**Quarterly**Report to Shareholders

# TransCanada Reports Third Quarter 2016 Financial Results
## Strong Operating Performance Reflects Acquisition of Columbia Pipeline Group

CALGARY, Alberta – **November 1, 2016** – TransCanada Corporation (TSX, NYSE: TRP) (TransCanada) today announced a net loss attributable to common shares for third quarter 2016 of $135 million or $0.17 per share compared to net income of $402 million or $0.57 per share for the same period in 2015. Third quarter 2016 results included a $656 million after-tax goodwill impairment charge related to our U.S. Northeast Power business. Excluding the net loss on the goodwill impairment and certain other specific items, comparable earnings for third quarter 2016 were $622 million or $0.78 per share compared to $440 million or $0.62 per share for the same period in 2015. TransCanada's Board of Directors also declared a quarterly dividend of $0.565 per common share for the quarter ending December 31, 2016, equivalent to $2.26 per common share on an annualized basis.

"Excluding specific items, comparable earnings per share for the quarter were significantly higher than last year as a result of the Columbia acquisition and continued solid performance from our large portfolio of high-quality energy infrastructure assets," said Russ Girling, TransCanada's president and chief executive officer. "Since completing the Columbia transaction, we have made significant progress in integrating its operations with our existing U.S. natural gas pipeline business and are well on track to realize the targeted US$250 million of annualized benefits associated with the acquisition."

On July 1, 2016, TransCanada completed the acquisition of Columbia Pipeline Group, Inc. (Columbia) for US$13 billion. Columbia operates a portfolio of approximately 24,000 km (15,000 miles) of regulated natural gas pipelines, 300 Bcf of natural gas storage facilities and related midstream assets.

"The addition of Columbia reinforces our position as one of North America's leading energy infrastructure companies with an extensive pipeline network that links the continent's most prolific natural gas supply basins to its most attractive markets," added Girling. "Looking forward, the addition of Columbia's US$7.7 billion growth program brings our industry-leading portfolio of near-term capital projects to over $25 billion. As these projects progress through the permitting and construction phases and into operation over the balance of the decade, they are expected to generate significant growth in earnings and cash flow and support an expected annual dividend growth rate at the upper end of the Company's previous expectation of eight to 10 per cent through 2020."

### Highlights

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

- Third quarter financial results
  - Net loss attributable to common shares of $135 million or $0.17 per share
  - Comparable earnings of $622 million or $0.78 per share
  - Comparable earnings before interest, taxes, depreciation and amortization (EBITDA) of $1.9 billion
  - Comparable funds generated from operations of $1.4 billion
  - Comparable distributable cash flow of $1.0 billion or $1.29 per common share
- Declared a quarterly dividend of $0.565 per common share for the quarter ending December 31, 2016
- On July 1, 2016, we closed the US$13 billion acquisition of Columbia comprised of a purchase price of approximately US$10.3 billion and Columbia debt of approximately US$2.7 billion
- On July 4, 2016, 96.6 million subscription receipts were exchanged into the same number of common shares

- Announced the reinstatement of issuance of common shares from treasury at a two per cent discount under TransCanada's Dividend Reinvestment Plan commencing with the dividends declared on July 27, 2016
- Issued US$1.2 billion of junior subordinated notes in the United States that mature in 2076
- Announced that ANR filed a comprehensive settlement of its current Natural Gas Act Section 4 rate case with the Federal Energy Regulatory Commission (FERC)
- Launched an open season on the Canadian Mainline seeking binding commitments on a new long-term, fixed price tolling option
- On November 1, 2016, we announced the following strategic updates:
  - Expect to realize approximately US$3.7 billion from the monetization of our U.S. Northeast Power business
  - The decision to maintain our current ownership interest in our growing Mexican natural gas pipeline business
  - An agreement to purchase all of the common units of Columbia Pipeline Partners LP (CPPL) for US$17.00 per common unit for a total amount of approximately US$915 million
  - A bought deal offering of TransCanada common shares.

  These initiatives, along with our stable base business and $25 billion of secured near-term growth, position us to deliver an expected annual dividend growth rate at the upper end of the Company's previous expectation of eight to 10 per cent through 2020.

Net income attributable to common shares decreased by $537 million to a net loss of $135 million or $0.17 per share for the three months ended September 30, 2016 compared to the same period last year. Third quarter 2016 included a $656 million after-tax goodwill impairment charge, an after-tax charge of $67 million related to costs associated with the acquisition of Columbia, a $50 million after-tax charge related to risk management activities, recognition of $28 million of income tax recoveries resulting from a third party sale of Keystone XL project assets, a $9 million after-tax charge related to Keystone XL maintenance and liquidation costs and $3 million of after-tax costs related to the sale of our U.S. Northeast Power business. All of these specific items are excluded from comparable earnings.

Comparable earnings for third quarter 2016 were $622 million or $0.78 per share compared to $440 million or $0.62 per share for the same period in 2015, an increase of $182 million or $0.16 per share. The increase was primarily the net effect of a higher contribution from U.S. Pipelines primarily due to incremental earnings from Columbia following the acquisition on July 1, 2016 and higher ANR transportation and storage revenue resulting from higher rates effective August 1, 2016; a higher contribution from Mexican pipelines primarily due to earnings from Topolobampo beginning in July 2016; higher interest income and other due to 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; higher earnings from U.S. Power mainly due to incremental earnings from the Ironwood power plant acquired in February 2016 and higher sales to customers in the PJM market partially offset by lower capacity revenues in New York; higher earnings from Bruce Power mainly due to lower depreciation and our increased ownership interest partially offset by higher losses from contracting activities; and higher earnings from Canadian Pipelines primarily due to a higher NGTL investment base and incentive earnings from the Canadian Mainline and NGTL. These gains were partially offset by higher interest expense from debt issuances and lower capitalized interest as well as lower earnings from Liquids Pipelines due to the net effect of higher contracted and lower uncontracted volumes on Keystone Pipeline and lower volumes on Marketlink.

Notable recent developments include:

**Corporate:**

- *Acquisition of Columbia Pipeline Group:* On July 1, 2016, we closed the US$13 billion acquisition of Columbia comprised of a purchase price of approximately US$10.3 billion and Columbia debt of approximately US$2.7 billion. The acquisition was financed through proceeds of $4.4 billion from the sale of subscription receipts, senior unsecured asset bridge term loan credit facilities in the aggregate amount of US$6.9 billion and existing cash on hand. The sale of the subscription receipts was completed on April 1, 2016 through a public offering and following the closing of the acquisition, were exchanged into 96.6 million TransCanada common shares.

- *Monetization of U.S. Northeast Power business:* On November 1, 2016, we announced that we expect to realize approximately US$3.7 billion from the monetization of our the U.S. Northeast Power business. This includes the announced 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 TC Hydro to Great River Hydro, LLC, an affiliate of ArcLight Capital Partners, LLC for US$1.065 billion, with the remainder attributed to the marketing business which is expected to be realized going forward. These two sale transactions are expected to close in the first half of 2017 subject to certain regulatory and other approvals and will include 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 at September 30, 2016, an approximate $863 million after-tax net loss on the sale of the thermal and wind package to be recorded in fourth quarter 2016 and an approximate $443 million after-tax gain on the sale of the hydro assets upon close of that transaction. Proceeds from these sales and future realization of value of the marketing business will be used to repay a portion of the US$6.9 billion senior unsecured asset bridge term loan credit facilities which were used to partially finance the Columbia acquisition earlier this year.
- *Decision to maintain our current ownership interest in Mexican natural gas pipelines*: On November 1, 2016, we announced a decision to maintain our current 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 maintaining a simple corporate structure. We currently own and operate the Tamazunchale and Guadalajara natural gas pipelines and are in the process of investing US$3.8 billion to develop and complete construction of four additional pipelines plus fund our interest in the Sur de Texas project, all of which will serve growing natural gas demand in Mexico. All projects are expected to be in-service by the end of 2018 and are underpinned by 25-year take-or-pay contracts with the Comisión Federal de Electricidad (CFE). Once completed, we expect our Mexican natural gas pipeline assets to be accretive to earnings per share and generate approximately US$575 million of annual EBITDA, up from US$181 million in 2015.
- *Common Equity Offering:* On November 1, 2016, in conjunction with our decision to maintain our current ownership interest in a growing Mexican natural gas pipelines business, and concurrent with the release of these financial results, we also entered into an agreement with a group of underwriters to proceed with an offering of common shares. The common shares will be offered to the public in Canada and the United States through the underwriters or their representatives. The offering is subject to the receipt of all necessary regulatory and stock exchange approvals. Proceeds from the offering will be used to repay a portion of the US $6.9 billion senior unsecured asset bridge term loan credit facilities which were used to partially finance the acquisition of Columbia.
- *Agreement to Acquire Columbia Pipeline Partners LP:* On November 1, 2016, we announced that we have entered into an agreement and plan of merger through which our wholly-owned subsidiary, Columbia Pipeline Group, Inc., has 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 first quarter 2017 subject to receipt of CPPL unitholder approval and customary closing conditions and is expected to be accretive to earnings per share and simplify our corporate structure.
- *Dividend Declaration:* Our Board of Directors declared a quarterly dividend of $0.565 per share for the quarter ending December 31, 2016 on TransCanada's outstanding common shares. The quarterly amount is equivalent to $2.26 per common share on an annualized basis.

- *Dividend Reinvestment Plan:* Approximately $175 million or 39 per cent of dividends paid on October 31 were reinvested in TransCanada common shares through our Dividend Reinvestment Plan following the reinstatement of issuance from Treasury at a two per cent discount announced in July 2016.
- *Other Financing Activities:* In August 2016, TransCanada Trust issued US$1.2 billion of 60-year junior subordinated trust notes to third party investors with a fixed interest rate of 5.875 per cent for the first ten years converting to a floating rate thereafter. The notes are callable at par beginning ten years following their issuance. All of the proceeds of the issuance by the Trust were loaned to us in US$1.2 billion junior subordinated notes at a rate of 6.125 per cent which includes a 0.25 per cent administration charge. On a subordinated basis, the obligations of the Trust are guaranteed by TransCanada.

**Natural Gas Pipelines:**

- *NGTL System*: On October 31, 2016, the Government of Canada approved our $1.3 billion NGTL 2017 Facilities Application. In addition, on October 6, 2016, the NEB recommended to the government approval of the $439 million Towerbirch Project. This project consists of a 55 km (34 miles) pipeline loop and a 32 km (20 miles) pipeline extension of the NGTL System in northwest Alberta and northeast B.C. The NEB approved NGTL's continued use of its existing rolled-in toll methodology for this project. Of NGTL's $5.4 billion near-term capital program, we have received approvals for $4.0 billion, while $0.5 billion has been filed and is awaiting approval. Approximately $0.9 billion is expected to be filed with regulators in the future.
- *North Montney Mainline:* In March 2016, we filed a request with the NEB for a one year extension to the June 10, 2016 sunset clause in the North Montney Mainline project Certificate of Public Convenience and Necessity. On September 15, 2016, the NEB approved the sunset clause extension to June 10, 2017. The extension continues to be subject to the condition that construction shall not begin until a positive Final Investment Decision (FID) has been made on the Pacific Northwest LNG (PNW LNG) Project. NGTL continues to work with our customers and stakeholders to be ready to initiate construction of the North Montney facilities, however, the in-service date will be finalized once a FID has been made.
- *Canadian Mainline Tolling Option:* On October 13, 2016, we launched an open season on the Canadian Mainline seeking binding commitments on a new long-term, fixed-price proposal to transport WCSB supply from the Empress receipt point in Alberta to the Dawn hub in Southern Ontario. The contract term for this service is ten years with tolls ranging from $0.75/GJ to $0.82/GJ depending on the shippers' contract volume commitments. Early termination rights are provided and can be exercised following the initial five years of service upon payment of a premium fee. Subject to a successful Open Season that closes November 10, 2016 and to NEB regulatory approval, the new service is targeted to begin November 1, 2017.
- *Columbia Capital Projects:* As part of the Columbia acquisition, we are progressing a US$7.4 billion capital expansion and modernization program across the Columbia system for facilities planned to be in-service from 2016 to 2020. We also expect to invest approximately US$0.3 billion to construct the Gibraltar Pipeline project, an approximate 1 MMDth/d dry gas header pipeline in southwest Pennsylvania.
- *ANR Section 4 Rate Case Settlement:* On September 16, 2016, ANR filed with FERC an unopposed settlement agreement with its customers for approval. Effective August 1, 2016, transmission reservation rates increased by 34.8 percent with storage rates largely remaining unchanged. The settlement includes a moratorium on further rate changes until August 1, 2019. ANR may file for new rates after that date if it has spent more than US$0.8 billion in capital additions but must file for new rates with an effective date of no later than August 1, 2022.
- *Topolobampo Pipeline:* In July, we began collecting revenue on the US$1 billion Topolobampo project under a force majeure provision in the 25-year contract with the Comisión Federal de Electricidad. The physical in-service date is expected to be delayed into 2017 due to right-of-way acquisition delays.

- *Prince Rupert Gas Transmission:* On September 27, 2016, PNW LNG received an environmental certificate from the Government of Canada for a proposed LNG plant at Prince Rupert, B.C. PNW LNG has indicated they will conduct a total project review over the coming months prior to announcing next steps for the project.
- *Coastal GasLink:* On July 11, 2016, the LNG Canada joint venture participants announced a delay to their FID for the proposed liquefied natural gas facility in Kitimat, BC. At this time a future FID date has not been determined. In light of this announcement we are working with LNG Canada to determine the appropriate pacing of the Coastal GasLink development schedule and work activities.

**Liquids Pipelines:**

- *Houston Lateral and Terminal*: In August 2016, the Houston Lateral pipeline and terminal, an extension from the Keystone Pipeline System to Houston, Texas went into service. The terminal has an initial storage capacity of 700,000 barrels of crude oil.
- *Energy East Pipeline*: On August 8, 2016, the NEB commenced the first of a series of community panel sessions held along the pipeline route in New Brunswick. Panel sessions scheduled for the week of August 29, 2016 in Montréal, Québec were subsequently canceled as three NEB panelists announced their decision to recuse themselves from continuing to sit on the panel to review the project due to allegations of reasonable apprehension of bias. The Chair of the NEB and the Vice Chair, who is also a panel member, have recused themselves of any further duties related to the project. As a result, all hearings for the project were adjourned until further notice as we wait on the federal government to appoint new NEB members and then for the NEB to establish a new panel to hear our applications. The new panel members will then determine how the review process is to be re-initiated. As a result of these actions, we expect a delay in the NEB review process.

**Energy:**

- *Bécancour Tolling Agreement:* In August 2015, we executed an agreement with Hydro Québec (HQ) allowing HQ to dispatch up to 570 MW of peak winter capacity from our Bécancour facility for a term of 20 years commencing in December 2016. The regulator in Québec, Régie de l'énergie (the Régie), initially accepted this agreement for implementation but in July 2016, the Régie reversed its initial decision. HQ continues to advocate for the contract on its economic merit as part of their strategy to meet the winter peak capacity needs of the province and is pursuing regulatory options for our agreement to be reinstated. We expect the project need and potential timing will be reassessed in the recently released review of HQ's ten year supply plan.

**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 90,300 kilometres (56,100 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 664 billion cubic feet of storage capacity. A large independent power producer, TransCanada owns or has interests in over 10,500 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.

### Forward Looking Information

This release contains certain information that is forward-looking and is subject to important risks and uncertainties (such statements are usually accompanied by words such as "anticipate", "expect", "believe", "may", "will", "should", "estimate", "intend" or other similar words). Forward-looking statements in this document are intended to provide TransCanada security holders and potential investors with information regarding TransCanada and its subsidiaries, including management's assessment of TransCanada's and its subsidiaries' future plans and financial outlook. All forward-looking statements reflect TransCanada's beliefs and assumptions based on information available at the time the statements were made and as such are not guarantees of future performance. Readers are cautioned not to place undue reliance on this forward-looking information, which is given as of the date it is expressed in this news release, and not to use future-oriented information or financial outlooks for anything other than their intended purpose. TransCanada undertakes no obligation to update or revise any forward-looking information except as required by law. For additional information on the assumptions made, and the risks and uncertainties which could cause actual results to differ from the anticipated results, refer to TransCanada's Quarterly Report to Shareholders dated November 1, 2016 and 2015 Annual Report on our website at www.transcanada.com or filed under TransCanada's profile on SEDAR at www.sedar.com and with the U.S. Securities and Exchange Commission at www.sec.gov and available on TransCanada's website at www.transcanada.com.

### Non-GAAP Measures

This news release contains references to non-GAAP measures, including comparable earnings, comparable EBITDA, comparable distributable cash flow, comparable funds generated from operations, funds generated from operations, comparable earnings per share and comparable distributable cash flow per share, that do not have any standardized meaning as prescribed by U.S. GAAP and therefore are unlikely to be comparable to similar measures presented by other companies. These non-GAAP measures are calculated on a consistent basis from period to period and are adjusted for specific items in each period, as applicable. For more information on non-GAAP measures, refer to TransCanada's Quarterly Report to Shareholders dated November 1, 2016.

### Additional Information and Where to Find it

In connection with the proposed acquisition of the outstanding common units of CPPL, CPPL will file with the SEC a proxy statement with respect to a special meeting of its unitholders to be convened to approve the transaction. The definitive proxy statement will be mailed to the unitholders of CPPL. INVESTORS ARE URGED TO READ THE PROXY STATEMENT AND ANY OTHER RELEVANT DOCUMENTS WHEN THEY BECOME AVAILABLE, BECAUSE THEY WILL CONTAIN IMPORTANT INFORMATION ABOUT THE TRANSACTION.

Investors will be able to obtain these materials, when they are available, and other documents filed with the SEC free of charge at the SEC's website, www.sec.gov. In addition, copies of the proxy statement, when available, may be obtained free of charge by accessing CPPL's website at www.columbiapipelinepartners.com or by writing CPPL at 5151 San Felipe Street, Suite 2500, Houston, Texas 77056, Attention: Corporate Secretary. Investors may also read and copy any reports, statements and other information filed by CPPL with the SEC, at the SEC public reference room at 100 F Street, N.E., Washington, D.C. 20549. Please call the SEC at 1-800-SEC-0330 or visit the SEC's website for further information on its public reference room.

### Participants in the Merger Solicitation

Columbia, an indirect wholly owned subsidiary of the Company, and certain of its directors, executive officers and other members of management and employees may be deemed to be participants in the solicitation of proxies in respect of the transaction. Information regarding Columbia's directors and executive officers is available in its Current Report on Form 8-K filed with the SEC on July 1, 2016. Other information regarding the participants in the proxy solicitation and a description of their direct and indirect interests, by security holdings or otherwise, will be contained in the proxy statement and other relevant materials to be filed with the SEC when they become available.

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# Quarterly report to shareholders

## Third quarter 2016

### Financial highlights

| (unaudited - millions of $, except per share amounts) | three months ended September 30 | | nine months ended September 30 | |
|---|---|---|---|---|
| | **2016** | **2015** | **2016** | **2015** |
| **Income** | | | | |
| Revenues | **3,632** | 2,944 | **8,886** | 8,449 |
| Net (loss)/income attributable to common shares | **(135)** | 402 | **482** | 1,218 |
| per common share - basic and diluted | **($0.17)** | $0.57 | **$0.66** | $1.72 |
| Comparable EBITDA[1] | **1,886** | 1,483 | **4,757** | 4,381 |
| Comparable earnings[1] | **622** | 440 | **1,482** | 1,302 |
| per common share[1] | **$0.78** | $0.62 | **$2.02** | $1.84 |
| | | | | |
| **Operating cash flow** | | | | |
| Net cash provided by operations | **1,183** | 1,247 | **3,277** | 2,976 |
| Comparable funds generated from operations[1] | **1,411** | 1,148 | **3,529** | 3,374 |
| Comparable distributable cash flow[1] | **1,025** | 953 | **2,701** | 2,774 |
| per common share[1] | **$1.29** | $1.34 | **$3.68** | $3.91 |
| | | | | |
| **Investing activities** | | | | |
| Capital spending - capital expenditures | **1,444** | 976 | **3,262** | 2,748 |
| - projects in development | **62** | 130 | **219** | 465 |
| Contributions to equity investments | **286** | 105 | **570** | 303 |
| Acquisitions, net of cash acquired | **12,609** | — | **13,608** | — |
| Proceeds from sale of assets, net of transaction costs | **—** | — | **6** | — |
| | | | | |
| **Dividends declared** | | | | |
| Per common share | **$0.565** | $0.52 | **$1.695** | $1.56 |
| **Basic common shares outstanding (millions)** | | | | |
| Average for the period | **797** | 709 | **734** | 709 |
| End of period | **800** | 709 | **800** | 709 |

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.

# Management's discussion and analysis

November 1, 2016

This management's discussion and analysis (MD&A) contains information to help the reader make investment decisions about TransCanada Corporation. It discusses our business, operations, financial position, risks and other factors for the three and nine months ended September 30, 2016, and should be read with the accompanying unaudited condensed consolidated financial statements for the three and nine months ended September 30, 2016 which have been prepared in accordance with U.S. GAAP. On July 1, 2016, we completed the acquisition of Columbia Pipeline Group, Inc. (Columbia). For further information on the acquisition refer to note 4 of the September 30, 2016 unaudited condensed consolidated financial statements. The three and nine months ended September 30, 2016 amounts reflect the results of Columbia post-acquisition from July 1, 2016. Comparative figures do not include Columbia.

This MD&A should also be read in conjunction with our December 31, 2015 audited consolidated financial statements and notes and the MD&A in our 2015 Annual Report.

# About this document

Throughout this MD&A, the terms, ***we, us, our*** and ***TransCanada*** mean TransCanada Corporation and its subsidiaries. Abbreviations and acronyms that are not defined in this MD&A are defined in the glossary in our 2015 Annual Report. All information is as of November 1, 2016 and all amounts are in Canadian dollars, unless noted otherwise.

### FORWARD-LOOKING INFORMATION

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

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

Forward-looking statements in this MD&A may 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 costs for planned projects, including projects under construction 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 MD&A.

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
- timing of financings and hedging
- regulatory decisions and outcomes
- termination of the Alberta PPAs
- foreign exchange rates
- 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
- acquisitions and divestitures.

**Risks and uncertainties**

- our ability to realize the anticipated benefits of 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.

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, except as required 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

We use the following non-GAAP measures:

- EBITDA
- EBIT
- funds generated from operations
- comparable funds generated from operations
- comparable distributable cash flow
- comparable distributable cash flow per common share
- comparable earnings
- comparable earnings per common share
- comparable EBITDA
- comparable EBIT
- comparable income from equity investments
- comparable interest expense
- comparable interest income and other
- comparable income tax expense.

These measures do not have any standardized meaning as prescribed by U.S. GAAP and therefore may not be comparable to similar measures presented by other entities. Please see the Reconciliation of non-GAAP measures section in this MD&A for a reconciliation of the GAAP measures to the non-GAAP measures.

### EBITDA and EBIT

We use EBITDA as an approximate measure of our pre-tax operating cash flow. It measures our earnings before deducting financial charges, income tax, depreciation and amortization, net income attributable to non-controlling interests and preferred share dividends, and includes income from equity investments. EBIT measures our earnings from ongoing operations and is a useful measure of our performance and an effective tool for evaluating trends in each segment as it is equivalent to our segmented earnings. It is calculated in the same way as EBITDA, less 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 Financial condition section for a reconciliation to net cash provided by operations.

### Comparable measures

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

| Comparable measure | Original measure |
|---|---|
| comparable earnings | net income attributable to common shares |
| comparable earnings per common share | net income per common share |
| comparable EBITDA | segmented earnings |
| comparable EBIT | segmented earnings |
| comparable funds generated from operations | cash provided by operations |
| comparable distributable cash flow | cash provided by operations |
| comparable income from equity investments | income from equity investments |
| comparable interest expense | interest expense |
| comparable interest income and other | interest income and other |
| comparable income tax expense | income tax expense |

Our decision not to include 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 rates
- gains or losses on sales of assets
- 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 ongoing maintenance and liquidation costs
- acquisition costs.

We calculate comparable earnings by excluding 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 distributable cash flow**

Comparable distributable cash flow is defined as comparable funds generated from operations plus distributions received from operating activities in excess of equity earnings from equity-accounted for investments 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.

We believe comparable distributable cash flow is a useful supplemental measure of performance that defines cash available to common shareholders before capital allocation. See the Financial condition section for a reconciliation to net cash provided by operations.

## Consolidated results - third quarter 2016

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 restated to reflect this change.

| | three months ended September 30 | | nine months ended September 30 | |
|---|---|---|---|---|
| (unaudited - millions of $, except per share amounts) | **2016** | **2015** | **2016** | **2015** |
| Natural Gas Pipelines | **753** | 522 | **1,952** | 1,627 |
| Liquids Pipelines | **187** | 284 | **609** | 773 |
| Energy | **(825)** | 244 | **(569)** | 715 |
| Corporate | **(37)** | (31) | **(155)** | (94) |
| **Total segmented earnings** | **78** | 1,019 | **1,837** | 3,021 |
| Interest expense | **(522)** | (341) | **(1,456)** | (990) |
| Interest income and other | **122** | 16 | **440** | 83 |
| **(Loss)/Income before income taxes** | **(322)** | 694 | **821** | 2,114 |
| Income tax recovery/(expense) | **266** | (223) | **(78)** | (680) |
| **Net (loss)/income** | **(56)** | 471 | **743** | 1,434 |
| Net income attributable to non-controlling interests | **(52)** | (46) | **(184)** | (145) |
| **Net (loss)/income attributable to controlling interests** | **(108)** | 425 | **559** | 1,289 |
| Preferred share dividends | **(27)** | (23) | **(77)** | (71) |
| **Net (loss)/income attributable to common shares** | **(135)** | 402 | **482** | 1,218 |
| **Net (loss)/income per common share - basic and diluted** | **($0.17)** | $0.57 | **$0.66** | $1.72 |

Net income attributable to common shares decreased by $537 million to a net loss of $135 million for the three months ended September 30, 2016 and decreased $736 million for the nine months ended September 30, 2016 compared to the same periods in 2015. The 2016 results included:

- a $656 million after-tax impairment on the Ravenswood goodwill. As a result of information received during the process to monetize our U.S. Northeast Power business in third quarter 2016, it was determined that the fair value of Ravenswood no longer exceeds its carrying value.
- a $176 million after-tax impairment charge in first quarter on the carrying value of our Alberta PPAs as a result of our decision to terminate the PPAs
- costs associated with the acquisition of Columbia including an after-tax charge of $67 million in third quarter, primarily relating to retention, severance and integration expenses, and $206 million year-to-date which included $109 million related to the dividend equivalent payments on the subscription receipts issued as part of the permanent financing of the transaction, $36 million related to acquisition costs and $6 million related to interest earned on the subscription receipt funds held in escrow
- $28 million of income tax recoveries in third quarter related to the realized loss on a third party sale of Keystone XL project assets. A provision for the expected loss on these assets was included in our fourth quarter 2015 impairment charge, but the related income tax recoveries could not be recorded until realized
- an after-tax charge of $9 million in third quarter and $24 million year-to-date 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 charge of $10 million year-to-date for restructuring charges mainly related to 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
- $3 million of after-tax costs related to the monetization of our U.S. Northeast Power business

- an additional $3 million after-tax loss on the sale of TC Offshore which closed on March 31, 2016.

The 2015 results included:

- an after-tax charge of $6 million in third quarter and $14 million year-to-date for severance costs primarily as a result of the restructuring of our major projects group in response to delayed timelines on certain of our major projects, along with a continued focus on enhancing the efficiency and effectiveness of our operations
- a $34 million adjustment to income tax expense due to the enactment of a two per cent increase in the Alberta corporate income tax rate in June 2015.

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 $182 million and $180 million for the three and nine months ended September 30, 2016 compared to the same periods in 2015 as discussed below in the reconciliation of net income to comparable earnings.

