – life extension[5]	2019-2023	2.2	0.6
Other			
Non-recoverable maintenance capital expenditures[6]	2019-2021	0.7	0.2
		32.7	**10.8**
Foreign exchange impact on secured projects[7]		**3.9**	**2.4**
Total secured projects (Cdn$)		**36.6**	**13.2**

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

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

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

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

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

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

7 Reflects U.S./Canada foreign exchange rate of 1.36 at December 31, 2018.

Projects under development

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

(billions of $)	Estimated project cost[1]	Carrying value at December 31, 2018
Canadian Natural Gas Pipelines		
NGTL System – Merrick	1.9	—
Liquids Pipelines		
Keystone XL[2]	US 8.0	US 0.6
Heartland and TC Terminals[3]	0.9	0.1
Grand Rapids Phase II[3]	0.7	—
Keystone Hardisty Terminal[3]	0.3	0.1
Energy		
Bruce Power – life extension[4]	6.0	—
	17.8	**0.8**
Foreign exchange impact on projects under development[5]	**2.9**	**0.2**
Total projects under development (Cdn$)	**20.7**	**1.0**

1 Amounts reflect our proportionate share of joint venture costs where applicable.

2 Carrying value reflects amount remaining after impairment charge recorded in 2015, along with additional amounts capitalized from January 1, 2018.

3 Regulatory approvals have been obtained and additional commercial support is being pursued.

4 Reflects our proportionate share of Major Component Replacement program costs for Units 3, 4, 5, 7 and 8, and the remaining Asset Management program costs beyond 2023.

5 Reflects U.S./Canada foreign exchange rate of 1.36 at December 31, 2018.

Canadian Natural Gas Pipelines

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

	three months ended December 31		year ended December 31	
(millions of $)	**2018**	**2017**	**2018**	**2017**
NGTL System	**313**	274	**1,197**	996
Canadian Mainline	**481**	269	**1,073**	1,043
Other Canadian pipelines[1]	**24**	26	**109**	105
Comparable EBITDA	**818**	569	**2,379**	2,144
Depreciation and amortization	**(368)**	(236)	**(1,129)**	(908)
Comparable EBIT and segmented earnings	**450**	333	**1,250**	1,236

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

Canadian Natural Gas Pipelines segmented earnings increased by $117 million for the three months ended December 31, 2018 compared to the same period in 2017 and are equivalent to comparable EBIT.

Net income and comparable EBITDA for our rate-regulated Canadian natural gas pipelines are primarily 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 revenues on a flow-through basis.

NET INCOME AND AVERAGE INVESTMENT BASE

	three months ended December 31		year ended December 31	
(millions of $)	**2018**	**2017**	**2018**	**2017**
Net Income				
NGTL System	**109**	91	**398**	352
Canadian Mainline	**61**	50	**182**	199
Average investment base				
NGTL System			**9,669**	8,385
Canadian Mainline			**3,828**	4,184

Net income for the NGTL System increased by $18 million for the three months ended December 31, 2018 compared to the same period in 2017 mainly due to a higher average investment base as a result of continued system expansions and higher OM&A incentive earnings. In June 2018, the NEB approved NGTL's 2018-2019 Settlement which is effective from January 1, 2018 to December 31, 2019. It includes an ROE of 10.1 per cent on 40 per cent deemed common equity, a mechanism for sharing variances above and below a fixed annual OM&A amount, flow-through treatment of all other costs and an increase in composite depreciation rates from 3.18 per cent to 3.45 per cent.

Net income for the Canadian Mainline increased by $11 million for the three months ended December 31, 2018 compared to the same period in 2017 primarily due to higher incentive earnings. In December 2018, an NEB decision was received for the 2018-2020 Tolls Review (NEB 2018 Decision) and, as such, incentive earnings for the full year of 2018 were recorded in fourth quarter 2018. The NEB 2018 Decision also included an accelerated amortization of the December 31, 2017 LTAA balance and an increase to the composite depreciation rate from 3.2 per cent to 3.9 per cent.

COMPARABLE EBITDA

Comparable EBITDA increased by $249 million for the three months ended December 31, 2018 compared to the same period in 2017 primarily due to the recovery of increased depreciation as a result of higher rates approved in both the Mainline NEB 2018 Decision and the NGTL 2018-2019 Settlement, as well as higher flow-through taxes and incentive earnings. The full year impact of higher depreciation, flow-through taxes and incentive earnings as a result of the Canadian Mainline NEB 2018 Decision was reflected in fourth quarter 2018.

DEPRECIATION AND AMORTIZATION

Depreciation and amortization increased by $132 million for the three months ended December 31, 2018 compared to the same period in 2017 mainly due to the increase in depreciation rates approved in the Mainline NEB 2018 Decision and the NGTL 2018-2019 Settlement, as well as NGTL System facilities that were placed in service in 2018.

