TransCanada Reports Solid Second Quarter 2016 Financial Results
Transformational Columbia Acquisition to Enhance Future Growth

CALGARY, Alberta – **July 28, 2016** – TransCanada Corporation (TSX, NYSE: TRP) (TransCanada) today announced net income attributable to common shares for second quarter 2016 of $365 million or $0.52 per share compared to $429 million or $0.60 per share for the same period in 2015. Comparable earnings for second quarter 2016 were $366 million or $0.52 per share compared to $397 million or $0.56 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 September 30, 2016, equivalent to $2.26 per common share on an annualized basis.

"Our portfolio of high-quality energy infrastructure assets continued to perform well during the second quarter of 2016," said Russ Girling, TransCanada's president and chief executive officer. "Net income was impacted by one-time dividend equivalent payments on the subscription receipts related to the acquisition of Columbia, while comparable earnings largely reflected planned maintenance activities at Bruce Power including an approximate once-a-decade station containment outage. With the addition of Columbia and Bruce Power's planned maintenance outages now largely complete, we expect to generate stronger results going forward."

On July 1, 2016, TransCanada completed the acquisition of Columbia Pipeline Group, Inc. (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 subscription receipts issued in April to fund a portion of the Columbia acquisition were exchanged into common shares following closing.

"The Columbia acquisition reinforces TransCanada's position as a leading North American energy infrastructure company with an extensive pipeline network linking the continent's most prolific natural gas supply basins to its most attractive markets," added Girling. "The Columbia assets are very complementary to our existing business and we expect significant synergies and growth in the years to come. Our industry-leading $25 billion portfolio of near-term capital projects builds upon a solid portfolio of stable and predictable pipeline and energy assets that together supports and may augment an expected eight to ten per cent annual dividend growth rate through 2020."

Highlights

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

- Second quarter financial results
  - Net income attributable to common shares of $365 million or $0.52 per share
  - Comparable earnings of $366 million or $0.52 per share
  - Comparable earnings before interest, taxes, depreciation and amortization (EBITDA) of $1.4 billion
  - Funds generated from operations of $831 million, including $109 million of dividend equivalent payments on the subscription receipts
  - Comparable distributable cash flow of $698 million or $0.99 per common share
- Declared a quarterly dividend of $0.565 per common share for the quarter ending September 30, 2016
- 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
- On July 4, 2016, exchanged 96.6 million subscription receipts into the same number of common shares

- Awarded a contract to construct the US$2.1 billion Sur de Texas to Tuxpan pipeline in Mexico, a joint venture with IEnova. TransCanada holds a 60 per cent interest in the joint venture and will operate the pipeline
- Announced 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
- Continued to advance the monetization of the Company's U.S. Northeast power assets and a minority interest in its Mexican pipeline business.

Net income attributable to common shares decreased by $64 million to $365 million or $0.52 per share for the three months ended June 30, 2016 compared to the same period last year. Second quarter 2016 included a charge of $113 million related to costs associated with the Columbia acquisition which were primarily related to the dividend equivalent payments on the subscription receipts, a net after-tax $10 million restructuring charge related to expected future losses under lease commitments, and $9 million after-tax related to Keystone XL maintenance and liquidation costs. All of these specific items are excluded from comparable earnings.

Comparable earnings for second quarter 2016 were $366 million or $0.52 per share compared to $397 million or $0.56 per share for the same period in 2015. Comparable earnings were lower in the period due to higher interest expenses as a result of debt issuances and lower capitalized interest, higher planned maintenance outage days at Bruce Power, lower volumes on the Keystone and Marketlink pipelines, and lower earnings from Western Power, partially offset by realized gains in 2016 versus realized losses in 2015 on derivatives used to manage our foreign exchange exposure, higher AFUDC on our rate-regulated projects, greater earnings from ANR due to higher transportation revenue and lower OM&A expenses, and higher earnings from U.S. Power mainly due to incremental earnings from Ironwood.

Notable recent developments include:

Corporate:

- *Acquisition of Columbia Pipeline Group:* 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 initially financed through proceeds of $4.4 billion from the sale of subscription receipts, 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 closing of the acquisition, were exchanged into 96.6 million TransCanada common shares. We are targeting US$250 million of annual cost, revenue and financing benefits over the next two years and expect the acquisition, net of financing and the planned asset monetizations, to be accretive to earnings per share in the first full year of ownership.
- *Monetization of U.S. Northeast power assets and a minority interest in Mexican pipelines:* The permanent financing for the acquisition of the Columbia Pipeline Group involves portfolio management that includes the monetization of our U.S. Northeast power assets and a minority interest in our Mexico gas pipeline business. The process of engaging advisors has been completed and the initial stages of soliciting interested parties is well underway. We expect to provide an update as to the outcome of that process by the end of 2016. Proceeds from these monetizations will be used to retire draws from the bridge loan facilities.
- *Master Limited Partnership Strategy Review:* On July 1, 2016, we announced that a financial advisor has been retained to assist us in developing a master limited partnership (MLP) strategy. A decision on the MLP strategy is expected to be communicated by the end of 2016.
- *Dividend Declaration:* Our Board of Directors declared a quarterly dividend of $0.565 per share for the quarter ending September 30, 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:* Reinstated 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.

- *Debt offerings:* During the second quarter TransCanada issued $300 million of seven year medium term notes and $700 million of thirty year notes in Canada at interest rates of 3.69 per cent and 4.35 per cent, respectively. In addition, ANR completed a private placement of US$240 million of ten year senior unsecured notes at a rate of 4.14 per cent in the United States.

Natural Gas Pipelines:

- *NGTL System*: In second quarter 2016, we placed approximately $450 million of facilities in service with another $400 million of facilities approved and currently under construction. New long term delivery contracts on the NGTL System to the Alberta/BC border (Sundre Crossover project) will require construction of approximately $135 million in facilities not previously included in our 2018 Facilities program. We are currently assessing additional demand requests. A re-evaluation of facility requirements to meet future aggregate system service requirements has been undertaken. As a result, some changes in our spending profile are expected to occur to match revised facility in-service dates. The total estimated projected capital for the NGTL System remains at approximately $7.3 billion, including the Sundre Crossover project, and the North Montney and Merrick pipelines. We expect deferrals of approximately $225 million related to the 2016/17 Facilities program and $210 million related to the 2018 Facilities program with revised in-service dates from 2018 through 2020.
- *Sur de Texas-Tuxpan Pipeline:* On June 13, 2016, we announced that our joint venture with IEnova was chosen to build, own and operate the US$2.1 billion Sur de Texas-Tuxpan pipeline in Mexico. Construction of the pipeline is supported by a 25-year natural gas transportation service contract for 2.6 billion cubic feet per day with the Comisión Federal de Electricidad (CFE). TransCanada holds a 60 per cent interest in the joint venture and will operate the asset. We expect to invest approximately US$1.3 billion in the partnership to construct the 42-inch diameter, approximately 800-kilometre (km) (497-mile) pipeline and anticipate an 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 pipeline will connect to TransCanada's Tamazunchale and Tuxpan-Tula pipelines as well as with other transporters in the region.
- *Tula-Villa de Reyes Pipeline:* On April 11, 2016, we announced we were awarded the contract to build, own and operate the Tula-Villa de Reyes pipeline in Mexico. Construction of the pipeline is supported by a 25-year natural gas transportation service contract for 886 million cubic feet per day with the CFE. We expect to invest approximately US$550 million in 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.
- *ANR Section 4 Rate Case:* In January 2016, ANR filed a Section 4 Rate Case with the Federal Energy Regulatory Commission (FERC) that requests an increase to ANR's maximum transportation rates. In February 2016, the FERC issued an order that accepted and suspended ANR's rate and tariff changes to become effective August 1, 2016, subject to refund and the outcome of a hearing. In addition, in March 2016, the FERC established a procedural schedule for the hearing and appointed a settlement judge to assist the parties in their settlement negotiations. The hearing is currently scheduled for early February 2017.
- *Coastal GasLink:* On July 11, 2016, the LNG Canada joint venture participants announced a delay to their final investment decision 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, TransCanada is working with LNG Canada to determine the appropriate pacing of the Coastal GasLink development schedule and work activities.

Liquids Pipelines:

- ***Houston Lateral and Terminal*:** We commenced commercial transactions in July 2016 for August 2016 deliveries on the Houston Lateral pipeline and terminal, an extension from the Keystone Pipeline System to Houston, Texas. The terminal has an initial storage capacity of 700,000 barrels of crude oil.
- ***Energy East Pipeline*:** On May 17, 2016, we filed a consolidated application with the National Energy Board (NEB) for Energy East. On June 16, 2016, Energy East achieved a major milestone with the NEB determining the application sufficiently complete to initiate the formal regulatory review process. This determination of completeness marks the start of the mandated twenty one 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.

Energy:

- *Bruce Power Financing:* 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. Distributions received from Bruce Power in second quarter 2016 included $725 million from this financing program.

Teleconference and Webcast:

We will hold a teleconference and webcast on Thursday, July 28, 2016 to discuss our second quarter 2016 financial results. Russ Girling, TransCanada President and Chief Executive Officer, and Don Marchand, Executive Vice-President, Corporate Development and Chief Financial Officer, along with other members of the TransCanada executive leadership team, will discuss the financial results and Company developments at 9 a.m. (MT) / 11 a.m. (ET).

Members of the investment community and other interested parties are invited to participate by calling 866.225.6564 or 416.340.2220 (Toronto area). Please dial in 10 minutes prior to the start of the call. No pass code is required. A live webcast of the teleconference will be available at www.transcanada.com.

A replay of the teleconference will be available two hours after the conclusion of the call until midnight (ET) on August 4, 2016. Please call 800.408.3053 or 905.694.9451 (Toronto area) and enter pass code 1967464.

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 July 27, 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, 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 July 27, 2016.

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Quarterly report to shareholders

Second quarter 2016

Financial highlights

(unaudited - millions of $, except per share amounts)	three months ended June 30		six months ended June 30	
	2016	**2015**	**2016**	**2015**
Income				
Revenues	**2,751**	2,631	**5,254**	5,505
Net income attributable to common shares	**365**	429	**617**	816
per common share - basic and diluted	**$0.52**	$0.60	**$0.88**	$1.15
Comparable EBITDA[1]	**1,369**	1,367	**2,871**	2,898
Comparable earnings[1]	**366**	397	**860**	862
per common share[1]	**$0.52**	$0.56	**$1.22**	$1.22
Operating cash flow				
Funds generated from operations[1]	**831**	1,061	**1,956**	2,214
Decrease/(increase) in operating working capital	**218**	(92)	**138**	(485)
Net cash provided by operations	**1,049**	969	**2,094**	1,729
Comparable distributable cash flow[1]	**698**	861	**1,668**	1,817
per common share[1]	**$0.99**	$1.21	**$2.37**	$2.56
Investing activities				
Capital spending - capital expenditures	**982**	966	**1,818**	1,772
- projects in development	**90**	172	**157**	335
Contributions to equity investments	**114**	105	**284**	198
Acquisitions, net of cash acquired	**4**	—	**999**	—
Proceeds from sale of assets, net of transaction costs	**—**	—	**6**	—
Dividends declared				
Per common share	**$0.565**	$0.52	**$1.13**	$1.04
Basic common shares outstanding (millions)				
Average for the period	**703**	709	**703**	709
End of period	**703**	709	**703**	709

1 Comparable EBITDA, comparable earnings, comparable earnings per common share, 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

July 27, 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 six months ended June 30, 2016, and should be read with the accompanying unaudited condensed consolidated financial statements for the three and six months ended June 30, 2016 which have been prepared in accordance with U.S. GAAP. For greater certainty, given our acquisition of Columbia Pipeline Group, Inc. (Columbia) was not completed until July 1, 2016, Columbia was not a subsidiary during the period ended June 30, 2016 and its results have not been reflected in our condensed consolidated financial statements for the three and six months ended June 30, 2016.