## RECONCILIATION OF NET INCOME TO COMPARABLE EARNINGS

| | three months ended September 30 | | nine months ended September 30 | |
|---|---|---|---|---|
| (unaudited - millions of $, except per share amounts) | **2016** | **2015** | **2016** | **2015** |
| **Net (loss)/income attributable to common shares** | **(135)** | 402 | **482** | 1,218 |
| **Specific items (net of tax):** | | | | |
| Ravenswood goodwill impairment | **656** | — | **656** | — |
| Alberta PPA terminations | **—** | — | **176** | — |
| Acquisition related costs - Columbia | **67** | — | **206** | — |
| Keystone XL income tax recoveries | **(28)** | — | **(28)** | — |
| Keystone XL asset costs | **9** | — | **24** | — |
| Restructuring costs | **—** | 6 | **10** | 14 |
| TC Offshore loss on sale | **—** | — | **3** | — |
| U.S. Northeast Power business monetization | **3** | — | **3** | — |
| Alberta corporate income tax rate increase | **—** | — | **—** | 34 |
| Risk management activities[1] | **50** | 32 | **(50)** | 36 |
| **Comparable earnings** | **622** | 440 | **1,482** | 1,302 |
| | | | | |
| **Net (loss)/income per common share** | **($0.17)** | $0.57 | **$0.66** | $1.72 |
| **Specific items (net of tax):** | | | | |
| Ravenswood goodwill impairment | **0.82** | — | **0.89** | — |
| Alberta PPA terminations | **—** | — | **0.25** | — |
| Acquisition related costs - Columbia | **0.09** | — | **0.29** | — |
| Keystone XL income tax recoveries | **(0.03)** | — | **(0.04)** | — |
| Keystone XL asset costs | **0.01** | — | **0.03** | — |
| Restructuring costs | **—** | 0.01 | **0.01** | 0.02 |
| U.S. Northeast Power business monetization | **—** | — | **—** | — |
| Alberta corporate income tax rate increase | **—** | — | **—** | 0.05 |
| Risk management activities | **0.06** | 0.04 | **(0.07)** | 0.05 |
| **Comparable earnings per share** | **$0.78** | $0.62 | **$2.02** | $1.84 |

1

| **Risk management activities** (unaudited - millions of $) | **three months ended September 30** | | **nine months ended September 30** | |
|---|---|---|---|---|
| | **2016** | **2015** | **2016** | **2015** |
| Canadian Power | **(4)** | (14) | **3** | (7) |
| U.S. Power | **(73)** | (5) | **16** | (22) |
| Liquids marketing | **(8)** | — | **(6)** | — |
| Natural Gas Storage | **4** | 2 | **9** | 2 |
| Foreign exchange | **—** | (26) | **49** | (25) |
| Income tax attributable to risk management activities | **31** | 11 | **(21)** | 16 |
| **Total unrealized (losses)/gains from risk management activities** | **(50)** | (32) | **50** | (36) |

Comparable earnings increased by $182 million for the three months ended September 30, 2016 compared to the same period in 2015. This was primarily the net effect of:

- higher earnings from U.S. Pipelines due to incremental earnings from Columbia following the July 1, 2016 acquisition and higher ANR transportation and storage revenue resulting from higher rates effective August 1, 2016
- higher interest expense from debt issuances and lower capitalized interest
- lower earnings from Liquids Pipelines due to higher contracted and lower uncontracted volumes on Keystone Pipeline and lower volumes on Marketlink
- higher contribution from Mexican pipelines primarily due to earnings from Topolobampo beginning in July 2016
- higher interest income and other due to 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
- higher earnings from U.S. Power mainly due to incremental earnings from the Ironwood power plant acquired in February 2016 and higher sales to customers in the PJM market, offset by lower capacity revenues in New York
- higher earnings from Bruce Power mainly due to lower depreciation and our increased ownership interest, partially offset by higher losses from contracting activities
- higher earnings from Canadian Pipelines primarily due to a higher NGTL investment base and incentive earnings from Canadian Mainline and NGTL.

Comparable earnings increased by $180 million for the nine months ended September 30, 2016 compared to the same period in 2015. This was primarily the net effect of:

- higher earnings from our U.S. Pipelines due to incremental earnings from Columbia following the July 1, 2016 acquisition, higher ANR transportation and storage revenue resulting from higher rates effective August 1, 2016, higher ANR Southeast Mainline transportation revenues and lower OM&A expenses
- higher interest expense from debt issuances and lower capitalized interest
- higher interest income and other due to increased AFUDC related to our rate-regulated projects and 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
- lower earnings from Liquids Pipelines due to higher contracted and lower uncontracted volumes on Keystone Pipeline and lower volumes on Marketlink

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 long-term 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 as of September 30, 2016, consists of $25 billion of near-term projects and $48 billion of commercially secured medium- to longer-term projects. Amounts presented exclude maintenance capital expenditures, capitalized interest and AFUDC.

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

### Near-term projects

| **at September 30, 2016**<br>(unaudited - billions of $) | **Segment** | **Expected in-service date** | **Estimated project cost** | **Carrying value** |
|---|---|---|---|---|
| Topolobampo[1] | Natural Gas Pipelines | 2017 | US 1.0 | US 0.9 |
| Mazatlán | Natural Gas Pipelines | 2016 | US 0.4 | US 0.3 |
| Canadian Mainline | Natural Gas Pipelines | 2016-2017 | 0.7 | 0.4 |
| NGTL - 2016/17 Facilities | Natural Gas Pipelines | 2016-2020 | 2.7 | 0.8 |
| - North Montney | Natural Gas Pipelines | 2017+[2] | 1.7 | 0.3 |
| - 2018 Facilities | Natural Gas Pipelines | 2018-2020 | 0.6 | — |
| - Other | Natural Gas Pipelines | 2016-2018 | 0.4 | — |
| Grand Rapids[3] | Liquids Pipelines | 2017 | 0.9 | 0.8 |
| Northern Courier | Liquids Pipelines | 2017 | 1.0 | 0.8 |
| Tula | Natural Gas Pipelines | 2017 | US 0.5 | US 0.2 |
| Columbia - Leach XPress | Natural Gas Pipelines | 2017 | US 1.4 | US 0.3 |
| - Rayne XPress | Natural Gas Pipelines | 2017 | US 0.4 | US 0.2 |
| - Gibraltar | Natural Gas Pipelines | 2017 | US 0.3 | US 0.2 |
| - Modernization I | Natural Gas Pipelines | 2016-2017 | US 0.6 | US 0.3 |
| - Cameron Access | Natural Gas Pipelines | 2018 | US 0.3 | US 0.1 |
| - WB XPress | Natural Gas Pipelines | 2018 | US 0.9 | US 0.2 |
| - Mountaineer XPress | Natural Gas Pipelines | 2018 | US 2.0 | US 0.1 |
| - Gulf XPress | Natural Gas Pipelines | 2018 | US 0.7 | — |
| - Modernization II | Natural Gas Pipelines | 2018-2020 | US 1.1 | — |
| Napanee | Energy | 2018 | 1.1 | 0.5 |
| Villa de Reyes | Natural Gas Pipelines | 2018 | US 0.6 | US 0.1 |
| Sur de Texas[3] | Natural Gas Pipelines | 2018 | US 1.3 | — |
| Bruce Power - life extension[3] | Energy | 2016-2020 | 1.2 | 0.1 |
| | | | **21.8** | **6.6** |
| Foreign exchange impact on near-term projects[4] | | | **3.6** | **0.9** |
| **Total near-term projects CAD** | | | **25.4** | **7.5** |

1 CFE has recognized that a force majeure has delayed construction and revenue has been recorded in third quarter 2016 as per terms of the Transportation Service Agreement (TSA). See the Recent developments section for more information.

2 In-service date is dependent on a positive final investment decision.

3 Our proportionate share.

4 Reflects U.S./Canada foreign exchange rate of $1.31 at September 30, 2016.

### Medium to longer-term projects

| at September 30, 2016<br>(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 | Natural Gas Pipelines | 2.0 | 0.1 |
| **BC west coast LNG-related projects** | | | |
| Coastal GasLink | Natural Gas Pipelines | 4.8 | 0.4 |
| Prince Rupert Gas Transmission | Natural Gas Pipelines | 5.0 | 0.5 |
| NGTL System - Merrick | Natural Gas Pipelines | 1.9 | — |
| | | 45.2 | 2.3 |
| Foreign exchange impact on medium to longer-term projects[4] | | 2.7 | 0.1 |
| **Total medium to longer-term projects** | | **47.9** | **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 $1.31 at September 30, 2016.

## Outlook

Our overall comparable earnings outlook for 2016 will be higher than what was previously included in the 2015 Annual Report due to the net impact of the acquisition of Columbia on July 1, 2016, increased earnings from the remainder of our Natural Gas Pipelines' assets, changes in our Canadian Power business and lower than expected Liquids and U.S. Power earnings, each of which are addressed within the relevant section of the MD&A.

### Consolidated capital spending, equity investments and acquisition

Our expected total capital expenditures as outlined in the 2015 Annual Report remains unchanged.

On April 11, 2016, we announced that we were chosen to build, own and operate the Villa de Reyes pipeline in Mexico. On June 13, 2016, we announced that our joint venture with IEnova, Infraestructura Marina del Golfo (IMG), was chosen to build, own and operate the Sur de Texas natural gas pipeline in Mexico. On July 1, 2016, we acquired Columbia. Although we expect to defer capital expenditures on several of our other natural gas pipelines projects, we expect to spend an estimated additional $1 billion on Columbia capital projects in 2016, approximately $300 million on the Villa de Reyes pipeline project and $200 million on the Sur de Texas pipeline project.

## 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 restated to reflect this change. In addition, Columbia results are included in the Natural Gas Pipelines segment from its acquisition on July 1, 2016. Comparative periods do not include Columbia.

| | three months ended September 30 | | nine months ended September 30 | |
|---|---|---|---|---|
| (unaudited - millions of $) | **2016** | **2015** | **2016** | **2015** |
| Comparable EBITDA | **1,196** | 806 | **2,974** | 2,472 |
| Depreciation and amortization | **(361)** | (284) | **(936)** | (845) |
| **Comparable EBIT** | **835** | 522 | **2,038** | 1,627 |
| Specific items: | | | | |
| Acquisition related costs - Columbia | **(82)** | — | **(82)** | — |
| TC Offshore loss on sale | **—** | — | **(4)** | — |
| **Segmented earnings** | **753** | 522 | **1,952** | 1,627 |

Natural Gas Pipelines segmented earnings increased by $231 million and $325 million for the three and nine months ended September 30, 2016 compared to the same periods in 2015. Segmented earnings for the three and nine months ended September 30, 2016 included $82 million primarily related to retention and severance expenses incurred within the Natural Gas Pipelines segment resulting from the Columbia acquisition. Year-to-date 2016 segmented earnings also included an additional $4 million pre-tax loss on the sale of TC Offshore. These amounts have been excluded from our calculation of comparable EBIT. The remainder of the Natural Gas Pipelines segmented earnings are equivalent to comparable EBIT, which, along with comparable EBITDA, are discussed below.

| (unaudited - millions of $) | three months ended September 30 | | nine months ended September 30 | |
|---|---|---|---|---|
| | **2016** | **2015** | **2016** | **2015** |
| **Canadian Pipelines** | | | | |
| Canadian Mainline | **285** | 286 | **825** | 866 |
| NGTL System | **253** | 223 | **736** | 666 |
| Foothills | **24** | 26 | **76** | 79 |
| Other Canadian pipelines[1] | **7** | 7 | **20** | 21 |
| **Canadian Pipelines - comparable EBITDA** | **569** | 542 | **1,657** | 1,632 |
| Depreciation and amortization | **(219)** | (212) | **(653)** | (632) |
| **Canadian Pipelines - comparable EBIT** | **350** | 330 | **1,004** | 1,000 |
| **U.S. and International Pipelines** (US$) | | | | |
| Columbia[2] | **174** | — | **174** | — |
| ANR | **76** | 52 | **235** | 171 |
| TC PipeLines, LP[1,3] | **32** | 25 | **90** | 76 |
| Great Lakes[3,4] | **11** | 8 | **47** | 35 |
| Other U.S. pipelines (Iroquois[1], GTN[3,5], PNGTS[3,6]) | **10** | 13 | **33** | 65 |
| Mexico | **82** | 44 | **165** | 138 |
| International and other[1,7] | **(6)** | (2) | **(2)** | 2 |
| Non-controlling interests[8] | **94** | 68 | **264** | 208 |
| **U.S. and International Pipelines - comparable EBITDA** | **473** | 208 | **1,006** | 695 |
| Depreciation and amortization | **(107)** | (55) | **(214)** | (169) |
| **U.S. and International Pipelines - comparable EBIT** | **366** | 153 | **792** | 526 |
| Foreign exchange impact | **121** | 48 | **254** | 136 |
| **U.S. and International Pipelines - comparable EBIT** (Cdn$) | **487** | 201 | **1,046** | 662 |
| **Business Development comparable EBITDA and EBIT** | **(2)** | (9) | **(12)** | (35) |
| **Natural Gas Pipelines - comparable EBIT** | **835** | 522 | **2,038** | 1,627 |

1 Results from TQM, Northern Border, Iroquois and TransGas reflect our share of equity income from these investments. On March 31, 2016, we closed the acquisition of an additional 4.87 per cent interest in Iroquois and an additional 0.65 per cent interest was acquired on May 1, 2016.

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

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

| | ownership percentage as of | | | | |
|---|---|---|---|---|---|
| | **September 30, 2016** | **June 30, 2016** | **March 31, 2016** | **January 1, 2016** | **April 1, 2015** |
| TCLP | 27.1 | 27.4 | 27.9 | 28.0 | 28.3 |
| Effective ownership through TCLP: | | | | | |
| GTN | 27.1 | 27.4 | 27.9 | 28.0 | 28.3 |
| Great Lakes | 12.6 | 12.7 | 13.0 | 13.0 | 13.1 |
| PNGTS | 13.5 | 13.7 | 13.9 | 14.0 | — |

4 Represents our 53.6 per cent direct ownership interest. The remaining 46.4 per cent is held by TCLP.

5 Represents our 30 per cent direct ownership interest until April 1, 2015 at which point the 30 per cent interest was sold to TCLP.

6 Represents our 61.7 per cent ownership interest in 2015 and 11.8 per cent effective January 1, 2016 as a result of the sale of 49.9 per cent interest to TCLP.

[7] Includes our share of equity income from TransGas as well as general and administration costs relating to our U.S. and International Pipelines.
[8] Comparable EBITDA for the portions of TCLP, PNGTS and Columbia Pipeline Partners LP that we do not own.

## CANADIAN PIPELINES

Net income and comparable EBITDA for our rate-regulated Canadian 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 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 PIPELINES

| | three months ended September 30 | | nine months ended September 30 | |
|---|---|---|---|---|
| (unaudited - millions of $) | **2016** | 2015 | **2016** | 2015 |
| Canadian Mainline | **52** | 47 | **154** | 161 |
| NGTL System | **81** | 70 | **233** | 200 |
| Foothills | **4** | 3 | **11** | 11 |

Net income for the Canadian Mainline increased by $5 million for the three months ended September 30, 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. Net Income for the Canadian Mainline decreased by $7 million for the nine months ended September 30, 2016 compared to the same period in 2015 due to a lower average investment base and higher carrying charges, partially offset by higher incentive earnings in 2016.

Net income for the NGTL System increased by $11 million and $33 million for the three and nine months ended September 30, 2016 compared to the same periods in 2015 mainly due to a higher average investment base and OM&A incentive earnings recorded in 2016.

## U.S. AND INTERNATIONAL PIPELINES

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.

The results for Columbia include our 91.6 per cent effective ownership of Columbia Gas Transmission, Columbia Gulf Transmission, Columbia Midstream and Columbia Energy Ventures through a 84.3 per cent direct ownership and our 46.5 per cent ownership in Columbia Pipeline Partners LP which owns the remaining 15.7 per cent ownership interest in these assets.

Comparable EBITDA for U.S. and International Pipelines increased by US$265 million and US$311 million for the three and nine months ended September 30, 2016 compared to the same periods in 2015. This was the net effect of:

- US$174 million of contributions from Columbia as a result of the acquisition on July 1, 2016
- higher contribution from Mexican pipelines primarily due to incremental earnings from Topolobampo. The Topolobampo project has experienced a delay in construction, which, under the terms of the TSA, constitutes a force majeure and, as a result, we began realizing revenue in July 2016.
- higher ANR transportation and storage revenue resulting from higher rates as part of our rates settlement effective August 1, 2016, higher ANR Southeast Mainline transportation revenues and lower OM&A expenses, offset by a first quarter 2015 non-recurring settlement with a producer
- higher transportation revenues from Great Lakes
- higher contribution from TC PipeLines, LP.

As well, a stronger U.S. dollar on a year-to-date basis in 2016 compared to 2015 had a positive impact on the Canadian dollar equivalent comparable earnings from our U.S. and International operations.

### DEPRECIATION AND AMORTIZATION

Depreciation and amortization increased by $77 million and $91 million for the three and nine months ended September 30, 2016 compared to the same periods in 2015 mainly due to the Columbia acquisition on July 1, 2016, a higher investment base on the NGTL System, increased depreciation rates on ANR following the rate settlement, and the effect of a stronger U.S. dollar.

### BUSINESS DEVELOPMENT

Business development expenses were lower by $7 million and $23 million for the three and nine months ended September 30, 2016 compared to the same periods in 2015 mainly due to the capitalization of business development activities in 2016 related to the successful Mexico projects, a focus on the Columbia acquisition and decreased business development activity in other areas in 2016.

### OUTLOOK

The 2016 earnings outlook for the Canadian regulated and Mexican pipelines remains consistent with what we disclosed in the 2015 Annual Report. We are expecting an increase in 2016 earnings from U.S. Pipelines as a result of the acquisition of Columbia on July 1, 2016 although the impact of the related financing will be reflected in our Corporate segment. Earnings for the other U.S. Pipelines are expected to be slightly higher this year as a result of higher revenues and lower costs.

### OPERATING STATISTICS - WHOLLY OWNED PIPELINES

| **nine months ended September 30** | **Canadian Mainline[1]** | | **NGTL System[2]** | | **ANR[3]** | |
|---|---|---|---|---|---|---|
| (unaudited) | **2016** | **2015** | **2016** | **2015** | **2016** | **2015** |
| Average investment base (millions of $) | **4,423** | 4,840 | **7,401** | 6,599 | **n/a** | n/a |
| Delivery volumes (Bcf): | | | | | | |
| Total | **1,217** | 1,204 | **2,978** | 2,871 | **1,190** | 1,212 |
| Average per day | **4.4** | 4.4 | **10.9** | 10.5 | **4.3** | 4.4 |

1 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 nine months ended September 30, 2016 were 802 Bcf (2015 – 833 Bcf). Average per day was 2.9 Bcf (2015 – 3.1 Bcf).

2 Field receipt volumes for the NGTL System for the nine months ended September 30, 2016 were 3,080 Bcf (2015 – 2,994 Bcf). Average per day was 11.2 Bcf (2015 – 11.0 Bcf).

3 Under its current rates, which are approved by the FERC, changes in average investment base do not affect results.

## 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 restated to reflect this change.

| | three months ended September 30 | | nine months ended September 30 | |
|---|---|---|---|---|
| (unaudited - millions of $) | **2016** | 2015 | **2016** | 2015 |
| Comparable EBITDA | **281** | 352 | **861** | 970 |
| Depreciation and amortization | **(72)** | (68) | **(209)** | (197) |
| **Comparable EBIT** | **209** | 284 | **652** | 773 |
| Specific items: | | | | |
| Keystone XL asset costs | **(14)** | — | **(37)** | — |
| Risk management activities | **(8)** | — | **(6)** | — |
| **Segmented earnings** | **187** | 284 | **609** | 773 |

Liquids Pipelines segmented earnings decreased by $97 million and $164 million for the three and nine months ended September 30, 2016 compared to the same periods 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. These amounts have been excluded from our calculation of comparable EBIT. The remainder of the Liquids Pipelines segmented earnings are equivalent to comparable EBIT, which, along with comparable EBITDA, are discussed below.

| | three months ended September 30 | | nine months ended September 30 | |
|---|---|---|---|---|
| (unaudited - millions of $) | **2016** | 2015 | **2016** | 2015 |
| Keystone Pipeline System | **284** | 360 | **870** | 988 |
| Liquids Pipelines Business Development and Other | **(3)** | (8) | **(9)** | (18) |
| **Liquids Pipelines - comparable EBITDA** | **281** | 352 | **861** | 970 |
| Depreciation and amortization | **(72)** | (68) | **(209)** | (197) |
| **Liquids Pipelines - comparable EBIT** | **209** | 284 | **652** | 773 |
| | | | | |
| **Comparable EBIT denominated as follows:** | | | | |
| Canadian dollars | **52** | 57 | **164** | 172 |
| U.S. dollars | **119** | 171 | **369** | 474 |
| Foreign exchange impact | **38** | 56 | **119** | 127 |
| | **209** | 284 | **652** | 773 |

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 the Keystone Pipeline System decreased by $76 million and $118 million for the three and nine months ended September 30, 2016 compared to the same periods in 2015 and was due to the net effect of lower uncontracted volumes on Keystone Pipeline and lower volumes on Marketlink, partially offset by higher contracted volumes on Keystone Pipeline.

### BUSINESS DEVELOPMENT AND OTHER

Business development and other, which primarily includes business development activity and our marketing business, decreased by $5 million and $9 million for the three and nine months ended September 30, 2016 compared to the same periods in 2015 and was the effect of lower business development spending and a growing contribution from the marketing business.

### DEPRECIATION AND AMORTIZATION

Depreciation and amortization increased by $4 million and $12 million for the three and nine months ended September 30, 2016 compared to the same periods in 2015 as a result of new facilities being placed in service and the effect of a stronger U.S. dollar.

### OUTLOOK

Excluding specified items, our 2016 earnings are expected to be lower than our 2015 earnings due to lower uncontracted volumes and market conditions related to the lower crude oil price environment.

Following our Keystone XL impairment charge in 2015, expenditures on the project for the maintenance and liquidation of project assets are being expensed pending further advancement of this project and are expected to be approximately $55 million before tax ($36 million after tax) in 2016. These costs will continue to be excluded from comparable earnings.

## 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 restated to reflect this change.

| | three months ended September 30 | | nine months ended September 30 | |
|---|---|---|---|---|
| (unaudited - millions of $) | **2016** | 2015 | **2016** | 2015 |
| **Comparable EBITDA** | **419** | 340 | **984** | 990 |
| Depreciation and amortization | **(81)** | (79) | **(251)** | (248) |
| **Comparable EBIT** | **338** | 261 | **733** | 742 |
| Specific items: | | | | |
| Ravenswood goodwill impairment | **(1,085)** | — | **(1,085)** | — |
| Alberta PPA terminations | **—** | — | **(240)** | — |
| U.S. Northeast Power business monetization | **(5)** | — | **(5)** | — |
| Risk management activities | **(73)** | (17) | **28** | (27) |
| **Segmented (losses)/earnings** | **(825)** | 244 | **(569)** | 715 |

Energy segmented earnings decreased by $1,069 million and $1,284 million to segmented losses of $825 million and $569 million for the three and nine months ended September 30, 2016 compared to the same periods in 2015 and included the following specific items that have been excluded from comparable EBIT:

- a $1,085 million pre-tax impairment charge on the Ravenswood goodwill. As a result of information received during the process to monetize our U.S. Northeast Power business in third quarter 2016, it was determined that the fair value of Ravenswood no longer exceeds its carrying value.
- a $240 million pre-tax charge, which included a $29 million impairment of our equity investment in ASTC Power Partnership, on the carrying value of our Alberta PPAs as a result of our decision to terminate the PPAs in March 2016
- $5 million of pre-tax costs related to the process of monetizing our U.S. Northeast Power business
- 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 September 30 | | nine months ended September 30 | |
|---|---|---|---|---|
| (unaudited - millions of $, pre-tax) | **2016** | 2015 | **2016** | 2015 |
| Canadian Power | **(4)** | (14) | **3** | (7) |
| U.S. Power | **(73)** | (5) | **16** | (22) |
| Natural Gas Storage | **4** | 2 | **9** | 2 |
| **Total unrealized (losses)/gains from risk management activities** | **(73)** | (17) | **28** | (27) |

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 sell 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, has contributed to higher volatility in U.S. Power risk management activities.

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

| | three months ended September 30 | | nine months ended September 30 | |
|---|---|---|---|---|
| (unaudited - millions of $) | **2016** | **2015** | **2016** | **2015** |
| **Canadian Power** | | | | |
| Western Power[1] | **26** | 24 | **49** | 73 |
| Eastern Power | **82** | 86 | **270** | 306 |
| Bruce Power | **76** | 57 | **210** | 202 |
| **Canadian Power - comparable EBITDA**[1,2] | **184** | 167 | **529** | 581 |
| Depreciation and amortization | **(35)** | (47) | **(117)** | (141) |
| **Canadian Power - comparable EBIT**[1,2] | **149** | 120 | **412** | 440 |
| **U.S. Power** (US$) | | | | |
| **U.S. Power - comparable EBITDA** | **164** | 140 | **323** | 335 |
| Depreciation and amortization | **(33)** | (23) | **(95)** | (78) |
| **U.S. Power - comparable EBIT** | **131** | 117 | **228** | 257 |
| Foreign exchange impact | **44** | 36 | **74** | 68 |
| **U.S. Power - comparable EBIT** (Cdn$) | **175** | 153 | **302** | 325 |
| **Natural Gas Storage and other - comparable EBITDA** | **20** | (1) | **39** | 8 |
| Depreciation and amortization | **(3)** | (3) | **(9)** | (9) |
| **Natural Gas Storage and other - comparable EBIT** | **17** | (4) | **30** | (1) |
| **Business Development comparable EBITDA and EBIT** | **(3)** | (8) | **(11)** | (22) |
| **Energy - comparable EBIT**[1,2] | **338** | 261 | **733** | 742 |

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.

Comparable EBITDA for Energy increased by $79 million for the three months ended September 30, 2016 compared to the same period in 2015 due to the net effect of:

- higher earnings from U.S. Power mainly due to incremental earnings from the Ironwood power plant acquired in February 2016 and higher contributions from sales to customers in the PJM market, offset by lower capacity revenues in New York
- higher earnings from Natural Gas Storage due to higher realized natural gas storage price spreads
- higher earnings from Bruce Power mainly due to lower depreciation and our increased ownership interest, partially offset by higher losses from contracting activities.

Comparable EBITDA for Energy decreased by $6 million for the nine months ended September 30, 2016 compared to the same period in 2015 due to the net effect of:

- lower earnings from Eastern Power due to lower contributions from the sales of unused natural gas transportation and lower contractual earnings at Bécancour
- higher earnings from Natural Gas Storage due to higher realized natural gas storage price spreads

- lower earnings from Western Power as a result of lower realized power prices and termination of the PPAs
- higher earnings from Bruce Power mainly due to lower depreciation and our increased ownership interest, partially offset by lower volumes and higher operating costs from higher planned outage days.

## CANADIAN POWER

### Western and Eastern Power

| | three months ended September 30 | | nine months ended September 30 | |
|---|---|---|---|---|
| (unaudited - millions of $) | **2016** | 2015 | **2016** | 2015 |
| **Revenue**[1] | | | | |
| Western Power | **39** | 126 | **170** | 412 |
| Eastern Power | **112** | 119 | **315** | 358 |
| Other[2] | **2** | 1 | **31** | 49 |
| | **153** | 246 | **516** | 819 |
| Comparable income from equity investments[3] | **9** | (2) | **16** | 13 |
| Commodity purchases resold | **(1)** | (83) | **(60)** | (266) |
| Plant operating costs and other | **(57)** | (65) | **(150)** | (194) |
| Exclude risk management activities[1] | **4** | 14 | **(3)** | 7 |
| **Comparable EBITDA**[4] | **108** | 110 | **319** | 379 |
| Depreciation and amortization | **(35)** | (47) | **(117)** | (141) |
| **Comparable EBIT**[4] | **73** | 63 | **202** | 238 |

| | | | | |
|---|---|---|---|---|
| **Breakdown of comparable EBITDA** | | | | |
| Western Power[4] | **26** | 24 | **49** | 73 |
| Eastern Power | **82** | 86 | **270** | 306 |
| **Comparable EBITDA**[4] | **108** | 110 | **319** | 379 |

1 The realized and unrealized gains and losses from financial derivatives used to manage Canadian Power's assets are presented on a net basis in Western and Eastern Power revenues. The unrealized gains and losses from financial derivatives included in revenue are 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 comparable equity income from our investments in ASTC Power Partnership, which held the Sundance B PPA, and Portlands Energy. Comparable equity income does not include any gains or losses related to our risk management activities and, for the nine months ended September 30, 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.

### Sales volumes and plant availability

Includes our share of volumes from our equity investments.

| (unaudited) | three months ended September 30 2016 | 2015 | nine months ended September 30 2016 | 2015 |
|---|---|---|---|---|
| **Sales volumes (GWh)** | | | | |
| Supply | | | | |
| Generation | | | | |
| Western Power | **606** | 589 | **1,824** | 1,876 |
| Eastern Power | **1,152** | 1,083 | **2,767** | 3,145 |
| Purchased | | | | |
| Sundance A & B and Sheerness PPAs[1] | **—** | 2,734 | **1,620** | 7,226 |
| Other purchases | **21** | 281 | **409** | 677 |
| | **1,779** | 4,687 | **6,620** | 12,924 |
| **Sales** | | | | |
| Contracted | | | | |
| Western Power | **627** | 2,188 | **2,752** | 5,627 |
| Eastern Power | **1,152** | 1,083 | **2,767** | 3,145 |
| Spot | | | | |
| Western Power | **—** | 1,416 | **1,101** | 4,152 |
| | **1,779** | 4,687 | **6,620** | 12,924 |
| **Plant availability**[2] | | | | |
| Western Power[3] | **94%** | 96% | **92%** | 97% |
| Eastern Power[4] | **96%** | 96% | **93%** | 97% |

1 Includes volumes from Sundance A and Sheerness PPAs and our 50 per cent ownership interest of the Sundance B PPA held through the ASTC Power Partnership up to March 7, 2016.
2 The percentage of time the plant was available to generate power, regardless of whether it was running.
3 Does not include facilities that provided power to us under PPAs.
4 Does not include Bécancour because power generation remains suspended.

### Western Power

Comparable EBITDA for Western Power increased by $2 million for the three months ended September 30, 2016 compared to the same period in 2015 mainly due to higher realized prices on generated volumes offset by lower earnings following the termination of the PPAs.

Comparable EBITDA for Western Power decreased by $24 million for the nine months ended September 30, 2016 compared to the same period in 2015 due to lower realized power prices and termination of the 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. Comparable income from equity investments included earnings from the ASTC Power Partnership which held our 50 per cent ownership in the Sundance B PPA. See the Recent developments section for more information on the PPA terminations.

Average spot market power prices in Alberta decreased 31 per cent from $26/MWh to $18/MWh for the three months ended September 30, 2016 and decreased 54 per cent from $37/MWh to $17/MWh for the nine months ended September 30, 2016 compared to the same periods in 2015. The Alberta power market remained well-supplied and power consumption was down due to a weak economy. Realized power prices on power sales can be higher or lower than spot market power prices in any given period as a result of contracting activities.

One hundred per cent of Western Power sales volumes were sold under contract in third quarter 2016 compared to 61 per cent in third quarter 2015.

Depreciation and amortization decreased by $12 million and $24 million for the three and nine months ended September 30, 2016 compared to the same periods in 2015 following the termination of the PPAs.

