NewsRelease

TransCanada Reports Fourth Quarter and Year-End 2016 Financial Results
10.6% Dividend Increase Reflects Strong Performance and Growth Outlook

CALGARY, Alberta – **February 16, 2017** – TransCanada Corporation (TSX, NYSE: TRP) (TransCanada) today announced a net loss attributable to common shares for fourth quarter 2016 of $358 million or $0.43 per share compared to a net loss of $2.5 billion or $3.47 per share for the same period in 2015. For the year ended December 31, 2016, net income attributable to common shares was $124 million or $0.16 per share compared to a net loss of $1.2 billion or $1.75 per share in 2015. Comparable earnings for fourth quarter 2016 were $626 million or $0.75 per share compared to $453 million or $0.64 per share for the same period in 2015. For the year ended December 31, 2016, comparable earnings were $2.1 billion or $2.78 per share compared to $1.8 billion or $2.48 per share in 2015. TransCanada's Board of Directors also declared a quarterly dividend of $0.625 per common share for the quarter ending March 31, 2017, equivalent to $2.50 per common share on an annualized basis, an increase of 10.6 per cent. This is the seventeenth consecutive year the Board of Directors has raised the dividend.

"Excluding specific items, we generated record financial results in 2016," said Russ Girling, TransCanada's president and chief executive officer. "Comparable earnings per share increased 12 per cent when compared to 2015 while net cash provided by operations exceeded $5 billion for the first time in the Company's history."

"It was also a transformational year for TransCanada," added Girling. "The Columbia acquisition reinforced our position as one of North America's leading energy infrastructure companies with an extensive pipeline network linking the continent's most prolific natural gas supply basins to its most attractive markets and provided us with another growth platform. Today we are advancing an industry leading $23 billion near-term capital program that is expected to generate significant growth in earnings and cash flow and support an expected annual dividend growth rate at the upper end of an eight to 10 per cent range through 2020."

"We also continue to progress a number of additional medium to longer-term organic growth opportunities in our three core businesses of natural gas pipelines, liquids pipelines and energy. This portfolio is currently comprised of more than $45 billion in large-scale projects that include Keystone XL and the Bruce Power life extension program. Success in advancing these or other growth initiatives could augment or extend the Company's dividend growth outlook through 2020 and beyond," concluded Girling.

Fourth Quarter and Year-End Highlights

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

- Fourth quarter 2016 financial results
  - Net loss attributable to common shares of $358 million or $0.43 per share
  - Comparable earnings of $626 million or $0.75 per share
  - Comparable earnings before interest, taxes, depreciation and amortization (EBITDA) of $1.9 billion
  - Net cash provided by operations of $1.6 billion
  - Comparable funds generated from operations of $1.4 billion
  - Comparable distributable cash flow of $964 million or $1.16 per common share
- For the year ended December 31, 2016:
  - Net income attributable to common shares of $124 million or $0.16 per share
  - Comparable earnings of $2.1 billion or $2.78 per share
  - Comparable EBITDA of $6.6 billion

- Net cash provided by operations of $5.1 billion
- Comparable funds generated from operations of $5.2 billion
- Comparable distributable cash flow of $3.7 billion or $4.83 per common share

- Fourth Quarter Highlights:
  - Announced a 10.6 per cent increase in the quarterly common share dividend to $0.625 per common share for the quarter ending March 31, 2017
  - Announced the sale of our U.S. Northeast Power assets for aggregate proceeds of US$3.3 billion excluding the value expected to be realized from our power marketing business
  - Announced our decision to maintain our full ownership interest in a growing Mexican natural gas business
  - Announced the planned acquisition of Columbia Pipeline Partners LP (CPPL) at a price of US$17.00 per common unit. The transaction is expected to close in the first quarter 2017.
  - Raised approximately $3.5 billion through the issuance of 60.2 million common shares at a price of $58.50 per common share
  - Raised $1.0 billion through an offering of 40 million first preferred shares at $25 per share
  - Announced the $0.6 billion Saddle West expansion of the NGTL System to increase natural gas transportation capacity on the northwest portion of the network
  - On January 26, 2017, submitted a Presidential Permit application to the U.S. Department of State for approval of the Keystone XL project

Net loss attributable to common shares decreased by $2.1 billion to a net loss of $358 million or $0.43 per share for the three months ended December 31, 2016 compared to the same period last year. Fourth quarter 2016 included an $870 million after-tax loss related to the monetization of our U.S. Northeast Power business, an additional $68 million after-tax charge to settle the termination of our Alberta PPAs, an after-tax charge of $67 million for costs associated with the acquisition of Columbia Pipeline Group, Inc. (Columbia), and certain other specific items including unrealized gains and losses on risk management activities. Fourth quarter 2015 included a $2.9 billion after-tax impairment charge related to Keystone XL and related projects as well as certain other specific items. All of these specific items are excluded from comparable earnings.

Net income attributable to common shares for the year ended December 31, 2016 was $124 million or $0.16 per share compared to a net loss of $1.2 billion or $1.75 per share in 2015. Results in 2016 included a net loss of $2.0 billion related to specific items including those noted above for the fourth quarter as well as a $656 million after-tax impairment of Ravenswood goodwill, an additional $176 after-tax impairment charge on the carrying value of our Alberta PPAs as a result of our decision to terminate the PPAs, $206 million of additional after-tax costs associated with the acquisition of Columbia, primarily related to the dividend equivalent payments on the subscription receipts, and certain other specific items including unrealized gains and losses on risk management activities. Results in 2015 included the $2.9 billion after-tax impairment charge related to Keystone XL noted above and certain other specific items. These amounts were excluded from comparable earnings.

Comparable earnings for fourth quarter 2016 were $626 million or $0.75 per share compared to $453 million or $0.64 per share for the same period in 2015, an increase of $173 million or $0.11 per share. The increase was primarily the net effect of higher contributions from U.S. Pipelines due to incremental earnings from Columbia following the July 1, 2016 acquisition and higher ANR transportation revenue resulting from higher rates effective August 1, 2016, higher interest expense from debt issuances and lower capitalized interest, a higher contribution from Mexican pipelines primarily due to earnings from Topolobampo beginning in July 2016, reduced earnings from Liquids Pipelines due to the net effect of lower volumes on Marketlink and higher volumes on Keystone pipeline, higher earnings from Western Power due to higher realized prices on generated volumes and termination of the Alberta PPAs, and higher earnings from Natural Gas Storage due to higher realized natural gas storage price spreads.

Comparable earnings for the year ended December 31, 2016 were $2.1 billion or $2.78 per share compared to $1.8 billion or $2.48 per share in 2015. Higher income from our U.S. Pipelines due to incremental earnings from Columbia and ANR, higher AFUDC on our rate-regulated projects, an increased contribution from our Mexico Pipelines due to earnings from Topolobampo and higher earnings from our natural gas storage assets were partially offset by lower earnings from our Liquids Pipelines.

Per share figures in 2016 also include the dilutive effect of issuing 161 million common shares in 2016.

Notable recent developments include:

Corporate:

- ***Common Share Dividend:*** Our Board of Directors declared a quarterly dividend of $0.625 per share for the quarter ending March 31, 2017 on TransCanada's outstanding common shares. The quarterly amount is equivalent to $2.50 per common share on an annualized basis, an increase of 10.6 per cent. This is the seventeenth consecutive year the Board of Directors has raised the dividend.
- ***Monetization of U.S. Northeast power business:*** On November 1, 2016, we announced the sale of Ravenswood, Ironwood, Ocean State Power and Kibby Wind to Helix Generation, LLC, an affiliate of LS Power Equity Advisors for US$2.2 billion and the sale of TC Hydro to Great River Hydro, LLC, an affiliate of ArcLight Capital Partners, LLC for US$1.065 billion. These two sale transactions are expected to close in the first half of 2017 subject to certain regulatory and other approvals and will include customary closing adjustments. These sales are expected to result in an approximate $1.1 billion after-tax net loss which is comprised of a $656 million after-tax goodwill impairment charge recorded in third quarter 2016, an approximate $870 million after-tax net loss on the sale of the thermal and wind package recorded in fourth quarter 2016 and an approximate $440 million after-tax gain on the sale of the hydro assets to be recorded upon the close of that transaction. We are also in the process of monetizing the U.S. Northeast power marketing business. Proceeds from these sales and future realization of value of the marketing business will be used to repay the remaining portion of the acquisition bridge facilities which were used to partially finance the Columbia acquisition.
- ***Decision to maintain our full ownership interest in Mexican natural gas pipelines***: On November 1, 2016, we announced a decision to maintain our full ownership interest in a growing portfolio of natural gas pipeline assets in Mexico rather than sell a minority interest in six of these pipelines, which is consistent with maximizing shareholder value and maintaining a simplified corporate structure.
- ***Columbia Pipeline Partners LP:*** On November 1, 2016, we announced that we entered into an agreement and plan of merger through which our wholly-owned subsidiary, Columbia Pipeline Group, Inc., agreed to acquire, for cash, all of the outstanding publicly held common units of CPPL at a price of US$17.00 per common unit for an aggregate transaction value of approximately US$915 million. The transaction is expected to close in the first quarter 2017.
- ***Common equity offering:*** On November 16, 2016, in conjunction with our decision to maintain our full ownership interest in a growing Mexican natural gas pipelines business, we issued 60.2 million common shares at a price of $58.50 for total gross proceeds of approximately $3.5 billion. Proceeds from the offering were used to repay a portion of the US$6.9 billion acquisition bridge facilities which partially financed the Columbia acquisition.
- ***Preferred share issuance:*** In November 2016, we raised $1.0 billion in gross proceeds through an offering of 40 million Series 15 cumulative redeemable first preferred shares at $25 per share. The fixed dividend rate on the Series 15 preferred shares was set for its initial period at 4.9 per cent per annum and will reset every five years to a rate equal to the sum of the then applicable five-year Government of Canada bond yield plus 3.85 per cent, subject to a floor of not less than 4.9 per cent per annum.
- ***Dividend Reinvestment Plan:*** Currently, approximately 39 per cent of the common share dividends declared are reinvested in TransCanada common shares through our Dividend Reinvestment Plan.

Natural Gas Pipelines:

- ***NGTL System***: On October 6, 2016, the National Energy Board (NEB) recommended to the Canadian federal government approval of the $0.4 billion Towerbirch Project, including the continued use of the existing rolled-in toll methodology for this project. On October 31, 2016, the Government of Canada approved our $1.3 billion NGTL System 2017 Facilities Application. On December 7, 2016, we announced the $0.6 billion Saddle West expansion of the NGTL System to increase natural gas transportation capacity on the northwest portion of our system. The project is expected to be in-service in 2019. In total, NGTL is currently advancing a $3.7 billion near-term capital program excluding the $1.7 billion North Montney project. We currently have regulatory approval for $2.0 billion of facilities and plan to place in service $1.6 billion of new facilities in 2017.
- ***Canadian Mainline:*** In fourth quarter 2016, we placed in service the approximate $310 million Kings North Connector and the approximate $75 million compressor unit addition at Station 130 on the Canadian Mainline system. In late 2017, we expect the $200 million Vaughan Loop project to be in service.
- ***Columbia Projects:*** We are progressing a US$7.1 billion capital expansion and modernization program across the Columbia system for facilities planned to be completed through 2020. On January 19, 2017, the Federal Energy Regulatory Commission (FERC) approved the construction of the US$1.4 billion Leach XPress project and the US$0.4 billion Rayne XPress project. We are targeting an in-service date of November 1, 2017 for both projects.
- ***Mazatlán Project:*** Physical construction of the US$0.4 billion project is complete and is awaiting natural gas supply from upstream interconnecting pipelines. We have met our contractual obligations and thus the collection and recognition of revenue began as per terms of our Transportation Service Agreement (TSA) with the Comisión Federal de Electricidad (CFE) in December 2016.
- ***Topolobampo Project:*** We began collecting and recognizing revenue on the US$1.0 billion project in July 2016 under a force majeure provision in the 25-year contract with the CFE. The physical in-service date is expected to be delayed into 2017 due to delays with indigenous consultations by others.