U.S. Natural Gas Pipelines

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

	three months ended December 31		year ended December 31	
(millions of US$, unless noted otherwise)	**2018**	**2017**	**2018**	**2017**
Columbia Gas	**236**	177	**873**	623
ANR	**138**	99	**508**	400
TC PipeLines, LP[1,2]	**36**	31	**138**	118
Midstream	**21**	23	**122**	93
Columbia Gulf	**30**	21	**120**	76
Great Lakes[2,3]	**23**	15	**97**	64
Other U.S. pipelines[1,2,4]	**18**	16	**68**	80
Non-controlling interests[5]	**111**	93	**415**	359
Comparable EBITDA	**613**	475	**2,341**	1,813
Depreciation and amortization	**(131)**	(113)	**(511)**	(453)
Comparable EBIT	**482**	362	**1,830**	1,360
Foreign exchange impact	**155**	99	**541**	410
Comparable EBIT (Cdn$)	**637**	461	**2,371**	1,770
Specific item:				
Bison asset impairment[6]	**(722)**	—	**(722)**	—
Tuscarora goodwill impairment[6]	**(79)**	—	**(79)**	—
Bison contract terminations[6]	**130**	—	**130**	—
Integration and acquisition related costs – Columbia	**—**	—	**—**	(10)
Segmented (losses)/earnings (Cdn$)	**(34)**	461	**1,700**	1,760

1 Results reflect our earnings from TC PipeLines, LP's ownership interests in GTN, Great Lakes, Iroquois, Northern Border, Bison, Portland, North Baja and Tuscarora, as well as general and administrative costs related to TC PipeLines, LP. Results from Northern Border and Iroquois reflect our share of equity income from these investments. TC PipeLines, LP acquired 49.34 per cent of our 50 per cent interest in Iroquois on June 1, 2017. On June 1, 2017, we sold the remaining 11.81 per cent of Portland to TC PipeLines, LP.

2 TC PipeLines, LP periodically conducted at-the-market equity issuances which decreased our ownership in TC PipeLines, LP. Effective March 2018, this program ceased to be utilized. At December 31, 2018 our ownership interest in TC PipeLines, LP was 25.5 per cent compared to 25.7 per cent at December 31, 2017.

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

4 Results reflect earnings from our direct ownership interests in Crossroads, as well as Iroquois and Portland until June 1, 2017, our effective ownership in Millennium and Hardy Storage, and general and administrative and business development costs related to U.S. natural gas pipelines.

5 Results reflect earnings attributable to portions of TC PipeLines, LP, Portland (until June 1, 2017) and Columbia Pipeline Partners LP (CPPL) (until February 17, 2017) that we do not own.

6 These amounts were recorded in TC PipeLines, LP. The pre-tax impact to us is 25.5 per cent of these amounts net of non-controlling interests.

U.S. Natural Gas Pipelines segmented earnings decreased by $495 million for the three months ended December 31, 2018 compared to the same period in 2017.

Segmented earnings for the three months ended December 31, 2018 included:

- a $722 million non-cash asset impairment charge related to Bison
- a $79 million non-cash goodwill impairment charge related to Tuscarora
- $130 million of termination payments received on two of Bison's transportation contracts which was recorded in Revenues.

The amounts for each of these specified items are pre-tax and before reduction for the 74.5 per cent non-controlling interests in TC PipeLines, LP and have been excluded from our calculation of comparable EBIT. A stronger U.S. dollar in fourth quarter 2018 had a positive impact on the Canadian dollar equivalent segmented earnings from our U.S. operations compared to the same period in 2017.

Comparable EBITDA for U.S. Natural Gas Pipelines increased by US$138 million for the three months ended December 31, 2018 compared to the same period in 2017 and was primarily the net effect of:

- increased earnings from Columbia Gas and Columbia Gulf growth projects placed in service and additional contract sales on ANR and Great Lakes
- increased earnings due to the amortization of the net regulatory liabilities that were recorded at the end of 2017, partially offset by a reduction in certain rates on Columbia Gas as a result of U.S. Tax Reform.

DEPRECIATION AND AMORTIZATION

Depreciation and amortization increased by US$18 million for the three months ended December 31, 2018 compared to the same period in 2017 mainly due to new projects placed in service.

Mexico Natural Gas Pipelines

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

	three months ended December 31		year ended December 31	
(millions of US$, unless noted otherwise)	**2018**	**2017**	**2018**	**2017**
Topolobampo	**44**	38	**172**	157
Tamazunchale	**31**	27	**127**	112
Mazatlán	**20**	16	**78**	65
Guadalajara	**18**	17	**71**	68
Sur de Texas[1]	**2**	(6)	**16**	8
Other	**—**	(1)	**4**	(11)
Comparable EBITDA	**115**	91	**468**	399
Depreciation and amortization	**(19)**	(18)	**(75)**	(72)
Comparable EBIT	**96**	73	**393**	327
Foreign exchange impact	**32**	20	**117**	99
Comparable EBIT and segmented earnings (Cdn$)	**128**	93	**510**	426

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 increased by $35 million for the three months ended December 31, 2018 compared to the same period in 2017 and are equivalent to comparable EBIT.

Comparable EBITDA for Mexico Natural Gas Pipelines increased by US$24 million for the three months ended December 31, 2018 compared to the same period in 2017 primarily due to:

- higher revenues from operations as a result of changes in timing of revenue recognition
- 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 interest expense on this inter-affiliate loan is fully offset in Interest income and other in the Corporate segment
- incremental earnings from a CRE tariff increase.