We continue to expect Western Power 2016 earnings to be consistent with 2015 earnings. Although Alberta power prices are expected to remain low in the remaining months of 2016, the natural gas-fired cogeneration assets are expected to perform well in the lower natural gas price environment and the March 2016 decision to exercise the right to terminate the PPAs is expected to result in savings from the otherwise increased costs related to carbon emissions.

### Eastern Power

Comparable EBITDA for Eastern Power decreased by $4 million and $36 million for the three and nine months ended September 30, 2016 compared to the same period in 2015 mainly due to lower contractual earnings at Bécancour, and lower earnings on the sale of unused natural gas transportation for the nine months ended September 30, 2016 compared to the same period in 2015.

Our 2016 earnings outlook provided in the 2015 Annual Report will be modestly lower as a result of a delay in the implementation of amendments to the Bécancour electricity supply contract. See the Recent developments section for more information about this agreement.

## 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.

| | three months ended September 30 | | nine months ended September 30 | |
|---|---|---|---|---|
| (unaudited - millions of $, unless noted otherwise) | **2016** | **2015** | **2016** | **2015** |
| **Income from equity investments**[1] | **76** | 57 | **210** | 202 |
| Comprised of: | | | | |
| Revenues | **365** | 298 | **1,094** | 945 |
| Operating expenses | **(204)** | (159) | **(643)** | (498) |
| Depreciation and other | **(85)** | (82) | **(241)** | (245) |
| | **76** | 57 | **210** | 202 |
| **Bruce Power - Other information** | | | | |
| Plant availability[2] | **88%** | 86% | **82%** | 85% |
| Planned outage days | **50** | 88 | **335** | 287 |
| Unplanned outage days | **37** | 8 | **49** | 30 |
| Sales volumes (GWh)[1] | **5,886** | 4,621 | **16,420** | 13,970 |
| Realized sales price per MWh[3,4] | **$66** | $64 | **$66** | $66 |

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.

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.

4 Excludes unrealized gains and losses on contracting activities and revenues from cobalt sales.

Equity income from Bruce Power increased by $19 million and $8 million for the three and nine months ended September 30, 2016 compared to the same periods in 2015 mainly due to lower depreciation as a result of the Bruce Power facility's operating life extension and our increased ownership interest. These increases were partially offset by higher losses from contracting activities in the three months ended September 30, 2016 and lower volumes and higher operating costs from higher planned outage days for the nine months ended September 30, 2016 compared to the same periods 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 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 contract price[1] | per MWh |
|---|---|
| January 1, 2016 - March 31, 2016 | $65.73 |
| April 1, 2016 - March 31, 2017 | $66.38 |

1 Includes fuel and lease expenses recovery on a flow-through basis estimated at approximately $8.00 per MWh.

Prior to the amended agreement with the IESO, all of the output from Bruce units 1 to 4 was sold at a fixed price/MWh which was adjusted annually on April 1 for inflation and other provisions under the contract.

| Bruce Units 1 to 4 contract price[1] | per MWh |
|---|---|
| April 1, 2014 - March 31, 2015 | $76.70 |
| April 1, 2015 - December 31, 2015 | $78.42 |

1 Includes fuel expense recovery on a flow-through basis estimated at approximately $5.00 per MWh.

Prior to the amended agreement with the IESO, all output from Bruce units 5 to 8 was subject to a floor price adjusted annually for inflation on April 1.

| Bruce Units 5 to 8 floor price | per MWh |
|---|---|
| April 1, 2014 - March 31, 2015 | $52.86 |
| April 1, 2015 - December 31, 2015 | $54.13 |

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.

During second quarter 2016, Bruce units 1 to 4 were removed from service for approximately three weeks to facilitate a station containment outage. The station containment outage involved inspecting and maintaining key safety systems including containment structures and is required to be completed approximately once every decade. Additional planned maintenance was completed on unit 3 in third quarter 2016. Planned maintenance on unit 7 began in third quarter 2016 and is scheduled to be completed in fourth quarter 2016. The overall average plant availability percentage in 2016 is expected to be in the low 80s.

We expect 2016 equity income from Bruce Power to be slightly higher than our 2016 Outlook in the 2015 Annual Report primarily due to strong results year-to-date.

# U.S. POWER

| (unaudited - millions of US$) | three months ended September 30 2016 | 2015 | nine months ended September 30 2016 | 2015 |
|---|---|---|---|---|
| **Revenue**[1] | | | | |
| Power[2] | **764** | 568 | **1,666** | 1,552 |
| Capacity | **84** | 99 | **223** | 254 |
| | **848** | 667 | **1,889** | 1,806 |
| Commodity purchases resold | **(594)** | (412) | **(1,188)** | (1,159) |
| Plant operating costs and other[3] | **(147)** | (119) | **(362)** | (329) |
| Exclude risk management activities[2] | **57** | 4 | **(16)** | 17 |
| **Comparable EBITDA**[1] | **164** | 140 | **323** | 335 |
| Depreciation and amortization | **(33)** | (23) | **(95)** | (78) |
| **Comparable EBIT**[1] | **131** | 117 | **228** | 257 |

1 Includes Ironwood acquisition commencing February 1, 2016.

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

3 Includes the cost of fuel consumed in generation.

## Sales volumes and plant availability

| (unaudited) | three months ended September 30 2016 | 2015 | nine months ended September 30 2016 | 2015 |
|---|---|---|---|---|
| **Physical sales volumes (GWh)** | | | | |
| Supply | | | | |
| Generation[1] | **4,387** | 2,707 | **10,043** | 5,756 |
| Purchased | **9,924** | 6,919 | **19,734** | 15,800 |
| | **14,311** | 9,626 | **29,777** | 21,556 |
| **Plant availability**[2,3] | **97%** | 93% | **85%** | 77% |

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.

3 Plant availability was lower in the nine months ended September 30, 2015 compared to the same period in 2016 due to an unplanned outage at the Ravenswood facility from September 2014 to May 2015.

## U.S. Power - other information

| (unaudited) | three months ended September 30 2016 | 2015 | nine months ended September 30 2016 | 2015 |
|---|---|---|---|---|
| **Average Spot Power Prices (US$ per MWh)** | | | | |
| New England[1] | **32** | 29 | **29** | 47 |
| New York[2] | **33** | 31 | **29** | 44 |
| PJM[3] | **28** | n/a | **25** | n/a |
| Average New York[2] Spot Capacity Prices (US$ per KW-M) | **12.19** | 15.27 | **9.39** | 12.18 |

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 the nine months ended September 30, 2016 is from the Ironwood acquisition date of February 1 to September 30, 2016.

Comparable EBITDA for U.S. Power increased US$24 million for the three months ended September 30, 2016 compared to the same period in 2015 primarily due to the net effect of:

- higher earnings due to our acquisition of the Ironwood power plant on February 1, 2016
- higher sales to wholesale utility customers in the PJM market
- lower capacity revenues due to lower realized capacity prices in New York and the impact of lower availability as a result of a unit outage from September 2014 to May 2015, partially offset by insurance recoveries, net of deductibles at Ravenswood.

Comparable EBITDA for U.S. Power decreased US$12 million for the nine months ended September 30, 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 and the impact of lower availability as a result of a unit outage from September 2014 to May 2015, partially offset by insurance recoveries, net of deductibles at Ravenswood
- lower margins on sales to wholesale, commercial and industrial customers partially offset by higher sales to customers in the PJM wholesale utility market
- lower realized power prices at our facilities in New York and New England, partially offset by lower fuel costs
- higher earnings due to our acquisition of the Ironwood power plant
- insurance recoveries related to an unplanned outage at the Ravenswood facility that occurred in 2008.

Higher sales to wholesale utility customers in the PJM market resulted in higher earnings for the three months ended September 30, 2016 compared to the same period in 2015 as we continue to expand our customer base in the PJM market. However, significantly lower realized power prices and mild winter weather have resulted in lower margins in our wholesale business in both the PJM and New England markets for the nine months ended September 30, 2016 compared to the same period in 2015, the impact of which was primarily seen in the first quarter results.

Wholesale electricity prices in New York and New England were slightly higher for the three months ended September 30, 2016 and significantly lower for the nine months ended September 30, 2016 compared to the same periods in 2015 primarily due to unseasonably warm weather in first quarter 2016. In New England, spot power prices for the three and nine months ended September 30, 2016 were 10 per cent higher and 38 per cent lower compared to the same periods in 2015. In New York City, spot power prices for the three and nine months ended September 30, 2016 were six per cent higher and 34 per cent lower compared to the same periods in 2015.

Average New York Zone J spot capacity prices were approximately 20 per cent and 23 per cent lower for the three and nine months ended September 30, 2016 compared to the same periods 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 acquired in February 2016.

Capacity revenues were also negatively impacted by an outage at Unit 30 from September 2014 to May 2015 at Ravenswood. The calculation used by the NYISO to determine the capacity volume for which a generator is compensated utilizes a rolling average forced outage rate. As a result of this methodology, outages impact capacity volumes and associated revenues on a lagged basis. Accordingly, capacity revenues for the three and nine months ended September 30, 2016 were negatively impacted compared to the same periods in 2015. The outage continues to be included in the rolling average forced outage rate. Insurance recoveries, net of deductibles, for this event have been received and 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 received in June 2016 and a portion of the proceeds were recognized in Power Revenue.

Physical generation volumes in 2016 were higher compared to the same period in 2015 due to our acquisition of the Ironwood power plant and higher generation at our Ravenswood facilities. Physical purchased volumes sold to wholesale, commercial and industrial customers were higher for the three and nine month months ended September 30, 2016 than the same periods in 2015 as we have expanded our customer base in the PJM and New England markets.

As at September 30, 2016, approximately 1,500 GWh, or 43 per cent, of U.S. Power's planned generation was contracted for the remainder of 2016 and 3,900 GWh, or 30 per cent, for 2017. Planned generation fluctuates depending on hydrology, wind conditions, commodity prices and the resulting dispatch of the assets. Power sales fluctuate based on customer usage and plant availability.

U.S. Power results for 2016 are not expected to be significantly impacted by the announced monetization of the U.S. Northeast Power business as these transactions are not expected to close until the first half of 2017. See the Recent developments section for more information. Nevertheless, operating results for the full year in 2016 are expected to be lower than the Outlook in our 2015 Annual Report due to lower commodity prices experienced in the first half of 2016.

## NATURAL GAS STORAGE AND OTHER

Comparable EBITDA increased by $21 million and $31 million for the three and nine months ended September 30, 2016 compared to the same periods in 2015 mainly due to increased storage revenues as a result of higher realized natural gas storage price spreads.

The full year 2016 results are expected to be higher compared to 2015 due to the lack of seasonal winter weather conditions, excess natural gas supply and the resulting increase in natural gas storage price spreads which have provided the opportunity to hedge available storage capacity at higher values than originally expected in the Outlook in our 2015 Annual Report.

# 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 restated to reflect this change.

| | three months ended September 30 | | nine months ended September 30 | |
|---|---|---|---|---|
| (unaudited - millions of $) | 2016 | 2015 | 2016 | 2015 |
| **Comparable EBITDA** | **(10)** | (15) | **(62)** | (51) |
| Depreciation and amortization | **(13)** | (8) | **(29)** | (23) |
| **Comparable EBIT** | **(23)** | (23) | **(91)** | (74) |
| Specific items: | | | | |
| Acquisition related costs - Columbia | **(14)** | — | **(50)** | — |
| Restructuring costs | **—** | (8) | **(14)** | (20) |
| **Segmented losses** | **(37)** | (31) | **(155)** | (94) |

Corporate segmented losses in 2016 increased by $6 million and $61 million for the three and nine months ended September 30, 2016 compared to the same periods 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.

### Interest expense

| | three months ended September 30 | | nine months ended September 30 | |
|---|---|---|---|---|
| (unaudited - millions of $) | 2016 | 2015 | 2016 | 2015 |
| **Comparable interest on long-term debt** (including interest on junior subordinated notes) | | | | |
| Canadian-dollar denominated | **(122)** | (109) | **(343)** | (324) |
| U.S. dollar-denominated (US$) | **(315)** | (231) | **(811)** | (677) |
| Foreign exchange impact | **(102)** | (72) | **(260)** | (177) |
| | **(539)** | (412) | **(1,414)** | (1,178) |
| Other interest and amortization expense | **(23)** | (11) | **(60)** | (35) |
| Capitalized interest | **46** | 82 | **133** | 223 |
| **Comparable interest expense** | **(516)** | (341) | **(1,341)** | (990) |
| Specific item: | | | | |
| Acquisition related costs - Columbia[1] | **(6)** | — | **(115)** | — |
| **Interest expense** | **(522)** | (341) | **(1,456)** | (990) |

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 acquisitions related costs. See the Financial condition section for more information.

Comparable interest expense increased by $175 million and $351 million for the three and nine months ended September 30, 2016 compared to the same periods in 2015 due to the net effect of:

- higher interest expense as a result of long-term debt issuances in 2015 and 2016, partially offset by Canadian and U.S. dollar-denominated debt maturities

- higher interest expense on debt acquired in the acquisition of Columbia on July 1, 2016
- higher foreign exchange on interest on U.S. dollar denominated debt
- lower capitalized interest on Keystone XL and related projects following the November 6, 2015 denial of a U.S. Presidential Permit, partially offset by higher capitalized interest on liquids projects, LNG projects and the Napanee power generating facility.

## Interest income and other

| | three months ended September 30 | | nine months ended September 30 | |
|---|---|---|---|---|
| (unaudited - millions of $) | **2016** | **2015** | **2016** | **2015** |
| **AFUDC** | | | | |
| Canadian-dollar denominated | **44** | 30 | **133** | 81 |
| U.S. dollar-denominated (US$) | **55** | 37 | **149** | 98 |
| Foreign exchange impact | **11** | 11 | **40** | 25 |
| **Total AFUDC** | **110** | 78 | **322** | 204 |
| Other | **12** | (36) | **63** | (96) |
| **Comparable interest income and other** | **122** | 42 | **385** | 108 |
| Specific items: | | | | |
| Acquisition related costs - Columbia[1] | **—** | — | **6** | — |
| Risk management activities | **—** | (26) | **49** | (25) |
| **Interest income and other** | **122** | 16 | **440** | 83 |

1 This amount represents interest income on the gross proceeds of the subscriptions receipts issued to partially fund the Columbia acquisition. See the Financial condition section for more information.

Comparable interest income and other increased by $80 million and $277 million for the three and nine months ended September 30, 2016 compared to the same periods in 2015 due to the net effect of:

- higher AFUDC related to our rate-regulated projects, primarily Mexico Pipelines, Energy East Pipeline, NGTL expansion and Columbia projects
- 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.

## Income tax expense

| (unaudited - millions of $) | three months ended September 30 2016 | 2015 | nine months ended September 30 2016 | 2015 |
|---|---|---|---|---|
| **Comparable income tax expense** | **(261)** | (236) | **(630)** | (668) |
| Specific items: | | | | |
| Ravenswood goodwill impairment | **429** | — | **429** | — |
| Alberta PPA terminations | **—** | — | **64** | — |
| Acquisition related costs - Columbia | **32** | — | **32** | — |
| Keystone XL income tax recoveries | **28** | — | **28** | — |
| Keystone XL asset costs | **5** | — | **13** | — |
| Restructuring costs | **—** | 2 | **4** | 6 |
| TC Offshore loss on sale | **—** | — | **1** | — |
| U.S. Northeast Power business monetization | **2** | — | **2** | — |
| Alberta corporate income tax rate increase | **—** | — | **—** | (34) |
| Risk management activities | **31** | 11 | **(21)** | 16 |
| **Income tax recovery/(expense)** | **266** | (223) | **(78)** | (680) |

Comparable income tax expense increased by $25 million and decreased by $38 million for the three and nine months ended September 30, 2016 compared to the same periods in 2015 and was mainly the result of changes in the proportion of income earned between Canadian and foreign jurisdictions and lower flow-through taxes in 2016 on Canadian regulated pipelines.

## Net income attributable to non-controlling interests

| (unaudited - millions of $) | three months ended September 30 2016 | 2015 | nine months ended September 30 2016 | 2015 |
|---|---|---|---|---|
| **Comparable net income attributable to non-controlling interests** | **(55)** | (46) | **(187)** | (145) |
| Specific item: | | | | |
| Acquisition related costs - Columbia | **3** | — | **3** | — |
| **Net income attributable to non-controlling interests** | **(52)** | (46) | **(184)** | (145) |

Net income attributable to non-controlling interests increased by $6 million and $39 million for the three and nine months ended September 30, 2016 compared to the same periods in 2015 and included a $3 million charge related to the non-controlling interest portion of retention and severance expenses resulting from the Columbia acquisition.

Comparable net income attributable to non-controlling interests increased by $9 million and $42 million for the three and nine months ended September 30, 2016 compared to the same periods 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 on the Canadian dollar equivalent earnings from TC PipeLines, LP increased net income attributable to non-controlling interests year-over-year.

## Preferred share dividends

| (unaudited - millions of $) | three months ended September 30 2016 | 2015 | nine months ended September 30 2016 | 2015 |
|---|---|---|---|---|
| **Preferred share dividends** | **(27)** | (23) | **(77)** | (71) |

Preferred share dividends increased by $4 million and $6 million for the three and nine months ended September 30, 2016 compared to the same periods in 2015 primarily due to preferred shares issuances in 2016 and 2015 offset by lower dividend rates on certain series.

# Recent developments

## ACQUISITION OF COLUMBIA PIPELINE GROUP, INC.

### Acquisition

On July 1, 2016, we closed the acquisition of Columbia valued at US$13 billion comprised of a purchase price of approximately US$10.3 billion and Columbia debt of approximately US$2.7 billion. The acquisition was financed through proceeds of $4.4 billion from the sale of subscription receipts, draws on bridge term loan credit facilities in the aggregate amount of US$6.9 billion and existing cash on hand. The sale of the subscription receipts was completed on April 1, 2016 through a public offering and, following the closing of the acquisition, were exchanged into 96.6 million TransCanada common shares. See Financial condition section for additional information on the bridge term loan credit facilities and the subscription receipts.

Columbia operates a portfolio of approximately 24,000 km (15,000 miles) of regulated natural gas pipelines, 300 Bcf of natural gas storage facilities and related midstream assets. We acquired Columbia to expand our natural gas business in the U.S. market, positioning ourselves for additional long-term growth opportunities. The acquisition also includes a large portfolio of new capital growth projects which includes seven pipeline expansion projects designed to transport growing supply from the Marcellus / Utica production basins to markets as well as a scheduled program for modernization of existing infrastructure out to 2020 to ensure the continuation of a safe, reliable and efficient system. We are currently executing plans to ensure an effective integration of Columbia into the TransCanada organization. We remain on track to realizing our $250 million of annual cost, revenue and financing benefits.

The following table summarizes the acquisition related costs for Columbia that have been excluded from comparable earnings for the three and nine months ended September 30, 2016.

| | three months ended September 30 | nine months ended September 30 |
|---|---|---|
| (unaudited - millions of $) | **2016** | **2016** |
| Natural Gas Pipelines | 82 | 82 |
| Corporate | 14 | 50 |
| Interest expense | 6 | 115 |
| Interest income and other | — | (6) |
| Income tax expense | (32) | (32) |
| Non-controlling interests | (3) | (3) |
| **Total excluded from comparable earnings** | **67** | **206** |

### Monetization of U.S. Northeast Power business

We currently expect to realize approximately US$3.7 billion from the monetization of our U.S. Northeast Power business. This includes the November 1, 2016 announced 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 TC Hydro to Great River Hydro, LLC, an affiliate of ArcLight Capital Partners, LLC for US$1.065 billion, with the remainder attributed to the marketing business which is expected to be realized going forward. These two sale transactions are expected to close in the first half of 2017 subject to certain regulatory and other approvals and will include 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 at September 30, 2016, an approximate $863 million after-tax net loss on the sale of the thermal and wind package to be recorded in fourth quarter 2016 and an approximate $443 million after-tax gain on the sale of the hydro assets to be recorded upon close of that transaction. Proceeds from these sales and future realization of value of the marketing business will be used to repay a portion of the US$6.9 billion senior unsecured asset bridge term loan credit facilities which were used to partially finance the Columbia acquisition earlier this year.

### Minority interest in Mexican pipelines

As part of the Columbia acquisition financing plan, we previously disclosed our intention to monetize a minority interest in our Mexico natural gas pipeline business. 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 maintaining a simple corporate structure. We currently own and operate the Tamazunchale and Guadalajara pipelines and are investing US$3.8 billion to develop and complete construction of four additional pipelines plus fund our interest in the Sur de Texas project, all of which will serve growing natural gas demand in Mexico. All projects are expected to be in-service by the end of 2018 and are underpinned by 25-year take-or-pay contracts with the CFE. Once completed, we expect our Mexican natural gas pipeline assets to be accretive to earnings per share and generate approximately US$575 million of annual EBITDA, up from US$181 million in 2015.

In connection with this decision, we also entered into an agreement with a group of underwriters to proceed with a common equity offering concurrent with the release of these financial results. See Corporate recent developments for more information.

# NATURAL GAS PIPELINES

## Canadian Regulated Pipelines

### NGTL System

On October 31, 2016, the Government of Canada approved our $1.3 billion NGTL 2017 Facilities Application. In addition, on October 6, 2016, the NEB recommended to the government approval of the $0.4 billion Towerbirch Project. This project consists of a 55 km (34 miles) pipeline loop and a 32 km (20 miles) pipeline extension of the NGTL System in northwest Alberta and northeast B.C. The NEB approved NGTL's continued use of its existing rolled-in toll methodology for this project. Of NGTL's $5.4 billion near-term capital program we have received approvals for $4.0 billion, while $0.5 billion has been filed and is awaiting approval. Approximately $0.9 billion is expected to be filed with regulators in the future.

We continue to work closely with our shippers to ensure that new proposed facilities meet our shippers and market demands. In second quarter 2016, we added new long term delivery contracts on the NGTL System to meet demand in the Pacific Northwest and California which will require the construction of $135 million of new facilities (the Sundre Crossover Project) that were not previously included in our 2018 Facilities program. The open season process supporting the development of these new contracts identified further demand for service to this market that we are currently assessing.

In second quarter 2016, in response to cancellations or deferrals of our certain customer projects, contract non-renewals, and contract transfers, we re-evaluated planned facility requirements to meet future aggregate system service requirements and made changes in the spending profile of our programs to match revised in-service dates. The projected expansion capital spend for the NGTL System remains at approximately $7.3 billion, including the new Sundre Crossover Project, the North Montney and Merrick pipelines and the cancellation of a $66 million project. We have deferred approximately $225 million of spending for facilities in the 2016/17 Facilities program with revised service dates of 2018 through 2020 as well as $210 million of spending for facilities in the 2018 Facilities program with revised service dates of 2019 and 2020.

#### *North Montney Mainline*

In March 2016, we filed a request with the NEB for a one year extension to the June 10, 2016 sunset clause in the North Montney Mainline (NMML) project Certificate of Public Convenience and Necessity (CPCN). On September 15, 2016, the NEB approved the sunset clause extension to June 10, 2017. The extension continues to be subject to the condition that construction shall not begin until a positive Final Investment Decision (FID) has been made on the Pacific Northwest LNG (PNW LNG) Project. NGTL continues to work with our customers and stakeholders to be ready to initiate construction of the NMML facilities, however, the in-service date will be finalized once a FID has been made.

#### *2016-2017 NGTL Revenue Requirement Settlement*

In April 2016, the NEB approved the NGTL revenue requirement settlement application that was filed in December 2015, subject to certain reporting requirements that were subsequently met and approved by the NEB. The settlement includes a ROE of 10.1 per cent on a deemed common equity of 40 per cent, continuation of 2015 depreciation rates, a mechanism for sharing variances above and below a fixed annual operating, maintenance and administration cost amount and flow-through treatment of all other costs.

### Canadian Mainline Tolling Option Open Season

On October 13, 2016, we launched an open season for the Canadian Mainline, seeking binding commitments on our new long-term, fixed-price proposal to transport WCSB supply from the Empress receipt point in Alberta to the Dawn hub in Southern Ontario. The contract term for this service is ten years with tolls ranging from $0.75/GJ to $0.82/GJ depending on the shippers' contract volume commitments. Early termination rights are provided and can be exercised following the initial five years of service upon payment of a premium fee. Subject to a successful open season that closes November 10, 2016, and to NEB regulatory approval, the new service is targeted to begin November 1, 2017.

## U.S. Pipelines

### Columbia Capital Projects

The July 1, 2016 acquisition of Columbia included a capital expansion program that was underway for new facilities planned to be in service in 2017 and 2018 as well as modernization programs for existing assets to be completed through 2020. The large capital expansion program consists of US$7.4 billion related to our regulated pipeline business and US$0.3 billion related to our midstream business. The following summarizes the key capital projects for this new set of assets that are now part of the our overall Natural Gas Pipelines footprint in North America.

***Leach XPress***

This Columbia Gas Transmission (TCO) project is designed to transport up to 1.5 Bcf/d of Marcellus and Utica gas supply to delivery points along the pipeline and to the Leach interconnect with the Columbia Gulf System (CGT). The project consists of 219 km (136 miles) of 36-inch greenfield pipe, 39 km (24 miles) of 36-inch loop, three km (two miles) of 30-inch greenfield pipe, 82.8 MW (111,000 hp) of greenfield compression and 24.6 MW (33,000 hp) of brownfield compression. We expect the project, with an estimated capital investment of US$1.4 billion, to be in service in fourth quarter 2017. The FERC 7(C) application was filed in June 2015 and the Final Environmental Impact Statement (FEIS) was received September 1, 2016.

***Rayne XPress***

This CGT project is designed to transport up to 1.1 Bcf/d of southwest Marcellus and Utica production associated with the Leach XPress expansion and an interconnect with the Texas Eastern System (TETCO) to various delivery points on the CGT system and Gulf Coast. The project consists of bi-directional compressor station modifications along the CGT system, 38.8 MW (52,000 hp) of greenfield compression, 20.1 MW (27,000 hp) of replacement compression and six km (four miles) of 30-inch pipe replacement. We expect the project, with an estimated capital investment of US$420 million, to be in service in fourth quarter 2017. The FERC 7(C) application was filed in July 2015 and the FEIS was received September 1, 2016.

***Mountaineer XPress***

This TCO project is designed to transport up to 2.7 Bcf/d of Marcellus and Utica gas supply to delivery points along the pipeline and to the Leach interconnect with the CGT system. The project consists of 264 km (164 miles) of 36-inch greenfield pipeline, ten km (six miles) of 24-inch lateral pipeline, 0.6 km (0.4 miles) of 30-inch replacement pipeline, 114.1 MW (153,000 hp) of greenfield compression and 55.9 MW (75,000 hp) of brownfield compression. We expect this project, with an estimated capital investment of US$2 billion, to be in service in fourth quarter 2018. The FERC 7(C) application was filed in April 2016.

***Gulf XPress***

This CGT project is designed to transport up to 0.9 Bcf/d associated with the Mountaineer XPress expansion to various delivery points on the CGT system and Gulf Coast. The project consists of adding seven greenfield midpoint compressor stations along the CGT System route totaling 182.7 MW (254,000 hp). We expect this project, with an estimated capital investment of US$0.7 billion, to be placed in service in fourth quarter 2018. The FERC 7(C) application was filed in April 2016.

***Cameron Access Project***

This CGT project is designed to transport up to 0.8 Bcf/d of gas supply to the Cameron LNG export terminal in Louisiana. The project consists of 44 km (27 miles) of 36-inch greenfield pipeline, 11 km (seven miles) of 30-inch looping and 9.7 MW (13,000 hp) of greenfield compression. We expect this project, with an estimated capital investment of US$300 million, to be in service in first quarter 2018. The FERC certificate was received in September 2015.

***WB XPress***

This TCO project is designed to transport up to 1.3 Bcf/d of Marcellus gas supply westbound (0.8 Bcf/d) to the Gulf Coast via an interconnect with the Tennessee Gas Pipeline, and eastbound (0.5 Bcf/d) to Mid-Atlantic markets, WGL Midstream and Transco interconnects. The project consists of 47 km (29 miles) of various diameter pipeline, 338 km (210 miles) of restoring and uprating maximum operating pressure of existing pipeline, 29.8 MW (40,000 hp) of greenfield compression and 99.9 MW (134,000 hp) of brownfield compression. We expect this project, with an estimated capital investment of US$0.9 billion, to have a Western build  in service in the beginning of second quarter 2018 and an Eastern build in service in fourth quarter 2018. The FERC 7(C) application for both segments was filed in December 2015.

***Modernization I & II***

TCO and its customers have entered into a settlement arrangement, approved by FERC, which provides recovery and return on investment to modernize its system, improve system integrity and enhance service reliability and flexibility. The modernization program includes, among other things, replacement of aging pipeline and compressor facilities, enhancements to system inspection capabilities and improvements in control systems. Modernization I has been approved for up to US$0.6 billion of work yet to be completed in 2016 through 2017. Modernization II has been approved for up to US$1.1 billion of work to be completed in 2018 through 2020. As per terms of the arrangements, facilities in service by October 31 collect revenues effective February 1 of the following year.

***Columbia Midstream - Gibraltar Pipeline Project***

We expect to invest US$260 million to construct an approximate 1 MMDth/d dry gas header pipeline in southwest Pennsylvania to be completed in multiple phases with an initial in-service date in fourth quarter 2016 and a final in-service date in fourth quarter 2017.

**ANR Section 4 Rate Case Settlement**

ANR reached a settlement with its shippers effective August 1, 2016 and filed the final, unopposed settlement agreement with the FERC for approval on September 16, 2016. Transmission reservation rates will increase by 34.8 per cent and storage rates will remain the same for contracts one to three years in length, while increasing slightly for contracts of less than one year and decreasing slightly for contracts more than three years in duration. There is a moratorium on any further rate changes until August 1, 2019. ANR may file for new rates after that date if it has spent more than US$0.8 billion in capital additions, but must file for new rates no later than an effective date of August 1, 2022.