Liquids Pipelines:

- ***Keystone XL:*** On January 24, 2017, the U.S. President signed a Presidential Memorandum inviting TransCanada to refile an application for the U.S. Presidential Permit. On January 26, 2017, we filed a Presidential Permit application with the U.S. Department of State for the project. The pipeline would begin in Hardisty, Alberta, and extend south to Steele City, Nebraska. Given the passage of time since the November 6, 2015 denial of the Presidential Permit, we are updating our shipping contracts and some shippers may increase or decrease their volume commitments. We expect the project to retain sufficient commercial support for TransCanada to make a final investment decision.
- ***White Spruce:*** In December 2016, we finalized a long-term transportation agreement to develop and construct the 20-inch diameter White Spruce pipeline, which will transport crude oil from a major oil sands plant in northeast Alberta into the Grand Rapids pipeline system. The total capital cost for the project is approximately $200 million and it is expected to be in service in 2018 subject to regulatory approvals.
- ***Energy East*:** In January 2017, the NEB appointed three new panel members to undertake the review of the project. On January 27, 2017, the new NEB panel members voided all decisions made by the previous Hearing Panel and the new panel members will decide how to move forward with the hearing. TransCanada is not required to refile its application. Once the new panel members determine that the project application is complete, and issue a hearing order, the 21-month NEB review period will commence.

Energy:

- *Alberta PPAs:* In December 2016, we engaged in negotiations with the Government of Alberta and finalized terms of the settlement of all legal disputes related to the PPA terminations. The Government and the Balancing Pool agreed to our termination of the PPAs resulting in the transfer of all our obligations under the PPAs to the Balancing Pool. Upon final settlement of the PPA terminations, we transferred to the Balancing Pool a package of environmental credits held to offset the PPA emissions costs and recorded a non-cash charge of $92 million before tax ($68 million after tax) in fourth quarter 2016 related to the carrying value of these credits.
- *Napanee:* Construction continues on a 900 MW natural gas-fired power plant at Ontario Power Generation's Lennox site in eastern Ontario in the town of Greater Napanee. We expect to invest approximately $1.1 billion in the Napanee facility during construction and commercial operations are expected to begin in 2018. Production from the facility is fully contracted with the IESO.
- *Bruce Power Financing:* In February 2017, Bruce Power issued additional bonds under its financing program and distributed $362 million to TransCanada.

Teleconference and Webcast:

We will hold a teleconference and webcast on Thursday, February 16, 2017 to discuss our fourth quarter 2016 financial results as well as provide an update on our business and financial outlook. Russ Girling, TransCanada President and Chief Executive Officer, and Don Marchand, Executive Vice-President and Chief Financial Officer, along with other members of the TransCanada executive leadership team, will discuss the financial results and Company developments at 1 p.m. (MT) / 3 p.m. (ET).

Members of the investment community and other interested parties are invited to participate by calling 800.377.0758 or 416.340.2218 (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.

A replay of the teleconference will be available two hours after the conclusion of the call until midnight (ET) on February 23, 2017. Please call 800.408.3053 or 905.694.9451 (Toronto area) and enter pass code 9119753.

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

With more than 65 years' experience, TransCanada is a leader in the responsible development and reliable operation of North American energy infrastructure including natural gas and liquids pipelines, power generation and gas storage facilities. TransCanada operates a network of natural gas pipelines that extends more than 91,500 kilometres (56,900 miles), tapping into virtually all major gas supply basins in North America. TransCanada is the continent's largest provider of gas storage and related services with 653 billion cubic feet of storage capacity. A large independent power producer, TransCanada owns or has interests in over 10,700 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 over 4,300 kilometres (2,700 miles) connecting growing continental oil supplies to key markets and refineries. TransCanada's common shares trade on the Toronto and New York stock exchanges under the symbol TRP. Visit TransCanada.com and our blog to learn more, or connect with us on social media and 3BL Media.

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Fourth quarter 2016 financial highlights

(unaudited - millions of $, except per share amounts)	three months ended December 31 2016	three months ended December 31 2015	year ended December 31 2016	year ended December 31 2015
Income				
Revenues	**3,619**	2,851	**12,505**	11,300
Net (loss)/income attributable to common shares	**(358)**	(2,458)	**124**	(1,240)
per common share - basic and diluted	**($0.43)**	($3.47)	**$0.16**	($1.75)
Comparable EBITDA[1]	**1,890**	1,527	**6,647**	5,908
Comparable earnings[1]	**626**	453	**2,108**	1,755
per common share[1]	**$0.75**	$0.64	**$2.78**	$2.48
Operating cash flow				
Net cash provided by operations	**1,575**	1,196	**5,069**	4,384
Comparable funds generated from operations[1]	**1,425**	1,229	**5,171**	4,815
Comparable distributable cash flow[1]	**964**	797	**3,665**	3,562
per common share[1]	**$1.16**	$1.13	**$4.83**	$5.02
Investing activities				
Capital spending - capital expenditures	**1,745**	1,170	**5,007**	3,918
- projects in development	**76**	46	**295**	511
Contributions to equity investments	**195**	190	**765**	493
Acquisitions, net of cash acquired	**—**	236	**13,608**	236
Proceeds from sale of assets, net of transaction costs	**—**	—	**6**	—
Dividends declared				
Per common share	**$0.565**	$0.52	**$2.26**	$2.08
Basic common shares outstanding (millions)				
Average for the period	**832**	708	**759**	709
End of period	**864**	703	**864**	703

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

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:

- planned changes in our business including the divestiture of certain assets
- our financial and operational performance, including the performance of our subsidiaries
- expectations or projections about strategies and goals for growth and expansion
- expected cash flows and future financing options available to us
- expected dividend growth
- expected costs for planned projects, including projects under construction, permitting and in development
- expected schedules for planned projects (including anticipated construction and completion dates)
- expected regulatory processes and outcomes
- expected impact of regulatory outcomes
- expected outcomes with respect to legal proceedings, including arbitration and insurance claims
- expected capital expenditures and contractual obligations
- expected operating and financial results
- the expected impact of future accounting changes, commitments and contingent liabilities
- 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

- planned monetization of our U.S. Northeast power business
- inflation rates, commodity prices and capacity prices
- nature and scope of hedging
- regulatory decisions and outcomes
- the Canadian dollar to U.S. dollar exchange rate remains at or near current levels
- interest rates
- tax rates
- planned and unplanned outages and the use of our pipeline and energy assets
- integrity and reliability of our assets
- access to capital markets
- anticipated construction costs, schedules and completion dates.

Risks and uncertainties

- our ability to realize the anticipated benefits from the acquisition of Columbia
- timing and execution of our planned asset sales
- our ability to successfully implement our strategic initiatives
- whether our strategic initiatives will yield the expected benefits
- the operating performance of our pipeline and energy assets

- amount of capacity sold and rates achieved in our pipeline businesses
- the availability and price of energy commodities
- the amount of capacity payments and revenues we receive from our energy business
- regulatory decisions and outcomes
- outcomes of legal proceedings, including arbitration and insurance claims
- performance and credit risk of our counterparties
- changes in market commodity prices
- changes in the political environment
- changes in environmental and other laws and regulations
- competitive factors in the pipeline and energy sectors
- construction and completion of capital projects
- costs for labour, equipment and materials
- access to capital markets
- interest, tax and foreign exchange rates
- weather
- cyber security
- technological developments
- economic conditions in North America as well as globally.

You can read more about these factors and others in reports we have filed with Canadian securities regulators and the SEC, including the MD&A in our 2015 Annual Report.

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

FOR MORE INFORMATION

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

NON-GAAP MEASURES

This news release references the following non-GAAP measures:

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

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

Comparable measures

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

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

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

Comparable earnings

Comparable earnings represents earnings or loss attributable to common shareholders on a consolidated basis adjusted for specific items. Comparable earnings is comprised of segmented earnings, interest expense, AFUDC, interest income and other, income taxes and non-controlling interests adjusted for the specific items.

Comparable EBIT and comparable EBITDA

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

Funds generated from operations

Funds generated from operations includes 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. See the Reconciliation of non-GAAP measures section for a reconciliation to net cash provided by operations.

Comparable distributable cash flow

Comparable distributable cash flow is defined as comparable funds generated from operations less preferred share dividends, distributions to non-controlling interests and maintenance capital expenditures. Maintenance capital expenditures are expenditures incurred to maintain our operating capacity, asset integrity and reliability, and include amounts attributable to our proportionate share of maintenance capital expenditures on our equity investments. Although we deduct maintenance capital expenditures in determining comparable distributable cash flow, in certain of our rate-regulated businesses, maintenance capital expenditures are included in their respective rate bases, on which we earn a regulated return and recover depreciation through future tolls.

Effective December 31, 2016, we adopted, on a retrospective basis, a new accounting standard under U.S. GAAP which allows us to classify certain distributed earnings received from equity investments as cash from operations on the consolidated statement of cash flows, which had previously been included in Investing activities. As a result, we no longer need to adjust for distributions in excess of equity earnings in the calculation of comparable distributable cash flow.

We believe comparable distributable cash flow is a useful supplemental measure of performance that defines cash available to common shareholders before capital allocation.

The following table identifies our non-GAAP measures against their equivalent GAAP measures.

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

Consolidated results - fourth quarter 2016

We operate in three core businesses - Natural Gas Pipelines, Liquids Pipelines and Energy. As a result of our acquisition of Columbia on July 1, 2016 and the pending monetization of the U.S. Northeast power business, we have determined that a change in our operating segments is appropriate. Accordingly, we consider ourselves to be operating our business in the following segments: Canadian Natural Gas Pipelines, U.S. Natural Gas Pipelines, Mexico Natural Gas Pipelines, Liquids Pipelines and Energy. This provides information that is aligned with how management decisions about our business are made and how performance of our business is assessed. We also have a non-operational Corporate segment consisting of corporate and administrative functions that provide governance and other support to our operational business segments. Prior period segment information has been adjusted to reflect the new segments.