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 July 27, 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 assets and a minority interest in our Mexican natural gas pipeline 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
- distributable cash flow
- distributable cash flow per common share
- comparable earnings
- comparable earnings per common share
- comparable EBITDA
- comparable EBIT
- comparable distributable cash flow
- comparable distributable cash flow per common share
- 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.

Distributable cash flow

Distributable cash flow is defined as funds generated from operations plus distributions received from operating activities in excess of equity earnings 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 it 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.

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	EBITDA
comparable EBIT	segmented earnings
comparable distributable cash flow	distributable cash flow
comparable distributable cash flow per common share	distributable cash flow per common share
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 assets and investments 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.

Consolidated results - second 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 June 30		six months ended June 30	
(unaudited - millions of $, except per share amounts)	**2016**	2015	**2016**	2015
Natural Gas Pipelines	**592**	517	**1,199**	1,105
Liquids Pipelines	**204**	247	**422**	489
Energy	**378**	262	**256**	471
Corporate	**(58)**	(32)	**(118)**	(63)
Total segmented earnings	**1,116**	994	**1,759**	2,002
Interest expense	**(514)**	(331)	**(934)**	(649)
Interest income and other	**117**	81	**318**	67
Income before income taxes	**719**	744	**1,143**	1,420
Income tax expense	**(274)**	(250)	**(344)**	(457)
Net income	**445**	494	**799**	963
Net income attributable to non-controlling interests	**(52)**	(40)	**(132)**	(99)
Net income attributable to controlling interests	**393**	454	**667**	864
Preferred share dividends	**(28)**	(25)	**(50)**	(48)
Net income attributable to common shares	**365**	429	**617**	816
Net income per common share - basic and diluted	**$0.52**	$0.60	**$0.88**	$1.15

Net income attributable to common shares decreased by $64 million and $199 million for the three and six months ended June 30, 2016 compared to the same periods in 2015. The 2016 results included:

- 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
- a charge of $113 million in second quarter and $139 million year-to-date related to costs associated with the acquisition of Columbia. In second quarter, $109 million related to the dividend equivalent payments on the subscription receipts issued as part of the permanent financing of the transaction, $10 million ($36 million year-to-date) related to acquisition costs and $6 million related to interest earned on the funds held in escrow
- an after-tax charge of $9 million in second quarter and $15 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 in second quarter 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
- an additional $3 million after-tax loss on the sale of TC Offshore which closed on March 31, 2016.

The 2015 results included:

- 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
- an after-tax charge of $8 million 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.

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 decreased by $31 million and $2 million for the three and six months ended June 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 June 30		six months ended June 30	
(unaudited - millions of $, except per share amounts)	**2016**	**2015**	**2016**	**2015**
Net income attributable to common shares	**365**	429	**617**	816
Specific items (net of tax):				
Alberta PPA terminations	**—**	—	**176**	—
Acquisition costs - Columbia Pipeline Group	**113**	—	**139**	—
Keystone XL asset costs	**9**	—	**15**	—
Restructuring costs	**10**	8	**10**	8
TC Offshore loss on sale	**—**	—	**3**	—
Alberta corporate income tax rate increase	**—**	34	**—**	34
Risk management activities[1]	**(131)**	(74)	**(100)**	4
Comparable earnings	**366**	397	**860**	862
Net income per common share	**$0.52**	$0.60	**$0.88**	$1.15
Specific items (net of tax):				
Alberta PPA terminations	**—**	—	**0.25**	—
Acquisition costs - Columbia Pipeline Group	**0.16**	—	**0.20**	—
Keystone XL asset costs	**0.01**	—	**0.02**	—
Restructuring costs	**0.01**	0.01	**0.01**	0.01
Alberta corporate income tax rate increase	**—**	0.05	**—**	0.05
Risk management activities	**(0.18)**	(0.10)	**(0.14)**	0.01
Comparable earnings per share	**$0.52**	$0.56	**$1.22**	$1.22

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Risk management activities	three months ended June 30		six months ended June 30	
(unaudited - millions of $)	**2016**	**2015**	**2016**	**2015**
Canadian Power	**20**	29	**7**	7
U.S. Power	**204**	51	**89**	(17)
Liquids marketing	**4**	—	**2**	—
Natural Gas Storage	**—**	(1)	**5**	—
Foreign exchange	**(4)**	30	**49**	1
Income tax attributable to risk management activities	**(93)**	(35)	**(52)**	5
Total gains/(losses) from risk management activities	**131**	74	**100**	(4)

Comparable earnings decreased by $31 million for the three months ended June 30, 2016 compared to the same period in 2015. This was primarily the net effect of:

- 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
- higher interest expense from debt issuances and lower capitalized interest
- lower earnings from Bruce Power mainly due to higher planned outage days, partially offset by lower depreciation
- higher earnings from U.S. and International Pipelines due to higher ANR Southeast Mainline transportation revenues and lower OM&A expenses
- lower earnings from Liquids Pipelines due to lower uncontracted volumes on Keystone Pipeline and lower volumes on Marketlink
- higher earnings from U.S. Power mainly due to incremental earnings from the Ironwood power plant acquired February 1, 2016 and insurance recoveries related to an unplanned outage at Ravenswood
- lower earnings from Western Power as a result of lower realized power prices and lower PPA volumes following the termination of the PPAs.

Comparable earnings decreased by $2 million for the six months ended June 30, 2016 compared to the same period in 2015. This was primarily the net effect of:

- 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
- higher interest expense from debt issuances and lower capitalized interest
- lower earnings from Liquids Pipelines due to lower uncontracted volumes on Keystone Pipeline and lower volumes on Marketlink
- higher earnings from our U.S. and International Pipelines due to higher ANR Southeast Mainline transportation revenues and lower OM&A expenses, offset by a first quarter 2015 non-recurring settlement
- lower earnings from U.S. Power mainly due to decreased margins on sales to wholesale, commercial and industrial customers, the impact of lower capacity prices in New York and lower realized prices in both New England and New York, offset by incremental earnings from the Ironwood power plant and insurance recoveries related to an unplanned outage at Ravenswood
- lower earnings from Eastern Power due to lower earnings on the sale of unused natural gas transportation and lower contractual earnings at Bécancour
- lower earnings from Western Power as a result of lower realized power prices and lower PPA volumes following the termination of the PPAs.

The stronger U.S. dollar this quarter compared to the same period in 2015 positively impacted the translated results in our U.S. 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 June 30, 2016, consists of $15 billion of near-term projects and $45 billion of commercially secured medium- to longer-term projects. Amounts presented exclude the impact of foreign exchange, 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.

at June 30, 2016 (unaudited - billions of $)	**Estimated project cost**	**Carrying value**
Summary		
Near-term	14.6	5.0
Medium- to longer-term	45.2	2.3
Total capital program	**59.8**	**7.3**
Foreign exchange impact on Capital Program[1]	3.9	0.7

[1] Reflects U.S./Canada foreign exchange rate of $1.30 at June 30, 2016.

at June 30, 2016 (unaudited - billions of $)	**Segment**	**Expected in-service date**	**Estimated project cost**	**Carrying value**
Houston Lateral and Terminal	Liquids Pipelines	2016	US 0.6	US 0.6
Topolobampo	Natural Gas Pipelines	2016	US 1.0	US 0.9
Mazatlan	Natural Gas Pipelines	2016	US 0.4	US 0.3
Canadian Mainline	Natural Gas Pipelines	2016-2017	0.7	0.2
NGTL - 2016/17 Facilities	Natural Gas Pipelines	2016-2020	2.7	0.7
- North Montney	Natural Gas Pipelines	2017	1.7	0.3
- 2018 Facilities	Natural Gas Pipelines	2018-2020	0.6	—
- Other	Natural Gas Pipelines	2016-2018	0.4	0.1
Grand Rapids[1]	Liquids Pipelines	2017	0.9	0.7
Northern Courier	Liquids Pipelines	2017	1.0	0.7
Tuxpan-Tula	Natural Gas Pipelines	2017	US 0.5	US 0.1
Napanee	Energy	2018	1.0	0.4
Tula-Villa de Reyes	Natural Gas Pipelines	2018	US 0.6	—
Sur de Texas-Tuxpan[1]	Natural Gas Pipelines	2018	US 1.3	—
Bruce Power - life extension[1]	Energy	2016-2020	1.2	—
Total near-term projects			**14.6**	**5.0**

[1] Our proportionate share.

at June 30, 2016 (unaudited - billions of $)	Segment	Estimated project cost	Carrying value
Heartland and TC Terminals	Liquids Pipelines	0.9	0.1
Upland	Liquids Pipelines	US 0.6	—
Grand Rapids Phase 2[1]	Liquids Pipelines	0.7	—
Bruce Power - life extension[1]	Energy	5.3	—
Keystone projects			
Keystone XL[2]	Liquids Pipelines	US 8.0	US 0.3
Keystone Hardisty Terminal[2]	Liquids Pipelines	0.3	0.1
Energy East projects			
Energy East[3]	Liquids Pipelines	15.7	0.8
Eastern Mainline	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	—
Total medium to longer-term projects		**45.2**	**2.3**

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.

Our capital program as of July 1, 2016, including Columbia projects, consists of $25 billion of near-term projects.

at July 1, 2016 (Acquisition date) (unaudited - billions of US$)	Segment	Expected in-service date	Estimated project cost
Columbia Pipeline Group			
Modernization I	Natural Gas Pipelines	2017-2018	US 0.6
Modernization II	Natural Gas Pipelines	2019-2021	US 1.1
Leach XPress	Natural Gas Pipelines	2017	US 1.4
WB XPress	Natural Gas Pipelines	2018	US 0.8
Mountaineer XPress	Natural Gas Pipelines	2018	US 2.0
Rayne XPress	Natural Gas Pipelines	2017	US 0.4
Cameron Access	Natural Gas Pipelines	2018	US 0.3
Gulf XPress	Natural Gas Pipelines	2018	US 0.7
Total Columbia projects			**US 7.3**
Total Columbia projects - Canadian $			**9.5**

Outlook

Our overall earnings outlook for our 2016 earnings, excluding specific items, will be modestly 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, changes in our Canadian Power business and lower than expected U.S. Power earnings, each of which are addressed within the relevant section of the MD&A.

Consolidated capital spending, equity investments and acquisition

On April 11, 2016, we announced that we were chosen to build, own and operate the US$550 million Tula-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 US$2.1 billion Sur de Texas-Tuxpan natural gas pipeline in Mexico. On July 1, 2016, we acquired Columbia for US$10.3 billion. In addition to the capital expenditures outlined in the 2015 Annual Report, we expect to spend an estimated additional $1 billion on Columbia capital projects in 2016, approximately $300 million on the Tula-Villa de Reyes pipeline and $150 million on the Sur de Texas-Tuxpan natural gas pipeline.