**Columbia Pipeline Partners LP**

On November 1, 2016, we announced that we have entered into an agreement and plan of merger through which our wholly-owned subsidiary, Columbia Pipeline Group, Inc, has agreed to acquire, for cash, all of the outstanding publicly held common units of Columbia Pipeline Partners LP (CPPL) at a price of US$17.00 per common unit for an aggregate transaction value of approximately US$915 million. Common unitholders will also continue to receive regular quarterly distributions of US$0.1975 per common unit including a pro-rated distribution for any partial period to the closing date. The transaction is expected to close in first quarter 2017 subject to receipt of CPPL unitholder approval and customary closing conditions, and is expected to be accretive to earnings per share and simplify our corporate structure. There will be no gain or loss recorded on closing this transaction as CPPL is a consolidated subsidiary.

## Mexico

**Topolobampo Pipeline**

The Topolobampo project is a 530 km (329 miles), 30-inch pipeline with a capacity of 670 MMcf/d and a cost of US$1 billion that will deliver natural gas from interconnections with third party pipelines to Topolobampo, Sinaloa and into the Mazatlán pipeline. Construction of the pipeline is supported by a 25-year natural gas Transportation Service Agreement (TSA) for 670 MMcf/d with the CFE. The physical in-service date is expected to be delayed into 2017 due to right-of-way acquisition delays. Under the terms of the TSA, this delay is recognized as a force majeure event with provisions allowing for the collection of revenue as per the original TSA service commencement date of July 2016.

**Mazatlán Pipeline**

The Mazatlán project is a 413 km (257 miles), 24-inch diameter pipeline running from El Oro to Mazatlán within the state of Sinaloa with an estimated cost of US$0.4 billion and is supported by 25-year contract with the CFE. Construction of the pipeline is supported by a 25-year natural gas TSA for 200 MMcf/d with the CFE. Physical construction is complete and is awaiting natural gas to commence in-service under the contract.

**Tula Pipeline**

The Tula project is a US$500 million, 36 inch, 250 km (155 mile) pipeline with a contracted capacity of 886 MMcf/d for 25 years with the CFE. The pipeline begins at Tuxpan, Veracruz extending through the states of Puebla and Hidalgo, supplying natural gas to markets near Tula, Querétaro. Construction has commenced with one pipeline spread and at the compressor stations.

**Villa de Reyes Pipeline**

On April 11, 2016, we announced that we were awarded the contract to build, own and operate the Villa de Reyes pipeline in Mexico. Construction of the pipeline is supported by a 25-year natural gas transportation service contract for 886 MMcf/d with the CFE. We expect to invest approximately US$0.5 billion to construct a 36-inch diameter, 420 km (261 mile) pipeline with an anticipated in-service date of early 2018. The pipeline will begin in Tula, in the state of Hidalgo, and terminate in Villa de Reyes, in the state of San Luis Potosí, transporting natural gas to power generation facilities in the central region of the country. The project will interconnect with our Tamazunchale and Tuxpan-Tula pipelines as well as with other transporters in the region.

**Sur de Texas Pipeline**

On June 13, 2016, we announced that our joint venture with IEnova had been chosen to build, own and operate the US$2.1 billion Sur de Texas pipeline in Mexico. Construction of the pipeline is supported by a 25-year natural gas transportation service contract for 2.6 bcf/d with the CFE. We expect to invest approximately US$1.3 billion in the partnership to construct the 42-inch diameter, approximately 800 km (497 mile) pipeline with an anticipated in-service date of late 2018. The pipeline will start offshore in the Gulf of Mexico, at the border point near Brownsville, Texas, and end in Tuxpan, Mexico in the state of Veracruz. The project will deliver natural gas to our Tamazunchale and Tuxpan-Tula pipelines and to other transporters in the region.

## LNG Pipeline Projects

**Prince Rupert Gas Transmission**

On September 27, 2016, Pacific NorthWest LNG (PNW LNG) received an environmental certificate from the Government of Canada for a proposed LNG plant at Prince Rupert, B.C. PNW LNG has indicated they will conduct a total project review over the coming months prior to announcing next steps for the project.

PRGT continues engagement with Aboriginal groups and other stakeholders along the route in preparation for a FID by PNW LNG. To date, PRGT has executed long-term project agreements with twelve First Nation groups along the pipeline route.

**Coastal GasLink**

On July 11th, 2016, the LNG Canada joint venture participants announced a delay to their FID for the proposed liquefied natural gas facility in Kitimat, B.C. At this time, a future FID date has not been determined. In light of this announcement, we are working with LNG Canada to determine the appropriate pacing of the Coastal GasLink development schedule and work activities.

## LIQUIDS PIPELINES

### Keystone Pipeline

On April 2, 2016, we shut down the Keystone pipeline after a leak was detected along the pipeline right-of-way in Hutchinson County, South Dakota. We reported the total volume of the release of 400 barrels to the National Response Center and the Pipeline and Hazardous Materials Safety and Administration (PHMSA). Temporary repairs were completed on April 9, 2016, and the Keystone pipeline was restarted on April 10, 2016. On May 5, 2016, permanent pipeline repairs were completed and restoration work was completed on July 3, 2016. Corrective measures required by PHMSA were completed in September 2016. This shutdown did not significantly impact our 2016 earnings.

### Houston Lateral and Terminal

In August 2016, the Houston Lateral pipeline and terminal, an extension from the Keystone Pipeline System to Houston, Texas, went into service. The terminal has an initial storage capacity for 700,000 barrels of crude oil.

### Energy East Pipeline

On March 1, 2016, the Province of Québec filed a court action seeking an injunction to compel the Energy East Pipeline to comply with the province’s environmental regulations. On March 30, 2016, the Québec Superior Court joined the injunction action led by the Province of Québec with the prior action led by Québec Environmental Law Centre / Centre québécois du droit de l’environnement (CQDE), which sought a declaration to compel Energy East to submit to the mandatory provincial environmental review process. As a result of communication with the Ministère du Développement durable, Environnement et la Lutte contre les changements climatiques, on April 22, 2016, we filed a project review engaging an environmental assessment under the Environmental Quality Act (Québec) according to an agreed upon schedule for key steps in that process. This process is in addition to environmental assessment required under the NEB Act and the Canadian Environmental Assessment Act, 2012. The Attorney General for Québec has agreed to suspend its litigation against TransCanada and Energy East and to withdraw it once the provincial environmental assessment process has been completed. The CQDE has similarly agreed to suspend the action. These suspensions are in effect until early November 2016, but may have to be extended given the delay in the NEB process noted below.

On May 17, 2016, we filed a consolidated application with the NEB for Energy East. On June 16, 2016, Energy East achieved a major milestone with the NEB’s announcement determining the Energy East application is sufficiently complete to initiate the formal regulatory review process. This determination of completeness also marked the start of the mandated 21 month NEB review process which culminates in a formal recommendation to the Governor in Council (Federal Cabinet). The Governor in Council will then have six months to decide whether to approve the project and, if so, on what conditions. On July 20, 2016, the NEB issued the hearing order which provides further detail on the regulatory process.

On August 8, 2016, the NEB commenced the first of a series of community panel sessions held along the pipeline route in New Brunswick. Panel sessions scheduled for the week of August 29, 2016 in Montréal, Québec were subsequently cancelled as three NEB panelists announced their decision to recuse themselves from continuing to sit on the panel to review the project due to allegations of reasonable apprehension of bias. The Chair of the NEB and the Vice Chair, who is also a panel member, have recused themselves of any further duties related to the project. As a result, all hearings for the project were adjourned until further notice as we wait on the federal government to appoint new NEB members and then for the NEB to establish a new panel to hear our applications. The new panel members will then determine how the review process is to be re-initiated. As a result of these actions, we expect a delay in the NEB review process.

### Keystone XL NAFTA challenge

On June 24, 2016, we filed a Request for Arbitration in a dispute against the U.S. Government pursuant to the Convention on Settlement of Investment Disputes between States and Nationals of Other States, the Rules of Procedure for the Institution of Conciliation and Arbitration Proceedings and Chapter 11 of the North American Free Trade Agreement (NAFTA). The claim arises out of the November 6, 2015 denial of our application for a Presidential Permit to construct the Keystone XL Pipeline. We have requested an award of damages arising from the U.S. Government's breaches of its NAFTA obligations in an amount of more than US$15 billion, together with applicable interest and the costs of arbitration.

## ENERGY

### Alberta PPAs

On March 7, 2016, we issued notice to the Balancing Pool to terminate our Alberta PPAs. The arrangements contain a provision that permits the PPA buyers to terminate the PPAs if there is a change in the law that makes the arrangements unprofitable or more unprofitable. This termination affects the Sheerness, Sundance A and Sundance B PPAs. On July 22, 2016, we, along with the ASTC Power Partnership, referred the matter to be resolved by binding arbitration pursuant to the dispute resolution provisions of the PPAs. On July 25, 2016, the Government of Alberta brought an application in the Court of Queen's Bench to prevent the Balancing Pool from allowing termination of a PPA held by another party which contains identically worded termination provisions to our PPAs. The outcome of this court application may affect resolution of the arbitration of the Sheerness, Sundance A and Sundance B PPAs. The Balancing Pool has refused to proceed with the arbitrations pending resolution of the court application. On October 20, 2016, we made an application to the Court of Queen's Bench requesting that the court order the Balancing Pool to proceed. Unprofitable market conditions are expected to continue as costs related to carbon emissions have increased and are forecast to continue to increase over the remaining term of the PPA agreements. We expect the termination will improve cash flow and comparable earnings in the near term.

As a result of our decision to terminate the PPAs, we recorded a non-cash impairment charge of $240 million before tax ($176 million after tax) comprised of $211 million before tax ($155 million after tax) related to the carrying value of our Sundance A and Sheerness PPAs and $29 million before tax ($21 million after tax) on our equity investment in the ASTC Power Partnership which holds the Sundance B PPA.

### Ontario Cap and Trade

In May 2016, legislation enabling Ontario's cap and trade program was signed into law with the new regulation taking effect July 1, 2016. This regulation sets a limit on annual province-wide greenhouse gas emissions beginning in January 2017 and introduces a market to administer the purchase and trading of emissions allowances. The regulation places the compliance obligation for emissions from our natural gas fired power facilities on local gas distributors, with the distributors flowing the associated costs to the assets.

The IESO is continuing to develop proposed contract amendments for eligible contract holders to address costs and other issues associated with this change in law. We do not expect a significant overall impact as a result of this new regulation.

### Bécancour tolling agreement

In August 2015, we executed an agreement with Hydro Québec (HQ) allowing HQ to dispatch up to 570 MW of peak winter capacity from our Bécancour facility for a term of 20 years commencing in December 2016. The regulator in Québec, Régie de l'énergie (the Régie), initially accepted this agreement for implementation but in July 2016, the Régie reversed this initial decision. HQ continues to advocate for the contract on its economic merit as part of their strategy to meet the winter peak capacity needs of the province and is pursuing regulatory options for our agreement to be reinstated. We expect the project need and potential timing will be reassessed in the recently released review of HQ's ten year supply plan.

### Bruce Power financing

In second quarter 2016, Bruce Power issued bonds and borrowed under its bank credit facility as part of a financing program to fund its capital program and make distributions to its partners. Distributions received from Bruce Power in second quarter 2016 included $725 million from this financing program.

## CORPORATE

### Common equity offering

On November 1, 2016, in conjunction with our decision to maintain our current ownership interest in a growing Mexican natural gas pipelines business, and concurrent with the release of these financial results, we also entered into an agreement with a group of underwriters to proceed with an offering of common shares. The common shares will be offered to the public in Canada and the United States through the underwriters or their representatives. The offering is subject to the receipt of all necessary regulatory and stock exchange approvals.

Proceeds from the offering will be used to repay a portion of the US$6.9 billion senior unsecured asset bridge term loan credit facilities which were used to finance a portion of the purchase price of Columbia. The closing for the offering is expected to be on November 16, 2016.

### Dividend Reinvestment Plan

Under our Dividend Reinvestment Plan (DRP), eligible holders of common and preferred shares of TransCanada can reinvest their dividends and make optional cash payments to obtain TransCanada common shares. Commencing with dividends declared on July 27, 2016, common shares will be issued from treasury at a discount of two per cent.

# Financial condition

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

We believe we have the financial capacity to fund our existing capital program through our predictable cash flow from our operations, access to capital markets (including through the establishment of an at-the-market equity issuance program, if applicable), monetization of assets, cash on hand and substantial committed credit facilities.

At September 30, 2016, our current assets were $5.4 billion and current liabilities were $6.1 billion, leaving us with a working capital deficit of $0.7 billion compared to a deficit of $3.4 billion at December 31, 2015. Our working capital deficiency is considered to be in the normal course of business and is managed through:

- our ability to generate cash flow from operations
- our access to capital markets
- approximately $8.6 billion of unutilized, unsecured committed credit facilities.

## CASH PROVIDED BY OPERATING ACTIVITIES

| | three months ended September 30 | | nine months ended September 30 | |
|---|---|---|---|---|
| (unaudited - millions of $) | **2016** | **2015** | **2016** | **2015** |
| Net cash provided by operations | **1,183** | 1,247 | **3,277** | 2,976 |
| Increase/(decrease) in operating working capital | **110** | (107) | **(28)** | 378 |
| Funds generated from operations[1] | **1,293** | 1,140 | **3,249** | 3,354 |
| Specific items: | | | | |
| Acquisition related costs - Columbia | **99** | — | **238** | — |
| Keystone XL asset costs | **14** | — | **37** | — |
| Restructuring costs | **—** | 8 | **—** | 20 |
| U.S. Northeast Power business monetization | **5** | — | **5** | — |
| Current income taxes | **—** | — | **—** | — |
| **Comparable funds generated from operations** | **1,411** | 1,148 | **3,529** | 3,374 |
| Dividends on preferred shares | **(28)** | (23) | **(74)** | (69) |
| Distributions paid to non-controlling interests | **(77)** | (60) | **(201)** | (168) |
| Distributions received in excess of equity earnings[2] | **30** | 111 | **217** | 221 |
| Maintenance capital expenditures including equity investments | **(311)** | (223) | **(770)** | (584) |
| **Comparable distributable cash flow** | **1,025** | 953 | **2,701** | 2,774 |
| **Comparable distributable cash flow per common share** | **$1.29** | $1.34 | **$3.68** | $3.91 |

1 See the non-GAAP measures section in this MD&A for further discussion of funds generated from operations.

2 Reflects distributions received from equity investee operating activities and excludes additional distributions of $725 million resulting from Bruce Power's financing program.

## COMPARABLE FUNDS GENERATED FROM OPERATIONS

Comparable funds generated from operations is a non-GAAP measure. 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. We calculate this comparable measure by adjusting funds generated from operations for specific items we believe are significant but not reflective of our underlying operations. See the non-GAAP measures section of this MD&A for further discussion on specific items.

Comparable funds generated from operations increased $263 million and $155 million for the three and nine months ended September 30, 2016 compared to the same periods in 2015 primarily due to the increase in net income due to the Columbia acquisition on July 1, 2016.

## COMPARABLE DISTRIBUTABLE CASH FLOW

Comparable distributable cash flow, a non-GAAP measure, helps us assess the cash available to common shareholders before capital allocation. See our non-GAAP measures section for more information.

Maintenance capital expenditures for the three and nine months ended September 30, 2016 on our Canadian regulated natural gas pipelines were $105 million and $202 million, respectively (2015 - $87 million and $201 million, respectively) which contributed to their respective rate bases and net income.

## CASH USED IN INVESTING ACTIVITIES

| | three months ended September 30 | | nine months ended September 30 | |
|---|---|---|---|---|
| (unaudited - millions of $) | **2016** | **2015** | **2016** | **2015** |
| **Capital spending** | | | | |
| Capital expenditures | **(1,444)** | (976) | **(3,262)** | (2,748) |
| Capital projects in development | **(62)** | (130) | **(219)** | (465) |
| | **(1,506)** | (1,106) | **(3,481)** | (3,213) |
| Contributions to equity investments | **(286)** | (105) | **(570)** | (303) |
| Restricted cash | **13,113** | — | **—** | — |
| Acquisitions, net of cash acquired | **(12,609)** | — | **(13,608)** | — |
| Proceeds from sale of assets, net of transaction costs | **—** | — | **6** | — |
| Distributions received in excess of equity earnings | **30** | 111 | **942** | 221 |
| Deferred amounts and other | **38** | 36 | **18** | 240 |
| **Net cash used in investing activities** | **(1,220)** | (1,064) | **(16,693)** | (3,055) |

Capital expenditures in 2016 were primarily related to:

- expansion of the NGTL System
- construction of Mexico pipelines
- expansion of the ANR pipeline
- expansion of Columbia pipelines
- construction of the Northern Courier pipeline
- expansion of the Canadian Mainline
- construction of the Napanee power generating facility.

Costs incurred on capital projects under development primarily relate to the Energy East and LNG pipeline projects.

Contributions to equity investments have increased in 2016 compared to 2015 primarily due to our investments in Grand Rapids, Bruce Power and Sur de Texas.

Restricted cash held in escrow at June 30, 2016 was used for the purchase of Columbia on July 1, 2016.

On February 1, 2016, we acquired the Ironwood natural gas fired, combined cycle power plant with a capacity of 778 MW, for US$653 million in cash after post-acquisition adjustments.

On March 31, 2016, we acquired an additional 4.87 per cent interest in Iroquois for an aggregate purchase price of US$54 million. On May 1, 2016, we acquired an additional 0.65 per cent for an aggregate purchase price of US$7 million. As a result of these acquisitions, our interest in Iroquois has increased to 50 per cent.

The increase in distributions received in excess of equity earnings is primarily due to distributions from Bruce Power. In second quarter 2016, Bruce Power issued bonds and borrowed under its bank credit facility as part of its financing program to fund its capital program and make distributions to its partners  which resulted in $725 million being received by us.

## CASH PROVIDED BY FINANCING ACTIVITIES

| (unaudited - millions of $) | three months ended September 30 | | nine months ended September 30 | |
|---|---|---|---|---|
| | **2016** | **2015** | **2016** | **2015** |
| Notes payable repaid, net | **(423)** | (358) | **(100)** | (828) |
| Long-term debt issued, net of issue costs | **6** | 962 | **12,333** | 3,323 |
| Long-term debt repaid | **(53)** | (183) | **(2,343)** | (2,066) |
| Junior subordinated notes issued, net of issue costs | **1,551** | — | **1,551** | 917 |
| Dividends and distributions paid | **(502)** | (452) | **(1,434)** | (1,315) |
| Common shares/subscription receipts issued, net of issue costs | **(37)** | 1 | **4,337** | 12 |
| Common shares repurchased | **—** | — | **(14)** | — |
| Partnership units of subsidiary issued, net of issue costs | **45** | — | **151** | 31 |
| Preferred shares issued, net of issue costs | **—** | — | **492** | 243 |
| **Net cash provided by/(used in) financing activities** | **587** | (30) | **14,973** | 317 |

## LONG-TERM DEBT ISSUED

| (unaudited - millions of $)<br>**Company** | **Issue date** | **Type** | **Maturity date** | **Amount** | **Interest rate** |
|---|---|---|---|---|---|
| **TRANSCANADA PIPELINES LIMITED** | | | | | |
| | June 2016 | Acquisition Bridge Facility[1] | June 2018 | US $5,213 | Floating |
| | June 2016 | Medium Term Notes | July 2023 | $300 | 3.690%[2] |
| | June 2016 | Medium Term Notes | June 2046 | $700 | 4.350% |
| | January 2016 | Senior Unsecured Notes | January 2019 | US $400 | 3.125% |
| | January 2016 | Senior Unsecured Notes | January 2026 | US $850 | 4.875% |
| **ANR PIPELINE COMPANY** | | | | | |
| | June 2016 | Senior Unsecured Notes | June 2026 | US $240 | 4.140% |
| **TRANSCANADA PIPELINE USA LTD.** | | | | | |
| | June 2016 | Acquisition Bridge Facility[1] | June 2018 | US $1,700 | Floating |
| **TUSCARORA GAS TRANSMISSION COMPANY** | | | | | |
| | April 2016 | Term Loan | April 2019 | US $9.5 | Floating |

1 These facilities were put in place to finance a portion of the Columbia acquisition and bear interest at LIBOR plus an applicable margin. Proceeds from the U.S. Northeast Power business monetizations and the November 2016 common equity offering will be used to partially repay these facilities.

2 Reflects coupon rate on re-opening of existing medium term notes (MTN) issue. New MTNs were issued at a premium resulting in a re-issuance yield of 2.69 per cent.

## JUNIOR SUBORDINATED DEBT ISSUED

| (unaudited - millions of $)<br>**Company** | **Issue date** | **Type** | **Maturity date** | **Amount** | **Interest rate** |
|---|---|---|---|---|---|
| **TRANSCANADA PIPELINES LIMITED** | | | | | |
| | August 2016 | Junior Subordinated Unsecured Notes[1] | August 2076 | US $1,200 | 6.125%[2] |

1 The Junior subordinated unsecured notes are subordinated in right of payment to existing and future senior indebtedness or other obligations of TCPL and are callable at TCPL's option at any time on or after August 15, 2026 at 100 per cent of the principal amount plus accrued and unpaid interest to the date of redemption.

2 The Junior subordinated unsecured notes were issued to TransCanada Trust. The interest rate is fixed at 6.125 per cent per annum and will reset starting August 2026 until August 2046 to the three month LIBOR plus 4.89 per cent per annum; from August 2046 to August 2076 the interest rate will reset to the three month LIBOR plus 5.64 per cent per annum.

On August 15, 2016, TransCanada Trust (the Trust), a wholly owned trust subsidiary of TCPL, issued US$1.2 billion of Trust Notes to third party investors with a fixed interest rate of 5.875 per cent for the first ten years converting to a floating rate thereafter. The proceeds of the Trust Notes were loaned to TCPL through the subscription for US$1.2 billion of junior subordinated notes of TCPL at a rate of 6.125 per cent which includes a 0.25 per cent administration charge. While the obligations of the Trust are fully guaranteed by TCPL on a subordinated basis, the Trust is not consolidated in TransCanada's financial statements because TCPL does not have a variable interest in the Trust and the only substantive assets of the Trust are receivables from TCPL.

Pursuant to the terms of the Trust Notes and related agreements, in certain circumstances (1) TCPL may issue deferral preferred shares to holders of the Trust Notes in lieu of interest; and (2) TransCanada and TCPL would be prohibited from declaring or paying dividends on or redeeming their outstanding preferred shares (or, if none are outstanding, their respective common shares) until all deferral preferred shares are redeemed by TCPL. The Trust Notes may also be automatically exchanged for preferred shares of TCPL upon certain kinds of bankruptcy and insolvency events. All of these preferred shares would rank equally with other outstanding first preferred shares of TCPL.

## LONG-TERM DEBT RETIRED

| (unaudited - millions of $)<br>**Company** | **Retirement date** | **Type** | **Amount** | **Interest rate** |
|---|---|---|---|---|
| **TRANSCANADA PIPELINES LIMITED** | | | | |
| | October 2016 | Medium Term Notes | $400 | 4.65% |
| | June 2016 | Senior Unsecured Notes | US $84 | 7.69% |
| | June 2016 | Senior Unsecured Notes | US $500 | Floating |
| | January 2016 | Senior Unsecured Notes | US $750 | 0.75% |
| **NOVA GAS TRANSMISSION LTD.** | | | | |
| | February 2016 | Debentures | $225 | 12.20% |

## COMMON SHARES REPURCHASED

In November 2015, the TSX approved our normal course issuer bid (NCIB), which allows for the repurchase and cancellation of up to 21.3 million common shares, representing three per cent of our then issued and outstanding common shares, between November 23, 2015 and November 22, 2016 at prevailing market prices plus brokerage fees, or such other prices as may be permitted by the TSX. Since inception of the NCIB, 7.1 million shares were repurchased at an average price of $43.63. With the acquisition of Columbia, we do not anticipate further repurchases under this NCIB.

The following table summarizes shares repurchased in 2016 under the NCIB:

| **at September 30, 2016**<br>(millions of $, except number of common shares and per share data) | |
|---|---|
| Number of common shares repurchased[1] | 305,407 |
| Weighted-average price per common share[2] | $44.90 |
| Amount repurchased | $13.7 |

1 Includes repurchases of common shares pursuant to private agreements with third-parties.

2 Includes brokerage fees.

## SUBSCRIPTION RECEIPTS

On April 1, 2016, we issued 96.6 million subscription receipts to partially fund the Columbia acquisition at a price of $45.75 each for total proceeds of $4.4 billion. Each subscription receipt holder received one common share upon closing of the Columbia acquisition. Holders received dividend equivalent payments per subscription receipt equal to dividends declared on each common share, with the first payment on April 29, 2016 for holders of record at close of business on April 15, 2016. The second dividend equivalent payment was made on July 29, 2016 to holders of record at the close of business on June 30, 2016. For the nine months ended September 30, 2016, $109 million of dividend equivalent payments were recorded as interest expense and have been excluded from comparable earnings. See the Reconciliation of non-GAAP measures section.

Interest income of $6 million relating to the proceeds while held in escrow has also been excluded from comparable earnings. See the Reconciliation of non-GAAP measures section.

On July 4, 2016, the subscription receipts were automatically exchanged for TransCanada common shares in accordance with the terms of the subscription receipt agreement and were delisted from the TSX.

## DIVIDEND REINVESTMENT PLAN

Under our Dividend Reinvestment Plan (DRP), eligible holders of common and preferred shares of TransCanada can reinvest their dividends and make optional cash payments to obtain TransCanada common shares. Commencing with dividends declared on July 27, 2016, common shares will be issued from treasury at a discount of two per cent. Approximately $175 million or 39 per cent of dividends paid on October 31, 2016 were reinvested in TransCanada common shares.

## PREFERRED SHARE ISSUANCE AND CONVERSION

In February 2016, holders of 1.3 million Series 5 cumulative redeemable first preferred shares exercised their option to convert to Series 6 cumulative redeemable first preferred shares and receive quarterly floating rate cumulative dividends at an annual rate equal to the applicable 90-day Government of Canada treasury bill rate plus 1.54 per cent which will reset every quarter going forward. The fixed dividend rate on the remaining Series 5 preferred shares was reset for five years at 2.263 per cent per annum. Such rate will reset every five years.

In April 2016, we completed a public offering of 20 million Series 13 cumulative redeemable first preferred shares at $25 per share resulting in gross proceeds of $500 million. The Series 13 preferred shareholders will have the right to convert their Series 13 preferred shares into Series 14 cumulative redeemable first preferred shares on May 31, 2021 and on the last business day of May of every fifth year thereafter. The holders of Series 14 preferred shares will be entitled to receive quarterly floating rate cumulative dividends at an annual rate equal to the sum of the then applicable 90-day Government of Canada treasury bill rate plus 4.69 per cent. The fixed dividend rate on the Series 13 preferred shares was set for its initial period at 5.5 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 4.69 per cent subject to a floor of not less than 5.5 per cent per annum.

The following table summarizes the impact of the 2016 conversion and issuance of preferred shares discussed above:

| (unaudited) | **Number of shares issued and outstanding** (thousands) | **Current yield** | **Annual dividend per share**[1] | **Redemption price per share**[2] | **Redemption and conversion option date**[2,3] | **Right to convert into**[3] |
|---|---|---|---|---|---|---|
| **Cumulative first preferred shares** | | | | | | |
| Series 5 | 12,714 | 2.263% | $0.56575 | $25.00 | January 30, 2021 | Series 6 |
| Series 6 | 1,286 | Floating[4] | Floating | $25.00 | January 30, 2021 | Series 5 |
| Series 13 | 20,000 | 5.5% | $1.375 | $25.00 | May 31, 2021 | Series 14 |

1 Holders of the cumulative redeemable first preferred shares set out in this table are entitled to receive a fixed cumulative quarterly preferred dividend, as and when declared by the Board, with the exception of Series 6 preferred shares. The holders of Series 6 preferred shares are entitled to receive a quarterly floating rate cumulative preferred dividend, as and when declared by the Board.

2 We may, at our option, redeem all or a portion of the outstanding preferred shares for the redemption price per share, plus all accrued and unpaid dividends, on the redemption option date and on every fifth anniversary date thereafter. In addition, Series 6 preferred shares are redeemable by us at any time other than on a designated redemption option date for $25.50 per share plus all accrued and unpaid dividends on such redemption date.

3 The holder will have the right, subject to certain conditions, to convert their first preferred shares of a specified series into first preferred shares of another specified series on the conversion option date and every fifth anniversary thereafter.

4 Commencing September 30, 2016, the floating quarterly dividend rate for the Series 6 preferred shares is 2.073 per cent and will reset every quarter going forward.

## TC PIPELINES, LP AT-THE-MARKET (ATM) EQUITY ISSUANCE PROGRAM

Since January 1, 2016, 2.7 million common units were issued under the TC PipeLines, LP ATM program generating net proceeds of approximately US$143 million. Our ownership interest in TC PipeLines, LP was 27 per cent as a result of issuances under the ATM program and resulting dilution.

In connection with the late filing of an employee-related Form 8-K with the SEC, in March 2016, TC PipeLines, LP became ineligible to use the then effective shelf registration statement upon the filing of its 2015 Annual Report. As a result, it was determined that the purchasers of the 1.6 million common units that were issued from March 8, 2016 to May 19, 2016 under the ATM program may have a rescission right for an amount equal to the purchase price paid for the units, plus statutory interest and less any distributions paid, upon the return of such units to TC PipeLines, LP. No unitholder has claimed or attempted to exercise any rescission rights to date and these rights expire one year from the date of purchase of the unit.