Certain costs previously reported in our Corporate segment are now being reported within the business segments as a result of our 2015 business transformation initiative. 2015 results have been adjusted to reflect this change. In addition, Columbia results are included in the U.S. Natural Gas Pipelines segment from its acquisition on July 1, 2016. Comparative periods do not include Columbia.

	three months ended December 31		year ended December 31	
(unaudited - millions of $, except per share amounts)	**2016**	**2015**	**2016**	**2015**
Canadian Natural Gas Pipelines	**379**	423	**1,373**	1,413
U.S. Natural Gas Pipelines	**416**	99	**1,219**	606
Mexico Natural Gas Pipelines	**105**	41	**290**	171
Liquids Pipelines	**218**	(3,416)	**827**	(2,643)
Energy	**(571)**	77	**(1,140)**	792
Corporate	**(71)**	(144)	**(256)**	(238)
Total segmented earnings/(losses)	**476**	(2,920)	**2,313**	101
Interest expense	**(542)**	(380)	**(1,998)**	(1,370)
Allowance for funds used during construction	**97**	91	**419**	295
Interest income and other	**(15)**	(11)	**103**	(132)
Income/(loss) before income taxes	**16**	(3,220)	**837**	(1,106)
Income tax (expense)/recovery	**(274)**	646	**(352)**	(34)
Net (loss)/income	**(258)**	(2,574)	**485**	(1,140)
Net (income)/loss attributable to non-controlling interests	**(68)**	139	**(252)**	(6)
Net (loss)/income attributable to controlling interests	**(326)**	(2,435)	**233**	(1,146)
Preferred share dividends	**(32)**	(23)	**(109)**	(94)
Net (loss)/income attributable to common shares	**(358)**	(2,458)	**124**	(1,240)
Net (loss)/income per common share - basic and diluted	**($0.43)**	($3.47)	**$0.16**	($1.75)

Net loss attributable to common shares decreased by $2,100 million or $3.04 per share to a net loss of $358 million or $0.43 per share for the three months ended December 31, 2016 compared to the same period in 2015. Net (loss)/income per common share in 2016 includes the dilutive effect of issuing 161 million common shares in 2016.

The 2016 results included:

- an $870 million after-tax charge related to the loss on U.S. Northeast power assets held for sale which included an $863 million after-tax loss on the thermal and wind package held for sale and $7 million of after-tax costs related to the monetization
- an additional $68 million after-tax loss on the transfer of environmental credits to the Balancing Pool upon final settlement of the Alberta PPA terminations

- an after-tax charge of $67 million for costs associated with the acquisition of Columbia which included a $44 million deferred tax adjustment upon acquisition and $23 million of retention, severance and integration costs
- an after-tax charge of $18 million related to Keystone XL costs for the maintenance and liquidation of project assets which are being expensed pending further advancement of the project
- an after-tax restructuring charge of $6 million for additional expected future losses under lease commitments. These charges form part of a restructuring initiative, which commenced in 2015, to maximize the effectiveness and efficiency of our existing operations and reduce overall costs.

The 2015 results included:

- a $2,891 million after-tax impairment charge on the carrying value of our investment in Keystone XL and related projects
- an $86 million after-tax loss provision related to the sale of TC Offshore which closed in early 2016
- a net charge of $60 million after tax for our business restructuring and transformation initiative comprised of $28 million mainly related to 2015 severance costs and a provision of $32 million for 2016 planned severance costs and expected future losses under lease commitments. These charges form part of a restructuring initiative which commenced in 2015 to maximize the effectiveness and efficiency of our existing operations and reduce overall costs
- a $43 million after-tax charge relating to an impairment in value on turbine equipment held for future use in our Energy business
- a charge of $27 million after-tax related to Bruce Power's retirement of debt in conjunction with the merger of the Bruce A and Bruce B partnerships
- a $199 million positive income adjustment related to the impact on our net income from non-controlling interests of TC PipeLines, LP's impairment of their equity investment in Great Lakes.

Net income in all periods included unrealized gains and losses from changes in risk management activities which we exclude, along with the above-noted items, to arrive at comparable earnings.

Comparable earnings increased by $173 million for the three months ended December 31, 2016 compared to the same period in 2015 as discussed below in the reconciliation of net income to comparable earnings.

RECONCILIATION OF NET INCOME TO COMPARABLE EARNINGS

	three months ended December 31		year ended December 31	
(unaudited - millions of $, except per share amounts)	2016	2015	2016	2015
Net (loss)/income attributable to common shares	**(358)**	(2,458)	**124**	(1,240)
Specific items (net of tax):				
Loss on U.S. Northeast power assets held for sale	**870**	—	**873**	—
Ravenswood goodwill impairment	**—**	—	**656**	—
Alberta PPA terminations and settlement	**68**	—	**244**	—
Acquisition related costs - Columbia	**67**	—	**273**	—
Keystone XL income tax recoveries	**—**	—	**(28)**	—
Keystone XL asset costs	**18**	—	**42**	—
Restructuring costs	**6**	60	**16**	74
TC Offshore loss on sale	**—**	86	**3**	86
Keystone XL impairment charge	**—**	2,891	**—**	2,891
Turbine equipment impairment charge	**—**	43	**—**	43
Alberta corporate income tax rate increase	**—**	—	**—**	34
Bruce Power merger - debt retirement charge	**—**	27	**—**	27
Non-controlling interests - (TC PipeLines, LP - Great Lakes impairment)	**—**	(199)	**—**	(199)
Risk management activities[1]	**(45)**	3	**(95)**	39
Comparable earnings	**626**	453	**2,108**	1,755
Net (loss)/income per common share	**($0.43)**	($3.47)	**$0.16**	($1.75)
Specific items (net of tax):				
Loss on U.S. Northeast power assets held for sale	**1.05**	—	**1.15**	—
Ravenswood goodwill impairment	**—**	—	**0.86**	—
Alberta PPA terminations and settlement	**0.08**	—	**0.32**	—
Acquisition related costs - Columbia	**0.08**	—	**0.37**	—
Keystone XL income tax recoveries	**—**	—	**(0.04)**	—
Keystone XL asset costs	**0.02**	—	**0.06**	—
Restructuring costs	**0.01**	0.08	**0.02**	0.10
TC Offshore loss on sale	**—**	0.12	**—**	0.12
Keystone XL impairment charge	**—**	4.08	**—**	4.08
Turbine equipment impairment charge	**—**	0.06	**—**	0.06
Alberta corporate income tax rate increase	**—**	—	**—**	0.05
Bruce Power merger - debt retirement charge	**—**	0.04	**—**	0.04
Non-controlling interests - (TC PipeLines, LP - Great Lakes impairment)	**—**	(0.28)	**—**	(0.28)
Risk management activities	**(0.06)**	0.01	**(0.12)**	0.06
Comparable earnings per share	**$0.75**	$0.64	**$2.78**	$2.48

1

Risk management activities	**three months ended December 31**		**year ended December 31**	
(unaudited - millions of $)	**2016**	**2015**	**2016**	**2015**
Canadian Power	**1**	(1)	**4**	(8)
U.S. Power	**97**	(8)	**113**	(30)
Liquids marketing	**4**	—	**(2)**	—
Natural Gas Storage	**(1)**	(1)	**8**	1
Foreign exchange	**(23)**	4	**26**	(21)
Income tax attributable to risk management activities	**(33)**	3	**(54)**	19
Total unrealized gains/(losses) from risk management activities	**45**	(3)	**95**	(39)

Comparable earnings increased by $173 million or $0.11 per share for the three months ended December 31, 2016 compared to the same period in 2015. Comparable earnings per share in 2016 includes the dilutive effect of issuing 161 million common shares in 2016.

The 2016 increase in comparable earnings was primarily the net effect of:

- higher earnings from U.S. Natural Gas Pipelines due to incremental earnings from Columbia following the July 1, 2016 acquisition and higher ANR transportation revenue resulting from higher rates effective August 1, 2016
- higher interest expense from debt issuances and lower capitalized interest
- higher earnings from Mexico Natural Gas Pipelines primarily due to earnings from Topolobampo beginning in July 2016
- lower earnings from Liquids Pipelines due to the net effect of lower volumes on Marketlink and higher volumes on Keystone pipeline
- higher earnings from Western Power due to higher realized prices on generated volumes and termination of the Alberta PPAs
- higher earnings from Natural Gas Storage due to higher realized natural gas storage price spreads.

The stronger U.S. dollar on a year-to-date basis compared to the same period in 2015 positively impacted the translated results of our U.S. and Mexican businesses, along with realized gains on foreign exchange hedges used to manage our exposure, however, this impact was partially offset by a corresponding increase in interest expense on U.S. dollar-denominated debt.

Capital Program

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

Our capital program consists of $23 billion of near-term projects and $48 billion of commercially secured medium and longer-term projects. Amounts presented exclude maintenance capital expenditures, capitalized interest and AFUDC.

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

Near-term projects

at December 31, 2016 (unaudited - billions of $)	Segment	Expected in-service date	Estimated project cost	Carrying value
Canadian Mainline	Canadian Natural Gas Pipelines	2017-2018	0.3	0.1
NGTL System – North Montney	Canadian Natural Gas Pipelines	2018+[1]	1.7	0.3
– Saddle West	Canadian Natural Gas Pipelines	2019	0.6	—
– 2016/17 Facilities	Canadian Natural Gas Pipelines	2017-2020	2.2	0.5
– 2018 Facilities	Canadian Natural Gas Pipelines	2018-2020	0.6	—
– Other	Canadian Natural Gas Pipelines	2017-2020	0.3	—
Grand Rapids[2]	Liquids Pipelines	2017	0.9	0.8
Northern Courier	Liquids Pipelines	2017	1.0	0.9
Columbia Gas[3] – Leach XPress	U.S. Natural Gas Pipelines	2017	US 1.4	US 0.4
– Modernization I	U.S. Natural Gas Pipelines	2017	US 0.2	—
– WB XPress	U.S. Natural Gas Pipelines	2018	US 0.8	US 0.2
– Mountaineer XPress	U.S. Natural Gas Pipelines	2018	US 2.0	US 0.1
– Modernization II	U.S. Natural Gas Pipelines	2018-2020	US 1.1	—
Columbia Gulf[3] – Rayne XPress	U.S. Natural Gas Pipelines	2017	US 0.4	US 0.2
– Cameron Access	U.S. Natural Gas Pipelines	2018	US 0.3	US 0.1
– Gulf XPress	U.S. Natural Gas Pipelines	2018	US 0.6	—
Midstream – Gibraltar	U.S. Natural Gas Pipelines	2017	US 0.3	US 0.2
Tula	Mexico Natural Gas Pipelines	2018	US 0.6	US 0.3
White Spruce	Liquids Pipelines	2018	0.2	—
Napanee	Energy	2018	1.1	0.7
Villa de Reyes	Mexico Natural Gas Pipelines	2018	US 0.6	US 0.2
Sur de Texas[2]	Mexico Natural Gas Pipelines	2018	US 1.3	US 0.1
Bruce Power - life extension[4]	Energy	up to 2020+	1.1	0.1
			19.6	**5.2**
Foreign exchange impact on near-term projects[5]			**3.3**	**0.6**
Total near-term projects (billions of Cdn$)			**22.9**	**5.8**

1 In-service date is dependent on a positive final investment decision (FID) on Prince Rupert Gas Transmission.
2 Our proportionate share.
3 The Columbia projects exclude AFUDC, whereas, previously announced estimated project costs included AFUDC.
4 Amounts reflect our proportionate share of the remaining capital costs that Bruce Power expects to incur on its life extension investment programs in advance of major refurbishment outages which are expected to begin in 2020.
5 Reflects U.S./Canada foreign exchange rate of $1.34 at December 31, 2016.