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.

	three months ended June 30		**six months ended June 30**	
(unaudited - millions of $)	**2016**	**2015**	**2016**	**2015**
Comparable EBITDA	**880**	799	**1,778**	1,666
Depreciation and amortization	**(288)**	(282)	**(575)**	(561)
Comparable EBIT	**592**	517	**1,203**	1,105
Specific item:				
TC Offshore loss on sale	**—**	—	**(4)**	—
Segmented earnings	**592**	517	**1,199**	1,105

Natural Gas Pipelines segmented earnings increased by $75 million and $94 million for the three and six months ended June 30, 2016 compared to the same periods in 2015. Segmented earnings for the six months ended June 30, 2016 included an additional $4 million pre-tax loss on the sale of TC Offshore. This amount has 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 $)	three months ended June 30 2016	2015	six months ended June 30 2016	2015
Canadian Pipelines				
Canadian Mainline	**300**	317	**540**	580
NGTL System	**249**	224	**483**	443
Foothills	**26**	27	**52**	53
Other Canadian pipelines[1]	**6**	8	**13**	14
Canadian Pipelines - comparable EBITDA	**581**	576	**1,088**	1,090
Depreciation and amortization	**(218)**	(211)	**(434)**	(420)
Canadian Pipelines - comparable EBIT	**363**	365	**654**	670
U.S. and International Pipelines (US$)				
ANR	**71**	33	**159**	119
TC PipeLines, LP[1,2]	**27**	25	**58**	51
Great Lakes[3]	**11**	7	**36**	27
Other U.S. pipelines (Iroquois[1], GTN[2,4], PNGTS[2,5])	**9**	11	**23**	52
Mexico (Guadalajara, Tamazunchale)	**42**	47	**83**	94
International and other[1,6]	**2**	2	**4**	4
Non-controlling interests[7]	**75**	66	**170**	140
U.S. and International Pipelines - comparable EBITDA	**237**	191	**533**	487
Depreciation and amortization	**(54)**	(57)	**(107)**	(114)
U.S. and International Pipelines - comparable EBIT	**183**	134	**426**	373
Foreign exchange impact	**49**	29	**133**	88
U.S. and International Pipelines - comparable EBIT (Cdn$)	**232**	163	**559**	461
Business Development comparable EBITDA and EBIT	**(3)**	(11)	**(10)**	(26)
Natural Gas Pipelines - comparable EBIT	**592**	517	**1,203**	1,105

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

2 On April 1, 2015, we sold our remaining 30 per cent direct interest in GTN to TC PipeLines, LP. On January 1, 2016, we sold a 49.9 per cent interest in PNGTS to TC PipeLines, LP. The following shows our ownership interest in TC PipeLines, LP and our effective ownership interest of GTN, Great Lakes and PNGTS through our ownership interest in TC PipeLines, LP for the periods presented.

	Ownership percentage as of June 30, 2016	March 31, 2016	December 31, 2015	April 1, 2015
TC PipeLines, LP	27.4	27.9	28.0	28.3
Effective ownership through TC PipeLines, LP:				
GTN	27.4	27.9	28.0	28.3
Great Lakes	12.7	13.0	13.0	13.1
PNGTS	13.7	13.9	—	—

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

4 Effective April 1, 2015, we have no direct ownership in GTN. Prior to that our direct ownership interest was 30 per cent effective July 1, 2013.

5 Represents our 61.7 per cent ownership interest in 2015. Effective January 1, 2016, our direct ownership interest in PNGTS was 11.8 per cent as a result of the dropdown transaction between us and TC PipeLines, LP.

6 Includes our share of the equity income from TransGas as well as general and administration costs relating to our U.S. and International Pipelines.

7 Comparable EBITDA for the portions of TC PipeLines, LP and PNGTS 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, the 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 June 30		six months ended June 30	
(unaudited - millions of $)	**2016**	**2015**	**2016**	**2015**
Canadian Mainline	**52**	67	**102**	114
NGTL System	**79**	66	**152**	130
Foothills	**3**	4	**7**	8

Net income for the Canadian Mainline decreased by $15 million for the three months ended June 30, 2016 compared to the same period in 2015 primarily due to lower incentive earnings and average investment base. Higher incentive earnings were recorded in the second quarter of 2015 because NEB approval of the 2015 - 2020 compliance tolls for the NEB 2014 Decision was received in June 2015 and second quarter 2015 results included the year-to-date impact. The NEB 2014 Decision included an approved ROE of 10.1 per cent with a possible range of achieved ROE outcomes between 8.7 to 11.5 per cent. Net Income for the Canadian Mainline decreased by $12 million for the six months ended June 30, 2016 compared to the same period in 2015 mainly due to a lower average investment base in 2016.

Net income for the NGTL System increased by $13 million and $22 million for the three and six months ended June 30, 2016 compared to the same periods in 2015 mainly due to a higher average investment base and OM&A incentives recorded in 2016.

U.S. AND INTERNATIONAL PIPELINES

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

Comparable EBITDA for U.S. and International Pipelines increased by US$46 million in both the three and six months ended June 30, 2016 compared to the same periods in 2015. This was the net effect of:

- higher ANR Southeast Mainline transportation revenues and lower OM&A expenses, offset by a first quarter 2015 non-recurring settlement
- lower contributions from Mexican Pipelines primarily due to lower revenue
- higher transportation revenues from Great Lakes
- higher contribution from TC PipeLines, LP.

As well, a stronger U.S. dollar 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 $6 million and $14 million for the three and six months ended June 30, 2016 compared to the same periods in 2015 mainly because of a higher investment base on the NGTL System and the effect of a stronger U.S. dollar.

BUSINESS DEVELOPMENT

Business development expenses were lower by $8 million and $16 million for the three and six months ended June 30, 2016 compared to the same periods in 2015 mainly due to capitalization of business development expenses, a focus on the Columbia acquisition and decreased business development activity.

OUTLOOK

The 2016 earnings outlook for the Canadian regulated and Mexican pipelines remain consistent with what we disclosed in the 2015 Annual Report. Earnings for the existing U.S. Pipelines are expected to be slightly higher this year as a result of higher revenues and lower costs. We are also expecting an increase in 2016 earnings 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.

OPERATING STATISTICS - WHOLLY OWNED PIPELINES

six months ended June 30	**Canadian Mainline**[1]		**NGTL System**[2]		**ANR**[3]	
(unaudited)	**2016**	**2015**	**2016**	**2015**	**2016**	**2015**
Average investment base (millions of $)	**4,398**	4,925	**7,357**	6,505	**n/a**	n/a
Delivery volumes (Bcf):						
Total	**849**	864	**1,994**	1,948	**822**	862
Average per day	**4.7**	4.8	**11.0**	10.8	**4.5**	4.8

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 six months ended June 30, 2016 were 530 Bcf (2015 – 564 Bcf). Average per day was 2.9 Bcf (2015 – 3.1 Bcf).

2 Field receipt volumes for the NGTL System for the six months ended June 30, 2016 were 2,075 Bcf (2015 – 2,006 Bcf). Average per day was 11.4 Bcf (2015 – 11.1 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 June 30		six months ended June 30	
(unaudited - millions of $)	**2016**	**2015**	**2016**	**2015**
Comparable EBITDA	**280**	313	**580**	618
Depreciation and amortization	**(67)**	(66)	**(137)**	(129)
Comparable EBIT	**213**	247	**443**	489
Specific items:				
Keystone XL asset costs	**(13)**	—	**(23)**	—
Risk management activities	**4**	—	**2**	—
Segmented earnings	**204**	247	**422**	489

Liquids Pipelines segmented earnings decreased by $43 million and $67 million for the three and six months ended June 30, 2016 compared to the same periods in 2015 and included a pre-tax charge related to Keystone XL costs for the maintenance and liquidation of project assets which are being expensed pending further advancement of the project, and unrealized gains from changes in the fair value of derivatives related to our liquids marketing business. These amounts have been excluded from our calculation of comparable EBIT. The remainder of the Liquids Pipelines segmented earnings are equivalent to comparable EBIT, which, along with comparable EBITDA, are discussed below.

	three months ended June 30		six months ended June 30	
(unaudited - millions of $)	**2016**	**2015**	**2016**	**2015**
Keystone Pipeline System	**279**	317	**586**	628
Liquids Pipelines Business Development and Other	**1**	(4)	**(6)**	(10)
Liquids Pipelines - comparable EBITDA	**280**	313	**580**	618
Depreciation and amortization	**(67)**	(66)	**(137)**	(129)
Liquids Pipelines - comparable EBIT	**213**	247	**443**	489
Comparable EBIT denominated as follows:				
Canadian dollars	**57**	55	**112**	115
U.S. dollars	**120**	156	**250**	303
Foreign exchange impact	**36**	36	**81**	71
	213	247	**443**	489

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 $38 million and $42 million for the three and six months ended June 30, 2016 compared to the same periods in 2015 and was the net effect of:

- lower uncontracted volumes on Keystone Pipeline
- lower volumes on Marketlink

- a stronger U.S. dollar which had a positive impact on the Canadian dollar equivalent comparable earnings from our U.S. operations.

BUSINESS DEVELOPMENT AND OTHER

Business development and other, which primarily includes business development activity and our marketing business, increased by $5 million and $4 million for the three and six months ended June 30, 2016 compared to the same periods in 2015 and was the net effect of:

- lower business development spending
- growing contribution of Liquids Marketing.

DEPRECIATION AND AMORTIZATION

Depreciation and amortization increased by $1 million and $8 million for the three and six months ended June 30, 2016 compared to the same periods in 2015 due to the effect of a stronger U.S. dollar.

OUTLOOK

Following our Keystone XL impairment charge in 2015, future expenditures on the project for the maintenance and liquidation of project assets, expected to be approximately $55 million before tax ($36 million after tax) in 2016, are being expensed pending further advancement of this project. These costs will 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 June 30		six months ended June 30	
(unaudited - millions of $)	**2016**	2015	**2016**	2015
Comparable EBITDA	**236**	267	**565**	650
Depreciation and amortization	**(82)**	(84)	**(170)**	(169)
Comparable EBIT	**154**	183	**395**	481
Specific items:				
Alberta PPA terminations	**—**	—	**(240)**	—
Risk management activities	**224**	79	**101**	(10)
Segmented earnings	**378**	262	**256**	471

Energy segmented earnings increased by $116 million and decreased by $215 million for the three and six months ended June 30, 2016 compared to the same periods in 2015.

Energy segmented earnings included the following specific items that have been excluded from comparable EBIT:

- 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
- unrealized gains and losses from changes in the fair value of certain derivatives used to reduce our exposure to certain commodity price risks as follows:

Risk management activities	three months ended June 30		six months ended June 30	
(unaudited - millions of $, pre-tax)	**2016**	2015	**2016**	2015
Canadian Power	**20**	29	**7**	7
U.S. Power	**204**	51	**89**	(17)
Natural Gas Storage	**—**	(1)	**5**	—
Total gains/(losses) from risk management activities	**224**	79	**101**	(10)

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 impact 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 assets, we were required to discontinue hedge accounting for certain cash flow hedges. This, along with the increased volume of our risk management activities associated with the expansion of our customer base in the PJM market, contributed to higher volatility in U.S. Power risk management activities. This increased level of volatility is reflected in the $204 million unrealized gain in second quarter 2016 and the $115 million unrealized loss in first quarter 2016.

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

	three months ended June 30		six months ended June 30	
(unaudited - millions of $)	2016	2015	2016	2015
Canadian Power				
Western Power[1]	**19**	34	**23**	49
Eastern Power	**85**	90	**188**	220
Bruce Power	**20**	66	**134**	145
Canadian Power - comparable EBITDA[1,2]	**124**	190	**345**	414
Depreciation and amortization	**(36)**	(46)	**(82)**	(94)
Canadian Power - comparable EBIT[1,2]	**88**	144	**263**	320
U.S. Power (US$)				
U.S. Power - comparable EBITDA	**83**	63	**159**	195
Depreciation and amortization	**(32)**	(28)	**(62)**	(55)
U.S. Power - comparable EBIT	**51**	35	**97**	140
Foreign exchange impact	**13**	8	**30**	32
U.S. Power - comparable EBIT (Cdn$)	**64**	43	**127**	172
Natural Gas Storage and other - comparable EBITDA	**10**	6	**19**	9
Depreciation and amortization	**(3)**	(3)	**(6)**	(6)
Natural Gas Storage and other - comparable EBIT	**7**	3	**13**	3
Business Development comparable EBITDA and EBIT	**(5)**	(7)	**(8)**	(14)
Energy - comparable EBIT[1,2]	**154**	183	**395**	481
Summary				
Energy - comparable EBITDA[1,2]	**236**	267	**565**	650
Comparable depreciation and amortization	**(82)**	(84)	**(170)**	(169)
Energy - comparable EBIT[1,2]	**154**	183	**395**	481

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

Comparable EBITDA for Energy decreased by $31 million for the three months ended June 30, 2016 compared to the same period in 2015 due to the net effect of:

- lower earnings from Bruce Power mainly due to higher planned outage days, partially offset by lower depreciation
- higher earnings from U.S. Power mainly due to incremental earnings from the Ironwood power plant in Lebanon, Pennsylvania acquired February 1, 2016 and insurance recoveries related to an unplanned outage at Ravenswood
- lower earnings from Western Power as a result of lower realized power prices and lower PPA volumes following the termination of the PPAs
- lower earnings from Eastern Power due to lower contractual earnings at Bécancour.