DEPRECIATION AND AMORTIZATION

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

Liquids Pipelines

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

	three months ended December 31		year ended December 31	
(millions of $)	**2018**	**2017**	**2018**	**2017**
Keystone Pipeline System	**401**	346	**1,443**	1,283
Intra-Alberta pipelines	**38**	29	**160**	33
Liquids marketing and other	**99**	26	**246**	32
Comparable EBITDA	**538**	401	**1,849**	1,348
Depreciation and amortization	**(87)**	(81)	**(341)**	(309)
Comparable EBIT	**451**	320	**1,508**	1,039
Specific items:				
Energy East impairment charge	**—**	(1,256)	**—**	(1,256)
Keystone XL asset costs	**—**	(11)	**—**	(34)
Risk management activities	**81**	15	**71**	—
Segmented earnings/(losses)	**532**	(932)	**1,579**	(251)

Comparable EBIT denominated as follows:				
Canadian dollars	**92**	80	**370**	255
U.S. dollars	**271**	188	**876**	604
Foreign exchange impact	**88**	52	**262**	180
	451	320	**1,508**	1,039

Liquids Pipelines segmented earnings increased by $1,464 million for the three months ended December 31, 2018 compared to the same period in 2017 and included the following specific items:

- a $1,256 million pre-tax impairment charge in 2017 for the Energy East pipeline and related projects
- $11 million of pre-tax costs in 2017 related to Keystone XL for the maintenance and liquidation of project assets which were expensed pending further advancement of the project
- unrealized gains from changes in the fair value of derivatives related to our liquids marketing business.

Comparable EBITDA for Liquids Pipelines increased by $137 million for the three months ended December 31, 2018 compared to the same period in 2017 primarily due to:

- higher contracted and uncontracted volumes on the Keystone Pipeline System
- higher contribution from liquids marketing activities from improved margins and volumes
- incremental contributions from intra-Alberta pipelines, Grand Rapids and Northern Courier, which began operations in the second half of 2017
- lower business development costs as a result of capitalizing Keystone XL expenditures in 2018
- a stronger U.S. dollar which had a positive impact on the Canadian dollar equivalent earnings from our U.S. operations.

DEPRECIATION AND AMORTIZATION

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

Energy

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

	three months ended December 31		year ended December 31	
(millions of Canadian $, unless noted otherwise)	**2018**	**2017**	**2018**	**2017**
Western and Eastern Power[1]	**99**	115	**428**	444
Bruce Power[1]	**66**	120	**311**	434
U.S. Power (US$)[2]	**—**	(8)	**—**	100
Foreign exchange impact on U.S. Power	**—**	(4)	**—**	30
Natural Gas Storage and other	**6**	15	**27**	55
Business Development[3]	**(4)**	(24)	**(14)**	(33)
Comparable EBITDA	**167**	214	**752**	1,030
Depreciation and amortization	**(27)**	(33)	**(119)**	(151)
Comparable EBIT	**140**	181	**633**	879
Specific items:				
Gain on sale of Cartier Wind power facilities	**170**	—	**170**	—
U.S. Northeast power marketing contracts	**(10)**	—	**(5)**	—
Net gain on sales of U.S. Northeast power generation assets	**—**	15	**—**	484
Gain on sale of Ontario solar assets	**—**	127	**—**	127
Risk management activities	**15**	149	**(19)**	62
Segmented earnings	**315**	472	**779**	1,552

1 Includes our share of equity income from our investments in Portlands Energy and Bruce Power.
2 In second quarter 2017, we completed the sales of our U.S. Northeast power generation assets.
3 Includes a $21 million impairment charge in 2017 related to obsolete equipment.

Energy segmented earnings were $157 million lower in the three months ended December 31, 2018 compared to the same period in 2017 and included the following specific items:

- a pre-tax gain in 2018 of $170 million related to the sale of our interests in the Cartier Wind power facilities
- a pre-tax net loss of $10 million related to our U.S. Northeast power marketing contracts. These results have been excluded from Energy's comparable earnings in 2018 as we do not consider the wind-down of the remaining contracts part of our underlying operations. The contract portfolio is scheduled to run-off through to mid-2020
- a pre-tax gain in 2017 of $127 million related to the sale of our Ontario solar assets
- a pre-tax net gain of $15 million in 2017 related to the monetization of our U.S. Northeast power generation assets
- unrealized gains and losses from changes in the fair value of derivatives used to reduce our exposure to certain commodity price risks, as noted in the table below.

Risk management activities	three months ended December 31		year ended December 31	
(millions of $, pre-tax)	**2018**	**2017**	**2018**	**2017**
Canadian Power	**—**	6	**3**	11
U.S. Power	**20**	136	**(11)**	39
Natural Gas Storage	**(5)**	7	**(11)**	12
Total unrealized gains/(losses) from risk management activities	**15**	149	**(19)**	62

Comparable EBITDA for Energy decreased by $47 million for the three months ended December 31, 2018 compared to the same period in 2017 primarily due to the net effect of:

- decreased earnings from Bruce Power primarily due to lower volumes resulting from higher outage days. Additional financial and operating information on Bruce Power is provided below
- decreased Western and Eastern Power results due to the sales of our Cartier Wind power facilities in October 2018 and our Ontario solar assets in December 2017, partially offset by higher Western Power realized margins on higher generation volumes
- lower Natural Gas Storage results primarily due to pipeline constraints in the Alberta natural gas market which limited our ability to access our storage facilities and resulted in lower realized natural gas storage price spreads.