## DIVIDENDS

On November 1, 2016, we declared quarterly dividends as follows:

| **Quarterly dividend on our common shares** |
|---|
| $0.565 per share |
| Payable on January 30, 2017 to shareholders of record at the close of business on January 3, 2017 |

| **Quarterly dividends on our preferred shares** | |
|---|---|
| **Series 1** | $0.204125 |
| **Series 2** | $0.15283060 |
| **Series 3** | $0.1345 |
| **Series 4** | $0.11212020 |
| Payable on December 30, 2016 to shareholders of record at the close of business on November 30, 2016 | |
| **Series 5** | $0.14143750 |
| **Series 6** | $0.13038299 |
| **Series 7** | $0.25 |
| **Series 9** | $0.265625 |
| Payable on January 30, 2017 to shareholders of record at the close of business on January 3, 2017 | |
| **Series 11** | $0.2375 |
| **Series 13** | $0.34375 |
| Payable on November 30, 2016 to shareholders of record at the close of business on November 14, 2016 | |

## SHARE INFORMATION

| as at October 28, 2016 | | |
|---|---|---|
| **Common shares** | **Issued and outstanding** | |
| | 800 million | |
| **Preferred shares** | **Issued and outstanding** | **Convertible to** |
| Series 1 | 9.5 million | Series 2 preferred shares |
| Series 2 | 12.5 million | Series 1 preferred shares |
| Series 3 | 8.5 million | Series 4 preferred shares |
| Series 4 | 5.5 million | Series 3 preferred shares |
| Series 5 | 12.7 million | Series 6 preferred shares |
| Series 6 | 1.3 million | Series 5 preferred shares |
| Series 7 | 24 million | Series 8 preferred shares |
| Series 9 | 18 million | Series 10 preferred shares |
| Series 11 | 10 million | Series 12 preferred shares |
| Series 13 | 20 million | Series 14 preferred shares |
| **Options to buy common shares** | **Outstanding** | **Exercisable** |
| | 11 million | 6 million |

## CREDIT FACILITIES

We use committed revolving credit facilities to support our commercial paper programs and, along with demand facilities, for general corporate purposes including issuing letters of credit, providing additional liquidity and completing the acquisition of Columbia.

At November 1, 2016, we had approximately $19.2 billion in unsecured credit facilities, including:

| Amount | Unused capacity | Subsidiary | Description and use | Matures |
|---|---|---|---|---|
| $3.0 billion | $3.0 billion | TCPL | Committed, syndicated, revolving, extendible TCPL credit facility that supports TCPL's Canadian commercial paper program | December 2020 |
| US$5.2 billion | — | TCPL | Committed, syndicated, senior asset sale bridge term loan commitment that supports the acquisition of Columbia[1] | June 2018 |
| US$1.0 billion | US$1.0 billion | TCPL | Committed, syndicated, revolving, extendible TCPL credit facility that supports TCPL's U.S. commercial paper program | December 2016 |
| US$1.7 billion | — | TCPL USA | Committed, syndicated, senior asset sale bridge term loan commitment that supports the acquisition of Columbia[1] | June 2018 |
| US$1.5 billion | US$1.3 billion | TCPL USA | Committed, syndicated, revolving, extendible TCPL USA credit facility that is used for TCPL USA general corporate purposes | December 2016 |
| US$1.5 billion | US$1.5 billion | TAIL/TCPM | Committed, syndicated, revolving, extendible credit facility that supports the joint TAIL/TCPM commercial paper program in the U.S. | December 2016 |
| $1.9 billion | $0.6 billion | TCPL/TCPL USA | Supports the issuance of letters of credit and provides additional liquidity | Demand |

1 These facilities were put in place to finance a portion of the Columbia acquisition and bear interest at the LIBOR plus an applicable margin. Proceeds from the U.S. Northeast Power business monetizations and the November 2016 common equity offering will be used to partially repay these facilities.

At November 1, 2016, our operated affiliates had an additional $0.4 billion of undrawn capacity on committed credit facilities.

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

### CONTRACTUAL OBLIGATIONS

Our capital commitments have increased by approximately $1.5 billion since December 31, 2015 as a result of the new commitments for the Tula, Villa de Reyes and Sur de Texas natural gas pipelines partially offset by decreased commitments on Grand Rapids and Napanee. Our other purchase obligations are consistent with the amounts reported at December 31, 2015.

Our commitments at December 31, 2015 included fixed payments net of sublease receipts for Alberta PPAs. With the March 7, 2016 notice to terminate our Sheerness, Sundance A and Sundance B PPAs, our future obligations from December 31, 2015 have decreased as follows: 2016 - $195 million, 2017 - $200 million, 2018 - $141 million, 2019 - $138 million and 2020 - $115 million. Our commitments for 2021 and beyond increased by approximately $0.5 billion as a result of the extension of premises leases in second quarter 2016. The acquisition of Columbia on July 1, 2016 resulted in a total increase to our contractual obligations of $349 million for transportation contracts and premises leases. There were no other material changes to our contractual obligations in third quarter 2016 or to payments due in the next five years or after. See the MD&A in our 2015 Annual Report for more information about our contractual obligations.

## Financial risks and financial instruments

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

Our liquids marketing business began operations in the first quarter of 2016. It enters into short-term or long-term pipeline and storage terminal capacity contracts, primarily on the Company's assets, increasing the utilization of those assets and earning the market value of the capacity. Derivative instruments are used to fix a portion of the variable price exposures that arise from physical liquids transactions.

See our 2015 Annual Report for more information about the risks we face in our business. Our risks have not changed substantially since December 31, 2015.

### LIQUIDITY RISK

We manage our liquidity risk by continuously forecasting our cash flow for a 12 month period to ensure we have adequate cash balances, cash flow from operations, committed and demand credit facilities and access to capital markets to meet our operating, financing and capital expenditure obligations under both normal and stressed economic conditions.

### COUNTERPARTY CREDIT RISK

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

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

We review our accounts receivable regularly and record allowances for doubtful accounts using the specific identification method. At September 30, 2016, we had no significant credit losses and no significant amounts past due or impaired. We had a credit risk concentration of $191 million (US$146 million) at September 30, 2016 with one counterparty (December 31, 2015 - $248 million (US$179 million)). This amount is secured by a guarantee from the counterparty's parent company and is expected to be fully collectible.

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

### FOREIGN EXCHANGE AND INTEREST RATE RISK

Certain of our businesses generate income in U.S. dollars, but since we report in Canadian dollars, changes in the value of the U.S. dollar against the Canadian dollar can affect our net income. As our U.S. dollar-denominated operations continue to grow, this exposure increases. The majority of this risk is offset by interest expense on U.S. dollar-denominated debt and further managed by using foreign exchange derivatives.

We have floating interest rate debt which subjects us to interest rate cash flow risk, a portion of which we manage using a combination of interest rate swaps and options.

### Average exchange rate - U.S. to Canadian dollars

| | |
|---|---|
| **three months ended September 30, 2016** | **1.31** |
| three months ended September 30, 2015 | 1.31 |
| | |
| **nine months ended September 30, 2016** | **1.32** |
| nine months ended September 30, 2015 | 1.26 |

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

### Significant U.S. dollar-denominated amounts

| | **three months ended September 30** | | **nine months ended September 30** | |
|---|---|---|---|---|
| (unaudited - millions of US$) | **2016** | **2015** | **2016** | **2015** |
| U.S. and International Natural Gas Pipelines comparable EBIT | **366** | 153 | **792** | 526 |
| U.S. Liquids Pipelines comparable EBIT | **119** | 171 | **369** | 474 |
| U.S. Power comparable EBIT | **131** | 117 | **228** | 257 |
| AFUDC on U.S. dollar-denominated projects | **55** | 37 | **149** | 98 |
| Interest on U.S. dollar-denominated long-term debt | **(315)** | (231) | **(811)** | (677) |
| Capitalized interest on U.S. dollar-denominated capital expenditures | **6** | 42 | **22** | 102 |
| U.S. non-controlling interests | **(38)** | (35) | **(138)** | (115) |
| | **324** | 254 | **611** | 665 |

### Derivatives designated as a net investment hedge

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

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

| | September 30, 2016 | | December 31, 2015 | |
|---|---|---|---|---|
| (unaudited - millions of Canadian $, unless noted otherwise) | Fair value[1] | Notional or principal amount | Fair value[1] | Notional or principal amount |
| **Asset/(liability)** | | | | |
| U.S. dollar cross-currency interest rate swaps (maturing 2016 to 2019)[2] | **(433)** | **US 2,400** | (730) | US 3,150 |
| U.S. dollar foreign exchange forward contracts (maturing 2016 to 2017) | **(16)** | **US 200** | 50 | US 1,800 |
| | **(449)** | **US 2,600** | (680) | US 4,950 |

1 Fair values equal carrying values.
2 In the three and nine months ended September 30, 2016, net realized gains of $1 million and $5 million, respectively, (2015 - gains of $2 million and $7 million, respectively) related to the interest component of cross-currency swaps settlements are included in interest expense.

### U.S. dollar-denominated debt designated as a net investment hedge

| (unaudited - millions of Canadian $, unless noted otherwise) | September 30, 2016 | December 31, 2015 |
|---|---|---|
| Notional amount | **30,200 (US 23,000)** | 23,100 (US 16,700) |
| Fair value | **33,700 (US 25,700)** | 23,800 (US 17,200) |

## FINANCIAL INSTRUMENTS

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

### Derivative instruments

We use derivative instruments to reduce volatility associated with fluctuations in commodity prices, interest rates and foreign exchange rates. We apply hedge accounting to derivative instruments that qualify and are designated for hedge accounting treatment.

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

### Balance sheet presentation of derivative instruments

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

| (unaudited - millions of $) | September 30, 2016 | December 31, 2015 |
|---|---|---|
| Other current assets | **332** | 442 |
| Intangible and other assets | **181** | 168 |
| Accounts payable and other | **(616)** | (926) |
| Other long-term liabilities | **(428)** | (625) |
| | **(531)** | (941) |

### Unrealized and realized gains/(losses) of derivative instruments

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

| | three months ended September 30 | | nine months ended September 30 | |
|---|---|---|---|---|
| (unaudited - millions of $, pre-tax) | 2016 | 2015 | 2016 | 2015 |
| **Derivative instruments held for trading**[1] | | | | |
| Amount of unrealized (losses)/gains in the period | | | | |
| Commodities[2] | **(97)** | (27) | **23** | (30) |
| Foreign exchange | **—** | (26) | **47** | (25) |
| Amount of realized (losses)/gains in the period | | | | |
| Commodities | **(23)** | (52) | **(165)** | (84) |
| Foreign exchange | **(5)** | (34) | **52** | (87) |
| **Derivative instruments in hedging relationships** | | | | |
| Amount of realized (losses)/gains in the period | | | | |
| Commodities | **(15)** | (35) | **(155)** | (132) |
| Foreign exchange | **5** | — | **(101)** | — |
| Interest rate | **1** | 2 | **4** | 6 |

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

2 Following the March 17, 2016 announcement of our intention to sell the U.S. Northeast Power business, a loss of $49 million and a gain of $7 million (2015 - nil) were recorded in net income in the three months ended March 31, 2016 relating to discontinued cash flow hedges where it was probable that the anticipated underlying transaction would not occur as a result of a future sale.

### Derivatives in cash flow hedging relationships

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

| | three months ended September 30 | | nine months ended September 30 | |
|---|---|---|---|---|
| (unaudited - millions of $, pre-tax) | **2016** | **2015** | **2016** | **2015** |
| Change in fair value of derivative instruments recognized in OCI (effective portion)[1] | | | | |
| Commodities | **7** | (48) | **33** | (77) |
| Foreign exchange | **(5)** | — | **—** | — |
| Interest rate | **4** | (1) | **—** | (1) |
| | **6** | (49) | **33** | (78) |
| Reclassification of (losses)/gains on derivative instruments from AOCI to net income (effective portion)[1] | | | | |
| Commodities[2] | **(7)** | 76 | **54** | 124 |
| Foreign exchange[3] | **5** | — | **—** | — |
| Interest rate[4] | **3** | 4 | **11** | 12 |
| | **1** | 80 | **65** | 136 |
| Gains/(losses) on derivative instruments recognized in net income (ineffective portion) | | | | |
| Commodities[2] | **14** | 10 | **(1)** | 3 |
| | **14** | 10 | **(1)** | 3 |

1 No amounts have been excluded from the assessment of hedge effectiveness. Amounts in parentheses indicate losses recorded to OCI.
2 Reported within revenues on the condensed consolidated statement of income.
3 Reported within interest income and other on the condensed consolidated statement of income.
4 Reported within interest expense on the condensed consolidated statement of income.

### Credit risk related contingent features of derivative instruments

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

Based on contracts in place and market prices at September 30, 2016, the aggregate fair value of all derivative contracts with credit-risk-related contingent features that were in a net liability position was $24 million (December 31, 2015 – $32 million), with collateral provided in the normal course of business of nil (December 31, 2015 – nil). If the credit-risk-related contingent features in these agreements were triggered on September 30, 2016, we would have been required to provide additional collateral of $24 million (December 31, 2015 – $32 million) to our counterparties. We have sufficient liquidity in the form of cash and undrawn committed revolving bank lines to meet these contingent obligations should they arise.

# Other information

## CONTROLS AND PROCEDURES

Management, including our President and CEO and our CFO, evaluated the effectiveness of our disclosure controls and procedures as at September 30, 2016, as required by the Canadian securities regulatory authorities and by the SEC, and concluded that our disclosure controls and procedures are effective at a reasonable assurance level.

We acquired Columbia on July 1, 2016. Assets attributable to Columbia as of July 1, 2016 represented approximately 25 per cent of our total assets as of July 1, 2016, and revenues attributable to Columbia for the period July 1, 2016 to September 30, 2016 represented approximately 12 per cent of our total revenues for third quarter 2016. Management is currently in the process of evaluating and integrating Columbia's controls over financial reporting with ours. We expect to complete this integration in 2017.

Other than as described above, there were no changes in third quarter 2016 that had or are likely to have a material impact on our internal control over financial reporting.

## CRITICAL ACCOUNTING ESTIMATES AND ACCOUNTING POLICY CHANGES

When we prepare financial statements that conform with U.S. GAAP, we are required to make estimates and assumptions that affect the timing and amount we record for our assets, liabilities, revenues and expenses because these items may be affected by future events. The fair value of assets and liabilities acquired in a business combination accounted for under the acquisition method are also subject to estimates and judgement. We base the estimates and assumptions on the most current information available, using our best judgement. We also regularly assess the assets and liabilities themselves. You can find a summary of our critical accounting estimates in our 2015 Annual Report.

### Impairment of long-lived assets and goodwill

We test goodwill for impairment on an annual basis or more frequently if events or changes in circumstances indicate that it might be impaired. As a result of information received during the process to monetize our U.S. Northeast Power business in third quarter 2016, it was determined that the fair value of Ravenswood did not exceed its carrying value, including goodwill, at September 30, 2016. The fair value of Ravenswood was determined using a combination of methods including a discounted cash flow approach and a range of expected consideration from a potential sale. Plant, property and equipment was also tested for impairment. As a result, at September 30, 2016, we recorded a goodwill impairment charge on the full goodwill amount of $1,085 million ($656 million after tax) related to the Ravenswood facility within the Energy segment and also determined there was no impairment on the plant, property and equipment.

At September 30, 2016, our goodwill included $1.9 billion related to the ANR natural gas transportation business. As a result of our ANR Section 4 rate case settlement filed on September 16, 2016, we tested this reporting unit for impairment. The fair value of this reporting unit was measured by using a discounted cash flow analysis incorporating the key terms of the settlement. While no impairment of goodwill was necessary, the estimated fair value of ANR exceeds its carrying value, including goodwill, by less than 10 per cent. Under the settlement, there is a moratorium on any further rate changes until August 1, 2019. Adverse conditions impacting rates and volumes on ANR beyond the moratorium period could result in a reduction for our estimated future cash flows, which could result in future impairment of a portion of the goodwill balance related to ANR.

Our significant accounting policies have remained unchanged since December 31, 2015 other than described below. You can find a summary of our significant accounting policies in our 2015 Annual Report.

## Changes in accounting policies for 2016

### Extraordinary and unusual income statement items

In January 2015, the FASB issued new guidance on extraordinary and unusual income statement items. This update eliminates from U.S. GAAP the concept of extraordinary items. This new guidance was effective January 1, 2016, was applied prospectively and did not have a material impact on our consolidated financial statements.

### Consolidation

In February 2015, the FASB issued new guidance on consolidation. This update requires that entities re-evaluate whether they should consolidate certain legal entities and eliminates the presumption that a general partner should consolidate a limited partnership. This new guidance was effective January 1, 2016, was applied retrospectively and did not result in any change to our consolidation conclusions. Disclosure requirements outlined in the new guidance are included in Note 16, Variable interest entities.

### Imputation of interest

In April 2015, the FASB issued new guidance on simplifying the accounting for debt issuance costs. The amendments in this update require that debt issuance costs be presented in the balance sheet as a direct deduction from the carrying amount of the debt liability consistent with debt discounts or premiums. This new guidance was effective January 1, 2016, was applied retrospectively and resulted in a reclassification of debt issuance costs previously recorded in Intangible and other assets to an offset of their respective debt liabilities on our consolidated balance sheet.

### Business combinations

In September 2015, the FASB issued guidance which intends to simplify the accounting measurement period adjustments in business combinations. The amended guidance requires an acquirer to recognize adjustments to the provisional amounts that are identified during the measurement period in the reporting period in which the adjustment amounts are determined. In the period the adjustment was determined, the guidance also requires the acquirer to record the effect on earnings of changes in depreciation, amortization, or other income effects, if any, as a result of the change to the provisional amounts, calculated as if the accounting had been completed at the acquisition date. This new guidance was effective January 1, 2016, was applied prospectively and did not have a material impact on our consolidated financial statements.

## Future accounting changes

### Revenue from contracts with customers

In 2014, the FASB issued new guidance on revenue from contracts with customers. This guidance supersedes the current revenue recognition requirements and most industry-specific guidance. This new guidance requires that an entity recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the company expects to be entitled in exchange for those goods or services. In July 2015, the FASB deferred the effective date of this new standard to January 1, 2018, with early adoption not permitted before January 1, 2017. There are two methods in which the amendment can be applied: (1) retrospectively to each prior reporting period presented, or (2) retrospectively with the cumulative effect recognized at the date of initial application. We are currently identifying existing customer contracts or groups of contracts that are within the scope of the new guidance and have begun an assessment in order to determine any impact on our consolidated financial statements.

### Inventory

In July 2015, the FASB issued new guidance on simplifying the measurement of inventory. The amendments in this update specify that an entity should measure inventory within the scope of this update at the lower of cost and net realizable value. Net realizable value is the estimated selling price in the ordinary course of business, less reasonably predictable costs of completion, disposal and transportation. This new guidance is effective January 1, 2017 and will be applied prospectively. We do not expect the adoption of this new standard to have a material impact on our consolidated financial statements.

**Financial instruments**

In January 2016, the FASB issued new guidance on the accounting for equity investments and financial liabilities. The new guidance will change the income statement effect of equity investments and the recognition of changes in fair value of financial liabilities when the fair value option is elected. The new guidance also requires us to assess valuation allowances for deferred tax assets related to available-for-sale debt securities in combination with our other deferred tax assets. This new guidance is effective January 1, 2018. We are currently evaluating the impact of the adoption of this guidance and have not yet determined the effect on our consolidated financial statements.

**Leases**

In February 2016, the FASB issued new guidance on leases. The new guidance requires lessees to recognize most leases, including operating leases, on the balance sheet as lease assets and lease liabilities. In addition, lessees may be required to reassess assumptions associated with existing leases as well as to provide expanded qualitative and quantitative disclosures. The new standard does not make extensive changes to lessor accounting. The new guidance is effective January 1, 2019 and will be applied using a modified retrospective approach. We are currently identifying existing lease agreements that are within the scope of the new guidance that may have an impact on our consolidated financial statements as a result of adopting this new standard.

**Derivatives and hedging**

In March 2016, the FASB issued new guidance that clarifies the requirements for assessing whether contingent call or put options that can accelerate the payment of principal on debt instruments are clearly and closely related to their debt hosts. The new guidance requires only an assessment of the four-step decision sequence outlined in GAAP to determine whether the economic characteristics and risks of call or put options are clearly and closely related to the economic characteristics and risks. This new guidance is effective January 1, 2017 and we do not expect the adoption of this guidance to have a material impact on our consolidated financial statements.

**Equity method investments**

In March 2016, the FASB issued new guidance that simplifies the transition to equity method accounting. The new guidance eliminates the requirement to retroactively apply the equity method of accounting when an increase in ownership interest in an investment qualifies it for equity method accounting. This new guidance is effective January 1, 2017 and will be applied prospectively. We do not expect the adoption of this new standard to have a material impact on our consolidated financial statements.

**Employee share-based payments**

In March 2016, the FASB issued new guidance that simplifies several aspects of the accounting for employee share-based payment transactions including the income tax consequences, classification of awards as either equity or liabilities, and classification on the statement of cash flows. The new guidance also permits entities to make an accounting policy election either to continue to estimate the total number of awards for which the requisite service period will not be rendered or to account for forfeitures when they occur. This new guidance is effective January 1, 2017 and we do not expect the adoption of this new standard to have a material impact on our consolidated financial statements.

**Measurement of credit losses on financial instruments**

In June 2016, the FASB issued new guidance that significantly changes how entities measure credit losses for most financial assets and certain other instruments that are not measured at fair value through net income. The new guidance amends the impairment model of financial instruments basing it on expected losses rather than incurred losses. These expected credit losses will be recognized as an allowance rather than a direct write-down of the amortized cost basis. The new guidance is effective January 1, 2020 and will be applied using a modified retrospective approach.

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

**Classification of certain cash receipts and cash payments**

In August 2016, the FASB issued new guidance to clarify how entities should classify certain cash receipts and cash payments. These include debt pre-payments or extinguishment costs, contingent consideration payments made after a business combination, proceeds from the settlement of insurance claims, proceeds from the settlement of corporate-owned life insurance and distributions received from equity method investees. The new guidance is effective January 1, 2018 and will be applied using a retrospective approach. The new guidance also specifies how the predominance principle should be applied when cash receipts and cash payments have aspects of more than one class of cash flows. We are currently evaluating the impact of the adoption of this guidance and have not yet determined the impact on our consolidated financial statements.

# Reconciliation of non-GAAP measures

| | three months ended September 30 | | nine months ended September 30 | |
|---|---|---|---|---|
| (unaudited - millions of $, except per share amounts) | **2016** | **2015** | **2016** | **2015** |
| **EBITDA** | **605** | 1,458 | **3,262** | 4,334 |
| Ravenswood goodwill impairment | **1,085** | — | **1,085** | — |
| Alberta PPA terminations | **—** | — | **240** | — |
| Acquisition related costs - Columbia | **96** | — | **132** | — |
| Keystone XL asset costs | **14** | — | **37** | — |
| Restructuring costs | **—** | 8 | **14** | 20 |
| TC Offshore loss on sale | **—** | — | **4** | — |
| U.S. Northeast Power business monetization | **5** | — | **5** | — |
| Risk management activities[1] | **81** | 17 | **(22)** | 27 |
| **Comparable EBITDA** | **1,886** | 1,483 | **4,757** | 4,381 |
| Depreciation and amortization | **(527)** | (439) | **(1,425)** | (1,313) |
| **Comparable EBIT** | **1,359** | 1,044 | **3,332** | 3,068 |
| **Other income statement items** | | | | |
| Comparable interest expense | **(516)** | (341) | **(1,341)** | (990) |
| Comparable interest income and other | **122** | 42 | **385** | 108 |
| Comparable income tax expense | **(261)** | (236) | **(630)** | (668) |
| Comparable net income attributable to non-controlling interests | **(55)** | (46) | **(187)** | (145) |
| Preferred share dividends | **(27)** | (23) | **(77)** | (71) |
| **Comparable earnings** | **622** | 440 | **1,482** | 1,302 |
| Specific items (net of tax): | | | | |
| Ravenswood goodwill impairment | **(656)** | — | **(656)** | — |
| Alberta PPA terminations | **—** | — | **(176)** | — |
| Acquisition related costs - Columbia | **(67)** | — | **(206)** | — |
| Keystone XL income tax recoveries | **28** | — | **28** | — |
| Keystone XL asset costs | **(9)** | — | **(24)** | — |
| Restructuring costs | **—** | (6) | **(10)** | (14) |
| TC Offshore loss on sale | **—** | — | **(3)** | — |
| U.S. Northeast Power business monetization | **(3)** | — | **(3)** | — |
| Alberta corporate income tax rate increase | **—** | — | **—** | (34) |
| Risk management activities[1] | **(50)** | (32) | **50** | (36) |
| **Net (loss)/income attributable to common shares** | **(135)** | 402 | **482** | 1,218 |
| **Comparable interest expense** | **(516)** | (341) | **(1,341)** | (990) |
| Specific item: | | | | |
| Acquisition related costs - Columbia | **(6)** | — | **(115)** | — |
| **Interest expense** | **(522)** | (341) | **(1,456)** | (990) |
| **Comparable interest income and other** | **122** | 42 | **385** | 108 |
| Specific items: | | | | |
| Acquisition related costs - Columbia | **—** | — | **6** | — |
| Risk management activities[1] | **—** | (26) | **49** | (25) |
| **Interest income and other** | **122** | 16 | **440** | 83 |

| (unaudited - millions of $, except per share amounts) | three months ended September 30 2016 | 2015 | nine months ended September 30 2016 | 2015 |
|---|---|---|---|---|
| **Comparable income tax expense** | **(261)** | (236) | **(630)** | (668) |
| Specific items: | | | | |
| Ravenswood goodwill impairment | **429** | — | **429** | — |
| Alberta PPA terminations | **—** | — | **64** | — |
| Acquisition related costs - Columbia | **32** | — | **32** | — |
| Keystone XL income tax recoveries | **28** | — | **28** | — |
| Keystone XL asset costs | **5** | — | **13** | — |
| Restructuring costs | **—** | 2 | **4** | 6 |
| TC Offshore loss on sale | **—** | — | **1** | — |
| U.S. Northeast Power business monetization | **2** | — | **2** | — |
| Alberta corporate income tax rate increase | **—** | — | **—** | (34) |
| Risk management activities[1] | **31** | 11 | **(21)** | 16 |
| **Income tax recovery/(expense)** | **266** | (223) | **(78)** | (680) |
| **Comparable net income attributable to non-controlling interests** | **(55)** | (46) | **(187)** | (145) |
| Specific item: | | | | |
| Acquisition related costs - Columbia | **3** | — | **3** | — |
| **Net income attributable to non-controlling interests** | **(52)** | (46) | **(184)** | (145) |
| **Comparable earnings per common share** | **$0.78** | $0.62 | **$2.02** | $1.84 |
| Specific items (net of tax): | | | | |
| Ravenswood goodwill impairment | **(0.82)** | — | **(0.89)** | — |
| Alberta PPA terminations | **—** | — | **(0.25)** | — |
| Acquisition related costs - Columbia | **(0.09)** | — | **(0.29)** | — |
| Keystone XL income tax recoveries | **0.03** | — | **0.04** | — |
| Keystone XL asset costs | **(0.01)** | — | **(0.03)** | — |
| Restructuring costs | **—** | (0.01) | **(0.01)** | (0.02) |
| U.S. Northeast Power business monetization | **—** | — | **—** | — |
| Alberta corporate income tax rate increase | **—** | — | **—** | (0.05) |
| Risk management activities | **(0.06)** | (0.04) | **0.07** | (0.05) |
| **Net (loss)/income per common share** | **($0.17)** | $0.57 | **$0.66** | $1.72 |

1

| **Risk management activities** (unaudited - millions of $) | three months ended September 30 2016 | 2015 | nine months ended September 30 2016 | 2015 |
|---|---|---|---|---|
| Canadian Power | **(4)** | (14) | **3** | (7) |
| U.S. Power | **(73)** | (5) | **16** | (22) |
| Liquids | **(8)** | — | **(6)** | — |
| Natural Gas Storage | **4** | 2 | **9** | 2 |
| Foreign exchange | **—** | (26) | **49** | (25) |
| Income tax attributable to risk management activities | **31** | 11 | **(21)** | 16 |
| **Total unrealized (losses)/gains from risk management activities** | **(50)** | (32) | **50** | (36) |

## Comparable EBITDA and EBIT by business segment

| three months ended September 30, 2016<br>(unaudited - millions of $) | Natural Gas Pipelines | Liquids Pipelines | Energy | Corporate | Total |
|---|---|---|---|---|---|
| **EBITDA** | **1,114** | **259** | **(744)** | **(24)** | **605** |
| Ravenswood goodwill impairment | — | — | 1,085 | — | 1,085 |
| Alberta PPA terminations | — | — | — | — | — |
| Acquisition related costs - Columbia | 82 | — | — | 14 | 96 |
| Keystone XL asset costs | — | 14 | — | — | 14 |
| Restructuring costs | — | — | — | — | — |
| U.S. Northeast Power business monetization | — | — | 5 | — | 5 |
| Risk management activities | — | 8 | 73 | — | 81 |
| **Comparable EBITDA** | **1,196** | **281** | **419** | **(10)** | **1,886** |
| Comparable depreciation and amortization | (361) | (72) | (81) | (13) | (527) |
| **Comparable EBIT** | **835** | **209** | **338** | **(23)** | **1,359** |

| three months ended September 30, 2015<br>(unaudited - millions of $) | Natural Gas Pipelines | Liquids Pipelines | Energy | Corporate | Total |
|---|---|---|---|---|---|
| **EBITDA** | 806 | 352 | 323 | (23) | 1,458 |
| Restructuring costs | — | — | — | 8 | 8 |
| Risk management activities | — | — | 17 | — | 17 |
| **Comparable EBITDA** | 806 | 352 | 340 | (15) | 1,483 |
| Comparable depreciation and amortization | (284) | (68) | (79) | (8) | (439) |
| **Comparable EBIT** | 522 | 284 | 261 | (23) | 1,044 |

| nine months ended September 30, 2016<br>(unaudited - millions of $) | Natural Gas Pipelines | Liquids Pipelines | Energy | Corporate | Total |
|---|---|---|---|---|---|
| **EBITDA** | **2,888** | **818** | **(318)** | **(126)** | **3,262** |
| Ravenswood goodwill impairment | — | — | 1,085 | — | 1,085 |
| Alberta PPA terminations | — | — | 240 | — | 240 |
| Acquisition related costs - Columbia | 82 | — | — | 50 | 132 |
| Keystone XL asset costs | — | 37 | — | — | 37 |
| Restructuring costs | — | — | — | 14 | 14 |
| TC Offshore loss on sale | 4 | — | — | — | 4 |
| U.S. Northeast Power business monetization | — | — | 5 | — | 5 |
| Risk management activities | — | 6 | (28) | — | (22) |
| **Comparable EBITDA** | **2,974** | **861** | **984** | **(62)** | **4,757** |
| Depreciation and amortization | (936) | (209) | (251) | (29) | (1,425) |
| **Comparable EBIT** | **2,038** | **652** | **733** | **(91)** | **3,332** |

| nine months ended September 30, 2015<br>(unaudited - millions of $) | Natural Gas Pipelines | Liquids Pipelines | Energy | Corporate | Total |
|---|---|---|---|---|---|
| **EBITDA** | 2,472 | 970 | 963 | (71) | 4,334 |
| Restructuring costs | — | — | — | 20 | 20 |
| Risk management activities | — | — | 27 | — | 27 |
| **Comparable EBITDA** | 2,472 | 970 | 990 | (51) | 4,381 |
| Depreciation and amortization | (845) | (197) | (248) | (23) | (1,313) |
| **Comparable EBIT** | 1,627 | 773 | 742 | (74) | 3,068 |

# Quarterly results

### SELECTED QUARTERLY CONSOLIDATED FINANCIAL DATA

| | 2016 | | | 2015 | | | | 2014 |
|---|---|---|---|---|---|---|---|---|
| (unaudited - millions of $, except per share amounts) | Third | Second | First | Fourth | Third | Second | First | Fourth |
| Revenues | **3,632** | 2,751 | 2,503 | 2,851 | 2,944 | 2,631 | 2,874 | 2,616 |
| Net (loss)/income attributable to common shares | **(135)** | 365 | 252 | (2,458) | 402 | 429 | 387 | 458 |
| Comparable earnings | **622** | 366 | 494 | 453 | 440 | 397 | 465 | 511 |
| Share statistics | | | | | | | | |
| Net (loss)/income per common share - basic and diluted | **($0.17)** | $0.52 | $0.36 | ($3.47) | $0.57 | $0.60 | $0.55 | $0.65 |
| Comparable earnings per share | **$0.78** | $0.52 | $0.70 | $0.64 | $0.62 | $0.56 | $0.66 | $0.72 |
| Dividends declared per common share | **$0.565** | $0.565 | $0.565 | $0.52 | $0.52 | $0.52 | $0.52 | $0.48 |

### FACTORS AFFECTING QUARTERLY FINANCIAL INFORMATION BY BUSINESS SEGMENT

Quarter-over-quarter revenues and net income sometimes fluctuate, the causes of which vary across our business segments.