Comparable EBITDA for Energy decreased by $85 million for the six months ended June 30, 2016 compared to the same period in 2015 due to the net effect of:

- lower earnings from U.S. Power mainly due to decreased margins on sales to wholesale, commercial and industrial customers, the impact of lower capacity prices in New York and lower realized prices in both New England and New York, offset by incremental earnings from the Ironwood power plant and insurance recoveries related to an unplanned outage at Ravenswood
- lower earnings from Eastern Power due to lower earnings on the sale of unused natural gas transportation and lower contractual earnings at Bécancour
- lower earnings from Western Power as a result of lower realized power prices and lower PPA volumes following the termination of the PPAs
- lower earnings from Bruce Power mainly due to higher planned outage days, partially offset by lower depreciation and higher gains from contracting activities
- higher earnings from Natural Gas Storage due to higher realized natural gas storage price spreads.

CANADIAN POWER

Western and Eastern Power

(unaudited - millions of $)	three months ended June 30 2016	three months ended June 30 2015	six months ended June 30 2016	six months ended June 30 2015
Revenue[1]				
Western Power	**56**	178	**131**	286
Eastern Power	**108**	114	**203**	239
Other[2]	**—**	3	**29**	48
	164	295	**363**	573
Comparable income from equity investments[3]	**7**	10	**7**	15
Commodity purchases resold	**—**	(93)	**(59)**	(183)
Plant operating costs and other	**(47)**	(59)	**(93)**	(129)
Exclude risk management activities[1]	**(20)**	(29)	**(7)**	(7)
Comparable EBITDA[4]	**104**	124	**211**	269
Depreciation and amortization	**(36)**	(46)	**(82)**	(94)
Comparable EBIT[4]	**68**	78	**129**	175

Breakdown of comparable EBITDA				
Western Power[4]	**19**	34	**23**	49
Eastern Power	**85**	90	**188**	220
Comparable EBITDA[4]	**104**	124	**211**	269

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 equity income from our investments in ASTC Power Partnership, which held the Sundance B PPA, and Portlands Energy. Comparable equity income excludes a $29 million charge related to the Sundance B PPA termination which was held in ASTC Power Partnership and does not include any gains or losses related to our risk management activities.

4 Includes 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 June 30 2016	2015	six months ended June 30 2016	2015
Sales volumes (GWh)				
Supply				
Generation				
Western Power	**528**	650	**1,218**	1,287
Eastern Power	**858**	739	**1,615**	2,062
Purchased				
Sundance A & B and Sheerness PPAs[1]	**—**	2,299	**1,620**	4,492
Other purchases	**177**	193	**388**	396
	1,563	3,881	**4,841**	8,237
Sales				
Contracted				
Western Power	**705**	1,794	**2,125**	3,439
Eastern Power	**858**	739	**1,615**	2,062
Spot				
Western Power	**—**	1,348	**1,101**	2,736
	1,563	3,881	**4,841**	8,237
Plant availability[2]				
Western Power[3,4]	**83%**	97%	**91%**	97%
Eastern Power[5]	**97%**	98%	**92%**	98%

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 Plant availability was lower in the three and six months ended June 30, 2016 than the same periods in 2015 due to an unplanned outage at the Mackay River facility as a result of the Northern Alberta wildfires.
5 Does not include Bécancour because power generation has been suspended since 2008.

Western Power

Comparable EBITDA for Western Power decreased by $15 million and $26 million for the three and six months ended June 30, 2016 compared to the same periods in 2015 due to lower realized power prices and lower PPA volumes following the 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 74 per cent from $57/MWh to $15/MWh for the three months ended June 30, 2016 and decreased 60 per cent from $43/MWh to $17/MWh for the six months ended June 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, warm weather and the Northern Alberta wildfires. 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 second quarter 2016 compared to 57 per cent in second quarter 2015.

Depreciation and amortization decreased by $10 million in second quarter 2016 compared to second quarter 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 2016, the natural gas-fired cogeneration assets are expected to perform well in the lower 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 $5 million and $32 million for the three and six months ended June 30, 2016 compared to the same periods in 2015. These decreases were mainly due to lower contractual earnings at Bécancour. In addition, Eastern Power had lower earnings on the sale of unused natural gas transportation for the six months ended June 30, 2016 compared to the same period in 2015.

Our 2016 earnings outlook provided in the 2015 Annual Report will be unfavourably impacted 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 the Bécancour tolling 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 June 30		six months ended June 30	
(unaudited - millions of $, unless noted otherwise)	**2016**	**2015**	**2016**	**2015**
Income from equity investments[1]	**20**	66	**134**	145
Comprised of:				
Revenues	**318**	316	**729**	647
Operating expenses	**(218)**	(167)	**(439)**	(339)
Depreciation and other	**(80)**	(83)	**(156)**	(163)
	20	66	**134**	145
Bruce Power - Other information				
Plant availability[2]	**71%**	75%	**80%**	84%
Planned outage days	**209**	160	**285**	199
Unplanned outage days	**4**	13	**12**	22
Sales volumes (GWh)[1]	**4,700**	4,365	**10,534**	9,349
Realized sales price per MWh[3,4]	**$68**	$68	**$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 revenues from contract settlements and cost flow-through items.

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

Equity income from Bruce Power decreased by $46 million and $11 million for the three and six months ended June 30, 2016 compared to the same periods in 2015 mainly due to lower volumes resulting from higher planned outage days partially offset by lower depreciation as a result of the Bruce Power facility's operating life extension. In addition, Bruce Power had higher gains from contracting activities for the six months ended June 30, 2016 compared to the same period in 2015.

In December 2015, Bruce Power entered into an agreement with the IESO to extend the operating life of the Bruce Power facility to 2064. As part of this agreement, Bruce Power began receiving a uniform price of $65.73 per MWh for all units, which includes certain flow-through items such as fuel and lease expenses recovery. Over time, the price will be subject to adjustments for the return of and on capital invested 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 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. Planned maintenance on unit 8 and unit 2 was also completed in second quarter 2016, while planned maintenance activities on unit 3 will continue into third quarter 2016. Additional planned maintenance is scheduled 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.

U.S. POWER

(unaudited - millions of US$)	three months ended June 30 2016	2015	six months ended June 30 2016	2015
Revenue				
Power[1]	**571**	379	**902**	984
Capacity	**77**	88	**139**	155
	648	467	**1,041**	1,139
Commodity purchases resold	**(289)**	(271)	**(594)**	(747)
Plant operating costs and other[2]	**(116)**	(92)	**(215)**	(210)
Exclude risk management activities[1]	**(160)**	(41)	**(73)**	13
Comparable EBITDA	**83**	63	**159**	195
Depreciation and amortization	**(32)**	(28)	**(62)**	(55)
Comparable EBIT	**51**	35	**97**	140

1 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.
2 Includes the cost of fuel consumed in generation.

Sales volumes and plant availability

(unaudited)	three months ended June 30 2016	2015	six months ended June 30 2016	2015
Physical sales volumes (GWh)				
Supply				
Generation[1]	**3,376**	2,135	**5,656**	3,049
Purchased	**5,062**	4,456	**9,810**	8,881
	8,438	6,591	**15,466**	11,930
Plant availability[2,3]	**86%**	77%	**79%**	69%

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 three and six months ended June 30, 2015 compared to the same periods 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 June 30 2016	2015	six months ended June 30 2016	2015
Average Spot Power Prices (US$ per MWh)				
New England[1]	**24**	25	**27**	55
New York[2]	**26**	28	**27**	51
PJM[3]	**22**	n/a	**23**	n/a
Average New York[2] Spot Capacity Prices (US$ per KW-M)	**10.12**	12.92	**7.98**	10.63

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

Comparable EBITDA for U.S. Power increased US$20 million for the three months ended June 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 earnings resulting from the timing of recognizing earnings on certain contracts in our power marketing business due to different power pricing profiles between the prices we charge our customers and the prices we pay for volumes purchased
- insurance recoveries related to an unplanned outage at the Ravenswood facility that occurred in 2008
- 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$36 million for the six months ended June 30, 2016 compared to the same period in 2015 primarily due to the net effect of:

- lower margins on sales to wholesale, commercial and industrial customers offset by higher sales to 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
- 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.

The timing of recognizing earnings on certain contracts in our U.S. power marketing business is impacted by different power pricing profiles between the prices we charge our customers and the prices we pay for volumes purchased to fulfill our sales obligations over the term of the contracts. The costs on volumes purchased to fulfill power sales commitments to wholesale, commercial and industrial customers include the impact of certain contracts to purchase power over multiple periods at a flat price. Because the price we charge our customers is typically shaped to the market, the impact of these two contract pricing profiles has generally resulted in higher earnings in January to March, offset by lower earnings between April and December with overall positive margins realized over the term of the contracts.

Average New York Zone J spot capacity prices were approximately 22 per cent and 25 per cent lower for the three and six months ended June 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 was partially offset by capacity revenues earned by our Ironwood power plant acquired in February 2016.

Capacity revenues were also negatively impacted by a unit outage 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 six months ended June 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. All insurance recoveries 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 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.

Wholesale electricity prices in New York and New England were lower for the three and six months ended June 30, 2016 compared to the same periods in 2015 primarily due to unseasonably warm weather in winter 2016. In New England, spot power prices for the three and six months ended June 30, 2016 were four per cent and 51 per cent lower compared to the same periods in 2015. In New York City, spot power prices for the three and six months ended June 30, 2016 were seven per cent and 47 per cent lower compared to the same periods in 2015. Both markets have also experienced lower natural gas commodity prices during 2016 compared to the same period in 2015.

Lower margins to wholesale, commercial and industrial customers in both PJM and New England markets resulted in lower earnings for the six months ended June 30, 2016 compared to the same period in 2015, the impact of which was primarily seen in first quarter earnings. Although we have expanded our customer base in the PJM market, significantly lower realized power prices and mild winter weather have resulted in lower margins in our wholesale business.

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 six month months ended June 30, 2016 than the same periods in 2015 as we have expanded our customer base in the PJM market.

As at June 30, 2016, approximately 4,700 GWh, or 60 per cent, of U.S. Power's planned generation was contracted for the remainder of 2016 and 4,200 GWh, or 34 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.

U.S. Power results for 2016 will be dependent on the timing of the previously announced monetization of the U.S. Northeast power assets. See the Recent developments section for more information about the Columbia acquisition and related financing. Nevertheless, operating results for the full year in 2016 are expected to be lower than our Outlook in our 2015 Annual Report due to lower commodity prices experienced in the first half of 2016 and forecast for the remainder of the year.