DEPRECIATION AND AMORTIZATION

Depreciation and amortization decreased by $6 million for the three months ended December 31, 2018 compared to the same period in 2017 primarily due to the cessation of depreciation on our Cartier Wind power facilities upon classification as held for sale at June 30, 2018.

BRUCE POWER

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

	three months ended December 31		year ended December 31	
(millions of $, unless noted otherwise)	**2018**	**2017**	**2018**	**2017**
Equity income included in comparable EBITDA and EBIT comprised of:				
Revenues[1]	**373**	414	**1,526**	1,626
Operating expenses	**(212)**	(208)	**(852)**	(846)
Depreciation and other	**(95)**	(86)	**(363)**	(346)
Comparable EBITDA and EBIT[2]	**66**	120	**311**	434
Bruce Power – other information				
Plant availability[3]	**83%**	92%	**87%**	90%
Planned outage days	**100**	43	**280**	221
Unplanned outage days	**15**	10	**92**	49
Sales volumes (GWh)[2]	**5,676**	6,275	**23,486**	24,368
Realized sales price per MWh[4]	**$68**	$67	**$67**	$67

1 Net of amounts recorded to reflect operating cost efficiencies shared with the IESO.
2 Represents our 48.3 per cent (2017 – 48.4 per cent) ownership interest in Bruce Power. Sales volumes include deemed generation.
3 The percentage of time the plant was available to generate power, regardless of whether it was running.
4 Calculation based on actual and deemed generation. Realized sales prices per MWh includes realized gains and losses from contracting activities and cost flow-through items. Excludes unrealized gains and losses on contracting activities and non-electricity revenues.

Planned maintenance on Unit 8 began and was completed in fourth quarter 2018. Planned maintenance on Unit 3 began in fourth quarter 2018 and is scheduled to be completed in first quarter 2019.

Corporate

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

(millions of $)	three months ended December 31 2018	three months ended December 31 2017	year ended December 31 2018	year ended December 31 2017
Comparable EBITDA and EBIT	**(34)**	(1)	**(59)**	(21)
Specific items:				
Foreign exchange gain – inter-affiliate loan[1]	**57**	64	**5**	63
Integration and acquisition related costs – Columbia	**—**	—	—	(81)
Segmented earnings/(losses)	**23**	63	**(54)**	(39)

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

Corporate segmented earnings decreased by $40 million for the three months ended December 31, 2018 compared to the same period in 2017 and included the following specific items:

- foreign exchange gains 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.

Comparable EBITDA decreased by $33 million for the three months ended December 31, 2018 compared to the same period in 2017, primarily due to increased general and administrative costs.

OTHER INCOME STATEMENT ITEMS

Interest expense

(millions of $)	three months ended December 31 2018	three months ended December 31 2017	year ended December 31 2018	year ended December 31 2017
Interest on long-term debt and junior subordinated notes				
Canadian dollar-denominated	**(142)**	(138)	**(549)**	(494)
U.S. dollar-denominated	**(344)**	(315)	**(1,325)**	(1,269)
Foreign exchange impact	**(111)**	(86)	**(394)**	(379)
	(597)	(539)	**(2,268)**	(2,142)
Other interest and amortization expense	**(41)**	(25)	**(121)**	(99)
Capitalized interest	**35**	23	**124**	173
Interest expense included in comparable earnings	**(603)**	(541)	**(2,265)**	(2,068)
Specific Item:				
Risk management activities	**—**	—	**—**	(1)
Interest expense	**(603)**	(541)	**(2,265)**	(2,069)

Interest expense increased by $62 million for the three months ended December 31, 2018 compared to the same period in 2017 and primarily reflects the net effect of:

- long-term debt and junior subordinated note issuances in 2018 and 2017, net of maturities
- higher capitalized interest primarily due to ongoing construction at Napanee and the recommencement of capitalization of Keystone XL costs in 2018, partially offset by the completion of Northern Courier in fourth quarter 2017
- higher levels of short-term borrowing
- foreign exchange impact on translation of U.S. dollar-denominated interest.

Allowance for funds used during construction

	three months ended December 31		year ended December 31	
(millions of $)	**2018**	**2017**	**2018**	**2017**
Allowance for funds used during construction				
Canadian dollar-denominated	**35**	25	**103**	174
U.S. dollar-denominated	**96**	91	**326**	259
Foreign exchange impact	**30**	24	**97**	74
Allowance for funds used during construction	**161**	140	**526**	507

AFUDC increased by $21 million for the three months ended December 31, 2018 compared to the same period in 2017.

The increase in Canadian dollar-denominated AFUDC is primarily due to higher capital expenditures on the NGTL System.