In Natural Gas Pipelines, quarter-over-quarter revenues and net income from the Canadian regulated pipelines generally remain relatively stable during any fiscal year. Our U.S. natural gas pipelines are generally seasonal in nature with higher earnings in the winter months as a result of increased customer demands. Over the long term, however, results from both our Canadian and U.S. natural gas pipelines fluctuate because of:

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

In Liquids Pipelines, revenues and net income are based on contracted crude oil transportation and uncommitted spot transportation. Quarter-over-quarter revenues and net income are also affected by:

- developments outside of the normal course of operations
- newly constructed assets being placed in service
- regulatory decisions.

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

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

## FACTORS AFFECTING FINANCIAL INFORMATION BY QUARTER

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

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

In third quarter 2016, comparable earnings excluded:

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

In second quarter 2016, comparable earnings excluded:

- a charge of $113 million related to costs associated with the acquisition of Columbia
- a charge of $9 million after tax related to Keystone XL costs for the maintenance and liquidation of project assets which are being expensed pending further advancement of the project
- a charge of $10 million after tax for restructuring charges mainly related to expected future losses under lease commitments.

In first quarter 2016, comparable earnings excluded:

- a $176 million after-tax impairment charge on the carrying value of our Alberta PPAs as a result of our decision to terminate the PPAs
- a charge of $26 million related to costs associated with the acquisition of Columbia
- a charge of $6 million after tax related to Keystone XL costs for the maintenance and liquidation of project assets which are being expensed pending further advancement of the project
- an additional $3 million after-tax loss on the sale of TC Offshore which closed on March 31, 2016.

In fourth quarter 2015, comparable earnings excluded:

- 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 expected to close 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 related to an impairment in value of 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.

In third quarter 2015, comparable earnings excluded a charge of $6 million after-tax for severance costs as part of a restructuring initiative to maximize the effectiveness and efficiency of our existing operations.

In second quarter 2015, comparable earnings excluded a $34 million adjustment to income tax expense due to the enactment of an increase in the Alberta corporate income tax rate in June 2015 and a charge of $8 million after-tax for severance costs primarily as a result of the restructuring of our major projects group in response to delayed timelines on certain of our major projects along with a continued focus on enhancing the efficiency and effectiveness of our operations.

In fourth quarter 2014, comparable earnings excluded an $8 million after-tax gain on the sale of our interest in Gas Pacifico/INNERGY.

# Condensed consolidated statement of income

| (unaudited - millions of Canadian $, except per share amounts) | three months ended September 30 | | nine months ended September 30 | |
|---|---|---|---|---|
| | **2016** | **2015** | **2016** | **2015** |
| **Revenues** | | | | |
| Natural Gas Pipelines | **1,884** | 1,305 | **4,511** | 3,896 |
| Liquids Pipelines | **440** | 507 | **1,292** | 1,410 |
| Energy | **1,308** | 1,132 | **3,083** | 3,143 |
| | **3,632** | 2,944 | **8,886** | 8,449 |
| **Income from Equity Investments** | **154** | 94 | **355** | 350 |
| **Operating and Other Expenses** | | | | |
| Plant operating costs and other | **1,177** | 823 | **2,646** | 2,344 |
| Commodity purchases resold | **783** | 624 | **1,628** | 1,731 |
| Property taxes | **136** | 133 | **405** | 390 |
| Depreciation and amortization | **527** | 439 | **1,425** | 1,313 |
| Goodwill and other asset impairment charges | **1,085** | — | **1,296** | — |
| | **3,708** | 2,019 | **7,400** | 5,778 |
| **Loss on Sale of Assets** | **—** | — | **(4)** | — |
| **Financial Charges** | | | | |
| Interest expense | **522** | 341 | **1,456** | 990 |
| Interest income and other | **(122)** | (16) | **(440)** | (83) |
| | **400** | 325 | **1,016** | 907 |
| **(Loss)/Income before Income Taxes** | **(322)** | 694 | **821** | 2,114 |
| **Income Tax (Recovery)/Expense** | | | | |
| Current | **14** | 30 | **103** | 124 |
| Deferred | **(280)** | 193 | **(25)** | 556 |
| | **(266)** | 223 | **78** | 680 |
| **Net (Loss)/Income** | **(56)** | 471 | **743** | 1,434 |
| Net income attributable to non-controlling interests | **52** | 46 | **184** | 145 |
| **Net (Loss)/Income Attributable to Controlling Interests** | **(108)** | 425 | **559** | 1,289 |
| Preferred share dividends | **27** | 23 | **77** | 71 |
| **Net (Loss)/Income Attributable to Common Shares** | **(135)** | 402 | **482** | 1,218 |
| **Net (Loss)/Income per Common Share** | | | | |
| Basic and diluted | **($0.17)** | $0.57 | **$0.66** | $1.72 |
| **Dividends Declared per Common Share** | **$0.565** | $0.52 | **$1.695** | $1.56 |
| **Weighted Average Number of Common Shares** (millions) | | | | |
| Basic | **797** | 709 | **734** | 709 |
| Diluted | **798** | 710 | **735** | 710 |

See accompanying notes to the condensed consolidated financial statements.

## Condensed consolidated statement of comprehensive income

| | three months ended September 30 | | nine months ended September 30 | |
|---|---|---|---|---|
| (unaudited - millions of Canadian $) | **2016** | **2015** | **2016** | **2015** |
| **Net (Loss)/Income** | **(56)** | 471 | **743** | 1,434 |
| **Other Comprehensive Income/(Loss), Net of Income Taxes** | | | | |
| Foreign currency translation gains/(losses) on net investment in foreign operations | **55** | 356 | **(152)** | 688 |
| Change in fair value of net investment hedges | **(1)** | (153) | **(9)** | (361) |
| Change in fair value of cash flow hedges | **5** | (29) | **21** | (50) |
| Reclassification to net income of gains on cash flow hedges | **—** | 50 | **40** | 83 |
| Reclassification to net income of actuarial gains and prior service costs on pension and other post-retirement benefit plans | **4** | 7 | **12** | 24 |
| Other comprehensive income on equity investments | **4** | 3 | **11** | 10 |
| Other comprehensive income/(loss) (Note 11) | **67** | 234 | **(77)** | 394 |
| **Comprehensive Income** | **11** | 705 | **666** | 1,828 |
| Comprehensive income attributable to non-controlling interests | **76** | 171 | **104** | 388 |
| **Comprehensive (Loss)/Income Attributable to Controlling Interests** | **(65)** | 534 | **562** | 1,440 |
| Preferred share dividends | **27** | 23 | **77** | 71 |
| **Comprehensive (Loss)/Income Attributable to Common Shares** | **(92)** | 511 | **485** | 1,369 |

See accompanying notes to the condensed consolidated financial statements.

# Condensed consolidated statement of cash flows

| | three months ended September 30 | | nine months ended September 30 | |
|---|---|---|---|---|
| (unaudited - millions of Canadian $) | **2016** | **2015** | **2016** | **2015** |
| **Cash Generated from Operations** | | | | |
| Net (loss)/income | **(56)** | 471 | **743** | 1,434 |
| Depreciation and amortization | **527** | 439 | **1,425** | 1,313 |
| Goodwill and other asset impairment charges | **1,085** | — | **1,296** | — |
| Deferred income taxes | **(280)** | 193 | **(25)** | 556 |
| Income from equity investments | **(154)** | (94) | **(355)** | (350) |
| Distributed earnings received from equity investments | **155** | 117 | **408** | 397 |
| Employee post-retirement benefits expense, net of funding | **4** | 11 | **(5)** | 41 |
| Loss on sale of assets | **—** | — | **4** | — |
| Equity allowance for funds used during construction | **(71)** | (45) | **(195)** | (115) |
| Unrealized losses/(gains) on financial instruments | **82** | 43 | **(71)** | 52 |
| Other | **1** | 5 | **24** | 26 |
| (Increase)/decrease in operating working capital | **(110)** | 107 | **28** | (378) |
| Net cash provided by operations | **1,183** | 1,247 | **3,277** | 2,976 |
| **Investing Activities** | | | | |
| Capital expenditures | **(1,444)** | (976) | **(3,262)** | (2,748) |
| Capital projects in development | **(62)** | (130) | **(219)** | (465) |
| Contributions to equity investments | **(286)** | (105) | **(570)** | (303) |
| Restricted cash | **13,113** | — | **—** | — |
| Acquisitions, net of cash acquired | **(12,609)** | — | **(13,608)** | — |
| Proceeds from sale of assets, net of transaction costs | **—** | — | **6** | — |
| Distributions received in excess of equity earnings | **30** | 111 | **942** | 221 |
| Deferred amounts and other | **38** | 36 | **18** | 240 |
| Net cash used in investing activities | **(1,220)** | (1,064) | **(16,693)** | (3,055) |
| **Financing Activities** | | | | |
| Notes payable repaid, net | **(423)** | (358) | **(100)** | (828) |
| Long-term debt issued, net of issue costs | **6** | 962 | **12,333** | 3,323 |
| Long-term debt repaid | **(53)** | (183) | **(2,343)** | (2,066) |
| Junior subordinated notes issued, net of issue costs | **1,551** | — | **1,551** | 917 |
| Dividends on common shares | **(397)** | (369) | **(1,159)** | (1,078) |
| Dividends on preferred shares | **(28)** | (23) | **(74)** | (69) |
| Distributions paid to non-controlling interests | **(77)** | (60) | **(201)** | (168) |
| Common shares/subscription receipts issued, net of issue costs | **(37)** | 1 | **4,337** | 12 |
| Common shares repurchased | **—** | — | **(14)** | — |
| Preferred shares issued, net of issue costs | **—** | — | **492** | 243 |
| Partnership units of subsidiary issued, net of issue costs | **45** | — | **151** | 31 |
| Net cash provided by/(used in) financing activities | **587** | (30) | **14,973** | 317 |
| **Effect of Foreign Exchange Rate Changes on Cash and Cash Equivalents** | **3** | 12 | **(127)** | 28 |
| **Increase in Cash and Cash Equivalents** | **553** | 165 | **1,430** | 266 |
| **Cash and Cash Equivalents** | | | | |
| Beginning of period | **1,727** | 590 | **850** | 489 |
| **Cash and Cash Equivalents** | | | | |
| End of period | **2,280** | 755 | **2,280** | 755 |

See accompanying notes to the condensed consolidated financial statements.

# Condensed consolidated balance sheet

| (unaudited - millions of Canadian $) | | September 30 2016 | December 31 2015 |
|---|---|---|---|
| **ASSETS** | | | |
| **Current Assets** | | | |
| Cash and cash equivalents | | **2,280** | 850 |
| Accounts receivable | | **1,765** | 1,387 |
| Inventories | | **424** | 323 |
| Other | | **927** | 1,358 |
| | | **5,396** | 3,918 |
| **Plant, Property and Equipment** | net of accumulated depreciation of $23,279 and $22,299, respectively | **56,203** | 44,817 |
| **Equity Investments** | | **6,496** | 6,214 |
| **Regulatory Assets** | | **1,346** | 1,184 |
| **Goodwill** | | **13,638** | 4,812 |
| **Intangible and Other Assets** | | **3,567** | 3,102 |
| **Restricted Investments** | | **612** | 351 |
| | | **87,258** | 64,398 |
| **LIABILITIES** | | | |
| **Current Liabilities** | | | |
| Notes payable | | **1,000** | 1,218 |
| Accounts payable and other | | **3,781** | 3,077 |
| Accrued interest | | **549** | 520 |
| Current portion of long-term debt | | **790** | 2,547 |
| | | **6,120** | 7,362 |
| **Regulatory Liabilities** | | **2,093** | 1,159 |
| **Other Long-Term Liabilities** | | **1,262** | 1,260 |
| **Deferred Income Tax Liabilities** | | **7,345** | 5,144 |
| **Long-Term Debt** | | **43,273** | 28,909 |
| **Junior Subordinated Notes** | | **3,842** | 2,409 |
| | | **63,935** | 46,243 |
| **Common Units of TC PipeLines, LP Subject to Rescission** | | **106** | — |
| **EQUITY** | | | |
| Common shares, no par value | | **16,480** | 12,102 |
| Issued and outstanding: | September 30, 2016 - 800 million shares | | |
| | December 31, 2015 - 703 million shares | | |
| Preferred shares | | **2,992** | 2,499 |
| Additional paid-in capital | | **—** | 7 |
| Retained earnings | | **1,992** | 2,769 |
| Accumulated other comprehensive loss (Note 11) | | **(936)** | (939) |
| **Controlling Interests** | | **20,528** | 16,438 |
| Non-controlling interests | | **2,689** | 1,717 |
| | | **23,217** | 18,155 |
| | | **87,258** | 64,398 |

**Commitments and Guarantees** (Note 15)
**Variable Interest Entities** (Note 16)
**Subsequent Events** (Note 17)

See accompanying notes to the condensed consolidated financial statements.

# Condensed consolidated statement of equity

| | nine months ended September 30 | |
|---|---|---|
| (unaudited - millions of Canadian $) | **2016** | **2015** |
| **Common Shares** | | |
| Balance at beginning of period | **12,102** | 12,202 |
| Shares issued on exercise of stock options | **70** | 12 |
| Shares repurchased | **(6)** | — |
| Shares issued on exchange of subscription receipts | **4,314** | — |
| Balance at end of period | **16,480** | 12,214 |
| **Preferred Shares** | | |
| Balance at beginning of period | **2,499** | 2,255 |
| Shares issued under public offering, net of issue costs | **493** | 244 |
| Balance at end of period | **2,992** | 2,499 |
| **Additional Paid-In Capital** | | |
| Balance at beginning of period | **7** | 370 |
| Issuance of stock options, net of exercises | **3** | 8 |
| Dilution impact from TC PipeLines, LP units issued | **17** | 4 |
| Impact of common shares repurchased | **(8)** | — |
| Impact of asset drop down to TC PipeLines, LP | **(38)** | (213) |
| Reclassification of Additional Paid-In Capital deficit to Retained Earnings | **19** | — |
| Balance at end of period | **—** | 169 |
| **Retained Earnings** | | |
| Balance at beginning of period | **2,769** | 5,478 |
| Net income attributable to controlling interests | **559** | 1,289 |
| Common share dividends | **(1,246)** | (1,106) |
| Preferred share dividends | **(71)** | (69) |
| Reclassification of Additional Paid-In Capital deficit to Retained Earnings | **(19)** | — |
| Balance at end of period | **1,992** | 5,592 |
| **Accumulated Other Comprehensive Loss** | | |
| Balance at beginning of period | **(939)** | (1,235) |
| Other comprehensive income | **3** | 151 |
| Balance at end of period | **(936)** | (1,084) |
| **Equity Attributable to Controlling Interests** | **20,528** | 19,390 |
| **Equity Attributable to Non-Controlling Interests** | | |
| Balance at beginning of period | **1,717** | 1,583 |
| Acquisition of non-controlling interests in Columbia Pipeline Partners LP | **1,051** | — |
| Net income attributable to non-controlling interests | | |
| TC PipeLines, LP | **153** | 132 |
| Portland | **27** | 13 |
| Columbia Pipeline Partners LP | **4** | — |
| Other comprehensive (loss)/income attributable to non-controlling interests | **(80)** | 243 |
| Issuance of TC PipeLines, LP units | | |
| Proceeds, net of issue costs | **151** | 31 |
| Decrease in TransCanada's ownership of TC PipeLines, LP | **(28)** | (6) |
| Reclassification to Common Units of TC PipeLines, LP Subject to Rescission | **(106)** | — |
| Distributions declared to non-controlling interests | **(200)** | (161) |
| Balance at end of period | **2,689** | 1,835 |
| **Total Equity** | **23,217** | 21,225 |

See accompanying notes to the condensed consolidated financial statements.

# Notes to condensed consolidated financial statements (unaudited)

## 1. Basis of presentation

These condensed consolidated financial statements of TransCanada Corporation (TransCanada or the Company), which now includes Columbia Pipeline Group (Columbia) have been prepared by management in accordance with U.S. GAAP. The accounting policies applied are consistent with those outlined in TransCanada's annual audited consolidated financial statements for the year ended December 31, 2015, except as described in Note 2, Accounting changes. Capitalized and abbreviated terms that are used but not otherwise defined herein are identified in TransCanada's 2015 Annual Report.

These condensed consolidated financial statements reflect adjustments, all of which are normal recurring adjustments that are, in the opinion of management, necessary to reflect fairly the financial position and results of operations for the respective periods. These condensed consolidated financial statements do not include all disclosures required in the annual financial statements and should be read in conjunction with the 2015 audited consolidated financial statements included in TransCanada's 2015 Annual Report. Certain comparative figures have been reclassified to conform with the current period's presentation.

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

### USE OF ESTIMATES AND JUDGEMENTS

In preparing these financial statements, TransCanada is required to make estimates and assumptions that affect both the amount and timing of recording assets, liabilities, revenues and expenses since the determination of these items may be dependent on future events. The fair value of assets and liabilities acquired in a business combination accounted for under the acquisition method are also subject to estimates and judgement. The Company uses the most current information available and exercises careful judgement in making these estimates and assumptions. In the opinion of management, these condensed consolidated financial statements have been properly prepared within reasonable limits of materiality and within the framework of the Company's significant accounting policies included in the consolidated financial statements for the year ended December 31, 2015, except as described in Note 2, Accounting changes.

## 2. Accounting changes

### CHANGES IN ACCOUNTING POLICIES FOR 2016

#### Extraordinary and unusual income statement items

In January 2015, the FASB issued new guidance on extraordinary and unusual income statement items. This update eliminates from U.S. GAAP the concept of extraordinary items. This new guidance was effective January 1, 2016, was applied prospectively and did not have a material impact on the Company's consolidated financial statements.

### Consolidation

In February 2015, the FASB issued new guidance on consolidation. This update requires that entities re-evaluate whether they should consolidate certain legal entities and eliminates the presumption that a general partner should consolidate a limited partnership. This new guidance was effective January 1, 2016, was applied retrospectively and did not result in any change to the Company's consolidation conclusions. Disclosure requirements outlined in the new guidance are included in Note 16, Variable Interest Entities.

### Imputation of interest

In April 2015, the FASB issued new guidance on simplifying the accounting for debt issuance costs. The amendments in this update require that debt issuance costs be presented in the balance sheet as a direct deduction from the carrying amount of the debt liability consistent with debt discounts or premiums. This new guidance was effective January 1, 2016, was applied retrospectively and resulted in a reclassification of debt issuance costs previously recorded in Intangible and other assets to an offset of their respective debt liabilities on the Company’s consolidated balance sheet.

### Business combinations

In September 2015, the FASB issued guidance which intends to simplify the accounting measurement period adjustments in business combinations. The amended guidance requires an acquirer to recognize adjustments to the provisional amounts that are identified during the measurement period in the reporting period in which the adjustment amounts are determined. In the period the adjustment was determined, the guidance also requires the acquirer to record the effect on earnings of changes in depreciation, amortization, or other income effects, if any, as a result of the change to the provisional amounts, calculated as if the accounting had been completed at the acquisition date. This new guidance was effective January 1, 2016, was applied prospectively and did not have a material impact on the Company's consolidated financial statements.

## FUTURE ACCOUNTING CHANGES

### Revenue from contracts with customers

In 2014, the FASB issued new guidance on revenue from contracts with customers. This guidance supersedes the current revenue recognition requirements and most industry-specific guidance. This new guidance requires that an entity recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the company expects to be entitled in exchange for those goods or services. In July 2015, the FASB deferred the effective date of this new standard to January 1, 2018, with early adoption not permitted before January 1, 2017. There are two methods in which the amendment can be applied: (1) retrospectively to each prior reporting period presented, or (2) retrospectively with the cumulative effect recognized at the date of initial application. The Company is currently identifying existing customer contracts or groups of contracts that are within the scope of the new guidance and has begun an assessment in order to determine any impact on the consolidated financial statements.

### Inventory

In July 2015, the FASB issued new guidance on simplifying the measurement of inventory. The amendments in this update specify that an entity should measure inventory within the scope of this update at the lower of cost and net realizable value. Net realizable value is the estimated selling price in the ordinary course of business, less reasonably predictable costs of completion, disposal and transportation. This new guidance is effective January 1, 2017 and will be applied prospectively. The Company does not expect the adoption of this new standard to have a material impact on its consolidated financial statements.

### Financial instruments

In January 2016, the FASB issued new guidance on the accounting for equity investments and financial liabilities. The new guidance will change the income statement effect of equity investments and the recognition of changes in fair value of financial liabilities when the fair value option is elected. The new guidance also requires the Company to assess valuation allowances for deferred tax assets related to available-for-sale debt securities in combination with their other deferred tax assets. This new guidance is effective January 1, 2018. The Company is currently evaluating the impact of the adoption of this guidance and has not yet determined the effect on its consolidated financial statements.

### Leases

In February 2016, the FASB issued new guidance on leases. The new guidance requires lessees to recognize most leases, including operating leases, on the balance sheet as lease assets and lease liabilities. In addition, lessees may be required to reassess assumptions associated with existing leases as well as to provide expanded qualitative and quantitative disclosures. The new standard does not make extensive changes to lessor accounting. The new guidance is effective January 1, 2019 and will be applied using a modified retrospective approach. The Company is currently identifying existing lease agreements that are within the scope of the new guidance that may have an impact on its consolidated financial statements as a result of adopting this new standard.

### Derivatives and hedging

In March 2016, the FASB issued new guidance that clarifies the requirements for assessing whether contingent call or put options that can accelerate the payment of principal on debt instruments are clearly and closely related to their debt hosts. The new guidance requires only an assessment of the four-step decision sequence outlined in GAAP to determine whether the economic characteristics and risks of call or put options are clearly and closely related to the economic characteristics and risks. This new guidance is effective January 1, 2017 and the Company does not expect the adoption of this new standard to have a material impact on its consolidated financial statements.

### Equity method investments

In March 2016, the FASB issued new guidance that simplifies the transition to equity method accounting. The new guidance eliminates the requirement to retroactively apply the equity method of accounting when an increase in ownership interest in an investment qualifies it for equity method accounting. This new guidance is effective January 1, 2017 and will be applied prospectively. The Company does not expect the adoption of this new standard to have a material impact on its consolidated financial statements.

### Employee share-based payments

In March 2016, the FASB issued new guidance that simplifies several aspects of the accounting for employee share-based payment transactions, including the income tax consequences, classification of awards as either equity or liabilities, and classification on the statement of cash flows. The new guidance also permits entities to make an accounting policy election either to continue to estimate the total number of awards for which the requisite service period will not be rendered or to account for forfeitures when they occur. This new guidance is effective January 1, 2017 and the Company does not expect the adoption of this new standard to have a material impact on its consolidated financial statements.

### Measurement of credit losses on financial instruments

In June 2016, the FASB issued new guidance that significantly changes how entities measure credit losses for most financial assets and certain other instruments that are not measured at fair value through net income. The new guidance amends the impairment model of financial instruments basing it on expected losses rather than incurred losses. These expected credit losses will be recognized as an allowance rather than a direct write-down of the amortized cost basis. The new guidance is effective January 1, 2020 and will be applied using a modified retrospective approach. The Company is currently evaluating the impact of the adoption of this guidance and has not yet determined the effect on its consolidated financial statements.

### Classification of certain cash receipts and cash payments

In August 2016, the FASB issued new guidance to clarify how entities should classify certain cash receipts and cash payments. These include debt pre-payments or extinguishment costs, contingent consideration payments made after a business combination, proceeds from the settlement of insurance claims, proceeds from the settlement of corporate-owned life insurance and distributions received from equity method investees. The new guidance is effective January 1, 2018 and will be applied using a retrospective approach. The new guidance also specifies how the predominance principle should be applied when cash receipts and cash payments have aspects of more than one class of cash flows. The Company is currently evaluating the impact of the adoption of this guidance and has not yet determined the impact on its consolidated financial statements.