NATURAL GAS STORAGE AND OTHER

Comparable EBITDA increased by $4 million and $10 million for the three and six months ended June 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 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 June 30		six months ended June 30	
(unaudited - millions of $)	2016	2015	2016	2015
Comparable EBITDA	**(27)**	(12)	**(52)**	(36)
Depreciation and amortization	**(7)**	(8)	**(16)**	(15)
Comparable EBIT	**(34)**	(20)	**(68)**	(51)
Specific items:				
Acquisition costs - Columbia Pipeline Group	**(10)**	—	**(36)**	—
Restructuring costs	**(14)**	(12)	**(14)**	(12)
Segmented losses	**(58)**	(32)	**(118)**	(63)

Corporate segmented losses in 2016 increased by $26 million and $55 million for the three and six months ended June 30, 2016 compared to the same periods in 2015 and included the following specific items that have been excluded from comparable EBIT:

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

Interest Expense

	three months ended June 30		six months ended June 30	
(unaudited - millions of $)	2016	2015	2016	2015
Comparable interest on long-term debt (including interest on junior subordinated notes)				
Canadian-dollar denominated	**(110)**	(106)	**(221)**	(215)
U.S. dollar-denominated (US$)	**(250)**	(228)	**(496)**	(446)
Foreign exchange impact	**(73)**	(57)	**(158)**	(105)
	(433)	(391)	**(875)**	(766)
Other interest and amortization expense	**(18)**	(11)	**(37)**	(24)
Capitalized interest	**46**	71	**87**	141
Comparable interest expense	**(405)**	(331)	**(825)**	(649)
Specific item:				
Acquisition costs - Columbia Pipeline Group[1]	**(109)**	—	**(109)**	—
Interest expense	**(514)**	(331)	**(934)**	(649)

1 This amount represents the dividend equivalent payments on the subscription receipts. See the Financial condition section for more information on the subscription receipts.

Comparable interest expense increased by $74 million and $176 million for the three and six months ended June 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

- a stronger U.S. dollar and its effect on the foreign exchange impact on interest expense related to 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

(unaudited - millions of $)	three months ended June 30		six months ended June 30	
	2016	**2015**	**2016**	**2015**
Comparable interest income and other				
AFUDC	**111**	68	**212**	126
Other	**4**	(17)	**51**	(60)
	115	51	**263**	66
Specific items:				
Acquisition costs - Columbia Pipeline Group[1]	**6**	—	**6**	—
Risk management activities	**(4)**	30	**49**	1
Interest income and other	**117**	81	**318**	67

1 This amount represents interest income on the gross proceeds of the subscriptions receipts held in escrow. See the Financial condition section for more information on the subscription receipts.

Comparable interest income and other increased by $64 million and $197 million for the three and six months ended June 30, 2016 compared to the same periods in 2015 due to the net effect of:

- increased AFUDC related to our rate-regulated projects including Mexico pipelines, expansions on the NGTL System and the ANR Southeast Mainline
- 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 June 30		six months ended June 30	
	2016	**2015**	**2016**	**2015**
Comparable income tax expense	**(189)**	(185)	**(369)**	(432)
Specific items:				
Alberta PPA terminations	**—**	—	**64**	—
Acquisition costs - Columbia Pipeline Group	**—**	—	**—**	—
Keystone XL asset costs	**4**	—	**8**	—
Restructuring costs	**4**	4	**4**	4
TC Offshore loss on sale	**—**	—	**1**	—
Alberta corporate income tax rate increase	**—**	(34)	**—**	(34)
Risk management activities	**(93)**	(35)	**(52)**	5
Income tax expense	**(274)**	(250)	**(344)**	(457)

Comparable income tax expense increased by $4 million and decreased by $63 million for the three and six months ended June 30, 2016 compared to the same periods in 2015 and was mainly the result of lower pre-tax earnings in 2016 compared to 2015, 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

	three months ended June 30		six months ended June 30	
(unaudited - millions of $)	**2016**	**2015**	**2016**	**2015**
Net income attributable to non-controlling interests	**(52)**	(40)	**(132)**	(99)

Net income attributable to non-controlling interests increased by $12 million and $33 million for the three and six months ended June 30, 2016 compared to the same periods in 2015 primarily due to 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 and the impact of a stronger U.S. dollar on the Canadian dollar equivalent earnings from TC PipeLines, LP.

Preferred share dividends

	three months ended June 30		six months ended June 30	
(unaudited - millions of $)	**2016**	**2015**	**2016**	**2015**
Preferred share dividends	**(28)**	(25)	**(50)**	(48)

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, 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 and delisted from the TSX. See Financial condition section for additional information on the bridge term loan credit facilities and the subscription receipts.

Columbia operates a portfolio of 24,250 km (15,100 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 long-term growth opportunities. The acquisition also includes a large portfolio of new capital growth projects totalling approximately US$7.3 billion which includes six 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 2021 to ensure a safe, reliable and efficient system. We have plans in place to ensure an effective transition to integrate Columbia into the TransCanada organization.

Acquisition-related expenses were $10 million and $36 million for the three and six months ended June 30, 2016 and have been excluded from comparable earnings. The dividend equivalent payments on the subscription receipts of $109 million were included in interest expense in the three and six months ended June 30, 2016 and the interest earned on the funds received from the subscription receipts held in escrow of $6 million have also been excluded from comparable earnings.

Monetization of U.S. Northeast power assets and a minority interest in Mexican pipelines

The permanent financing for the acquisition of the Columbia Pipeline Group involves portfolio management that includes the monetization of our U.S. Northeast power assets and a minority interest in our Mexico gas pipeline business.

The process of engaging advisors has been completed and the initial stages of soliciting interested parties is well underway. We expect to provide an update as to the outcome of that process by the end of 2016. Proceeds from these monetizations will be used to retire draws under the bridge term loan credit facilities.

Master Limited Partnership strategy review

On July 1, 2016, we announced that a financial advisor has been retained to assist us in developing a master limited partnership (MLP) strategy. A decision on the MLP strategy is expected to be communicated by the end of 2016.

NATURAL GAS PIPELINES

Canadian Regulated Pipelines

NGTL System

In second quarter 2016, we placed approximately $450 million of facilities in service with another $400 million of facilities approved and currently under construction, while approximately $2.9 billion of commercially secured expansion projects have not yet been filed with the regulators.

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

We have also seen some cancellation or deferral of our customer's specific projects, contract non-renewals, and contract transfers. As a result, we have re-evaluated planned facility requirements to meet future aggregate system service requirements and expect some changes in the spending profile of our programs to match revised facility in-service dates. The projected capital 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 are however, deferring approximately $225 million of spending for facilities in the 2016/17 Facilities program with revised service dates of 2018 through 2020. We are also deferring $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). The NEB has extended the sunset clause until the end of the year to allow time to further review the request and make a final decision subject to Governor-In-Council approval. A pre-construction CPCN condition requires that Petronas make a positive FID on the proposed Pacific Northwest LNG (PNW LNG) Project. Petronas is waiting on completion of the federal environmental assessment process for the LNG Project before it makes an FID. The environmental review process is currently scheduled to conclude this fall. NGTL continues to work with our customers and stakeholders to be ready to initiate construction of the NMML facilities for an in-service date as early as 2017, however, the in-service date will be finalized once a FID has been made.

2016-2017 NGTL Revenue Requirement Settlement

On April 7, 2016, the NEB approved the NGTL revenue requirement settlement application that was filed in December 2015, subject to certain reporting requirements. 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.

U.S. Pipelines

Iroquois Gas Transmission System

On March 31, 2016, we closed the acquisition of an additional 4.87 per cent interest in Iroquois Gas Transmission System, L.P. (Iroquois) from one of our partners for US$54 million. Following this acquisition, our ownership interest in Iroquois increased to 49.35 per cent. On May 1, 2016, we acquired an additional 0.65 per cent interest from the remaining partner equalizing our overall ownership interests to 50 per cent each.

ANR Section 4 Rate Case

In January 2016, ANR filed a Section 4 Rate Case with the FERC that requests an increase to ANR's maximum transportation rates. In February 2016, the FERC issued an order that accepted and suspended ANR’s rate and tariff changes to become effective August 1, 2016, subject to refund and the outcome of a hearing. In addition, in March 2016, the FERC established a procedural schedule for the hearing and appointed a settlement judge to assist the parties in their settlement negotiations. The hearing is currently scheduled for early February 2017.

TC Offshore

Effective March 31, 2016, we completed the sale of TC Offshore LLC to a third party. The sale includes 860 km (535 miles) of natural gas gathering and transmission pipeline, seven offshore platforms and other facilities.

Mexico

Tula-Villa de Reyes Pipeline

On April 11, 2016, we announced we were awarded the contract to build, own and operate the Tula-Villa de Reyes pipeline in Mexico. Construction of the pipeline is supported by a 25-year natural gas transportation service contract for 886 million cubic feet per day with the CFE. We expect to invest approximately US$550 million 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-Tuxpan 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 to Tuxpan pipeline in Mexico. Construction of the pipeline is supported by a 25-year natural gas transportation service contract for 2.6 billion cubic feet per day 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.

LNG Pipeline Projects

Prince Rupert Gas Transmission

PRGT continues to engage with Aboriginal groups and other stakeholders along the route in preparation for a FID by PNW LNG.

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, 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

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. Further investigative activities and corrective measures required by PHMSA are planned for 2016.

This shutdown is not expected to have a significant impact on our 2016 earnings.

Houston Lateral and Terminal

We commenced commercial transactions in July 2016 for August 2016 deliveries on the Houston Lateral pipeline and terminal, an extension from the Keystone Pipeline System to Houston, Texas. 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. We do not anticipate this will result in a delay with regard to the NEB's review process.

On March 17, 2016, the first phase of Energy East public hearings for the voluntary Québec le Bureau d'audiences publiques sur l'environnement (BAPE) process was completed. The voluntary BAPE hearing process is intended to inform the Province of Québec in its participation in the federal process and provides project information to the public. A second phase, consisting of a series of public input sessions, has been suspended as it has been replaced with the environmental assessment as described above.

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 marks 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. The NEB also noted, that starting on August 8, 2016, there will be a series of community panel sessions held along the pipeline route. On July 20, 2016, the NEB issued the hearing order which provides further detail on the regulatory process. We are currently reviewing the contents.

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. 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 carbon tax

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 will set a limit on annual province-wide greenhouse gas emissions beginning in January 2017 and will introduce 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 latter 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. Impacted contracts have varying provisions with respect to amendment entitlement and management is reviewing each of our contracts to assess potential impacts.

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 is considering its regulatory options in light of this development, as the need for winter peaking capacity remains.

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.

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, monetization of assets, cash on hand and substantial committed credit facilities.

CASH PROVIDED BY OPERATING ACTIVITIES

	three months ended June 30		six months ended June 30	
(unaudited - millions of $)	2016	2015	2016	2015
Funds generated from operations[1]	**831**	1,061	**1,956**	2,214
Decrease/(increase) in operating working capital	**218**	(92)	**138**	(485)
Net cash provided by operations	**1,049**	969	**2,094**	1,729

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

Funds generated from operations decreased $230 million and $258 million for the three and six months ended June 30, 2016 compared to the same periods in 2015. These decreases were primarily due to $109 million of dividend equivalent payments on the subscription receipts issued to partially finance the Columbia acquisition.

At June 30, 2016, our current assets were $4.6 billion and current liabilities were $9.9 billion, leaving us with a working capital deficit of $5.3 billion compared to a deficit of $3.4 billion at December 31, 2015. The increase was mainly due to subscription receipts held in preparation for the closing of the Columbia acquisition on July 1, 2016. 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 $8.7 billion of unutilized, unsecured committed credit facilities.