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

Interest income and other

	three months ended December 31		year ended December 31	
(millions of $)	**2018**	**2017**	**2018**	**2017**
Interest income and other included in comparable earnings	**11**	56	**177**	159
Specific items:				
Foreign exchange loss – inter-affiliate loan	**(57)**	(64)	**(5)**	(63)
Risk management activities	**(169)**	(1)	**(248)**	88
Interest income and other	**(215)**	(9)	**(76)**	184

Interest income and other decreased by $206 million for the three months ended December 31, 2018 compared to the same period in 2017 and was primarily the net effect of:

- higher unrealized losses on risk management activities in 2018 compared to 2017, reflecting the strengthening of the U.S. dollar at the end of 2018. These amounts have been excluded from comparable earnings
- realized losses in 2018 compared to realized gains in 2017 on derivatives used to manage our net exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income
- higher interest income combined with a lower 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. The offsetting currency-related gain and loss amounts are excluded from comparable earnings.

Income tax (expense)/recovery

(millions of $)	three months ended December 31 2018	2017	year ended December 31 2018	2017
Income tax expense included in comparable earnings	**(268)**	(234)	**(693)**	(839)
Specific items:				
MLP regulatory liability write-off	**115**	—	**115**	—
U.S. Tax Reform	**52**	804	**52**	804
Bison asset impairment	**44**	—	**44**	—
Sales of U.S. Northeast power generation assets	**27**	49	**27**	(177)
Tuscarora goodwill impairment	**5**	—	**5**	—
U.S. Northeast power marketing contracts	**3**	—	**1**	—
Gain on sale of Cartier Wind power facilities	**(27)**	—	**(27)**	—
Bison contract terminations	**(8)**	—	**(8)**	—
Energy East impairment charge	**—**	302	**—**	302
Gain on sale of Ontario solar assets	**—**	9	**—**	9
Keystone XL asset costs	**—**	2	**—**	6
Integration and acquisition related costs – Columbia	**—**	—	**—**	22
Keystone XL income tax recoveries	**—**	—	**—**	7
Risk management activities	**19**	(62)	**52**	(45)
Income tax (expense)/recovery	**(38)**	870	**(432)**	89

Income tax expense included in comparable earnings increased by $34 million for the three months ended December 31, 2018 compared to the same period in 2017. This was primarily due to higher comparable earnings before income taxes and higher flow-through income taxes in Canadian rate-regulated pipelines offset by lower income tax rates as a result of U.S. Tax Reform.

Net loss/(income) attributable to non-controlling interests

(millions of $)	three months ended December 31 2018	2017	year ended December 31 2018	2017
Net income attributable to non-controlling interests included in comparable earnings	**(86)**	(49)	**(315)**	(238)
Specific items:				
Bison impairment	**538**	—	**538**	—
Tuscarora goodwill impairment	**59**	—	**59**	—
Bison contract terminations	**(97)**	—	**(97)**	—
Net loss/(income) attributable to non-controlling interests	**414**	(49)	**185**	(238)

Net loss/(income) attributable to non-controlling interests decreased by $463 million for the three months ended December 31, 2018 compared to the same period in 2017 primarily due to the net effect of:

- a $538 million charge related to the non-controlling interests portion of a $722 million Bison asset impairment charge recorded by TC PipeLines, LP
- a $59 million charge related to the non-controlling interests portion of a $79 million Tuscarora goodwill impairment charge recorded by TC PipeLines, LP
- $97 million in income related to the non-controlling interests portion of Bison contract termination payments of $130 million received from certain customers and recorded by TC PipeLines, LP.

On consolidation, we recorded the non-controlling interests' 74.5 per cent of these transactions. These items have been excluded in the calculation of comparable earnings.

Net income attributable to non-controlling interests included in comparable earnings increased by $37 million for the three months ended December 31, 2018 compared to the same period in 2017 primarily due to higher earnings in TC PipeLines, LP.

Preferred share dividends

	three months ended December 31		year ended December 31	
(millions of $)	**2018**	**2017**	**2018**	**2017**
Preferred share dividends	**(41)**	(40)	**(163)**	(160)

Preferred share dividends remained largely consistent for the three months ended December 31, 2018 compared to the same period in 2017.

Cash Provided by Operating Activities

	three months ended December 31		year ended December 31	
(millions of $, except per share amounts)	**2018**	**2017**	**2018**	**2017**
Net cash provided by operations	**2,039**	1,390	**6,555**	5,230
(Decrease)/increase in operating working capital	**(28)**	49	**102**	273
Funds generated from operations	**2,011**	1,439	**6,657**	5,503
Specific items:				
Bison contract terminations	**(122)**	—	**(122)**	—
Net (gain)/loss on sales of U.S. Northeast power generation assets	**(14)**	—	**(14)**	20
U.S. Northeast power marketing contracts	**6**	—	**1**	—
Keystone XL asset costs	**—**	11	**—**	34
Integration and acquisition related costs – Columbia	**—**	—	**—**	84
Comparable funds generated from operations	**1,881**	1,450	**6,522**	5,641
Dividends on preferred shares	**(40)**	(39)	**(158)**	(155)
Distributions to non-controlling interests	**(51)**	(68)	**(225)**	(283)
Non-recoverable maintenance capital expenditures	**(63)**	(71)	**(254)**	(240)
Comparable distributable cash flow	**1,727**	1,272	**5,885**	4,963
Comparable distributable cash flow per common share	**$1.89**	$1.45	**$6.52**	$5.69