Medium to longer-term projects

The medium to longer-term projects have greater uncertainty with respect to timing and estimated project costs. The expected in-service dates of these projects are 2019 and beyond, and costs provided in the schedule below reflect the most recent costs for each project as filed with the various regulatory authorities or otherwise determined. These projects have all been commercially secured but are subject to approvals that include sponsor FID and/or complex regulatory processes.

at December 31, 2016 (unaudited - billions of $)	**Segment**	**Estimated project cost**	**Carrying value**
Heartland and TC Terminals	Liquids Pipelines	0.9	0.1
Upland	Liquids Pipelines	US 0.6	—
Grand Rapids Phase 2[1]	Liquids Pipelines	0.7	—
Bruce Power - life extension[1]	Energy	5.3	—
Keystone projects			
Keystone XL[2]	Liquids Pipelines	US 8.0	US 0.3
Keystone Hardisty Terminal[2]	Liquids Pipelines	0.3	0.1
Energy East projects			
Energy East[3]	Liquids Pipelines	15.7	0.8
Eastern Mainline	Canadian Natural Gas Pipelines	2.0	0.1
BC west coast LNG-related projects			
Coastal GasLink	Canadian Natural Gas Pipelines	4.8	0.4
Prince Rupert Gas Transmission	Canadian Natural Gas Pipelines	5.0	0.5
NGTL System - Merrick	Canadian Natural Gas Pipelines	1.9	—
		45.2	2.3
Foreign exchange impact on medium to longer-term projects[4]		2.9	0.1
Total medium to longer-term projects (billions of Cdn$)		**48.1**	**2.4**

1 Our proportionate share.
2 Carrying value reflects amount remaining after impairment charge recorded in fourth quarter 2015.
3 Excludes transfer of Canadian Mainline natural gas assets.
4 Reflects U.S./Canada foreign exchange rate of $1.34 at December 31, 2016.

Canadian Natural Gas Pipelines

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented earnings (the equivalent GAAP measure). Certain costs previously reported in our Corporate segment are now being reported within the business segments as a result of our 2015 business transformation initiative. 2015 results have been adjusted to reflect this change.

	three months ended December 31		year ended December 31	
(unaudited - millions of $)	**2016**	**2015**	**2016**	**2015**
NGTL System	**262**	255	**998**	920
Canadian Mainline	**312**	350	**1,137**	1,216
Other Canadian pipelines[1]	**28**	32	**118**	133
Business development	**(3)**	(1)	**(7)**	(11)
Comparable EBITDA	**599**	636	**2,246**	2,258
Depreciation and amortization	**(220)**	(213)	**(873)**	(845)
Comparable EBIT and segmented earnings	**379**	423	**1,373**	1,413

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

Canadian Natural Gas Pipelines comparable EBIT and segmented earnings decreased by $44 million for the three months ended December 31, 2016 compared to the same period in 2015.

Net income and comparable EBITDA for our rate-regulated Canadian Natural Gas Pipelines are generally affected by our approved ROE, our investment base, our level of deemed common equity and incentive earnings or losses. Changes in depreciation, financial charges and income taxes also impact comparable EBITDA but do not have a significant impact on net income as they are almost entirely recovered in revenues on a flow-through basis.

NET INCOME - WHOLLY OWNED CANADIAN NATURAL GAS PIPELINES

	three months ended December 31		year ended December 31	
(unaudited - millions of $)	**2016**	**2015**	**2016**	**2015**
NGTL System	**85**	69	**318**	269
Canadian Mainline	**54**	52	**208**	213

Net income for the NGTL System increased by $16 million for the three months ended December 31, 2016 compared to the same period in 2015 mainly due to a higher average investment base and OM&A incentive earnings recorded in 2016.

Net income for the Canadian Mainline increased by $2 million for the three months ended December 31, 2016 compared to the same period in 2015 primarily due to higher incentive earnings, partially offset by a lower average investment base and higher carrying charges to shippers on the 2016 net revenue surplus.

DEPRECIATION AND AMORTIZATION

Depreciation and amortization increased by $7 million for the three months ended December 31, 2016 compared to the same period in 2015 mainly due to new NGTL System facilities that were placed in service in 2016.

OPERATING STATISTICS - WHOLLY OWNED PIPELINES

year ended December 31	NGTL System[1]		Canadian Mainline[2]	
(unaudited)	**2016**	**2015**	**2016**	**2015**
Average investment base (millions of $)	**7,451**	6,698	**4,441**	4,784
Delivery volumes (Bcf):				
Total	**4,055**	3,884	**1,634**	1,595
Average per day	**11.1**	10.6	**4.5**	4.4

1 Field receipt volumes for the NGTL System for the year ended December 31, 2016 were 4,117 Bcf (2015 – 4,029 Bcf). Average per day was 11.3 Bcf (2015 – 11.0 Bcf).

2 Canadian Mainline's throughput volumes represent physical deliveries to domestic and export markets. Physical receipts originating at the Alberta border and in Saskatchewan for the year ended December 31, 2016 were 1,055 Bcf (2015 – 1,122 Bcf). Average per day was 2.9 Bcf (2015 – 3.1 Bcf).

U.S. Natural Gas Pipelines

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented earnings (the equivalent GAAP measure). Certain costs previously reported in our Corporate segment are now being reported within the business segments as a result of our 2015 business transformation initiative. 2015 results have been adjusted to reflect this change. In addition, Columbia results are included in the U.S. Natural Gas Pipelines segment from its acquisition on July 1, 2016. Comparative periods do not include Columbia.

	three months ended December 31		year ended December 31	
(unaudited - millions of US$, unless otherwise noted)	**2016**	**2015**	**2016**	**2015**
Columbia Gas[1]	**146**	—	**269**	—
ANR	**89**	53	**324**	225
TC PipeLines, LP[2,3]	**28**	30	**118**	106
Great Lakes[3,4]	**12**	28	**59**	63
Midstream[1]	**14**	—	**40**	—
Columbia Gulf[1]	**14**	—	**25**	—
Other U.S. pipelines[1,2,3,5]	**27**	22	**73**	85
Non-controlling interests[6]	**101**	84	**365**	292
Business development	**(1)**	—	**(3)**	(12)
Comparable EBITDA	**430**	217	**1,270**	759
Depreciation and amortization	**(108)**	(48)	**(300)**	(190)
Comparable EBIT	**322**	169	**970**	569
Foreign exchange impact	**105**	55	**316**	162
Comparable EBIT (Cdn$)	**427**	224	**1,286**	731
Specific items:				
Acquisition related costs - Columbia	**(11)**	—	**(63)**	—
TC Offshore loss on sale	**—**	(125)	**(4)**	(125)
Segmented earnings (Cdn$)	**416**	99	**1,219**	606

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

2 Results from Northern Border and Iroquois reflect our share of equity income from these investments. We acquired additional interests in Iroquois of 0.65 per cent on May 1, 2016 and 4.87 per cent on March 31, 2016.

3 TC PipeLines, LP periodically conducts at-the-market equity issuances which decrease our ownership in TC PipeLines, LP. On January 1, 2016, we sold a 49.9 per cent direct interest in PNGTS to TC PipeLines, LP and continue to hold an 11.8 per cent direct interest. On April 1, 2015, we sold our remaining 30 per cent direct interest in GTN to TC PipeLines, LP. The following shows our ownership interest in TC PipeLines, LP and our effective ownership interest of GTN, Great Lakes and PNGTS through our ownership interest in TC PipeLines, LP for the periods presented.

	Effective ownership percentage as of	
	December 31, 2016	**December 31, 2015**
TC PipeLines, LP	26.8	28.0
Effective ownership through TC PipeLines, LP:		
GTN	26.8	28.0
Great Lakes	12.5	13.0
PNGTS	13.4	—

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

5 Includes our direct ownership in Iroquois, PNGTS and GTN (until April 1, 2015); our effective ownership in Millennium and Hardy Storage; and general and administrative costs related to U.S. natural gas assets.

6. Comparable EBITDA for the portions of TC PipeLines, LP, PNGTS and Columbia Pipeline Partners LP that we do not own.

U.S. Natural Gas Pipelines segmented earnings increased by $317 million for the three months ended December 31, 2016 compared to the same period in 2015 mainly due to the acquisition of Columbia. Segmented earnings for the three months ended December 31, 2016 included an $11 million pre-tax charge, primarily related to retention and severance expenses resulting from the Columbia acquisition. Segmented earnings for the three months ended December 31, 2015 included a $125 million pre-tax loss provision ($86 million after tax) as a result of a December 2015 agreement to sell TC Offshore which closed in early 2016. These amounts have been excluded from our calculation of comparable EBIT.

Earnings for our U.S. natural gas pipelines operations, which include Columbia effective July 1, 2016, are generally affected by contracted volume levels, volumes delivered and the rates charged as well as by the cost of providing services. Columbia and ANR results are also affected by the contracting and pricing of its storage capacity and incidental commodity sales.

Comparable EBITDA for U.S. Pipelines increased by US$213 million for the three months ended December 31, 2016 compared to the same period in 2015. This was the net effect of:

- US$186 million of earnings from Columbia as a result of the acquisition on July 1, 2016
- higher ANR transportation revenue resulting from higher rates as part of a rate settlement effective August 1, 2016, higher Southeast Mainline transportation revenue and lower pipeline integrity costs, partially offset by lower incidental commodity sales
- lower transportation revenues from Great Lakes.

DEPRECIATION AND AMORTIZATION

Depreciation and amortization increased by US$60 million for the three months ended December 31, 2016 compared to the same period in 2015 mainly due to the Columbia acquisition on July 1, 2016 and increased depreciation rates on ANR following its rate settlement effective August 1, 2016.

Mexico Natural Gas Pipelines

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented earnings (the equivalent GAAP measure). Certain costs previously reported in our Corporate segment are now being reported within the business segments as a result of our 2015 business transformation initiative. 2015 results have been adjusted to reflect this change.

	three months ended December 31		year ended December 31	
(unaudited - millions of US$, unless otherwise noted)	**2016**	**2015**	**2016**	**2015**
Topolobampo	**41**	(1)	**81**	(3)
Tamazunchale	**26**	25	**106**	109
Guadalajara	**19**	17	**68**	70
Mazatlán	**5**	(1)	**5**	(2)
Other[1,2]	**(3)**	2	**(4)**	4
Business development	**(1)**	(4)	**(5)**	(12)
Comparable EBITDA	**87**	38	**251**	166
Depreciation and amortization	**(11)**	(7)	**(33)**	(34)
Comparable EBIT	**76**	31	**218**	132
Foreign exchange impact	**29**	10	**72**	39
Comparable EBIT and segmented earnings (Cdn$)	**105**	41	**290**	171

1 Includes our share of the equity income from TransGas.

2 Includes general and administrative costs related to our Mexico Natural Gas Pipelines as well as our 60 per cent effective interest in our joint venture with IEnova to build, own and operate the Sur de Texas pipeline.