COMPARABLE DISTRIBUTABLE CASH FLOW

	three months ended June 30		six months ended June 30	
(unaudited - millions of $)	2016	2015	2016	2015
Net cash provided by operations	**1,049**	969	**2,094**	1,729
(Decrease)/increase in operating working capital	**(218)**	92	**(138)**	485
Funds generated from operations	**831**	1,061	**1,956**	2,214
Dividends on preferred shares	**(23)**	(24)	**(46)**	(46)
Distributions paid to non-controlling interests	**(62)**	(54)	**(124)**	(108)
Distributions received in excess of equity earnings[1]	**99**	64	**187**	110
Maintenance capital expenditures including equity investments	**(269)**	(194)	**(459)**	(361)
Distributable cash flow	**576**	853	**1,514**	1,809
Specific items (net of tax):				
Acquisition costs - Columbia Pipeline Group	**113**	—	**139**	—
Keystone XL asset costs	**9**	—	**15**	—
Restructuring costs	**—**	8	**—**	8
Comparable distributable cash flow	**698**	861	**1,668**	1,817
Comparable distributable cash flow per common share	**$0.99**	$1.21	**$2.37**	$2.56

1 Reflects distributions received from operating activities and excludes additional distributions of $725 million following Bruce Power's financing program.

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 on our Canadian regulated natural gas pipelines were $42 million and $97 million for the three and six months ended June 30, 2016 compared to $61 million and $114 million for the same periods in 2015, which contributed to their respective rate bases and net income.

CASH USED IN INVESTING ACTIVITIES

	three months ended June 30		six months ended June 30	
(unaudited - millions of $)	**2016**	**2015**	**2016**	**2015**
Capital spending				
Capital expenditures	**(982)**	(966)	**(1,818)**	(1,772)
Capital projects in development	**(90)**	(172)	**(157)**	(335)
	(1,072)	(1,138)	**(1,975)**	(2,107)
Contributions to equity investments	**(114)**	(105)	**(284)**	(198)
Restricted cash	**(13,113)**	—	**(13,113)**	—
Acquisitions, net of cash acquired	**(4)**	—	**(999)**	—
Proceeds from sale of assets, net of transaction costs	**—**	—	**6**	—
Distributions received in excess of equity earnings	**824**	64	**912**	110
Deferred amounts and other	**(20)**	25	**(20)**	204
Net cash used in investing activities	**(13,499)**	(1,154)	**(15,473)**	(1,991)

Capital expenditures in 2016 were primarily related to:

- expansion of the NGTL System
- construction of Mexico pipelines
- expansion of the ANR pipeline
- 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 and Bruce Power.

Restricted cash represents the amount held in escrow at June 30, 2016 for the purchase of Columbia on July 1, 2016 and includes the proceeds from the sale of subscription receipts, net of dividend equivalent payments, and draws on the committed bridge loan credit facilities.

On February 1, 2016, we acquired the Ironwood natural gas fired, combined cycle power plant with a capacity of 778 MW, for US$657 million in cash before 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 the bank credit facility as part of its financing program to fund its capital program and make distributions to the partners. Therefore, the distributions received from Bruce Power in second quarter 2016 were funded from both operating and financing activities and included $725 million from Bruce Power financing program.

CASH PROVIDED BY FINANCING ACTIVITIES

(unaudited - millions of $)	three months ended June 30		six months ended June 30	
	2016	**2015**	**2016**	**2015**
Notes payable issued/(repaid), net	**(853)**	(749)	**323**	(470)
Long-term debt issued, net of issue costs	**10,335**	84	**12,327**	2,361
Long-term debt repaid	**(933)**	(867)	**(2,290)**	(1,883)
Junior subordinated notes issued, net of issue costs	**—**	917	**—**	917
Dividends and distributions paid	**(482)**	(446)	**(932)**	(863)
Common shares/subscription receipts issued, net of issue costs	**4,371**	1	**4,374**	11
Common shares repurchased	**—**	—	**(14)**	—
Partnership units of subsidiary issued, net of issue costs	**82**	27	**106**	31
Preferred shares issued, net of issue costs	**492**	—	**492**	243
Net cash provided by/(used in) financing activities	**13,012**	(1,033)	**14,386**	347

LONG-TERM DEBT ISSUED

(unaudited - millions of $) **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 specified asset monetizations must be used to repay these facilities. Proceeds from these facilities are held in Restricted cash. See Recent developments section for more information.

2 Reflects coupon rate. Re-issuance yield was 2.69 per cent.

LONG-TERM DEBT RETIRED

(unaudited - millions of $) **Company**	**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	12.20%

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 June 30, 2016 (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 entitled the holder to automatically receive one common share upon closing of the Columbia acquisition on July 1, 2016. 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 will be made on July 29, 2016 to holders of record at the close of business on June 30, 2016. For the three and six months ended June 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.

The gross proceeds from the sale of the subscription receipts, less any amounts used for dividend equivalent payments, were held in escrow pending the acquisition close on July 1, 2016 and recorded as Restricted cash as at June 30, 2016. Interest income of $6 million relating to the proceeds 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, 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 the dividends declared on July 27, 2016, common shares will be issued from treasury at a discount of two per cent in lieu of receiving cash dividends.

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.

On April 20, 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**[1]	**Annual dividend per share**[1]	**Redemption price per share**[2]	**Redemption and conversion option date**[1,2]	**Right to convert into**
Cumulative first preferred shares						
Series 5	12,714	2.263%	$0.56575	$25.00	January 30, 2021	Series 6
Series 6	1,286	Floating[3]	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 Commencing June 30, 2016, the floating quarterly dividend rate for the Series 6 preferred shares is 2.034 per cent and will reset every quarter going forward.

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

Since January 1, 2016, 1.6 million common units were issued under the TC PipeLines, LP ATM program generating net proceeds of approximately US$83 million. Our ownership interest in TC PipeLines, LP decreased to 27.4 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 July 27, 2016, we declared quarterly dividends as follows:

Quarterly dividend on our common shares
$0.565 per share
Payable on October 31, 2016 to shareholders of record at the close of business on September 30, 2016

Quarterly dividend equivalent payment on our subscription receipts[1]
$0.565 per subscription receipt
Payable on July 29, 2016 to holders of record at the close of business on June 30, 2016

1 Dividend equivalent payments are a term of the subscription receipts and are not declared by the Board.

Quarterly dividends on our preferred shares	
Series 1	$0.204125
Series 2	$0.15528142
Series 3	$0.1345
Series 4	$0.11506284
Payable on September 30, 2016 to shareholders of record at the close of business on August 31, 2016	
Series 5	$0.14143750
Series 6	$0.12781967
Series 7	$0.25
Series 9	$0.265625
Payable on October 31, 2016 to shareholders of record at the close of business on September 30, 2016	
Series 11	$0.2375
Series 13	$0.34375
Payable on August 31, 2016 to shareholders of record at the close of business on August 12, 2016	

SHARE INFORMATION

as at July 22, 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	7 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 July 27, 2016, we had approximately $19.1 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$1.5 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	$0.5 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 Libor plus an applicable margin. Proceeds from specified asset monetizations must be used to repay these facilities. See Recent developments section for more information.

At July 27, 2016, our operated affiliates had an additional $0.5 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 $0.2 billion since December 31, 2015 as a result of the new commitments for the Tuxpan-Tula, Tula-Villa de Reyes and Sur de Texas-Tuxpan 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 $0.3 billion as a result of the extension of premises leases in second quarter 2016. There were no other material changes to our contractual obligations in second 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
- restricted investments
- 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 June 30, 2016, we had no significant credit losses and no significant amounts past due or impaired. We had a credit risk concentration of $187 million (US$144 million) at June 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 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 June 30, 2016	**1.29**
three months ended June 30, 2015	1.23

six months ended June 30, 2016	**1.32**
six months ended June 30, 2015	1.24

The impact of changes in the value of the U.S. dollar on our U.S. and international operations 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 June 30		six months ended June 30	
(unaudited - millions of US$)	**2016**	**2015**	**2016**	**2015**
U.S. and International Natural Gas Pipelines comparable EBIT	**183**	134	**426**	373
U.S. Liquids Pipelines comparable EBIT	**120**	156	**250**	303
U.S. Power comparable EBIT	**51**	35	**97**	140
Interest on U.S. dollar-denominated long-term debt	**(250)**	(228)	**(496)**	(446)
Capitalized interest on U.S. dollar-denominated capital expenditures	**9**	29	**16**	60
U.S. non-controlling interests	**(40)**	(32)	**(100)**	(80)
	73	94	**193**	350

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:

	June 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]	**(499)**	**US 2,650**	(730)	US 3,150
U.S. dollar foreign exchange forward contracts (maturing 2016 to 2017)	**(37)**	**US 450**	50	US 1,800
	(536)	**US 3,100**	(680)	US 4,950

1 Fair values equal carrying values.
2 In the three and six months ended June 30, 2016, net realized gains of $2 million and $4 million, respectively, (2015 - gains of $2 million and $5 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)	June 30, 2016	December 31, 2015
Notional amount	**28,400 (US 21,800)**	23,100 (US 16,700)
Fair value	**31,200 (US 24,000)**	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 $)	June 30, 2016	December 31, 2015
Other current assets	**445**	442
Intangible and other assets	**195**	168
Accounts payable and other	**(734)**	(926)
Other long-term liabilities	**(432)**	(625)
	(526)	(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 June 30		six months ended June 30	
(unaudited - millions of $, pre-tax)	2016	2015	2016	2015
Derivative instruments held for trading[1]				
Amount of unrealized gains/(losses) in the period				
Commodities[2]	**187**	23	**120**	(3)
Foreign exchange	**20**	30	**47**	1
Amount of realized (losses)/gains in the period				
Commodities	**(47)**	(33)	**(142)**	(32)
Foreign exchange	**13**	(10)	**57**	(53)
Derivative instruments in hedging relationships				
Amount of realized (losses)/gains in the period				
Commodities	**(67)**	(113)	**(140)**	(97)
Foreign exchange	**(43)**	—	**(106)**	—
Interest rate	**1**	2	**3**	4

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 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 the condensed consolidated statement of OCI related to derivatives in cash flow hedging relationships is as follows:

	three months ended June 30		six months ended June 30	
(unaudited - millions of $, pre-tax)	**2016**	**2015**	**2016**	**2015**
Change in fair value of derivative instruments recognized in OCI (effective portion)[1]				
Commodities	**42**	(50)	**26**	(29)
Foreign exchange	**40**	—	**5**	—
Interest rate	**—**	—	**(1)**	—
	82	(50)	**30**	(29)
Reclassification of (losses)/gains on derivative instruments from AOCI to net income (effective portion)[1]				
Commodities[2]	**(21)**	(21)	**61**	48
Foreign exchange[3]	**(39)**	—	**(5)**	—
Interest rate[4]	**4**	4	**8**	8
	(56)	(17)	**64**	56
Gains/(losses) on derivative instruments recognized in net income (ineffective portion)				
Commodities[2]	**43**	56	**(15)**	(7)
	43	56	**(15)**	(7)

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 June 30, 2016, the aggregate fair value of all derivative contracts with credit-risk-related contingent features that were in a net liability position was $17 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 June 30, 2016, we would have been required to provide additional collateral of $17 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 June 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.

There were no changes in second 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. 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.

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 14, 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 are currently evaluating the impact of the adoption of this guidance and have not yet determined the effect 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.