COMPARABLE FUNDS GENERATED FROM OPERATIONS

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

Comparable funds generated from operations increased by $431 million for the three months ended December 31, 2018 compared to the same period in 2017. Approximately half of this increase was the result of reflecting the full year impact of recovering higher depreciation and flow-through taxes as well as the recognition of incentive earnings for the Canadian Mainline in fourth quarter 2018 upon receiving the Canadian Mainline NEB 2018 Decision in December 2018. The remainder of the increase is primarily due to higher comparable earnings (excluding Income from equity investments) adjusted for the cash impact of specific items, and higher distributions from our equity investments, partially offset by higher interest expense.

COMPARABLE DISTRIBUTABLE CASH FLOW

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

The increase in comparable distributable cash flow for the three months ended December 31, 2018 compared to the same period in 2017 reflects higher comparable funds generated from operations, as described above. Comparable distributable cash flow per common share for the three months ended December 31, 2018 also reflects the dilutive impact of common shares issued under the Corporate ATM program and DRP in 2017 and 2018.

In 2018, our determination of comparable distributable cash flow has been revised to exclude the deduction of maintenance capital expenditures for assets for which we have the ability to recover these costs in pipeline tolls. Comparative periods presented in the table have been adjusted accordingly. We believe that including only non-recoverable maintenance capital expenditures in the calculation of distributable cash flow best depicts the cash available for reinvestment or distribution to shareholders. For our rate-regulated Canadian and U.S. natural gas pipelines, we have the opportunity to recover and earn a return on maintenance capital expenditures through current and future tolls. Tolling arrangements in our liquids pipelines provide for the recovery of maintenance capital expenditures. Therefore, we have not deducted the recoverable maintenance capital expenditures for these businesses in the calculation of comparable distributable cash flow.

Reconciliation of non-GAAP measures

	three months ended December 31		year ended December 31	
(millions of $)	**2018**	**2017**	**2018**	**2017**
Comparable EBITDA				
Canadian Natural Gas Pipelines	**818**	569	**2,379**	2,144
U.S. Natural Gas Pipelines	**812**	604	**3,035**	2,357
Mexico Natural Gas Pipelines	**152**	116	**607**	519
Liquids Pipelines	**538**	401	**1,849**	1,348
Energy	**167**	214	**752**	1,030
Corporate	**(34)**	(1)	**(59)**	(21)
Comparable EBITDA	**2,453**	1,903	**8,563**	7,377
Depreciation and amortization	**(681)**	(516)	**(2,350)**	(2,048)
Comparable EBIT	**1,772**	1,387	**6,213**	5,329
Specific items:				
Bison asset impairment	**(722)**	—	**(722)**	—
Tuscarora goodwill impairment	**(79)**	—	**(79)**	—
U.S. Northeast power marketing contracts	**(10)**	—	**(5)**	—
Gain on sale of Cartier Wind power facilities	**170**	—	**170**	—
Bison contract terminations	**130**	—	**130**	—
Foreign exchange gain – inter-affiliate loan	**57**	64	**5**	63
Energy East impairment charge	**—**	(1,256)	**—**	(1,256)
Keystone XL asset costs	**—**	(11)	**—**	(34)
Gain on sale of Ontario solar assets	**—**	127	**—**	127
Net gain on sales of U.S. Northeast power generation assets	**—**	15	**—**	484
Integration and acquisition related costs – Columbia	**—**	—	**—**	(91)
Risk management activities	**96**	164	**52**	62
Segmented earnings	**1,414**	490	**5,764**	4,684

Condensed consolidated statement of income

(unaudited - millions of Canadian $, except per share amounts)	three months ended December 31		year ended December 31	
	2018	**2017**	**2018**	**2017**
Revenues				
Canadian Natural Gas Pipelines	**1,266**	968	**4,038**	3,693
U.S. Natural Gas Pipelines	**1,326**	900	**4,314**	3,584
Mexico Natural Gas Pipelines	**159**	138	**619**	570
Liquids Pipelines	**753**	599	**2,584**	2,009
Energy	**400**	1,012	**2,124**	3,593
	3,904	3,617	**13,679**	13,449
Income from Equity Investments	**222**	246	**714**	773
Operating and Other Expenses				
Plant operating costs and other	**1,011**	944	**3,591**	3,906
Commodity purchases resold	**249**	671	**1,488**	2,382
Property taxes	**140**	127	**569**	569
Depreciation and amortization	**681**	516	**2,350**	2,055
Goodwill and other asset impairment charges	**801**	1,257	**801**	1,257
	2,882	3,515	**8,799**	10,169
Gain on Sales of Assets	**170**	142	**170**	631
Financial Charges				
Interest expense	**603**	541	**2,265**	2,069
Allowance for funds used during construction	**(161)**	(140)	**(526)**	(507)
Interest income and other	**215**	9	**76**	(184)
	657	410	**1,815**	1,378
Income before Income Taxes	**757**	80	**3,949**	3,306
Income Tax Expense/(Recovery)				
Current	**146**	21	**315**	149
Deferred	**59**	(87)	**284**	566
Deferred – U.S. Tax Reform and 2018 FERC Actions	**(167)**	(804)	**(167)**	(804)
	38	(870)	**432**	(89)
Net Income	**719**	950	**3,517**	3,395
Net (loss)/income attributable to non-controlling interests	**(414)**	49	**(185)**	238
Net Income Attributable to Controlling Interests	**1,133**	901	**3,702**	3,157
Preferred share dividends	**41**	40	**163**	160
Net Income Attributable to Common Shares	**1,092**	861	**3,539**	2,997
Net Income per Common Share				
Basic	**$1.19**	$0.98	**$3.92**	$3.44
Diluted	**$1.19**	$0.98	**$3.92**	$3.43
Dividends Declared per Common Share	**$0.69**	$0.625	**$2.76**	$2.50
Weighted Average Number of Common Shares (millions)				
Basic	**915**	877	**902**	872
Diluted	**915**	879	**903**	874