Mexico segmented earnings increased by $64 million for the three months ended December 31, 2016 compared to the same period in 2015. Mexico Natural Gas Pipelines segmented earnings are equivalent to comparable EBIT.

Earnings from our Mexico operations are underpinned by long-term, stable, primarily U.S. dollar-denominated revenue contracts, and are affected by the cost of providing service.

Comparable EBITDA for Mexico Natural Gas Pipelines increased by US$49 million for the three months ended December 31, 2016 compared to the same period in 2015. This was the net effect of:

- incremental earnings from Topolobampo. The Topolobampo project has experienced a delay in construction which, under the terms of our Transportation Service Agreement (TSA) with the CFE, constitutes a force majeure event with provisions allowing for the collection and recognition of revenue as per the original TSA service commencement date of July 2016
- incremental earnings from Mazatlán. Construction is complete and the collection and recognition of revenue began per the terms of the TSA in December 2016.

DEPRECIATION AND AMORTIZATION

Depreciation and amortization increased by US$4 million for the three months ended December 31, 2016 compared to the same period in 2015 mainly due to the commencement of depreciation on Topolobampo.

Liquids Pipelines

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented earnings (the equivalent GAAP measure). Certain costs previously reported in our Corporate segment are now being reported within the business segments as a result of our 2015 business transformation initiative. 2015 results have been adjusted to reflect this change.

	three months ended December 31		**year ended December 31**	
(unaudited - millions of $)	**2016**	**2015**	**2016**	**2015**
Keystone Pipeline System	**299**	345	**1,169**	1,333
Business development and other	**6**	(6)	**(3)**	(24)
Comparable EBITDA	**305**	339	**1,166**	1,309
Depreciation and amortization	**(76)**	(69)	**(285)**	(266)
Comparable EBIT	**229**	270	**881**	1,043
Specific items:				
Keystone XL asset costs	**(15)**	—	**(52)**	—
Keystone XL impairment charge	**—**	(3,686)	**—**	(3,686)
Risk management activities	**4**	—	**(2)**	—
Segmented earnings/(loss)	**218**	(3,416)	**827**	(2,643)
Comparable EBIT denominated as follows:				
Canadian dollars	**64**	60	**228**	232
U.S. dollars	**124**	159	**493**	633
Foreign exchange impact	**41**	51	**160**	178
	229	270	**881**	1,043

Liquids Pipelines segmented earnings increased by $3,634 million for the three months ended December 31, 2016 compared to the same period in 2015 and included pre-tax charges related to Keystone XL costs for the maintenance and liquidation of project assets which are being expensed pending further advancement of the project as well as unrealized losses from changes in the fair value of derivatives related to our liquids marketing business. The segmented loss in 2015 included a $3,686 million pre-tax impairment charge related to Keystone XL and related projects in connection with the denial of the U.S. Presidential permit. These amounts have been excluded from our calculation of comparable EBIT. The remainder of the Liquids Pipelines segmented earnings are equivalent to comparable EBIT.

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

Comparable EBITDA for Liquids Pipelines decreased by $34 million for the three months ended December 31, 2016 compared to the same period in 2015 and was the net effect of:

- lower volumes on Marketlink
- higher volumes on Keystone pipeline
- a growing contribution from liquids marketing
- reduced business development activities.

DEPRECIATION AND AMORTIZATION

Depreciation and amortization increased by $7 million for the three months ended December 31, 2016 compared to the same period in 2015 as a result of new facilities being placed in service.

Energy

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented earnings (the equivalent GAAP measure). Certain costs previously reported in our Corporate segment are now being reported within the business segments as a result of our 2015 business transformation initiative. 2015 results have been adjusted to reflect this change.

	three months ended December 31		year ended December 31	
(unaudited - millions of $)	**2016**	**2015**	**2016**	**2015**
Canadian Power				
Western Power[1]	**26**	(1)	**75**	72
Eastern Power	**83**	84	**353**	390
Bruce Power	**83**	83	**293**	285
Canadian Power - comparable EBITDA[1,2]	**192**	166	**721**	747
Depreciation and amortization	**(25)**	(49)	**(142)**	(190)
Canadian Power - comparable EBIT[1,2]	**167**	117	**579**	557
U.S. Power (US$)				
U.S. Power - comparable EBITDA	**73**	79	**396**	414
Depreciation and amortization	**(10)**	(27)	**(105)**	(105)
U.S. Power - comparable EBIT	**63**	52	**291**	309
Foreign exchange impact	**20**	18	**94**	86
U.S. Power - comparable EBIT (Cdn$)	**83**	70	**385**	395
Natural Gas Storage and other - comparable EBITDA	**20**	6	**59**	14
Depreciation and amortization	**(3)**	(3)	**(12)**	(12)
Natural Gas Storage and other - comparable EBIT	**17**	3	**47**	2
Business Development comparable EBITDA and EBIT	**(4)**	(8)	**(15)**	(30)
Energy - comparable EBIT[1,2]	**263**	182	**996**	924
Specific items:				
Ravenswood goodwill impairment	**—**	—	**(1,085)**	—
Loss on U.S. Northeast power assets held for sale	**(839)**	—	**(844)**	—
Alberta PPA terminations and settlement	**(92)**	—	**(332)**	—
Turbine equipment impairment charge	**—**	(59)	**—**	(59)
Bruce Power merger - debt retirement charge	**—**	(36)	**—**	(36)
Risk management activities	**97**	(10)	**125**	(37)
Segmented (losses)/earnings	**(571)**	77	**(1,140)**	792

1 Included Sundance A and Sheerness PPAs, and the Sundance B PPA held through our investment in ASTC Power Partnership up to March 7, 2016.

2 Includes our share of equity income from our investments in Portlands Energy and Bruce Power, and ASTC Power Partnership up to March 7, 2016.

Energy segmented earnings decreased by $648 million to segmented losses of $571 million for the three months ended December 31, 2016 compared to the same period in 2015 and included the following specific items:

- a loss of $839 million before tax related to the loss on U.S. Northeast power assets held for sale which included an $829 million before tax loss on the thermal and wind package and $10 million of pre-tax costs related to the monetization
- a $92 million before tax loss on the transfer of environmental credits to the Balancing Pool upon final settlement of the Alberta PPA terminations
- a loss in 2015 of $59 million before tax relating to an impairment in value on turbine equipment previously purchased for a new power development project that did not proceed
- a charge in 2015 of $36 million before tax related to Bruce Power's retirement of debt in conjunction with the merger of the Bruce A and Bruce B partnerships
- unrealized gains and losses from changes in the fair value of derivatives used to reduce our exposure to certain commodity price risks as follows:

Risk management activities	**three months ended December 31**		**year ended December 31**	
(unaudited - millions of $, pre-tax)	**2016**	**2015**	**2016**	**2015**
Canadian Power	**1**	(1)	**4**	(8)
U.S. Power	**97**	(8)	**113**	(30)
Natural Gas Storage	**(1)**	(1)	**8**	1
Total unrealized gains/(losses) from risk management activities	**97**	(10)	**125**	(37)

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

Following the March 17, 2016 announcement of our intention to monetize the U.S. Northeast power business, we were required to discontinue hedge accounting for certain cash flow hedges. This, along with the increased volume of our risk management activities associated with the expansion of our customer base in the PJM market, contributed to higher volatility in U.S. Power risk management activities.

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

Comparable EBITDA for Energy increased by $35 million to $305 million for the three months ended December 31, 2016 compared to $270 million for the same period in 2015 primarily due to the net effect of:

- higher earnings from Western Power due to higher realized prices on generated volumes and termination of the Alberta PPAs
- higher earnings from Natural Gas Storage due to higher realized natural gas storage price spreads.

CANADIAN POWER

Western and Eastern Power

The following are the components of comparable EBITDA and comparable EBIT.

	three months ended December 31		year ended December 31	
(unaudited - millions of $)	**2016**	**2015**	**2016**	**2015**
Revenue[1]				
Western Power	**49**	123	**216**	542
Eastern Power	**96**	97	**411**	455
Other[2]	**12**	13	**43**	62
	157	233	**670**	1,059
Income/(loss) from equity investments[3]	**8**	(5)	**24**	8
Commodity purchases resold	**—**	(87)	**(60)**	(353)
Plant operating costs and other	**(56)**	(58)	**(206)**	(252)
Comparable EBITDA[4]	**109**	83	**428**	462
Depreciation and amortization	**(25)**	(49)	**(142)**	(190)
Comparable EBIT[4]	**84**	34	**286**	272
Breakdown of comparable EBITDA				
Western Power[4]	**26**	(1)	**75**	72
Eastern Power	**83**	84	**353**	390
Comparable EBITDA[4]	**109**	83	**428**	462
Plant availability[5]				
Western Power	**97%**	97%	**93%**	97%
Eastern Power[6]	**85%**	96%	**91%**	97%

1 Includes the realized gains and losses from financial derivatives used to manage Canadian Power's assets and are presented on a net basis in Western and Eastern Power revenues. The unrealized gains and losses from financial derivatives have been excluded to arrive at comparable EBITDA.

2 Includes revenues from the sale of unused natural gas transportation and sale of excess natural gas purchased for generation.

3 Includes our share of equity income from our investments in ASTC Power Partnership, which held the Sundance B PPA, and Portlands Energy. 2016 excludes a $29 million charge related to the Sundance B PPA termination which was held in ASTC Power Partnership.

4 Included Sundance A, Sundance B and Sheerness PPAs up to March 7, 2016.

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

6 Does not include Bécancour because power generation has been suspended since 2008.

Western Power

Comparable EBITDA for Western Power increased by $27 million for the three months ended December 31, 2016 compared to the same period in 2015 mainly due to higher realized prices on generated volumes and termination of the Alberta PPAs.

Results from the Alberta PPAs are included up to March 7, 2016 when we sent notice to the Balancing Pool to terminate the PPAs for the Sundance A, Sundance B and Sheerness facilities. Income/(loss) from equity investments included earnings from the ASTC Power Partnership which held our 50 per cent ownership in the Sundance B PPA.

Alberta power prices are impacted by several factors including the prevailing power supply and demand conditions and natural gas price levels. Average spot market power prices in Alberta increased five per cent from $21/MWh to $22/MWh for the three months ended December 31, 2016 compared to the same period in 2015. Average AECO natural gas prices increased by 25 per cent from approximately $2.34/GJ to $2.93/GJ for the three months ended December 31, 2016 compared to the same period in 2015. The Alberta power market remained well-supplied and power consumption was down primarily due to a weak economy.

Depreciation and amortization decreased by $24 million for the three months ended December 31, 2016 compared to the same period in 2015 following the termination of the Alberta PPAs.

Eastern Power

Comparable EBITDA for Eastern Power decreased by $1 million for the three months ended December 31, 2016 compared to the same period in 2015.