## 3. Segmented information

| **three months ended September 30** | **Natural Gas Pipelines** | | **Liquids Pipelines** | | **Energy** | | **Corporate** | | **Total** | |
|---|---|---|---|---|---|---|---|---|---|---|
| (unaudited - millions of Canadian $) | **2016** | **2015** | **2016** | **2015** | **2016** | **2015** | **2016** | **2015** | **2016** | **2015** |
| Revenues | **1,884** | 1,305 | **440** | 507 | **1,308** | 1,132 | **—** | — | **3,632** | 2,944 |
| Income from equity investments | **66** | 41 | **—** | — | **88** | 53 | **—** | — | **154** | 94 |
| Plant operating costs and other | **(733)** | (452) | **(160)** | (133) | **(260)** | (215) | **(24)** | (23) | **(1,177)** | (823) |
| Commodity purchases resold | **—** | — | **—** | — | **(783)** | (624) | **—** | — | **(783)** | (624) |
| Property taxes | **(103)** | (88) | **(21)** | (22) | **(12)** | (23) | **—** | — | **(136)** | (133) |
| Depreciation and amortization | **(361)** | (284) | **(72)** | (68) | **(81)** | (79) | **(13)** | (8) | **(527)** | (439) |
| Goodwill and other asset impairment charges | **—** | — | **—** | — | **(1,085)** | — | **—** | — | **(1,085)** | — |
| Segmented earnings/(losses) | **753** | 522 | **187** | 284 | **(825)** | 244 | **(37)** | (31) | **78** | 1,019 |
| Interest expense | | | | | | | | | **(522)** | (341) |
| Interest income and other | | | | | | | | | **122** | 16 |
| (Loss)/Income before income taxes | | | | | | | | | **(322)** | 694 |
| Income tax recovery/(expense) | | | | | | | | | **266** | (223) |
| Net (loss)/income | | | | | | | | | **(56)** | 471 |
| Net income attributable to non-controlling interests | | | | | | | | | **(52)** | (46) |
| **Net (loss)/income attributable to controlling interests** | | | | | | | | | **(108)** | 425 |
| Preferred share dividends | | | | | | | | | **(27)** | (23) |
| **Net (loss)/income attributable to common shares** | | | | | | | | | **(135)** | 402 |

| nine months ended September 30 | Natural Gas Pipelines | | Liquids Pipelines | | Energy | | Corporate | | Total | |
|---|---|---|---|---|---|---|---|---|---|---|
| (unaudited - millions of Canadian $) | **2016** | **2015** | **2016** | **2015** | **2016** | **2015** | **2016** | **2015** | **2016** | **2015** |
| Revenues | **4,511** | 3,896 | **1,292** | 1,410 | **3,083** | 3,143 | **—** | — | **8,886** | 8,449 |
| Income/(loss) from equity investments | **157** | 134 | **(1)** | — | **199** | 216 | **—** | — | **355** | 350 |
| Plant operating costs and other | **(1,496)** | (1,294) | **(406)** | (379) | **(618)** | (600) | **(126)** | (71) | **(2,646)** | (2,344) |
| Commodity purchases resold | **—** | — | **—** | — | **(1,628)** | (1,731) | **—** | — | **(1,628)** | (1,731) |
| Property taxes | **(280)** | (264) | **(67)** | (61) | **(58)** | (65) | **—** | — | **(405)** | (390) |
| Depreciation and amortization | **(936)** | (845) | **(209)** | (197) | **(251)** | (248) | **(29)** | (23) | **(1,425)** | (1,313) |
| Goodwill and other asset impairment charges | **—** | — | **—** | — | **(1,296)** | — | **—** | — | **(1,296)** | — |
| Loss on sale of assets | **(4)** | — | **—** | — | **—** | — | **—** | — | **(4)** | — |
| Segmented earnings/(losses) | **1,952** | 1,627 | **609** | 773 | **(569)** | 715 | **(155)** | (94) | **1,837** | 3,021 |
| Interest expense | | | | | | | | | **(1,456)** | (990) |
| Interest income and other | | | | | | | | | **440** | 83 |
| Income before income taxes | | | | | | | | | **821** | 2,114 |
| Income tax expense | | | | | | | | | **(78)** | (680) |
| Net income | | | | | | | | | **743** | 1,434 |
| Net income attributable to non-controlling interests | | | | | | | | | **(184)** | (145) |
| **Net income attributable to controlling interests** | | | | | | | | | **559** | 1,289 |
| Preferred share dividends | | | | | | | | | **(77)** | (71) |
| **Net income attributable to common shares** | | | | | | | | | **482** | 1,218 |

## TOTAL ASSETS

| (unaudited - millions of Canadian $) | September 30, 2016 | December 31, 2015 |
|---|---|---|
| Natural Gas Pipelines | **53,247** | 31,039 |
| Liquids Pipelines | **16,278** | 16,046 |
| Energy | **13,881** | 15,614 |
| Corporate | **3,852** | 1,699 |
| | **87,258** | 64,398 |

# 4. Acquisition of Columbia

On July 1, 2016, TransCanada acquired 100 per cent ownership of Columbia for a purchase price of US$10.3 billion in cash, based on US$25.50 per share for all of Columbia's outstanding common shares as well as restricted and performance stock units. The acquisition was financed through proceeds of approximately $4.4 billion from the sale of subscription receipts, draws on committed bridge term loan credit facilities in the aggregate amount of US$6.9 billion and existing cash on hand. The sale of the subscription receipts was completed on April 1, 2016 through a public offering. Upon closing of the acquisition, the subscription receipts were exchanged into approximately 96.6 million common shares of TransCanada. Refer to Note 7, Long-term debt for additional information on the bridge term loan credit facilities and Note 10, Equity and share capital for additional information on the subscription receipts.

Columbia operates a portfolio of approximately 24,000 km of regulated natural gas pipelines, 300 Bcf of natural gas storage facilities and related midstream assets in various regions in the U.S. TransCanada acquired Columbia to expand the Company’s natural gas business in the U.S. market, positioning the Company for additional long-term growth opportunities.

The Goodwill of $10.1 billion (US$7.7 billion) arising from the acquisition consists largely of the opportunities to expand the Company's natural gas pipelines segment in the U.S. market and to gain a stronger competitive position in the North American natural gas business. The Goodwill resulting from the acquisition is not deductible for income tax purposes.

The acquisition has been accounted for as a business combination using the acquisition method where the acquired tangible and intangible assets and assumed liabilities are recorded at their estimated fair values at the date of acquisition. The purchase price equation reflects management's estimate of the fair value of Columbia's assets and liabilities as at July 1, 2016.

| | July 1, 2016 | |
|---|---|---|
| (unaudited - millions of $) | **U.S.** | **Canadian** |
| **Purchase Price Consideration** | **10,294** | **13,392** |
| **Fair Value Assigned to Net Assets** | | |
| Current Assets | 658 | 856 |
| Plant, Property and Equipment | 7,556 | 9,830 |
| Equity Investments | 441 | 574 |
| Regulatory Assets | 190 | 248 |
| Intangibles and Other Assets | 135 | 175 |
| Current Liabilities | (597) | (777) |
| Regulatory Liabilities | (294) | (383) |
| Other Long-Term Liabilities | (144) | (187) |
| Deferred Income Tax Liabilities | (1,611) | (2,095) |
| Long-Term Debt | (2,981) | (3,878) |
| Non-controlling Interests | (808) | (1,051) |
| **Fair Value of Net Assets Acquired** | **2,545** | **3,312** |
| **Goodwill** | **7,749** | **10,080** |

The fair values of current assets including cash and cash equivalents, accounts receivable, inventories and other and the fair values of current liabilities including notes payable and accrued interest approximate their carrying values due to the short-term nature of these items. Certain acquisition related working capital items resulted in an adjustment to accounts payable and other.

Columbia's natural gas pipelines are subject to FERC regulations and, as a result, their rate bases are expected to be recovered with a reasonable rate of return over the life of the assets. These assets, as well as related regulatory assets and liabilities, have fair values equal to their carrying values. The fair value of mineral rights included in Columbia's plant, property and equipment was estimated using a discounted cash flow approach which resulted in a fair value increase of $241 million (US$185 million). The Company utilized an independent third party valuation in the assessment of fair value. The fair value of base gas included in Columbia's plant, property and equipment was determined by using quoted market prices multiplied by the volume of gas in place which resulted in a fair value increase of $836 million (US $642 million).

The fair value of Columbia's long-term debt was estimated using an income approach based on quoted market prices for similar debt instruments from external data service providers. This resulted in a fair value increase of $300 million (US $231 million).

The following table summarizes the fair value of Columbia's debt acquired by TransCanada.

| (unaudited - millions of $) | Maturity date | Type | Fair Value | Interest rate |
|---|---|---|---|---|
| **COLUMBIA PIPELINE GROUP INC.** | | | | |
| | June 2018 | Senior Unsecured Notes (US$500) | US $506 | 2.45% |
| | June 2020 | Senior Unsecured Notes (US$750) | US $779 | 3.30% |
| | June 2025 | Senior Unsecured Notes (US$1,000) | US $1,092 | 4.50% |
| | June 2045 | Senior Unsecured Notes (US$500) | US $604 | 5.80% |
| | | | **US $2,981** | |

The fair values of Columbia's defined pension benefit plan and OPEB plans were based on an actuarial valuation report as of the acquisition date. The fair value representing the funded status of the plans on the acquisition date resulted in an increase of $15 million (US$12 million) and $5 million (US$4 million) to Regulatory assets and Other long-term liabilities, respectively, and a decrease of $14 million (US$11 million) and $2 million (US$2 million) to Intangible and other assets and Regulatory liabilities, respectively.

Temporary differences created as a result of the fair value changes described above resulted in deferred tax assets and liabilities that were recorded at the Company's U.S. effective tax rate of 39 per cent.

The fair value of Columbia's non-controlling interest is based on the approximately 53.8 million Columbia Pipeline Partners LP common units outstanding to the public as of June 30, 2016, and valued at the June 30, 2016 closing price of US$15.00 per common unit.

Acquisition expenses of approximately $36 million are included in Plant operating costs and other in the condensed consolidated statement of income.

Upon completing the acquisition, the Company began consolidating Columbia. Columbia's significant accounting policies are consistent with TransCanada's and continue to be applied. Columbia contributed $427 million (US$327 million) to revenues and $55 million (US$42 million) to net income from the acquisition date to September 30, 2016.

The following supplemental unaudited pro forma consolidated financial information of the Company for the three and nine months ended September 30, 2016 and 2015 includes the results of operations for Columbia as if the acquisition had been completed on January 1, 2015.

| | three months ended September 30 | | nine months ended September 30 | |
|---|---|---|---|---|
| (unaudited - millions of Canadian $, except per share amounts) | **2016** | **2015** | **2016** | **2015** |
| **Revenues** | **3,632** | 3,364 | **9,783** | 9,680 |
| **Net (Loss)/Income** | **(56)** | 495 | **873** | 1,593 |
| **Net (Loss)/Income Attributable to Common Shares** | **(135)** | 411 | **580** | 1,342 |
| **Net (Loss)/Income per Common Share** | **($0.17)** | $0.51 | **$0.70** | $1.67 |

# 5. Goodwill and other asset impairments

### Goodwill impairment

TransCanada tests goodwill for impairment on an annual basis or more frequently if events or changes in circumstances indicate that goodwill might be impaired. As a result of information received during the process to monetize the Company's U.S. Northeast Power business in third quarter 2016, it was determined that the fair value of Ravenswood did not exceed its carrying value, including goodwill, at September 30, 2016. The fair value of Ravenswood was determined using a combination of methods including a discounted cash flow approach and a range of expected consideration from a potential sale. The expected cash flows were discounted using a risk-adjusted discount rate to determine the fair value. Plant, property and equipment was also tested for impairment. As a result, at September 30, 2016, the Company recorded a goodwill impairment charge on the full goodwill amount of $1,085 million ($656 million after-tax) related to the Ravenswood facility within the Energy segment and also determined there was no impairment on the plant, property and equipment.

### Power Purchase Arrangements

On March 7, 2016, TransCanada issued notice to the Balancing Pool of the decision to terminate its Sheerness and Sundance A PPAs. In accordance with a provision in the PPAs, a buyer is permitted to terminate the arrangement if a change in law occurs that makes the arrangement unprofitable or more unprofitable. As a result of recent changes in law surrounding the Alberta Specified Gas Emitters Regulation, the Company expects increasing costs related to carbon emissions to continue throughout the remaining terms of the PPAs resulting in increasing unprofitabilty. As such, at March 31, 2016, the Company recognized a non-cash impairment charge of $211 million ($155 million after-tax) in its Energy segment, which represents the carrying value of the PPAs.

On March 7, 2016, TransCanada also issued notice to the Balancing Pool of the decision to terminate its Sundance B PPA. The Sundance B PPA is held in the ASTC Power Partnership in which the Company holds a 50 per cent ownership interest. As a result, at March 31, 2016 the Company recognized a non-cash impairment charge of $29 million ($21 million after-tax) in its Energy segment, which represents the carrying value of the equity investment. This impairment charge is included in Income from equity investments on the condensed consolidated statement of income.

# 6. Income taxes

At September 30, 2016, the total unrecognized tax benefit of uncertain tax positions was approximately $20 million (December 31, 2015 - $17 million). TransCanada recognizes interest and penalties related to income tax uncertainties in income tax expense. Included in income tax expense for the three and nine months ended September 30, 2016 is nil for interest expense and nil for penalties (September 30, 2015 - nil for interest expense and nil for penalties). At September 30, 2016, the Company had $4 million accrued for interest expense and nil accrued for penalties (December 31, 2015 - $4 million accrued for interest expense and nil for penalties).

The effective tax rates for the nine-month periods ended September 30, 2016 and 2015 were 10 per cent and 32 per cent, respectively. The lower effective tax rate in 2016 was primarily the result of lower flow-through taxes in 2016 on Canadian regulated pipelines, changes in the proportion of income earned between Canadian and foreign jurisdictions and the goodwill impairment charge.

# 7. Long-term debt

## LONG-TERM DEBT ISSUED

The Company issued long-term debt in the nine months ended September 30, 2016 as follows:

| (unaudited - millions of Canadian $, unless noted otherwise) | Issue date | Type | Maturity date | Amount | Interest rate |
|---|---|---|---|---|---|
| **TRANSCANADA PIPELINES LIMITED** | | | | | |
| | June 2016 | Acquisition Bridge Facility[1] | June 2018 | US $5,213 | Floating |
| | June 2016 | Medium Term Notes | July 2023 | $300 | 3.690% [2] |
| | June 2016 | Medium Term Notes | June 2046 | $700 | 4.350% |
| | January 2016 | Senior Unsecured Notes | January 2019 | US $400 | 3.125% |
| | January 2016 | Senior Unsecured Notes | January 2026 | US $850 | 4.875% |
| **ANR PIPELINE COMPANY** | | | | | |
| | June 2016 | Senior Unsecured Notes | June 2026 | US $240 | 4.140% |
| **TRANSCANADA PIPELINE USA LTD.** | | | | | |
| | June 2016 | Acquisition Bridge Facility[1] | June 2018 | US $1,700 | Floating |
| **TUSCARORA GAS TRANSMISSION COMPANY** | | | | | |
| | April 2016 | Term Loan | April 2019 | US $9.5 | Floating |

1 These facilities were put in place to finance a portion of the Columbia acquisition and bear interest at Libor plus an applicable margin. Proceeds from the U.S. Northeast Power business sales and the November 2016 common equity offering will be used to partially repay these facilities.

2 Reflects coupon rate on re-opening of existing medium term notes (MTN) issue. New MTNs were issued at a premium resulting in a re-issuance yield of 2.69 per cent.

## LONG-TERM DEBT RETIRED

The Company retired long-term debt in the nine months ended September 30, 2016 as follows:

| (unaudited - millions of Canadian $, unless noted otherwise) | Retirement date | Type | Amount | Interest rate |
|---|---|---|---|---|
| **TRANSCANADA PIPELINES LIMITED** | | | | |
| | June 2016 | Senior Unsecured Notes | US $84 | 7.69% |
| | June 2016 | Senior Unsecured Notes | US $500 | Floating |
| | January 2016 | Senior Unsecured Notes | US $750 | 0.75% |
| **NOVA GAS TRANSMISSION LTD.** | | | | |
| | February 2016 | Debentures | $225 | 12.2% |

In the three and nine months ended September 30, 2016, TransCanada capitalized interest related to capital projects of $46 million and $133 million, respectively (2015 - $82 million and $223 million, respectively).

# 8. Junior subordinated notes

### JUNIOR SUBORDINATED DEBT ISSUED

| (unaudited - millions of Canadian $, unless noted otherwise) | Issue date | Type | Maturity date | Amount | Interest rate |
|---|---|---|---|---|---|
| **TRANSCANADA PIPELINES LIMITED** | August 2016 | Junior Subordinated Unsecured Notes[1] | August 2076 | US $1,200 | 6.125%[2] |

1 The Junior subordinated unsecured notes are subordinated in right of payment to existing and future senior indebtedness or other obligations of TCPL and are callable at TCPL's option at any time on or after August 15, 2026 at 100 per cent of the principal amount plus accrued and unpaid interest to the date of redemption.

2 The Junior subordinated notes were issued to TransCanada Trust. The interest rate is fixed at 6.125 per cent per annum and will reset starting August 2026 until August 2046 to the three month LIBOR plus 4.89 per cent per annum; from August 2046 to August 2076 the interest rate will reset to the three month LIBOR plus 5.64 per cent per annum.

On August 16, 2016, TransCanada Trust (the Trust), a 100 per cent owned financing trust subsidiary of TCPL, issued US $1.2 billion of Trust Notes - Series 2016-A (Trust Notes) to third party investors with a fixed interest rate of 5.875 per cent for the first ten years converting to a floating rate thereafter. All of the proceeds of the issuance by the Trust were loaned to TCPL through the subscription for US$1.2 billion of junior subordinated notes of TCPL at a rate of 6.125 per cent which includes a 0.25 per cent administration charge. While the obligations of the Trust are fully and unconditionally guaranteed by TCPL on a subordinated basis, the Trust is not consolidated in TransCanada's financial statements because TCPL does not have a variable interest in the Trust and the only substantive assets of the Trust are receivables from TCPL.

Pursuant to the terms of the Trust Notes and related agreements, in certain circumstances (1) TCPL may issue deferral preferred shares to holders of the Trust Notes in lieu of interest; and (2) TransCanada and TCPL would be prohibited from declaring or paying dividends on or redeeming their outstanding preferred shares (or, if none are outstanding, their respective common shares) until all deferral preferred shares are redeemed by TCPL. The Trust Notes may also be automatically exchanged for preferred shares of TCPL upon certain kinds of bankruptcy and insolvency events. All of these preferred shares would rank equally with any other outstanding first preferred shares of TCPL.

# 9. Common units of TC PipeLines, LP subject to rescission

In connection with the late filing of an employee-related Form 8-K with the SEC, in March 2016, TC PipeLines, LP became ineligible to use the then effective shelf registration statement upon the filing of its 2015 Annual Report. As a result, it was determined that the purchasers of the 1.6 million common units that were issued from March 8, 2016 to May 19, 2016 under the TC PipeLines, LP ATM program may have a rescission right for an amount equal to the purchase price paid for the units, plus statutory interest and less any distributions paid, upon the return of such units to TC PipeLines, LP. No unitholder has claimed or attempted to exercise any rescission rights to date and these rights expire one year from the date of purchase of the unit.

At September 30, 2016, $106 million (US$82 million) was recorded as Common Units of TC PipeLines, LP Subject to Rescission on the Condensed consolidated balance sheet. The Company classified these 1.6 million common units outside Equity because the potential rescission rights of the units are not within the control of the Company.

## 10. Equity and share capital

### COMMON SHARES

In January 2016, the Company repurchased and cancelled 305,407 of its common shares at an average price of $44.90 for a total of $14 million (weighted average cost of $6 million). The difference of $8 million between the total price paid and the weighted average cost was recorded in Additional paid-in capital.

On April 1, 2016, the Company issued 96.6 million subscription receipts to partially fund the Columbia acquisition at a price of $45.75 each for total proceeds of approximately $4.4 billion. Holders of subscription receipts received one common share in exchange for each subscription receipt upon closing of the Columbia acquisition. On April 29, 2016, holders of record at close of business on April 15, 2016 received a cash payment per subscription receipt that was equal to dividends declared on each common share. A second dividend equivalent payment was made on July 29, 2016 to holders of record at the close of business on June 30, 2016. For the nine months ended September 30, 2016, $109 million of dividend equivalent payments was recorded as interest expense.

### DIVIDEND REINVESTMENT PLAN

Under the Company's Dividend Reinvestment Plan (DRP), eligible holders of common and preferred shares of TransCanada can reinvest their dividends and make optional cash payments to obtain TransCanada common shares. Commencing with dividends declared on July 27, 2016, common shares will be issued from treasury at a discount of two per cent.

### PREFERRED SHARES

On February 1, 2016, holders of 1.3 million Series 5 cumulative redeemable first preferred shares exercised their option to convert to Series 6 cumulative redeemable first preferred shares and receive quarterly floating rate cumulative dividends at an annual rate equal to the applicable 90-day Government of Canada treasury bill rate plus 1.54 per cent which will reset every quarter going forward. The fixed dividend rate on the remaining Series 5 preferred shares was reset for five years at 2.263 per cent per annum. Such rate will reset every five years.

On April 20, 2016, the Company completed a public offering of 20 million Series 13 cumulative redeemable first preferred shares at $25 per share resulting in gross proceeds of $500 million. The Series 13 preferred shareholders will have the right to convert their Series 13 preferred shares into Series 14 cumulative redeemable first preferred shares on May 31, 2021 and on the last business day of May of every fifth year thereafter. The holders of Series 14 preferred shares will be entitled to receive quarterly floating rate cumulative dividends at an annual rate equal to the sum of the applicable 90-day Government of Canada treasury bill rate plus 4.69 per cent. The fixed dividend rate on the Series 13 preferred shares was set for five years at 5.5 per cent per annum. The dividend rate will reset every five years at a rate equal to the sum of the applicable five-year Government of Canada bond yield plus 4.69 per cent but not less than 5.5 per cent per annum.

### PREFERRED SHARE ISSUANCE AND CONVERSIONS

The following table summarizes the impact of the 2016 issuance and conversions of preferred shares discussed above:

| (unaudited) | Number of shares issued and outstanding (thousands) | Current yield | Annual dividend per share[1] | Redemption price per share[2] | Redemption and conversion option date[2,3] | Right to convert into[3] |
|---|---|---|---|---|---|---|
| **Cumulative first preferred shares** | | | | | | |
| Series 5 | 12,714 | 2.263% | $0.56575 | $25.00 | January 30, 2021 | Series 6 |
| Series 6 | 1,286 | Floating[4] | Floating | $25.00 | January 30, 2021 | Series 5 |
| Series 13 | 20,000 | 5.5% | $1.375 | $25.00 | May 31, 2021 | Series 14 |

1 Holders of the cumulative redeemable first preferred shares set out in this table are entitled to receive a fixed cumulative quarterly preferred dividend, as and when declared by the Board, with the exception of Series 6 preferred shares. The holders of Series 6 preferred shares are entitled to receive a quarterly floating rate cumulative preferred dividend as and when declared by the Board.

2 TransCanada may, at its option, redeem all or a portion of the outstanding shares for the redemption price per share, plus all accrued and unpaid dividends on the applicable redemption option date and on every fifth anniversary date thereafter. In addition, Series 6 preferred shares are redeemable by TransCanada at any time other than on a designated redemption option date for $25.50 per share plus all accrued and unpaid dividends on such redemption date.

3 The holder will have the right, subject to certain conditions, to convert their first preferred shares of a specified series into first preferred shares of another specified series on the conversion option date and every fifth anniversary thereafter.

4 Commencing September 30, 2016 the floating quarterly dividend rate for the Series 6 preferred shares is 2.073 per cent and will reset every quarter going forward.

## 11. Other comprehensive income/(loss) and accumulated other comprehensive loss

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

| **three months ended September 30, 2016** (unaudited - millions of Canadian $) | **Before tax amount** | **Income tax recovery/ (expense)** | **Net of tax amount** |
|---|---|---|---|
| Foreign currency translation gains on net investment in foreign operations | **55** | **—** | **55** |
| Change in fair value of net investment hedges | **(2)** | **1** | **(1)** |
| Change in fair value of cash flow hedges | **6** | **(1)** | **5** |
| Reclassification to net income of gains on cash flow hedges | **1** | **(1)** | **—** |
| Reclassification to net income of actuarial loss and prior service costs on pension and other post-retirement benefit plans | **6** | **(2)** | **4** |
| Other comprehensive income on equity investments | **5** | **(1)** | **4** |
| Other comprehensive income | **71** | **(4)** | **67** |

| **three months ended September 30, 2015**<br>(unaudited - millions of Canadian $) | **Before tax amount** | **Income tax recovery/ (expense)** | **Net of tax amount** |
|---|---|---|---|
| Foreign currency translation gains on net investment in foreign operations | 350 | 6 | 356 |
| Change in fair value of net investment hedges | (207) | 54 | (153) |
| Change in fair value of cash flow hedges | (49) | 20 | (29) |
| Reclassification to net income of gains on cash flow hedges | 80 | (30) | 50 |
| Reclassification to net income of actuarial loss and prior service costs on pension and other post-retirement benefit plans | 10 | (3) | 7 |
| Other comprehensive income on equity investments | 4 | (1) | 3 |
| Other comprehensive income | 188 | 46 | 234 |

| **nine months ended September 30, 2016**<br>(unaudited - millions of Canadian $) | **Before tax amount** | **Income tax recovery/ (expense)** | **Net of tax amount** |
|---|---|---|---|
| Foreign currency translation losses on net investment in foreign operations | **(150)** | **(2)** | **(152)** |
| Change in fair value of net investment hedges | **(12)** | **3** | **(9)** |
| Change in fair value of cash flow hedges | **33** | **(12)** | **21** |
| Reclassification to net income of gains on cash flow hedges | **65** | **(25)** | **40** |
| Reclassification to net income of actuarial loss and prior service costs on pension and other post-retirement benefit plans | **17** | **(5)** | **12** |
| Other comprehensive income on equity investments | **14** | **(3)** | **11** |
| Other comprehensive loss | **(33)** | **(44)** | **(77)** |

| **nine months ended September 30, 2015**<br>(unaudited - millions of Canadian $) | **Before tax amount** | **Income tax recovery/ (expense)** | **Net of tax amount** |
|---|---|---|---|
| Foreign currency translation gains on net investment in foreign operations | 675 | 13 | 688 |
| Change in fair value of net investment hedges | (490) | 129 | (361) |
| Change in fair value of cash flow hedges | (78) | 28 | (50) |
| Reclassification to net income of gains on cash flow hedges | 136 | (53) | 83 |
| Reclassification to net income of actuarial loss and prior service costs on pension and other post-retirement benefit plans | 30 | (6) | 24 |
| Other comprehensive income on equity investments | 13 | (3) | 10 |
| Other comprehensive income | 286 | 108 | 394 |

The changes in AOCI by component are as follows:

| **three months ended September 30, 2016**<br>(unaudited - millions of Canadian $) | **Currency translation adjustments** | **Cash flow hedges** | **Pension and OPEB plan adjustments** | **Equity investments** | **Total[1]** |
|---|---|---|---|---|---|
| AOCI balance at July 1, 2016 | **(497)** | **(38)** | **(190)** | **(254)** | **(979)** |
| Other comprehensive income before reclassifications[2] | **33** | **2** | **—** | **—** | **35** |
| Amounts reclassified from accumulated other comprehensive loss | **—** | **—** | **4** | **4** | **8** |
| Net current period other comprehensive income | **33** | **2** | **4** | **4** | **43** |
| **AOCI balance at September 30, 2016** | **(464)** | **(36)** | **(186)** | **(250)** | **(936)** |

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

2 Other comprehensive income before reclassifications on currency translation adjustments and cash flow hedges is net of non-controlling interest gains of $21 million and $3 million, respectively.

| **nine months ended September 30, 2016** (unaudited - millions of Canadian $) | **Currency translation adjustments** | **Cash flow hedges** | **Pension and OPEB plan adjustments** | **Equity investments** | **Total**[1] |
|---|---|---|---|---|---|
| AOCI balance at January 1, 2016 | **(383)** | **(97)** | **(198)** | **(261)** | **(939)** |
| Other comprehensive (loss)/income before reclassifications[2] | **(81)** | **21** | **—** | **—** | **(60)** |
| Amounts reclassified from accumulated other comprehensive loss | **—** | **40** | **12** | **11** | **63** |
| Net current period other comprehensive (loss)/ income[3] | **(81)** | **61** | **12** | **11** | **3** |
| **AOCI balance at September 30, 2016** | **(464)** | **(36)** | **(186)** | **(250)** | **(936)** |

1 All amounts are net of tax. Amounts in parentheses indicate losses recorded to OCI.
2 Other comprehensive (loss)/income before reclassifications on currency translation adjustments is net of non-controlling interest losses of $80 million.
3 Losses related to cash flow hedges reported in AOCI and expected to be reclassified to net income in the next 12 months are estimated to be $23 million ($14 million, net of tax) at September 30, 2016. These estimates assume constant commodity prices, interest rates and foreign exchange rates over time, however, the amounts reclassified will vary based on the actual value of these factors at the date of settlement.

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

| | **Amounts reclassified from accumulated other comprehensive loss**[1] | | | | **Affected line item in the condensed consolidated statement of income** |
|---|---|---|---|---|---|
| | **three months ended September 30** | | **nine months ended September 30** | | |
| (unaudited - millions of Canadian $) | **2016** | **2015** | **2016** | **2015** | |
| Cash flow hedges | | | | | |
| Commodities | **7** | (76) | **(54)** | (124) | Revenue (Energy) |
| Foreign exchange | **(5)** | — | **—** | — | Interest income and other |
| Interest | **(3)** | (4) | **(11)** | (12) | Interest expense |
| | **(1)** | (80) | **(65)** | (136) | Total before tax |
| | **1** | 30 | **25** | 53 | Income tax expense |
| | **—** | (50) | **(40)** | (83) | Net of tax |
| Pension and other post-retirement benefit plan adjustments | | | | | |
| Amortization of actuarial loss | **(6)** | (10) | **(17)** | (30) | [2] |
| | **2** | 3 | **5** | 6 | Income tax expense |
| | **(4)** | (7) | **(12)** | (24) | Net of tax |
| Equity investments | | | | | |
| Equity income | **(5)** | (4) | **(14)** | (13) | Income from equity investments |
| | **1** | 1 | **3** | 3 | Income tax expense |
| | **(4)** | (3) | **(11)** | (10) | Net of tax |

1 All amounts in parentheses indicate expenses to the condensed consolidated statement of income.
2 These accumulated other comprehensive loss components are included in the computation of net benefit cost. Refer to Note 12 for additional detail.

## 12. Employee post-retirement benefits

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

| | three months ended September 30 | | | | nine months ended September 30 | | | |
|---|---|---|---|---|---|---|---|---|
| | Pension benefit plans | | Other post-retirement benefit plans | | Pension benefit plans | | Other post-retirement benefit plans | |
| (unaudited - millions of Canadian $) | **2016** | **2015** | **2016** | **2015** | **2016** | **2015** | **2016** | **2015** |
| Service cost | **28** | 27 | **1** | 1 | **79** | 81 | **2** | 2 |
| Interest cost | **34** | 29 | **4** | 2 | **93** | 86 | **9** | 7 |
| Expected return on plan assets | **(48)** | (39) | **(5)** | (1) | **(127)** | (116) | **(6)** | (2) |
| Amortization of actuarial loss | **5** | 9 | **1** | 1 | **15** | 26 | **2** | 3 |
| Amortization of past service cost | **—** | — | **—** | — | **—** | 1 | **—** | — |
| Amortization of regulatory asset | **8** | 6 | **—** | — | **17** | 18 | **—** | — |
| Amortization of transitional obligation related to regulated business | **—** | — | **—** | 1 | **—** | — | **1** | 2 |
| **Net benefit cost recognized** | **27** | 32 | **1** | 4 | **77** | 96 | **8** | 12 |

## 13. Risk management and financial instruments

### RISK MANAGEMENT OVERVIEW

TransCanada has exposure to market risk and counterparty credit risk, and has strategies, policies and limits in place to manage the impact of these risks on earnings and cash flow.