Condensed consolidated statement of cash flows

(unaudited - millions of Canadian $)	three months ended December 31		year ended December 31	
	2018	**2017**	**2018**	**2017**
Cash Generated from Operations				
Net income	**719**	950	**3,517**	3,395
Depreciation and amortization	**681**	516	**2,350**	2,055
Goodwill and other asset impairment charges	**801**	1,257	**801**	1,257
Deferred income taxes	**59**	(87)	**284**	566
Deferred income taxes – U.S. Tax Reform and 2018 FERC Actions	**(167)**	(804)	**(167)**	(804)
Income from equity investments	**(222)**	(246)	**(714)**	(773)
Distributions received from operating activities of equity investments	**224**	227	**985**	970
Employee post-retirement benefits funding, net of expense	**(13)**	—	**(35)**	(64)
Gain on sale of assets	**(170)**	(142)	**(170)**	(631)
Equity allowance for funds used during construction	**(113)**	(113)	**(374)**	(362)
Unrealized losses/(gains) on financial instruments	**100**	(163)	**220**	(149)
Other	**112**	44	**(40)**	43
Decrease/(increase) in operating working capital	**28**	(49)	**(102)**	(273)
Net cash provided by operations	**2,039**	1,390	**6,555**	5,230
Investing Activities				
Capital expenditures	**(2,944)**	(2,000)	**(9,418)**	(7,383)
Capital projects in development	**(257)**	(11)	**(496)**	(146)
Contributions to equity investments	**(237)**	(541)	**(1,015)**	(1,681)
Proceeds from sales of assets, net of transaction costs	**614**	536	**614**	4,683
Reimbursement of costs related to capital projects in development	**470**	634	**470**	634
Other distributions from equity investments	**—**	—	**121**	362
Deferred amounts and other	**(373)**	(81)	**(295)**	(168)
Net cash used in investing activities	**(2,727)**	(1,463)	**(10,019)**	(3,699)
Financing Activities				
Notes payable (repaid)/issued, net	**(1,089)**	(194)	**817**	1,038
Long-term debt issued, net of issue costs	**1,879**	1,675	**6,238**	3,643
Long-term debt repaid	**(284)**	(1,570)	**(3,550)**	(7,085)
Junior subordinated notes issued, net of issue costs	**—**	—	**—**	3,468
Dividends on common shares	**(417)**	(357)	**(1,571)**	(1,339)
Dividends on preferred shares	**(40)**	(39)	**(158)**	(155)
Distributions to non-controlling interests	**(51)**	(68)	**(225)**	(283)
Common shares issued, net of issue costs	**9**	232	**1,148**	274
Partnership units of TC PipeLines, LP issued, net of issue costs	**—**	63	**49**	225
Common units of Columbia Pipeline Partners LP acquired	**—**	—	**—**	(1,205)
Net cash provided by/(used in) financing activities	**7**	(258)	**2,748**	(1,419)
Effect of Foreign Exchange Rate Changes on Cash and Cash Equivalents	**26**	(4)	**73**	(39)
(Decrease)/increase in Cash and Cash Equivalents	**(655)**	(335)	**(643)**	73
Cash and Cash Equivalents				
Beginning of period	**1,101**	1,424	**1,089**	1,016
Cash and Cash Equivalents				
End of period	**446**	1,089	**446**	1,089