BRUCE POWER

Bruce Power results reflect our proportionate share. Bruce A and B were merged in December 2015 and comparative information for 2015 is reported on a combined basis to reflect the merged entity. The following is our proportionate share of the components of comparable EBITDA and comparable EBIT.

	three months ended December 31		year ended December 31	
(unaudited - millions of $, unless noted otherwise)	**2016**	**2015**	**2016**	**2015**
Equity income included in comparable EBITDA and EBIT comprised of:				
Revenues	**376**	356	**1,470**	1,301
Operating expenses	**(206)**	(193)	**(849)**	(691)
Depreciation and other	**(87)**	(80)	**(328)**	(325)
Comparable EBITDA and EBIT[1]	**83**	83	**293**	285
Bruce Power - other information				
Plant availability[2]	**85%**	92%	**83%**	87%
Planned outage days	**80**	40	**415**	327
Unplanned outage days	**27**	15	**76**	45
Sales volumes (GWh)[1]	**5,758**	5,388	**22,178**	19,358
Realized sales price per MWh[3]	**$68**	$63	**$67**	$65

1 Represents our 48.5 per cent ownership interest in Bruce Power after the merger on December 4, 2015 and our 48.9 per cent ownership interest in Bruce A and 31.6 per cent ownership interest in Bruce B up to December 3, 2015. Sales volumes include deemed generation. Comparable EBITDA in 2015 excludes a $36 million debt retirement charge.

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

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

Comparable EBITDA from Bruce Power remained unchanged for the three months ended December 31, 2016 compared to the same period in 2015 mainly due to our increased ownership interest and higher realized sales price offset by lower volumes from increased outage days compared to the same period in 2015.

In December 2015, Bruce Power entered into an agreement with the IESO to extend the operating life of the Bruce Power facility to 2064. As part of this agreement, Bruce Power began receiving a uniform price of $65.73 per MWh for all units, which includes certain flow-through items such as fuel and lease expenses recovery. Over time, the price will be subject to adjustments for the return of and on capital invested in Bruce Power under the Asset Management and Major Component Replacement capital programs, along with various other pricing adjustments that allow for a better matching of revenues and costs over the long term.

Bruce Power also enters into fixed-price contracts under which it receives or pays the difference between the contract price and the spot price.

The contract with the IESO provides for payment if the IESO reduces Bruce Power's generation to balance the supply of and demand for electricity and/or manage other operating conditions of the Ontario power grid. The amount of the reduction is considered deemed generation for which Bruce Power is paid the contract price.

U.S. POWER (monetization expected to close in the first half of 2017)

The following are the components of comparable EBITDA and comparable EBIT.

	three months ended December 31		year ended December 31	
(unaudited - millions of US$)	2016	2015	2016	2015
Revenue[1]				
Power[2]	**542**	428	**2,192**	1,997
Capacity	**55**	63	**278**	317
	597	491	**2,470**	2,314
Commodity purchases resold	**(407)**	(315)	**(1,595)**	(1,474)
Plant operating costs and other[3]	**(117)**	(97)	**(479)**	(426)
Comparable EBITDA[1]	**73**	79	**396**	414
Depreciation and amortization[4]	**(10)**	(27)	**(105)**	(105)
Comparable EBIT[1]	**63**	52	**291**	309

1 Includes Ironwood commencing February 1, 2016.

2 Includes the realized gains and losses from financial derivatives used to manage U.S. Power's assets and are presented on a net basis in Power revenues. The unrealized gains and losses from financial derivatives are excluded to arrive at comparable EBITDA.

3 Includes the cost of fuel consumed in generation.

4 U.S. Power assets held for sale no longer depreciated beginning in November 2016.

Sales volumes and plant availability

	three months ended December 31		year ended December 31	
(unaudited)	2016	2015	2016	2015
Physical sales volumes (GWh)				
Supply				
Generation[1]	**2,709**	2,093	**12,752**	7,849
Purchased	**6,879**	5,137	**26,613**	20,937
	9,588	7,230	**39,365**	28,786
Plant availability[2]	**71%**	79%	**81%**	78%

1 Increase primarily due to Ironwood acquisition.

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

U.S. Power - other information

(unaudited)	three months ended December 31 2016	three months ended December 31 2015	year ended December 31 2016	year ended December 31 2015
Average Spot Power Prices (US$ per MWh)				
New England[1]	**34**	30	**30**	42
New York[2]	**31**	24	**29**	39
PJM[3]	**25**	n/a	**25**	n/a
Average New York[2] Spot Capacity Prices (US$ per KW-M)	**6.45**	9.22	**8.65**	11.44

1 New England ISO all hours Mass Hub price.
2 Zone J market in New York City where the Ravenswood plant operates.
3 The METED Zone price in Pennsylvania where the Ironwood plant operates. Average price for 2016 is from the Ironwood acquisition date of February 1, 2016.

Comparable EBITDA for U.S. Power decreased US$6 million for the three months ended December 31, 2016 compared to the same period in 2015 primarily due to the net effect of:

- lower capacity revenues due to lower realized capacity prices in New York, partially offset by recognition of insurance recoveries at Ravenswood
- insurance recoveries recognized in 2015 related to an unplanned outage at the Ravenswood facility that occurred in 2008
- higher earnings due to our acquisition of the Ironwood power plant on February 1, 2016
- higher margins and higher sales to wholesale, commercial and industrial customers in both the New England and PJM markets.

Average New York Zone J spot capacity prices were approximately 30 per cent lower for the three months ended December 31, 2016 compared to the same period in 2015. The decrease in spot prices and the offsetting impact of hedging activities resulted in lower realized capacity prices in New York. This was primarily due to an increase in demonstrated capability from existing resources in New York City's Zone J market. The impact of lower capacity prices in New York was partially offset by capacity revenues earned by our Ironwood power plant.

Insurance recoveries for the 2014 outage at Ravenswood are being recognized in capacity revenues to offset amounts lost during the periods impacted by the lower forced outage rate. As a result of these insurance recoveries, the Unit 30 unplanned outage has not had a significant impact on our earnings although the recording of earnings has not coincided exactly with lost revenues due to timing of the insurance proceeds. In addition, insurance recoveries related to an unplanned outage at the Ravenswood facility that occurred in 2008 were recognized in power revenue in December 2015.

Higher margins and higher sales volumes to wholesale, commercial, and industrial customers in both the New England and PJM markets resulted in higher earnings for the three months ended December 31, 2016 compared to the same period in 2015. The expansion of our customer base in these markets, combined with higher power prices during the three months ended December 31, 2016, provided the opportunity for higher earnings.

Wholesale electricity prices in New York and New England were higher for the three months ended December 31, 2016 compared to the same period in 2015. In New England, spot power prices for the three months ended December 31, 2016 were 13 per cent higher compared to the same period in 2015. In New York City, spot power prices for the three months ended December 31, 2016 were 29 per cent higher compared to the same period in 2015.

Physical generation volumes for the three months ended December 31, 2016 were higher compared to the same period in 2015 due to our acquisition of the Ironwood power plant. Physical purchased volumes sold to wholesale, commercial and industrial customers were higher for the three months ended December 31, 2016 than the same period in 2015 as we have expanded our customer base in the PJM and New England markets.

NATURAL GAS STORAGE AND OTHER

Comparable EBITDA increased by $14 million for the three months ended December 31, 2016 compared to the same period in 2015 mainly due to increased third party storage revenues as a result of higher realized natural gas storage price spreads.

Corporate

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented losses (the equivalent GAAP measure). Certain costs previously reported in our Corporate segment are now being reported within the business segments as a result of our 2015 business transformation initiative. 2015 results have been adjusted to reflect this change.

	three months ended December 31		year ended December 31	
(unaudited - millions of $)	**2016**	2015	**2016**	2015
Comparable EBITDA	**(8)**	(57)	**(70)**	(108)
Depreciation and amortization	**(19)**	(8)	**(48)**	(31)
Comparable EBIT	**(27)**	(65)	**(118)**	(139)
Specific items:				
Acquisition related costs - Columbia	**(36)**	—	**(116)**	—
Restructuring costs	**(8)**	(79)	**(22)**	(99)
Segmented losses	**(71)**	(144)	**(256)**	(238)

Corporate segmented losses decreased by $73 million for the three months ended December 31, 2016 compared to the same period in 2015 and included the following specific items that have been excluded from comparable EBIT:

- acquisition and integration costs associated with the acquisition of Columbia
- restructuring costs related to expected future losses under lease commitments.

Comparable EBITDA in 2015 included the portion of our corporate restructuring costs that were recovered through our tolling mechanisms. The increase in Corporate depreciation for the three months ended December 31, 2016 compared to 2015 reflected incremental depreciation on our Corporate capital additions, including those in Columbia.

OTHER INCOME STATEMENT ITEMS

Interest expense

(unaudited - millions of $)	three months ended December 31 2016	three months ended December 31 2015	year ended December 31 2016	year ended December 31 2015
Interest on long-term debt and junior subordinated notes				
Canadian dollar-denominated	**(109)**	(113)	**(452)**	(437)
U.S. dollar-denominated	**(316)**	(234)	**(1,127)**	(911)
Foreign exchange impact	**(106)**	(78)	**(366)**	(255)
	(531)	(425)	**(1,945)**	(1,603)
Other interest and amortization expense	**(54)**	(12)	**(114)**	(47)
Capitalized interest	**43**	57	**176**	280
Interest expense included in comparable earnings	**(542)**	(380)	**(1,883)**	(1,370)
Specific item:				
Acquisition related costs - Columbia[1]	**—**	—	**(115)**	—
Interest expense	**(542)**	(380)	**(1,998)**	(1,370)

1 This amount represents the dividend equivalent payments of $109 million on the subscription receipts issued to partially fund the Columbia acquisition and $6 million of other acquisition related costs, both of which are excluded from comparable earnings.

Interest expense increased by $162 million for the three months ended December 31, 2016 compared to the same period in 2015 due to the net effect of:

- higher interest expense as a result of debt assumed in the acquisition of Columbia on July 1, 2016
- higher interest expense as a result of long-term debt issuances, partially offset by Canadian and U.S. dollar-denominated debt maturities
- higher foreign exchange on interest expense related to U.S. dollar-denominated debt
- higher amortization expense on debt issuance costs related to the acquisition bridge facilities.

Allowance for funds used during construction

(unaudited - millions of $)	three months ended December 31 2016	three months ended December 31 2015	year ended December 31 2016	year ended December 31 2015
Canadian dollar-denominated	**48**	38	**181**	119
U.S. dollar-denominated	**32**	39	**181**	137
Foreign exchange impact	**17**	14	**57**	39
Allowance for funds used during construction	**97**	91	**419**	295

AFUDC increased by $6 million for the three months ended December 31, 2016 compared to the same period in 2015 primarily due to increased investment in our NGTL System expansions, Energy East and Columbia projects, partially offset by bringing into service the Topolobampo and Mazatlán pipelines.

Interest income and other

(unaudited - millions of $)	three months ended December 31		year ended December 31	
	2016	2015	2016	2015
Interest income and other included in comparable earnings	**8**	(15)	**71**	(111)
Specific items:				
Acquisition related costs - Columbia[1]	**—**	—	**6**	—
Risk management activities	**(23)**	4	**26**	(21)
Interest income and other	**(15)**	(11)	**103**	(132)

1 This amount represents interest income on the gross proceeds of the subscription receipts issued to partially fund the Columbia acquisition and is excluded from comparable earnings.