### COUNTERPARTY CREDIT RISK

TransCanada's maximum counterparty credit exposure with respect to financial instruments at September 30, 2016, without taking into account security held, consisted of cash and cash equivalents, accounts receivable, available for sale assets recorded at fair value, the fair value of derivative assets, notes, loans and advances receivable. The Company regularly reviews its accounts receivable and records an allowance for doubtful accounts as necessary using the specific identification method. At September 30, 2016, there were no significant amounts past due or impaired, and there were no significant credit losses during the period.

The Company had a credit risk concentration due from a counterparty of $191 million (US$146 million) at September 30, 2016 (December 31, 2015 - $248 million (US$179 million)). This amount is expected to be fully collectible and is secured by a guarantee from the counterparty's investment grade parent company.

### NET INVESTMENT IN FOREIGN OPERATIONS

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

#### U.S. dollar-denominated debt designated as a net investment hedge

| (unaudited - millions of Canadian $, unless noted otherwise) | September 30, 2016 | December 31, 2015 |
|---|---|---|
| Notional amount | **30,200 (US 23,000)** | 23,100 (US 16,700) |
| Fair value | **33,700 (US 25,700)** | 23,800 (US 17,200) |

### Derivatives designated as a net investment hedge

| (unaudited - millions of Canadian $, unless noted otherwise) | September 30, 2016 | | December 31, 2015 | |
|---|---|---|---|---|
| | Fair value[1] | Notional or principal amount | Fair value[1] | Notional or principal amount |
| **Asset/(liability)** | | | | |
| U.S. dollar cross-currency interest rate swaps (maturing 2016 to 2019)[2] | **(433)** | **US 2,400** | (730) | US 3,150 |
| U.S. dollar foreign exchange forward contracts (maturing 2016 to 2017) | **(16)** | **US 200** | 50 | US 1,800 |
| | **(449)** | **US 2,600** | (680) | US 4,950 |

1 Fair values equal carrying values.
2 In the three and nine months ended September 30, 2016, net realized gains of $1 million and $5 million, respectively, (2015 - gains of $2 million and $7 million, respectively) related to the interest component of cross-currency swap settlements are included in interest expense.

## FINANCIAL INSTRUMENTS

### Non-derivative financial instruments

#### Fair value of non-derivative financial instruments

The fair value of the Company's Notes receivable is calculated by discounting future payments of interest and principal using forward interest rates. The fair value of Long-term debt and Junior subordinated notes is estimated using an income approach based on quoted market prices for the same or similar debt instruments from external data service providers.

Available for sale assets are recorded at fair value which is calculated using quoted market prices where available. Certain non-derivative financial instruments included in cash and cash equivalents, accounts receivable, intangible and other assets, notes payable, accounts payable and other, accrued interest and other long-term liabilities have carrying amounts that approximate their fair value due to the nature of the item or the short time to maturity and would also be classified in Level II of the fair value hierarchy.

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

#### Balance sheet presentation of non-derivative financial instruments

The following table details the fair value of the non-derivative financial instruments, excluding those where carrying amounts approximate fair value, and would be classified in Level II of the fair value hierarchy:

| (unaudited - millions of Canadian $) | September 30, 2016 | | December 31, 2015 | |
|---|---|---|---|---|
| | Carrying amount | Fair value | Carrying amount | Fair value |
| Notes receivable[1] | **158** | **209** | 214 | 265 |
| Current and long-term debt[2,3] | **(44,063)** | **(46,378)** | (31,456) | (34,309) |
| Junior subordinated notes | **(3,842)** | **(3,708)** | (2,409) | (2,011) |
| | **(47,747)** | **(49,877)** | (33,651) | (36,055) |

1 Notes receivable are included in other current assets and intangible and other assets on the condensed consolidated balance sheet.
2 Long-term debt is recorded at amortized cost except for US$800 million (December 31, 2015 - US$850 million) that is attributed to hedged risk and recorded at fair value.
3 Consolidated net income for the three and nine months ended September 30, 2016 included unrealized gains of $7 million and losses of $6 million, respectively, (2015 - losses of $9 million and $9 million, respectively) for fair value adjustments attributable to the hedged interest rate risk associated with interest rate swap fair value hedging relationships on US$800 million of long-term debt at September 30, 2016

(December 31, 2015 - US$850 million). There were no other unrealized gains or losses from fair value adjustments to the non-derivative financial instruments.

### Available for sale assets summary

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

| | September 30, 2016 | | December 31, 2015 | |
|---|---|---|---|---|
| (unaudited - millions of Canadian $) | LMCI restricted investments | Other restricted investments[2] | LMCI restricted investments | Other restricted investments[2] |
| Fair Values[1] | | | | |
| Fixed income securities (maturing within 5 years) | **—** | **137** | — | 90 |
| Fixed income securities (maturing in 5-10 years) | **11** | **—** | — | — |
| Fixed income securities (maturing after 10 years) | **480** | **—** | 261 | — |
| | **491** | **137** | 261 | 90 |

1 Available for sale assets are recorded at fair value and included in other current assets and restricted investments on the condensed consolidated balance sheet.
2 Other restricted investments have been set aside to fund insurance claim losses to be paid by the Company's wholly-owned captive insurance subsidiary.

| | September 30, 2016 | | September 30, 2015 | |
|---|---|---|---|---|
| (unaudited - millions of Canadian $) | LMCI restricted investments[1] | Other restricted investments[2] | LMCI restricted investments[1] | Other restricted investments[2] |
| Net unrealized gains/(losses) in the period | | | | |
| three months ended | **3** | **—** | 1 | — |
| nine months ended | **25** | **1** | (2) | — |
| Net realized gains in the period | | | | |
| three months ended | **—** | **—** | — | — |
| nine months ended | **1** | **—** | — | — |

1 Gains and losses arising from changes in the fair value of LMCI restricted investments impact the subsequent amounts to be collected through tolls to cover future pipeline abandonment costs. As a result, the Company records these gains and losses as regulatory assets or liabilities.
2 Unrealized gains and losses on other restricted investments are included in OCI.

## Derivative instruments

### Fair value of derivative instruments

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

In some cases, even though the derivatives are considered to be effective economic hedges, they do not meet the specific criteria for hedge accounting treatment or are not designated as a hedge and are accounted for at fair value with changes in fair value recorded in net income in the period of change. This may expose the Company to increased variability in reported earnings because the fair value of the derivative instruments can fluctuate significantly from period to period.

### Balance sheet presentation of derivative instruments

The balance sheet classification of the fair value of the derivative instruments as at September 30, 2016 is as follows:

| **at September 30, 2016** (unaudited - millions of Canadian $) | **Cash Flow Hedges** | **Fair Value Hedges** | **Net Investment Hedges** | **Held for Trading** | **Total Fair Value of Derivative Instruments**[1] |
|---|---|---|---|---|---|
| Other current assets | | | | | |
| Commodities[2] | **15** | **—** | **—** | **298** | **313** |
| Foreign exchange | **—** | **—** | **5** | **10** | **15** |
| Interest rate | **—** | **3** | **—** | **1** | **4** |
| | **15** | **3** | **5** | **309** | **332** |
| Intangible and other assets | | | | | |
| Commodities[2] | **5** | **—** | **—** | **165** | **170** |
| Foreign exchange | **—** | **—** | **6** | **—** | **6** |
| Interest rate | **—** | **4** | **—** | **1** | **5** |
| | **5** | **4** | **6** | **166** | **181** |
| **Total Derivative Assets** | **20** | **7** | **11** | **475** | **513** |
| Accounts payable and other | | | | | |
| Commodities[2] | **(32)** | **—** | **—** | **(336)** | **(368)** |
| Foreign exchange | **—** | **—** | **(231)** | **(15)** | **(246)** |
| Interest rate | **(2)** | **—** | **—** | **—** | **(2)** |
| | **(34)** | **—** | **(231)** | **(351)** | **(616)** |
| Other long-term liabilities | | | | | |
| Commodities[2] | **—** | **—** | **—** | **(198)** | **(198)** |
| Foreign exchange | **—** | **—** | **(229)** | **—** | **(229)** |
| Interest rate | **(1)** | **—** | **—** | **—** | **(1)** |
| | **(1)** | **—** | **(229)** | **(198)** | **(428)** |
| **Total Derivative Liabilities** | **(35)** | **—** | **(460)** | **(549)** | **(1,044)** |

1 Fair value equals carrying value.

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

The balance sheet classification of the fair value of the derivative instruments as at December 31, 2015 is as follows:

| **at December 31, 2015** (unaudited - millions of Canadian $) | **Cash Flow Hedges** | **Fair Value Hedges** | **Net Investment Hedges** | **Held for Trading** | **Total Fair Value of Derivative Instruments**[1] |
|---|---|---|---|---|---|
| Other current assets | | | | | |
| Commodities[2] | 46 | — | — | 326 | 372 |
| Foreign exchange | — | — | 65 | 2 | 67 |
| Interest rate | — | 1 | — | 2 | 3 |
| | 46 | 1 | 65 | 330 | 442 |
| Intangible and other assets | | | | | |
| Commodities[2] | 11 | — | — | 126 | 137 |
| Foreign exchange | — | — | 29 | — | 29 |
| Interest rate | — | 2 | — | — | 2 |
| | 11 | 2 | 29 | 126 | 168 |
| **Total Derivative Assets** | 57 | 3 | 94 | 456 | 610 |
| Accounts payable and other | | | | | |
| Commodities[2] | (112) | — | — | (443) | (555) |
| Foreign exchange | — | — | (313) | (54) | (367) |
| Interest rate | (1) | (1) | — | (2) | (4) |
| | (113) | (1) | (313) | (499) | (926) |
| Other long-term liabilities | | | | | |
| Commodities[2] | (31) | — | — | (131) | (162) |
| Foreign exchange | — | — | (461) | — | (461) |
| Interest rate | (1) | (1) | — | — | (2) |
| | (32) | (1) | (461) | (131) | (625) |
| **Total Derivative Liabilities** | (145) | (2) | (774) | (630) | (1,551) |

1 Fair value equals carrying value.
2 Includes purchases and sales of power and natural gas.

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

### Notional and Maturity Summary

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

| at September 30, 2016 | Power | Natural Gas | Liquids | Foreign Exchange | Interest |
|---|---|---|---|---|---|
| Purchases[1] | **87,257** | **187** | **6** | **—** | **—** |
| Sales[1] | **62,109** | **145** | **6** | **—** | **—** |
| Millions of dollars | **—** | **—** | **—** | **US 2,098** | **US 1,500** |
| Maturity dates | **2016-2020** | **2016-2020** | **2016** | **2016-2017** | **2016-2019** |

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

| at December 31, 2015 | Power | Natural Gas | Foreign Exchange | Interest |
|---|---|---|---|---|
| Purchases[1] | 70,331 | 133 | — | — |
| Sales[1] | 54,382 | 70 | — | — |
| Millions of dollars | — | — | US 1,476 | US 1,100 |
| Maturity dates | 2016–2020 | 2016–2020 | 2016 | 2016–2019 |

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

## Unrealized and Realized Gains/(Losses) of Derivative Instruments

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

| | three months ended September 30 | | nine months ended September 30 | |
|---|---|---|---|---|
| (unaudited - millions of Canadian $) | **2016** | **2015** | **2016** | **2015** |
| **Derivative instruments held for trading**[1] | | | | |
| Amount of unrealized (losses)/gains in the period | | | | |
| Commodities[2] | **(97)** | (27) | **23** | (30) |
| Foreign exchange | **—** | (26) | **47** | (25) |
| Amount of realized (losses)/gains in the period | | | | |
| Commodities | **(23)** | (52) | **(165)** | (84) |
| Foreign exchange | **(5)** | (34) | **52** | (87) |
| **Derivative instruments in hedging relationships** | | | | |
| Amount of realized (losses)/gains in the period | | | | |
| Commodities | **(15)** | (35) | **(155)** | (132) |
| Foreign exchange | **5** | — | **(101)** | — |
| Interest rate | **1** | 2 | **4** | 6 |

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

2 Following the March 17, 2016 announcement of the Company's intention to sell the U.S. Northeast power assets, a loss of $49 million and a gain of $7 million (2015 - nil) were recorded in net income in the three months ended March 31, 2016 relating to discontinued cash flow hedges where it was probable that the anticipated underlying transaction would not occur as a result of a future sale.

### Derivatives in cash flow hedging relationships

The components of OCI (Note 11) related to derivatives in cash flow hedging relationships including the portion attributable to non-controlling interests are as follows:

| | three months ended September 30 | | nine months ended September 30 | |
|---|---|---|---|---|
| (unaudited - millions of Canadian $, pre-tax) | **2016** | **2015** | **2016** | **2015** |
| Change in fair value of derivative instruments recognized in OCI (effective portion)[1] | | | | |
| Commodities | **7** | (48) | **33** | (77) |
| Foreign exchange | **(5)** | — | **—** | — |
| Interest rate | **4** | (1) | **—** | (1) |
| | **6** | (49) | **33** | (78) |
| Reclassification of (losses)/gains on derivative instruments from AOCI to net income (effective portion)[1] | | | | |
| Commodities[2] | **(7)** | 76 | **54** | 124 |
| Foreign exchange[3] | **5** | — | **—** | — |
| Interest rate[4] | **3** | 4 | **11** | 12 |
| | **1** | 80 | **65** | 136 |
| Gains/(losses) on derivative instruments recognized in net income (ineffective portion) | | | | |
| Commodities[2] | **14** | 10 | **(1)** | 3 |
| | **14** | 10 | **(1)** | 3 |

1 No amounts have been excluded from the assessment of hedge effectiveness. Amounts in parentheses indicate losses recorded to OCI.
2 Reported within revenues on the condensed consolidated statement of income.
3 Reported within interest income and other on the condensed consolidated statement of income.
4 Reported within interest expense on the condensed consolidated statement of income.

### Offsetting of derivative instruments

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

| **at September 30, 2016** (unaudited - millions of Canadian $) | **Gross derivative instruments presented on the balance sheet** | **Amounts available for offset**[1] | **Net amounts** |
|---|---|---|---|
| Derivative - Asset | | | |
| Commodities | **483** | **(382)** | **101** |
| Foreign exchange | **21** | **(21)** | **—** |
| Interest rate | **9** | **(1)** | **8** |
| Total | **513** | **(404)** | **109** |
| Derivative - Liability | | | |
| Commodities | **(566)** | **382** | **(184)** |
| Foreign exchange | **(475)** | **21** | **(454)** |
| Interest rate | **(3)** | **1** | **(2)** |
| Total | **(1,044)** | **404** | **(640)** |

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

The following table shows the impact on the presentation of the fair value of derivative instrument assets and liabilities had the Company elected to present these contracts on a net basis as at December 31, 2015:

| **at December 31, 2015**<br>(unaudited - millions of Canadian $) | **Gross derivative instruments presented on the balance sheet** | **Amounts available for offset**[1] | **Net amounts** |
|---|---|---|---|
| Derivative - Asset | | | |
| Commodities | 509 | (418) | 91 |
| Foreign exchange | 96 | (93) | 3 |
| Interest rate | 5 | (1) | 4 |
| Total | 610 | (512) | 98 |
| Derivative - Liability | | | |
| Commodities | (717) | 418 | (299) |
| Foreign exchange | (828) | 93 | (735) |
| Interest rate | (6) | 1 | (5) |
| Total | (1,551) | 512 | (1,039) |

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

With respect to the derivative instruments presented above as at September 30, 2016, the Company provided cash collateral of $228 million (December 31, 2015 - $482 million) and letters of credit of $11 million (December 31, 2015 - $41 million) to its counterparties. The Company held nil (December 31, 2015 - nil) in cash collateral and $3 million (December 31, 2015 - $2 million) in letters of credit from counterparties on asset exposures at September 30, 2016.

### Credit risk related contingent features of derivative instruments

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

Based on contracts in place and market prices at September 30, 2016, the aggregate fair value of all derivative instruments with credit-risk-related contingent features that were in a net liability position was $24 million (December 31, 2015 - $32 million), for which the Company had provided collateral in the normal course of business of nil (December 31, 2015 - nil). If the credit-risk-related contingent features in these agreements were triggered on September 30, 2016, the Company would have been required to provide additional collateral of $24 million (December 31, 2015 - $32 million) to its counterparties. Collateral may also need to be provided should the fair value of derivative instruments exceed pre-defined contractual exposure limit thresholds.

The Company has sufficient liquidity in the form of cash and undrawn committed revolving credit facilities to meet these contingent obligations should they arise.

## FAIR VALUE HIERARCHY

The Company's financial assets and liabilities recorded at fair value have been categorized into three categories based on a fair value hierarchy.

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

The fair value of the Company's derivative instrument assets and liabilities measured on a recurring basis, including both current and non-current portions for 2016, are categorized as follows:

| **at September 30, 2016**<br>(unaudited - millions of Canadian $, pre-tax) | **Quoted prices in active markets (Level I)**[1] | **Significant other observable inputs (Level II)**[1] | **Significant unobservable inputs (Level III)**[1] | **Total** |
|---|---|---|---|---|
| Derivative instrument assets: | | | | |
| Commodities | **66** | **394** | **23** | **483** |
| Foreign exchange | **—** | **21** | **—** | **21** |
| Interest rate | **—** | **9** | **—** | **9** |
| Derivative instrument liabilities: | | | | |
| Commodities | **(71)** | **(484)** | **(11)** | **(566)** |
| Foreign exchange | **—** | **(475)** | **—** | **(475)** |
| Interest rate | **—** | **(3)** | **—** | **(3)** |
| | **(5)** | **(538)** | **12** | **(531)** |

1 There were no transfers from Level I to Level II or from Level II to Level III for the nine months ended September 30, 2016.

The fair value of the Company's assets and liabilities measured on a recurring basis, including both current and non-current portions for 2015, are categorized as follows:

| at December 31, 2015<br>(unaudited - millions of Canadian $, pre-tax) | Quoted prices in active markets (Level I)[1] | Significant other observable inputs (Level II)[1] | Significant unobservable inputs (Level III)[1] | Total |
|---|---|---|---|---|
| Derivative instrument assets: | | | | |
| Commodities | 34 | 462 | 13 | 509 |
| Foreign exchange | — | 96 | — | 96 |
| Interest rate | — | 5 | — | 5 |
| Derivative instrument liabilities: | | | | |
| Commodities | (102) | (611) | (4) | (717) |
| Foreign exchange | — | (828) | — | (828) |
| Interest rate | — | (6) | — | (6) |
| | (68) | (882) | 9 | (941) |

1 There were no transfers from Level I to Level II or from Level II to Level III for the year ended December 31, 2015.

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

| | three months ended September 30 | | nine months ended September 30 | |
|---|---|---|---|---|
| (unaudited - millions of Canadian $, pre-tax) | **2016** | 2015 | **2016** | 2015 |
| Balance at beginning of period | **12** | 11 | **9** | 4 |
| Total gains/(losses) included in net income | **2** | (2) | **13** | 3 |
| Transfers out of Level III | **(3)** | — | **(6)** | 3 |
| Settlements | **1** | — | **(1)** | — |
| Sales | **—** | (1) | **(2)** | (1) |
| Total gains/(losses) included in OCI | **—** | 1 | **(1)** | — |
| Balance at end of period[1] | **12** | 9 | **12** | 9 |

1 For the three and nine months ended September 30, 2016, revenues include unrealized gains of $1 million and $3 million, respectively, attributed to derivatives in the Level III category that were still held at September 30, 2016 (2015 - losses of $2 million and gains of $6 million, respectively).

A 10 per cent increase or decrease in commodity prices, with all other variables held constant, would result in a $2 million decrease or increase in the fair value of outstanding derivative instruments included in Level III as at September 30, 2016.

## 14. Other acquisitions and dispositions

### Natural Gas Pipelines

**Portland Natural Gas Transmission System**

On January 1, 2016, TransCanada completed the sale of a 49.9 per cent interest in Portland Natural Gas Transmission System (PNGTS) to TC PipeLines, LP for an aggregate purchase price of US$223 million. Proceeds were comprised of US$188 million in cash and the assumption of US$35 million in proportional PNGTS debt.

**Iroquois Gas Transmission System LP**

On March 31, 2016, TransCanada acquired a 4.87 per cent interest in Iroquois for an aggregate purchase price of US$53.8 million, increasing TransCanada's interest in Iroquois to 49.35 per cent. On May 1, 2016, the Company acquired an additional 0.65 per cent interest for an aggregate purchase price of US$7.2 million, further increasing TransCanada's interest in Iroquois to 50 per cent.

**TC Offshore LLC**

On March 31, 2016, TransCanada completed the sale of TC Offshore LLC to a third party. This resulted in an additional loss on disposal of $4 million pre-tax which is included in loss of sale of assets in the condensed consolidated statement of income.

### Energy

**Ironwood**

On February 1, 2016, TransCanada acquired the Ironwood natural gas fired, combined cycle power plant in Lebanon, Pennsylvania, with a capacity of 778 MW, for US$653 million in cash after post-acquisition adjustments. The Ironwood power plant delivers energy into the PJM power market. The evaluation of assigned fair value of acquired assets and liabilities did not result in the recognition of goodwill. The Company began consolidating Ironwood as of the date of acquisition which has not had a material impact on the consolidated revenues and net income of the Company. In addition, the pro forma incremental impact on the Company's consolidated revenues and net income for each of the periods presented is not material.

## 15. Commitments and guarantees

TransCanada and its subsidiaries are subject to various legal proceedings, arbitrations and actions arising in the normal course of business. While the final outcome of such legal proceedings and actions cannot be predicted with certainty, it is the opinion of management that the resolution of such proceedings and actions will not have a material impact on the Company's consolidated financial position or results of operations.

### COMMITMENTS

TransCanada's commitments at December 31, 2015 included fixed payments, net of sublease receipts for Alberta PPAs. As a result of the March 7, 2016 notice to terminate our Sheerness, Sundance A and Sundance B PPAs, our future obligations from December 31, 2015 have decreased by: 2016 - $195 million, 2017 - $200 million, 2018 - $141 million, 2019 - $138 million and 2020 - $115 million. Our commitments for 2021 and beyond increased by approximately $0.5 billion as a result of the extension of premise leases in second quarter 2016. The acquisition of Columbia on July 1, 2016 resulted in a total increase to our obligations of $349 million for transportation contracts and premise leases.

### GUARANTEES

TransCanada and its joint venture partner on Bruce Power, BPC Generation Infrastructure Trust, have each severally guaranteed certain contingent financial obligations of Bruce Power related to a lease agreement and contractor and supplier services. The Company's exposure under certain of these guarantees is unlimited.

The Company and its partners in certain other jointly owned entities have either (i) jointly and severally, (ii) jointly or (iii) severally guaranteed the financial performance of these entities. Such agreements include guarantees and letters of credit which are primarily related to delivery of natural gas, construction services including purchase agreements and the payment of liabilities. For certain of these entities, any payments made by TransCanada under these guarantees in excess of its ownership interest are to be reimbursed by its partners.

The carrying value of these guarantees has been included in other long-term liabilities. Information regarding the Company’s guarantees is as follows:

| | | at September 30, 2016 | | at December 31, 2015 | |
|---|---|---|---|---|---|
| (unaudited - millions of Canadian $) | Term | Potential exposure[1] | Carrying value | Potential exposure[1] | Carrying value |
| Bruce Power | ranging to 2018[2] | **88** | **1** | 88 | 2 |
| Sur de Texas-Tuxpan | ranging to 2040 | **693** | **46** | — | — |
| Other jointly owned entities | ranging to 2040 | **135** | **31** | 139 | 24 |
| | | **916** | **78** | 227 | 26 |

1 TransCanada’s share of the potential estimated current or contingent exposure.
2 Except for one guarantee with no termination date.

## 16. Variable interest entities

As a result of the implementation of the new FASB guidance on consolidation, a number of entities controlled by TransCanada are now considered to be variable interest entities (VIEs). A VIE is a legal entity that does not have sufficient equity at risk to finance its activities without additional subordinated financial support or is structured such that equity investors lack the ability to make significant decisions relating to the entity’s operations through voting rights or do not substantively participate in the gains and losses of the entity.

In the normal course of business, the Company consolidates VIEs in which it has a variable interest and for which it is considered to be the primary beneficiary. VIEs in which the Company has a variable interest but is not the primary beneficiary are accounted for as equity investments.

### Consolidated VIEs

The Company's consolidated VIEs consist of legal entities where the Company has the power, through voting or similar rights, to direct the activities of the VIE that most significantly impact economic performance including purchasing or selling significant assets; maintenance and operations of assets; incurring additional indebtedness; or determining the strategic operating direction of the entity. In addition, the Company has the obligation to absorb losses or the right to receive benefits from the consolidated VIE that could potentially be significant to the VIE.

A significant portion of the Company’s assets are held through VIEs in which the Company holds a 100 per cent voting interest, the VIE meets the definition of a business and the VIE’s assets can be used for general corporate purposes. The assets and liabilities of the consolidated VIEs whose assets cannot be used for purposes other than the settlement of the VIE’s obligations are as follows:

| (unaudited - millions of Canadian $) | September 30, 2016 | December 31, 2015 |
|---|---|---|
| **ASSETS** | | |
| **Current Assets** | | |
| Cash and cash equivalents | **97** | 54 |
| Accounts receivable | **55** | 55 |
| Inventories | **23** | 25 |
| Other | **6** | 6 |
| | **181** | 140 |
| **Plant, Property and Equipment** | **3,624** | 3,704 |
| **Equity Investments** | **592** | 664 |
| **Goodwill** | **513** | 541 |
| | **4,910** | 5,049 |
| **LIABILITIES** | | |
| **Current Liabilities** | | |
| Accounts payable and other | **60** | 74 |
| Accrued interest | **22** | 21 |
| Current portion of long-term debt | **75** | 45 |
| | **157** | 140 |
| **Regulatory Liabilities** | **33** | 33 |
| **Other Long-Term Liabilities** | **5** | 4 |
| **Deferred Income Tax Liabilities** | **7** | — |
| **Long-Term Debt** | **2,858** | 2,998 |
| | **3,060** | 3,175 |

## Non-Consolidated VIEs

The Company's non-consolidated VIEs consist of legal entities where the Company does not have the power to direct the activities that most significantly impact the economic performance of these VIEs or where this power is shared with third parties. The Company contributes capital to these VIEs and receives ownership interests that provide it with residual claims on assets after liabilities are paid.

The carrying value of these VIEs and the maximum exposure to loss as a result of the Company's involvement with these VIEs are as follows:

| (unaudited - millions of Canadian $) | September 30, 2016 | December 31, 2015 |
|---|---|---|
| **Balance sheet** | | |
| Equity investments | **5,043** | 5,410 |
| **Off-balance sheet** | | |
| Potential exposure to guarantees | **222** | 227 |
| **Maximum exposure to loss** | **5,265** | 5,637 |

## 17. Subsequent events

### Assets held for sale

The Company's planned monetization of the U.S. Northeast Power business, for the purposes of permanently financing the Columbia acquisition, includes the sale of Ravenswood, Ironwood, Kibby Wind, Ocean State Power, TC Hydro and the marketing business, TransCanada Power Marketing (TCPM). On November 1, 2016, subsequent to the balance sheet date the Company entered into agreements to sell all of these assets except the marketing business, the value from which is still expected to be realized going forward.

The sale of Ravenswood, Ironwood, Kibby Wind and Ocean State Power to a third party is expected to close in the first half of 2017. As a result, effective November 1, 2016, the related assets and liabilities are classified as held for sale in the Energy segment and will be recorded at their fair values less costs to sell. This is expected to result in a loss on assets held for sale of approximately $899 million in fourth quarter 2016 or $863 million after tax which includes the reclassification of an estimated $61 million of foreign currency translation gains from AOCI to net income.

The sale of TC Hydro to another third party is also expected to close in the first half of 2017 resulting in an estimated gain of $719 million or $443 million after tax which includes the reclassification of an estimated $4 million of foreign currency translation gains from AOCI to net income. This gain will be recognized upon closing of the sale transaction. Effective November 1, 2016, the related assets and liabilities are classified as held for sale in the Energy segment.

As of November 1, 2016, TCPM does not meet the criteria to be classified as held for sale.

The following table details the assets and liabilities as at September 30, 2016 related to the U.S. Northeast Power business that are classified as held for sale effective November 1, 2016. The expected loss on assets held for sale of approximately $899 million (US$686 million) is not reflected in the table below.

| (unaudited - millions of $) | **U.S.** | **Canadian[1]** |
|---|---|---|
| **Assets held for sale** | | |
| Accounts receivable | 20 | 26 |
| Inventories | 57 | 75 |
| Other current assets | 107 | 140 |
| Plant, property and equipment | 2,862 | 3,754 |
| Intangible and other assets | 324 | 425 |
| **Total assets held for sale** | 3,370 | 4,420 |
| | | |
| **Liabilities related to assets held for sale** | | |
| Accounts payable and other | 27 | 35 |
| Other long-term liabilities | 31 | 41 |
| **Total liabilities related to assets held for sale** | 58 | 76 |

1 At September 30, 2016 exchange rate of $1.31

### Columbia Pipeline Partners LP

On November 1, 2016, TransCanada announced that it had entered into an agreement and plan of merger through which our wholly-owned subsidiary, Columbia, has agreed to acquire, for cash, all of the outstanding publicly held common units of Columbia Pipeline Partners LP (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 first quarter 2017 subject to receipt of CPPL unitholder approval and customary closing conditions. At September 30, 2016, the common units are recorded as non-controlling interests in these condensed consolidated financial statements. As a result, there will be no gain or loss recorded on closing this transaction.

### Common equity offering

On November 1, 2016, concurrent with the release of these financial results, the Company announced it has entered into an agreement with a group of underwriters to proceed with an offering of common shares. The closing for the offering is expected to be on November 16, 2016.