Condensed consolidated balance sheet

(unaudited - millions of Canadian $)		December 31, 2018	December 31, 2017
ASSETS			
Current Assets			
Cash and cash equivalents		**446**	1,089
Accounts receivable		**2,535**	2,522
Inventories		**431**	378
Assets held for sale		**543**	—
Other		**1,180**	691
		5,135	4,680
Plant, Property and Equipment	net of accumulated depreciation of $25,834 and $23,734, respectively	**66,503**	57,277
Equity Investments		**7,113**	6,366
Regulatory Assets		**1,548**	1,376
Goodwill		**14,178**	13,084
Loan Receivable from Affiliate		**1,315**	919
Intangible and Other Assets		**1,921**	1,484
Restricted Investments		**1,207**	915
		98,920	86,101
LIABILITIES			
Current Liabilities			
Notes payable		**2,762**	1,763
Accounts payable and other		**5,408**	4,057
Dividends payable		**668**	586
Accrued interest		**646**	605
Current portion of long-term debt		**3,462**	2,866
		12,946	9,877
Regulatory Liabilities		**3,930**	4,321
Other Long-Term Liabilities		**1,008**	727
Deferred Income Tax Liabilities		**6,026**	5,403
Long-Term Debt		**36,509**	31,875
Junior Subordinated Notes		**7,508**	7,007
		67,927	59,210
EQUITY			
Common shares, no par value		**23,174**	21,167
Issued and outstanding:	December 31, 2018 – 918 million shares		
	December 31, 2017 – 881 million shares		
Preferred shares		**3,980**	3,980
Additional paid-in capital		**17**	—
Retained earnings		**2,773**	1,623
Accumulated other comprehensive loss		**(606)**	(1,731)
Controlling Interests		**29,338**	25,039
Non-controlling interests		**1,655**	1,852
		30,993	26,891
		98,920	86,101

Segmented information

three months ended December 31, 2018 (unaudited - millions of Canadian $)	**Canadian Natural Gas Pipelines**	**U.S. Natural Gas Pipelines**	**Mexico Natural Gas Pipelines**	**Liquids Pipelines**	**Energy**	**Corporate**[1]	**Total**
Revenues	**1,266**	**1,326**	**159**	**753**	**400**	**—**	**3,904**
Intersegment revenues	**—**	**41**	**—**	**—**	**6**	**(47)** [2]	**—**
	1,266	**1,367**	**159**	**753**	**406**	**(47)**	**3,904**
Income from equity investments	**3**	**68**	**2**	**14**	**78**	**57** [3]	**222**
Plant operating costs and other	**(385)**	**(443)**	**(9)**	**(124)**	**(63)**	**13** [2]	**(1,011)**
Commodity purchases resold	**—**	**—**	**—**	**—**	**(249)**	**—**	**(249)**
Property taxes	**(66)**	**(50)**	**—**	**(24)**	**—**	**—**	**(140)**
Depreciation and amortization	**(368)**	**(175)**	**(24)**	**(87)**	**(27)**	**—**	**(681)**
Goodwill and other asset impairment charges	**—**	**(801)**	**—**	**—**	**—**	**—**	**(801)**
Gain on sale of assets	**—**	**—**	**—**	**—**	**170**	**—**	**170**
Segmented earnings/(losses)	**450**	**(34)**	**128**	**532**	**315**	**23**	**1,414**
Interest expense							**(603)**
Allowance for funds used during construction							**161**
Interest income and other[3]							**(215)**
Income before income taxes							**757**
Income tax expense							**(38)**
Net income							**719**
Net loss attributable to non-controlling interests							**414**
Net income attributable to controlling interests							**1,133**
Preferred share dividends							**(41)**
Net income attributable to common shares							**1,092**

1 Includes intersegment eliminations.

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

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

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) [2]	—
	968	920	138	599	1,012	(20)	3,617
Income/(loss) from equity investments	2	65	(9)	(6)	130	64 [3]	246
Plant operating costs and other	(342)	(336)	(13)	(186)	(86)	19 [2]	(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[3]							(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 Includes intersegment eliminations.

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

year ended December 31, 2018 (unaudited - millions of Canadian $)	Canadian Natural Gas Pipelines	U.S. Natural Gas Pipelines	Mexico Natural Gas Pipelines	Liquids Pipelines	Energy	Corporate[1]	Total
Revenues	4,038	4,314	619	2,584	2,124	—	13,679
Intersegment revenues	—	162	—	—	56	(218) [2]	—
	4,038	4,476	619	2,584	2,180	(218)	13,679
Income from equity investments	12	256	22	64	355	5 [3]	714
Plant operating costs and other	(1,405)	(1,368)	(34)	(630)	(313)	159 [2]	(3,591)
Commodity purchases resold	—	—	—	—	(1,488)	—	(1,488)
Property taxes	(266)	(199)	—	(98)	(6)	—	(569)
Depreciation and amortization	(1,129)	(664)	(97)	(341)	(119)	—	(2,350)
Goodwill and other asset impairment charges	—	(801)	—	—	—	—	(801)
Gain on sale of assets	—	—	—	—	170	—	170
Segmented earnings/(losses)	1,250	1,700	510	1,579	779	(54)	5,764
Interest expense							(2,265)
Allowance for funds used during construction							526
Interest income and other[3]							(76)
Income before income taxes							3,949
Income tax expense							(432)
Net income							3,517
Net loss attributable to non-controlling interests							185
Net income attributable to controlling interests							3,702
Preferred share dividends							(163)
Net income attributable to common shares							3,539

1 Includes intersegment eliminations.

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

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

TOTAL ASSETS BY SEGMENT

(unaudited - millions of Canadian $)	**December 31, 2018**	**December 31, 2017**
Canadian Natural Gas Pipelines	**18,407**	16,904
U.S. Natural Gas Pipelines	**44,115**	35,898
Mexico Natural Gas Pipelines	**7,058**	5,716
Liquids Pipelines	**17,352**	15,438
Energy	**8,475**	8,503
Corporate	**3,513**	3,642
	98,920	86,101