Interest income and other decreased by $4 million for the three months ended December 31, 2016 compared to the same period in 2015 due to the net effect of:

- unrealized losses on risk management activities in 2016 compared to gains in 2015. These amounts have been excluded from comparable earnings
- higher realized gains in 2016 compared to realized losses in 2015 on derivatives used to manage our net exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income
- the impact of a fluctuating U.S. dollar on the translation of foreign currency denominated working capital.

Income tax expense

(unaudited - millions of $)	three months ended December 31		year ended December 31	
	2016	2015	2016	2015
Income tax expense included in comparable earnings	**(211)**	(235)	**(841)**	(903)
Specific items:				
Ravenswood goodwill impairment	**—**	—	**429**	—
Loss on U.S. Northeast power assets held for sale	**(31)**	—	**(29)**	—
Alberta PPA terminations and settlement	**24**	—	**88**	—
Acquisition related costs - Columbia	**(22)**	—	**10**	—
Keystone XL income tax recoveries	**—**	—	**28**	—
Keystone XL asset costs	**(3)**	—	**10**	—
Restructuring costs	**2**	19	**6**	25
TC Offshore loss on sale	**—**	39	**1**	39
Keystone XL impairment charge	**—**	795	**—**	795
Turbine equipment impairment charge	**—**	16	**—**	16
Bruce Power merger - debt retirement charge	**—**	9	**—**	9
Alberta corporate income tax rate increase	**—**	—	**—**	(34)
Risk management activities	**(33)**	3	**(54)**	19
Income tax (expense)/recovery	**(274)**	646	**(352)**	(34)

Income tax expense included in comparable earnings decreased by $24 million for the three months ended December 31, 2016 compared to the same period in 2015 mainly due to a change in the proportion of income earned between Canadian and foreign jurisdictions and lower flow-through taxes in 2016 on Canadian regulated pipelines, partially offset by higher pre-tax earnings in 2016 compared to 2015.

Net income attributable to non-controlling interests

	three months ended December 31		year ended December 31	
(unaudited - millions of $)	**2016**	**2015**	**2016**	**2015**
Net income attributable to non-controlling interests included in comparable earnings	**(70)**	(60)	**(257)**	(205)
Specific items:				
Acquisition related costs - Columbia	**2**	—	**5**	—
TC PipeLines, LP - Great Lakes impairment	**—**	199	**—**	199
Net (income)/loss attributable to non-controlling interests	**(68)**	139	**(252)**	(6)

Net income attributable to non-controlling interests increased by $207 million for the three months ended December 31, 2016 compared to the same period in 2015 due to the net effect of a $2 million charge in 2016 related to the non-controlling interests' portion of retention and severance expenses resulting from the Columbia acquisition and an impairment charge recorded by TC PipeLines, LP in 2015 related to their equity investment goodwill in Great Lakes. On consolidation, we recorded the non-controlling interests' 72 per cent of this TC PipeLines, LP impairment charge, which was US$143 million, or $199 million (in Canadian dollars). TC PipeLines, LP's impairment charge is not recognized at the TransCanada consolidation level as a result of our lower carrying value of Great Lakes. Both of these amounts have been excluded from comparable earnings.

Net income attributable to non-controlling interests included in comparable earnings increased by $10 million for the three months ended December 31, 2016 compared to the same period in 2015 primarily due to the acquisition of Columbia which included a non-controlling interest in Columbia Pipeline Partners LP. In addition, the sale of our 30 per cent direct interest in GTN in April 2015 and 49.9 per cent direct interest in PNGTS in January 2016 to TC PipeLines, LP, along with the impact of a stronger U.S. dollar, increased net income attributable to non-controlling interests year-over-year.

Preferred share dividends

	three months ended December 31		year ended December 31	
(unaudited - millions of $)	**2016**	**2015**	**2016**	**2015**
Preferred share dividends	**(32)**	(23)	**(109)**	(94)

Preferred share dividends increased by $9 million for the three months ended December 31, 2016 compared to the same period in 2015 primarily due to the issuance of Series 13 and Series 15 preferred shares in April 2016 and November 2016.

Reconciliation of non-GAAP measures

	three months ended December 31		year ended December 31	
(unaudited - millions of $, except per share amounts)	**2016**	**2015**	**2016**	**2015**
Comparable EBITDA				
Canadian Natural Gas Pipelines	**599**	636	**2,246**	2,258
U.S. Natural Gas Pipelines	**569**	288	**1,683**	974
Mexico Natural Gas Pipelines	**120**	51	**333**	215
Liquids Pipelines	**305**	339	**1,166**	1,309
Energy	**305**	270	**1,289**	1,260
Corporate	**(8)**	(57)	**(70)**	(108)
Comparable EBITDA	**1,890**	1,527	**6,647**	5,908
Depreciation and amortization	**(514)**	(452)	**(1,939)**	(1,765)
Comparable EBIT	**1,376**	1,075	**4,708**	4,143
Specific items:				
Ravenswood goodwill impairment	**—**	—	**(1,085)**	—
Loss on U.S. Northeast power assets held for sale	**(839)**	—	**(844)**	—
Alberta PPA terminations and settlement	**(92)**	—	**(332)**	—
Acquisition related costs - Columbia	**(47)**	—	**(179)**	—
Keystone XL asset costs	**(15)**	—	**(52)**	—
Restructuring costs	**(8)**	(79)	**(22)**	(99)
TC Offshore loss on sale	**—**	(125)	**(4)**	(125)
Keystone XL impairment charge	**—**	(3,686)	**—**	(3,686)
Turbine equipment impairment charge	**—**	(59)	**—**	(59)
Bruce Power merger - debt retirement charge	**—**	(36)	**—**	(36)
Risk management activities[1]	**101**	(10)	**123**	(37)
Segmented earnings/(losses)	**476**	(2,920)	**2,313**	101

[1]

Risk management activities	three months ended December 31		year ended December 31	
(unaudited - millions of $)	**2016**	**2015**	**2016**	**2015**
Canadian Power	**1**	(1)	**4**	(8)
U.S. Power	**97**	(8)	**113**	(30)
Liquids marketing	**4**	—	**(2)**	—
Natural Gas Storage	**(1)**	(1)	**8**	1
Total unrealized gains/(losses) from risk management activities	**101**	(10)	**123**	(37)

Comparable Distributable Cash Flow

	three months ended December 31		year ended December 31	
(unaudited - millions of $)	**2016**	**2015**	**2016**	**2015**
Net cash provided by operations	**1,575**	1,196	**5,069**	4,384
(Decrease)/increase in operating working capital	**(220)**	(32)	**(248)**	346
Funds generated from operations	**1,355**	1,164	**4,821**	4,730
Specific items:				
Acquisition related costs - Columbia	**45**	—	**283**	—
Keystone XL asset costs	**15**	—	**52**	—
Restructuring costs	**—**	65	**—**	85
Loss on U.S. Northeast power assets held for sale	**10**	—	**15**	—
Comparable funds generated from operations	**1,425**	1,229	**5,171**	4,815
Dividends on preferred shares	**(26)**	(23)	**(100)**	(92)
Distributions paid to non-controlling interests	**(78)**	(56)	**(279)**	(224)
Maintenance capital expenditures including equity investments	**(357)**	(353)	**(1,127)**	(937)
Comparable distributable cash flow	**964**	797	**3,665**	3,562
Comparable distributable cash flow per common share	**$1.16**	$1.13	**$4.83**	$5.02

Comparable distributable cash flow, a non-GAAP measure, helps us assess the cash available to common shareholders before capital allocation. The increase from 2015 to 2016 was driven by an increase in funds generated from operations partially offset by higher maintenance capital expenditures primarily on Columbia pipelines since the acquisition on July 1, 2016 and ANR.

Although we deduct maintenance capital expenditures in determining comparable distributable cash flow, in certain of our rate-regulated businesses, maintenance capital expenditures are included in their respective rate bases, on which we earn a regulated return and recover depreciation through future tolls.

The following provides a breakdown of maintenance capital expenditures:

	three months ended December 31		year ended December 31	
(unaudited - millions of $)	**2016**	**2015**	**2016**	**2015**
Canadian Natural Gas Pipelines	**142**	146	**344**	347
U.S. Natural Gas Pipelines	**143**	118	**464**	298
Other	**72**	89	**319**	292
Maintenance capital expenditures including equity investments	**357**	353	**1,127**	937

Condensed consolidated statement of income

	three months ended December 31		year ended December 31	
(unaudited - millions of Canadian $, except per share amounts)	**2016**	**2015**	**2016**	**2015**
Revenues				
Canadian Natural Gas Pipelines	**1,005**	1,000	**3,682**	3,680
U.S. Natural Gas Pipelines	**941**	419	**2,526**	1,444
Mexico Natural Gas Pipelines	**129**	68	**378**	259
Liquids Pipelines	**463**	469	**1,755**	1,879
Energy	**1,081**	895	**4,164**	4,038
	3,619	2,851	**12,505**	11,300
Income from Equity Investments	**159**	90	**514**	440
Operating and Other Expenses				
Plant operating costs and other	**1,173**	906	**3,819**	3,250
Commodity purchases resold	**544**	506	**2,172**	2,237
Property taxes	**150**	127	**555**	517
Depreciation and amortization	**514**	452	**1,939**	1,765
Goodwill and other asset impairment charges	**92**	3,745	**1,388**	3,745
	2,473	5,736	**9,873**	11,514
Loss on Assets held for Sale/Sold	**(829)**	(125)	**(833)**	(125)
Financial Charges				
Interest expense	**542**	380	**1,998**	1,370
Allowance for funds used during construction	**(97)**	(91)	**(419)**	(295)
Interest income and other	**15**	11	**(103)**	132
	460	300	**1,476**	1,207
Income/(Loss) before Income Taxes	**16**	(3,220)	**837**	(1,106)
Income Tax Expense/(Recovery)				
Current	**53**	12	**156**	136
Deferred	**221**	(658)	**196**	(102)
	274	(646)	**352**	34
Net (Loss)/Income	**(258)**	(2,574)	**485**	(1,140)
Net income/(loss) attributable to non-controlling interests	**68**	(139)	**252**	6
Net (Loss)/Income Attributable to Controlling Interests	**(326)**	(2,435)	**233**	(1,146)
Preferred share dividends	**32**	23	**109**	94
Net (Loss)/Income Attributable to Common Shares	**(358)**	(2,458)	**124**	(1,240)
Net (Loss)/Income per Common Share				
Basic and diluted	**($0.43)**	($3.47)	**$0.16**	($1.75)
Dividends Declared per Common Share	**$0.565**	$0.52	**$2.26**	$2.08
Weighted Average Number of Common Shares (millions)				
Basic	**832**	708	**759**	709
Diluted	**833**	708	**760**	709