Reconciliation of non-GAAP measures

(unaudited - millions of $, except per share amounts)	three months ended June 30		six months ended June 30	
	2016	2015	2016	2015
EBITDA	**1,560**	1,434	**2,657**	2,876
Alberta PPA terminations	**—**	—	**240**	—
Acquisition costs - Columbia Pipeline Group	**10**	—	**36**	—
Keystone XL asset costs	**13**	—	**23**	—
Restructuring costs	**14**	12	**14**	12
TC Offshore loss on sale	**—**	—	**4**	—
Risk management activities[1]	**(228)**	(79)	**(103)**	10
Comparable EBITDA	**1,369**	1,367	**2,871**	2,898
Depreciation and amortization	**(444)**	(440)	**(898)**	(874)
Comparable EBIT	**925**	927	**1,973**	2,024
Other income statement items				
Comparable interest expense	**(405)**	(331)	**(825)**	(649)
Comparable interest income and other	**115**	51	**263**	66
Comparable income tax expense	**(189)**	(185)	**(369)**	(432)
Net income attributable to non-controlling interests	**(52)**	(40)	**(132)**	(99)
Preferred share dividends	**(28)**	(25)	**(50)**	(48)
Comparable earnings	**366**	397	**860**	862
Specific items (net of tax):				
Alberta PPA terminations	**—**	—	**(176)**	—
Acquisition costs - Columbia Pipeline Group	**(113)**	—	**(139)**	—
Keystone XL asset costs	**(9)**	—	**(15)**	—
Restructuring costs	**(10)**	(8)	**(10)**	(8)
TC Offshore loss on sale	**—**	—	**(3)**	—
Alberta corporate income tax rate increase	**—**	(34)	**—**	(34)
Risk management activities[1]	**131**	74	**100**	(4)
Net income attributable to common shares	**365**	429	**617**	816
Comparable interest expense	**(405)**	(331)	**(825)**	(649)
Specific item:				
Acquisition costs - Columbia Pipeline Group	**(109)**	—	**(109)**	—
Interest expense	**(514)**	(331)	**(934)**	(649)
Comparable interest income and other	**115**	51	**263**	66
Specific items:				
Acquisition costs - Columbia Pipeline Group	**6**	—	**6**	—
Risk management activities[1]	**(4)**	30	**49**	1
Interest income and other	**117**	81	**318**	67

(unaudited - millions of $, except per share amounts)	three months ended June 30 2016	three months ended June 30 2015	six months ended June 30 2016	six months ended June 30 2015
Comparable income tax expense	**(189)**	(185)	**(369)**	(432)
Specific items:				
Alberta PPA terminations	**—**	—	**64**	—
Acquisition costs - Columbia Pipeline Group	**—**	—	**—**	—
Keystone XL asset costs	**4**	—	**8**	—
Restructuring costs	**4**	4	**4**	4
TC Offshore loss on sale	**—**	—	**1**	—
Alberta corporate income tax rate increase	**—**	(34)	**—**	(34)
Risk management activities[1]	**(93)**	(35)	**(52)**	5
Income tax expense	**(274)**	(250)	**(344)**	(457)
Comparable earnings per common share	**$0.52**	$0.56	**$1.22**	$1.22
Specific items (net of tax):				
Alberta PPA terminations	**—**	—	**(0.25)**	—
Acquisition costs - Columbia Pipeline Group	**(0.16)**	—	**(0.20)**	—
Keystone XL asset costs	**(0.01)**	—	**(0.02)**	—
Restructuring costs	**(0.01)**	(0.01)	**(0.01)**	(0.01)
TC Offshore loss on sale	**—**	—	**—**	—
Alberta corporate income tax rate increase	**—**	(0.05)	**—**	(0.05)
Risk management activities	**0.18**	0.10	**0.14**	(0.01)
Net income per common share	**$0.52**	$0.60	**$0.88**	$1.15

1

Risk management activities (unaudited - millions of $)	three months ended June 30 2016	three months ended June 30 2015	six months ended June 30 2016	six months ended June 30 2015
Canadian Power	**20**	29	**7**	7
U.S. Power	**204**	51	**89**	(17)
Liquids	**4**	—	**2**	—
Natural Gas Storage	**—**	(1)	**5**	—
Foreign exchange	**(4)**	30	**49**	1
Income tax attributable to risk management activities	**(93)**	(35)	**(52)**	5
Total gains/(losses) from risk management activities	**131**	74	**100**	(4)

SECOND QUARTER 2016

Comparable EBITDA and EBIT by business segment

three months ended June 30, 2016 (unaudited - millions of $)	Natural Gas Pipelines	Liquids Pipelines	Energy	Corporate	Total
EBITDA	**880**	**271**	**460**	**(51)**	**1,560**
Alberta PPA terminations	—	—	—	—	—
Acquisition costs - Columbia Pipeline Group	—	—	—	**10**	**10**
Keystone XL asset costs	—	**13**	—	—	**13**
Restructuring costs	—	—	—	**14**	**14**
Risk management activities	—	**(4)**	**(224)**	—	**(228)**
Comparable EBITDA	**880**	**280**	**236**	**(27)**	**1,369**
Comparable depreciation and amortization	**(288)**	**(67)**	**(82)**	**(7)**	**(444)**
Comparable EBIT	**592**	**213**	**154**	**(34)**	**925**

three months ended June 30, 2015 (unaudited - millions of $)	Natural Gas Pipelines	Liquids Pipelines	Energy	Corporate	Total
EBITDA	799	313	346	(24)	1,434
Restructuring costs	—	—	—	12	12
Risk management activities	—	—	(79)	—	(79)
Comparable EBITDA	799	313	267	(12)	1,367
Comparable depreciation and amortization	(282)	(66)	(84)	(8)	(440)
Comparable EBIT	517	247	183	(20)	927

six months ended June 30, 2016 (unaudited - millions of $)	Natural Gas Pipelines	Liquids Pipelines	Energy	Corporate	Total
EBITDA	**1,774**	**559**	**426**	**(102)**	**2,657**
Alberta PPA terminations	—	—	**240**	—	**240**
Acquisition costs - Columbia Pipeline Group	—	—	—	**36**	**36**
Keystone XL asset costs	—	**23**	—	—	**23**
Restructuring costs	—	—	—	**14**	**14**
TC Offshore loss on sale	**4**	—	—	—	**4**
Risk management activities	—	**(2)**	**(101)**	—	**(103)**
Comparable EBITDA	**1,778**	**580**	**565**	**(52)**	**2,871**
Depreciation and amortization	**(575)**	**(137)**	**(170)**	**(16)**	**(898)**
Comparable EBIT	**1,203**	**443**	**395**	**(68)**	**1,973**

six months ended June 30, 2015 (unaudited - millions of $)	Natural Gas Pipelines	Liquids Pipelines	Energy	Corporate	Total
EBITDA	1,666	618	640	(48)	2,876
Restructuring costs	—	—	—	12	12
Risk management activities	—	—	10	—	10
Comparable EBITDA	1,666	618	650	(36)	2,898
Depreciation and amortization	(561)	(129)	(169)	(15)	(874)
Comparable EBIT	1,105	489	481	(51)	2,024

Quarterly results

SELECTED QUARTERLY CONSOLIDATED FINANCIAL DATA

	2016		2015				2014	
(unaudited - millions of $, except per share amounts)	Second	First	Fourth	Third	Second	First	Fourth	Third
Revenues	**2,751**	2,503	2,851	2,944	2,631	2,874	2,616	2,451
Net income attributable to common shares	**365**	252	(2,458)	402	429	387	458	457
Comparable earnings	**366**	494	453	440	397	465	511	450
Share statistics								
Net income per common share - basic and diluted	**$0.52**	$0.36	($3.47)	$0.57	$0.60	$0.55	$0.65	$0.64
Comparable earnings per share	**$0.52**	$0.70	$0.64	$0.62	$0.56	$0.66	$0.72	$0.63
Dividends declared per common share	**$0.565**	$0.565	$0.52	$0.57	$0.52	$0.52	$0.48	$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.

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 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 June 30 2016	three months ended June 30 2015	six months ended June 30 2016	six months ended June 30 2015
Revenues				
Natural Gas Pipelines	**1,314**	1,286	**2,627**	2,591
Liquids Pipelines	**416**	460	**852**	903
Energy	**1,021**	885	**1,775**	2,011
	2,751	2,631	**5,254**	5,505
Income from Equity Investments	**66**	119	**201**	256
Operating and Other Expenses				
Plant operating costs and other	**754**	767	**1,469**	1,521
Commodity purchases resold	**375**	426	**845**	1,107
Property taxes	**128**	123	**269**	257
Depreciation and amortization	**444**	440	**898**	874
Asset impairment charges	**—**	—	**211**	—
	1,701	1,756	**3,692**	3,759
Loss on Sale of Assets	**—**	—	**(4)**	—
Financial Charges				
Interest expense	**514**	331	**934**	649
Interest income and other	**(117)**	(81)	**(318)**	(67)
	397	250	**616**	582
Income before Income Taxes	**719**	744	**1,143**	1,420
Income Tax Expense				
Current	**55**	26	**89**	94
Deferred	**219**	224	**255**	363
	274	250	**344**	457
Net Income	**445**	494	**799**	963
Net income attributable to non-controlling interests	**52**	40	**132**	99
Net Income Attributable to Controlling Interests	**393**	454	**667**	864
Preferred share dividends	**28**	25	**50**	48
Net Income Attributable to Common Shares	**365**	429	**617**	816
Net Income per Common Share				
Basic and diluted	**$0.52**	$0.60	**$0.88**	$1.15
Dividends Declared per Common Share	**$0.565**	$0.52	**$1.13**	$1.04
Weighted Average Number of Common Shares (millions)				
Basic	**703**	709	**703**	709
Diluted	**703**	710	**703**	710

See accompanying notes to the condensed consolidated financial statements.

Condensed consolidated statement of comprehensive income

(unaudited - millions of Canadian $)	three months ended June 30 2016	three months ended June 30 2015	six months ended June 30 2016	six months ended June 30 2015
Net Income	**445**	494	**799**	963
Other Comprehensive Income/(Loss), Net of Income Taxes				
Foreign currency translation gains/(losses) on net investment in foreign operations	**5**	(137)	**(207)**	332
Change in fair value of net investment hedges	**(6)**	58	**(8)**	(208)
Change in fair value of cash flow hedges	**55**	(36)	**16**	(21)
Reclassification to net income of (losses)/gains on cash flow hedges	**(40)**	(11)	**40**	33
Reclassification to net income of actuarial gains and prior service costs on pension and other post-retirement benefit plans	**4**	10	**8**	17
Other comprehensive income on equity investments	**4**	4	**7**	7
Other comprehensive income/(loss) (Note 9)	**22**	(112)	**(144)**	160
Comprehensive Income	**467**	382	**655**	1,123
Comprehensive income attributable to non-controlling interests	**54**	10	**28**	217
Comprehensive Income Attributable to Controlling Interests	**413**	372	**627**	906
Preferred share dividends	**28**	25	**50**	48
Comprehensive Income Attributable to Common Shares	**385**	347	**577**	858

See accompanying notes to the condensed consolidated financial statements.