Condensed consolidated statement of cash flows

	three months ended December 31		year ended December 31	
(unaudited - millions of Canadian $)	**2016**	**2015**	**2016**	**2015**
Cash Generated from Operations				
Net (loss)/income	**(258)**	(2,574)	**485**	(1,140)
Depreciation and amortization	**514**	452	**1,939**	1,765
Goodwill and other asset impairment charges	**92**	3,745	**1,388**	3,745
Deferred income taxes	**221**	(658)	**196**	(102)
Income from equity investments	**(159)**	(90)	**(514)**	(440)
Distributions received from operating activities of equity investments	**219**	184	**844**	793
Employee post-retirement benefits expense, net of funding	**2**	3	**(3)**	44
Loss on assets held for sale/sold	**829**	125	**833**	125
Equity allowance for funds used during construction	**(58)**	(50)	**(253)**	(165)
Unrealized (gains)/losses on financial instruments	**(78)**	6	**(149)**	58
Other	**31**	21	**55**	47
Decrease/(increase) in operating working capital	**220**	32	**248**	(346)
Net cash provided by operations	**1,575**	1,196	**5,069**	4,384
Investing Activities				
Capital expenditures	**(1,745)**	(1,170)	**(5,007)**	(3,918)
Capital projects in development	**(76)**	(46)	**(295)**	(511)
Contributions to equity investments	**(195)**	(190)	**(765)**	(493)
Acquisitions, net of cash acquired	**—**	(236)	**(13,608)**	(236)
Proceeds from sale of assets, net of transaction costs	**—**	—	**6**	—
Other distributions from equity investments	**2**	—	**727**	9
Deferred amounts and other	**141**	30	**159**	270
Net cash used in investing activities	**(1,873)**	(1,612)	**(18,783)**	(4,879)
Financing Activities				
Notes payable repaid, net	**(229)**	(554)	**(329)**	(1,382)
Long-term debt issued, net of issue costs	**—**	1,722	**12,333**	5,045
Long-term debt repaid	**(4,810)**	(39)	**(7,153)**	(2,105)
Junior subordinated notes issued, net of issue costs	**(2)**	—	**1,549**	917
Dividends on common shares	**(277)**	(368)	**(1,436)**	(1,446)
Dividends on preferred shares	**(26)**	(23)	**(100)**	(92)
Distributions paid to non-controlling interests	**(78)**	(56)	**(279)**	(224)
Common shares issued, net of issue costs	**3,410**	15	**7,747**	27
Common shares repurchased	**—**	(294)	**(14)**	(294)
Preferred shares issued, net of issue costs	**982**	—	**1,474**	243
Partnership units of subsidiary issued, net of issue costs	**64**	24	**215**	55
Net cash (used in)/provided by financing activities	**(966)**	427	**14,007**	744
Effect of Foreign Exchange Rate Changes on Cash and Cash Equivalents	**—**	84	**(127)**	112
(Decrease)/increase in Cash and Cash Equivalents	**(1,264)**	95	**166**	361
Cash and Cash Equivalents				
Beginning of period	**2,280**	755	**850**	489
Cash and Cash Equivalents				
End of period	**1,016**	850	**1,016**	850

Condensed consolidated balance sheet

(unaudited - millions of Canadian $)		December 31 2016	December 31 2015
ASSETS			
Current Assets			
Cash and cash equivalents		**1,016**	850
Accounts receivable		**2,075**	1,387
Inventories		**368**	323
Assets held for sale		**3,717**	20
Other		**908**	1,338
		8,084	3,918
Plant, Property and Equipment	net of accumulated depreciation of $22,263 and $22,299, respectively	**54,475**	44,817
Equity Investments		**6,544**	6,214
Regulatory Assets		**1,322**	1,184
Goodwill		**13,958**	4,812
Intangible and Other Assets		**3,026**	3,102
Restricted Investments		**642**	351
		88,051	64,398
LIABILITIES			
Current Liabilities			
Notes payable		**774**	1,218
Accounts payable and other		**3,861**	2,653
Dividends payable		**526**	385
Accrued interest		**595**	520
Liabilities related to assets held for sale		**86**	39
Current portion of long-term debt		**1,838**	2,547
		7,680	7,362
Regulatory Liabilities		**2,121**	1,159
Other Long-Term Liabilities		**1,183**	1,260
Deferred Income Tax Liabilities		**7,662**	5,144
Long-Term Debt		**38,312**	28,909
Junior Subordinated Notes		**3,931**	2,409
		60,889	46,243
Common Units Subject to Rescission or Redemption		**1,179**	—
EQUITY			
Common shares, no par value		**20,099**	12,102
Issued and outstanding:	December 31, 2016 - 864 million shares		
	December 31, 2015 - 703 million shares		
Preferred shares		**3,980**	2,499
Additional paid-in capital		**—**	7
Retained earnings		**1,138**	2,769
Accumulated other comprehensive loss		**(960)**	(939)
Controlling Interests		**24,257**	16,438
Non-controlling interests		**1,726**	1,717
		25,983	18,155
		88,051	64,398

Segmented information

three months ended December 31, 2016 (unaudited - millions of Canadian $)	**Canadian Natural Gas Pipelines**	**U.S. Natural Gas Pipelines**	**Mexico Natural Gas Pipelines**	**Liquids Pipelines**	**Energy**	**Corporate**	**Total**
Revenues	**1,005**	**941**	**129**	**463**	**1,081**	**—**	**3,619**
Income from equity investments	**3**	**64**	**(1)**	**—**	**93**	**—**	**159**
Plant operating costs and other	**(344)**	**(405)**	**(8)**	**(148)**	**(216)**	**(52)**	**(1,173)**
Commodity purchases resold	**—**	**—**	**—**	**—**	**(544)**	**—**	**(544)**
Property taxes	**(65)**	**(42)**	**—**	**(21)**	**(22)**	**—**	**(150)**
Depreciation and amortization	**(220)**	**(142)**	**(15)**	**(76)**	**(42)**	**(19)**	**(514)**
Asset impairment charge	**—**	**—**	**—**	**—**	**(92)**	**—**	**(92)**
Loss on assets held for sale	**—**	**—**	**—**	**—**	**(829)**	**—**	**(829)**
Segmented earnings/(losses)	**379**	**416**	**105**	**218**	**(571)**	**(71)**	**476**
Interest expense							**(542)**
Allowance for funds used during construction							**97**
Interest income and other							**(15)**
Income before income taxes							**16**
Income tax expense							**(274)**
Net loss							**(258)**
Net income attributable to non-controlling interests							**(68)**
Net loss attributable to controlling interests							**(326)**
Preferred share dividends							**(32)**
Net loss attributable to common shares							**(358)**

three months ended December 31, 2015 (unaudited - millions of Canadian $)	Canadian Natural Gas Pipelines	U.S. Natural Gas Pipelines	Mexico Natural Gas Pipelines	Liquids Pipelines	Energy	Corporate	Total
Revenues	1,000	419	68	469	895	—	2,851
Income from equity investments	3	41	1	—	45	—	90
Plant operating costs and other	(300)	(154)	(18)	(112)	(186)	(136)	(906)
Commodity purchases resold	—	—	—	—	(506)	—	(506)
Property taxes	(67)	(18)	—	(18)	(24)	—	(127)
Depreciation and amortization	(213)	(64)	(10)	(69)	(88)	(8)	(452)
Goodwill and other asset impairment charges	—	—	—	(3,686)	(59)	—	(3,745)
Loss on assets held for sale	—	(125)	—	—	—	—	(125)
Segmented earnings/(losses)	423	99	41	(3,416)	77	(144)	(2,920)
Interest expense							(380)
Allowance for funds used during construction							91
Interest income and other							(11)
Loss before income taxes							(3,220)
Income tax recovery							646
Net loss							(2,574)
Net loss attributable to non-controlling interests							139
Net loss attributable to controlling interests							(2,435)
Preferred share dividends							(23)
Net loss attributable to common shares							(2,458)

year ended December 31, 2016 (unaudited - millions of Canadian $)	**Canadian Natural Gas Pipelines**	**U.S. Natural Gas Pipelines**	**Mexico Natural Gas Pipelines**	**Liquids Pipelines**	**Energy**	**Corporate**	**Total**
Revenues	**3,682**	**2,526**	**378**	**1,755**	**4,164**	**—**	**12,505**
Income from equity investments	**12**	**214**	**(3)**	**(1)**	**292**	**—**	**514**
Plant operating costs and other	**(1,181)**	**(1,000)**	**(42)**	**(554)**	**(834)**	**(208)**	**(3,819)**
Commodity purchases resold	**—**	**—**	**—**	**—**	**(2,172)**	**—**	**(2,172)**
Property taxes	**(267)**	**(120)**	**—**	**(88)**	**(80)**	**—**	**(555)**
Depreciation and amortization	**(873)**	**(397)**	**(43)**	**(285)**	**(293)**	**(48)**	**(1,939)**
Goodwill and other asset impairment charges	**—**	**—**	**—**	**—**	**(1,388)**	**—**	**(1,388)**
Loss on assets held for sale/sold	**—**	**(4)**	**—**	**—**	**(829)**	**—**	**(833)**
Segmented earnings/(losses)	**1,373**	**1,219**	**290**	**827**	**(1,140)**	**(256)**	**2,313**
Interest expense							**(1,998)**
Allowance for funds used during construction							**419**
Interest income and other							**103**
Income before income taxes							**837**
Income tax expense							**(352)**
Net income							**485**
Net income attributable to non-controlling interests							**(252)**
Net income attributable to controlling interests							**233**
Preferred share dividends							**(109)**
Net income attributable to common shares							**124**

year ended December 31, 2015 (unaudited - millions of Canadian $)	**Canadian Natural Gas Pipelines**	**U.S. Natural Gas Pipelines**	**Mexico Natural Gas Pipelines**	**Liquids Pipelines**	**Energy**	**Corporate**	**Total**
Revenues	3,680	1,444	259	1,879	4,038	—	11,300
Income from equity investments	12	162	5	—	261	—	440
Plant operating costs and other	(1,162)	(555)	(49)	(491)	(786)	(207)	(3,250)
Commodity purchases resold	—	—	—	—	(2,237)	—	(2,237)
Property taxes	(272)	(77)	—	(79)	(89)	—	(517)
Depreciation and amortization	(845)	(243)	(44)	(266)	(336)	(31)	(1,765)
Asset impairment charges	—	—	—	(3,686)	(59)	—	(3,745)
Loss on assets held for sale	—	(125)	—	—	—	—	(125)
Segmented earnings/(losses)	1,413	606	171	(2,643)	792	(238)	101
Interest expense							(1,370)
Allowance for funds used during construction							295
Interest income and other							(132)
Loss before income taxes							(1,106)
Income tax expense							(34)
Net loss							(1,140)
Net income attributable to non-controlling interests							(6)
Net loss attributable to controlling interests							(1,146)
Preferred share dividends							(94)
Net loss attributable to common shares							(1,240)

TOTAL ASSETS

(unaudited - millions of Canadian $)	December 31, 2016	December 31, 2015
Canadian Natural Gas Pipelines	**15,816**	15,038
U.S. Natural Gas Pipelines	**34,422**	12,207
Mexico Natural Gas Pipelines	**5,013**	3,787
Liquids Pipelines	**16,896**	16,046
Energy	**13,169**	15,614
Corporate	**2,735**	1,706
	88,051	64,398