Condensed consolidated statement of cash flows

	three months ended June 30		six months ended June 30	
(unaudited - millions of Canadian $)	**2016**	**2015**	**2016**	**2015**
Cash Generated from Operations				
Net income	**445**	494	**799**	963
Depreciation and amortization	**444**	440	**898**	874
Asset impairment charges	**—**	—	**211**	—
Deferred income taxes	**219**	224	**255**	363
Income from equity investments	**(66)**	(119)	**(201)**	(256)
Distributed earnings received from equity investments	**82**	145	**253**	280
Employee post-retirement benefits expense, net of funding	**(20)**	15	**(9)**	30
Loss on sale of assets	**—**	—	**4**	—
Equity allowance for funds used during construction	**(67)**	(37)	**(124)**	(70)
Unrealized (gains)/losses on financial instruments	**(224)**	(109)	**(153)**	9
Other	**18**	8	**23**	21
Decrease/(increase) in operating working capital	**218**	(92)	**138**	(485)
Net cash provided by operations	**1,049**	969	**2,094**	1,729
Investing Activities				
Capital expenditures	**(982)**	(966)	**(1,818)**	(1,772)
Capital projects in development	**(90)**	(172)	**(157)**	(335)
Contributions to equity investments	**(114)**	(105)	**(284)**	(198)
Restricted cash	**(13,113)**	—	**(13,113)**	—
Acquisitions, net of cash acquired	**(4)**	—	**(999)**	—
Proceeds from sale of assets, net of transaction costs	**—**	—	**6**	—
Distributions received in excess of equity earnings	**824**	64	**912**	110
Deferred amounts and other	**(20)**	25	**(20)**	204
Net cash used in investing activities	**(13,499)**	(1,154)	**(15,473)**	(1,991)
Financing Activities				
Notes payable (repaid)/issued, net	**(853)**	(749)	**323**	(470)
Long-term debt issued, net of issue costs	**10,335**	84	**12,327**	2,361
Long-term debt repaid	**(933)**	(867)	**(2,290)**	(1,883)
Junior subordinated notes issued, net of issue costs	**—**	917	**—**	917
Dividends on common shares	**(397)**	(368)	**(762)**	(709)
Dividends on preferred shares	**(23)**	(24)	**(46)**	(46)
Distributions paid to non-controlling interests	**(62)**	(54)	**(124)**	(108)
Common shares/subscription receipts issued, net of issue costs	**4,371**	1	**4,374**	11
Common shares repurchased	**—**	—	**(14)**	—
Preferred shares issued, net of issue costs	**492**	—	**492**	243
Partnership units of subsidiary issued, net of issue costs	**82**	27	**106**	31
Net cash provided by/(used in) financing activities	**13,012**	(1,033)	**14,386**	347
Effect of Foreign Exchange Rate Changes on Cash and Cash Equivalents	**(73)**	(13)	**(130)**	16
Increase/(decrease) in Cash and Cash Equivalents	**489**	(1,231)	**877**	101
Cash and Cash Equivalents				
Beginning of period	**1,238**	1,821	**850**	489
Cash and Cash Equivalents				
End of period	**1,727**	590	**1,727**	590

See accompanying notes to the condensed consolidated financial statements.

Condensed consolidated balance sheet

(unaudited - millions of Canadian $)		June 30, 2016	December 31, 2015
ASSETS			
Current Assets			
Cash and cash equivalents		**1,727**	850
Accounts receivable		**1,517**	1,388
Inventories		**394**	323
Other		**970**	1,353
		4,608	3,914
Restricted Cash		**13,113**	—
Plant, Property and Equipment	net of accumulated depreciation of $22,739 and $22,299, respectively	**45,125**	44,817
Equity Investments		**5,619**	6,214
Regulatory Assets		**1,118**	1,184
Goodwill		**4,523**	4,812
Intangible and Other Assets		**2,987**	3,050
Restricted Investments		**528**	351
		77,621	64,342
LIABILITIES			
Current Liabilities			
Notes payable		**1,421**	1,218
Accounts payable and other		**2,656**	3,021
Subscription receipts		**4,419**	—
Accrued interest		**582**	520
Current portion of long-term debt		**773**	2,547
		9,851	7,306
Regulatory Liabilities		**1,615**	1,159
Other Long-Term Liabilities		**1,108**	1,260
Deferred Income Tax Liabilities		**5,210**	5,144
Long-Term Debt		**39,152**	28,909
Junior Subordinated Notes		**2,264**	2,409
		59,200	46,187
Common Units of TC PipeLines, LP Subject to Rescission		**106**	—
EQUITY			
Common shares, no par value		**12,125**	12,102
Issued and outstanding:	June 30, 2016 - 703 million shares		
	December 31, 2015 - 703 million shares		
Preferred shares		**2,992**	2,499
Additional paid-in capital		**—**	7
Retained earnings		**2,576**	2,769
Accumulated other comprehensive loss (Note 9)		**(979)**	(939)
Controlling Interests		**16,714**	16,438
Non-controlling interests		**1,601**	1,717
		18,315	18,155
		77,621	64,342

Commitments and Guarantees (Note 13)

Variable Interest Entities (Note 14)

Subsequent Event (Note 15)

See accompanying notes to the condensed consolidated financial statements.

Condensed consolidated statement of equity

	six months ended June 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	**29**	12
Shares repurchased	**(6)**	—
Balance at end of period	**12,125**	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	**5**	5
Dilution impact from TC PipeLines, LP units issued	**12**	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	**22**	—
Balance at end of period	**—**	166
Retained Earnings		
Balance at beginning of period	**2,769**	5,478
Net income attributable to controlling interests	**667**	864
Common share dividends	**(794)**	(737)
Preferred share dividends	**(44)**	(46)
Reclassification of Additional Paid-In Capital deficit to Retained Earnings	**(22)**	—
Balance at end of period	**2,576**	5,559
Accumulated Other Comprehensive Loss		
Balance at beginning of period	**(939)**	(1,235)
Other comprehensive (loss)/income	**(40)**	42
Balance at end of period	**(979)**	(1,193)
Equity Attributable to Controlling Interests	**16,714**	19,245
Equity Attributable to Non-Controlling Interests		
Balance at beginning of period	**1,717**	1,583
Net income attributable to non-controlling interests		
TC PipeLines, LP	**110**	89
Portland	**22**	10
Other comprehensive (loss)/income attributable to non-controlling interests	**(104)**	118
Issuance of TC PipeLines, LP units		
Proceeds, net of issue costs	**106**	31
Decrease in TransCanada's ownership of TC PipeLines, LP	**(19)**	(6)
Reclassification to Common Units of TC PipeLines, LP Subject to Rescission	**(106)**	—
Distributions declared to non-controlling interests	**(125)**	(107)
Balance at end of period	**1,601**	1,718
Total Equity	**18,315**	20,963

See accompanying notes to the condensed consolidated financial statements.

Notes to condensed consolidated financial statements (unaudited)

1. Basis of presentation

These condensed consolidated financial statements of TransCanada Corporation (TransCanada or the Company) have been prepared by management in accordance with U.S. GAAP. The accounting policies applied are consistent with those outlined in TransCanada's annual audited consolidated financial statements for the year ended December 31, 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 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 14, 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 is currently evaluating the impact of the adoption of this guidance and has not yet determined the effect 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 the consolidated financial statements.

3. Segmented information

three months ended June 30	**Natural Gas Pipelines**		**Liquids Pipelines**		**Energy**		**Corporate**		**Total**	
(unaudited - millions of Canadian $)	**2016**	**2015**	**2016**	**2015**	**2016**	**2015**	**2016**	**2015**	**2016**	**2015**
Revenues	**1,314**	1,286	**416**	460	**1,021**	885	**—**	—	**2,751**	2,631
Income/(loss) from equity investments	**40**	39	**(1)**	—	**27**	80	**—**	—	**66**	119
Plant operating costs and other	**(391)**	(440)	**(121)**	(131)	**(191)**	(172)	**(51)**	(24)	**(754)**	(767)
Commodity purchases resold	**—**	—	**—**	—	**(375)**	(426)	**—**	—	**(375)**	(426)
Property taxes	**(83)**	(86)	**(23)**	(16)	**(22)**	(21)	**—**	—	**(128)**	(123)
Depreciation and amortization	**(288)**	(282)	**(67)**	(66)	**(82)**	(84)	**(7)**	(8)	**(444)**	(440)
Segmented earnings/(losses)	**592**	517	**204**	247	**378**	262	**(58)**	(32)	**1,116**	994
Interest expense									**(514)**	(331)
Interest income and other									**117**	81
Income before income taxes									**719**	744
Income tax expense									**(274)**	(250)
Net income									**445**	494
Net income attributable to non-controlling interests									**(52)**	(40)
Net income attributable to controlling interests									**393**	454
Preferred share dividends									**(28)**	(25)
Net income attributable to common shares									**365**	429

six months ended June 30	**Natural Gas Pipelines**		**Liquids Pipelines**		**Energy**		**Corporate**		**Total**	
(unaudited - millions of Canadian $)	**2016**	**2015**	**2016**	**2015**	**2016**	**2015**	**2016**	**2015**	**2016**	**2015**
Revenues	**2,627**	2,591	**852**	903	**1,775**	2,011	**—**	—	**5,254**	5,505
Income/(loss) from equity investments	**91**	93	**(1)**	—	**111**	163	**—**	—	**201**	256
Plant operating costs and other	**(763)**	(842)	**(246)**	(246)	**(358)**	(385)	**(102)**	(48)	**(1,469)**	(1,521)
Commodity purchases resold	**—**	—	**—**	—	**(845)**	(1,107)	**—**	—	**(845)**	(1,107)
Property taxes	**(177)**	(176)	**(46)**	(39)	**(46)**	(42)	**—**	—	**(269)**	(257)
Depreciation and amortization	**(575)**	(561)	**(137)**	(129)	**(170)**	(169)	**(16)**	(15)	**(898)**	(874)
Asset impairment charges	**—**	—	**—**	—	**(211)**	—	**—**	—	**(211)**	—
Loss on sale of assets	**(4)**	—	**—**	—	**—**	—	**—**	—	**(4)**	—
Segmented earnings/(losses)	**1,199**	1,105	**422**	489	**256**	471	**(118)**	(63)	**1,759**	2,002
Interest expense									**(934)**	(649)
Interest income and other									**318**	67
Income before income taxes									**1,143**	1,420
Income tax expense									**(344)**	(457)
Net income									**799**	963
Net income attributable to non-controlling interests									**(132)**	(99)
Net income attributable to controlling interests									**667**	864
Preferred share dividends									**(50)**	(48)
Net income attributable to common shares									**617**	816

TOTAL ASSETS

(unaudited - millions of Canadian $)	June 30, 2016	December 31, 2015
Natural Gas Pipelines	**30,996**	31,039
Liquids Pipelines	**15,928**	16,046
Energy	**14,916**	15,558
Corporate	**15,781**	1,699
	77,621	64,342

4. Asset impairment

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, 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.

5. Income taxes

At June 30, 2016, the total unrecognized tax benefit of uncertain tax positions was approximately $19 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 six months ended June 30, 2016 is $1 million for interest expense and nil for penalties (June 30, 2015 - nil for interest expense and nil for penalties). At June 30, 2016, the Company had $5 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 six-month periods ended June 30, 2016 and 2015 were 30 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 and changes in the proportion of income earned between Canadian and foreign jurisdictions.

6. Long-term debt

LONG-TERM DEBT ISSUED

The Company issued long-term debt in the six months ended June 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 specified asset sales must be used to repay these facilities. Proceeds from these facilities are held in Restricted cash. See Note 15, Subsequent event for more information.

2 Reflects coupon rate. Re-issuance yield was 2.69 per cent.

LONG-TERM DEBT RETIRED

The Company retired long-term debt in the six months ended June 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 six months ended June 30, 2016, TransCanada capitalized interest related to capital projects of $46 million and $87 million (2015 - $71 million and $141 million).

7. 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 distribution 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 June 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.

8. 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. Each subscription receipt entitles the holder to automatically receive one common share upon closing of the Columbia acquisition on July 1, 2016. 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 will be made on July 29, 2016 to holders of record at the close of business on June 30, 2016. The gross proceeds from the sale of the subscription receipts, less any amounts used for dividend equivalent payments, were held in escrow until the acquisition close date of July 1, 2016 and were included in Restricted cash. For the three and six months ended June 30, 2016, $109 million of dividend equivalent payments were recorded as interest expense.

DIVIDEND REINVESTMENT PLAN

Under the Company's Dividend Reinvestment Plan, 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 June 30, 2016, the floating quarterly dividend rate for the Series 6 preferred shares is 2.034 per cent and will reset every quarter going forward.

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

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

three months ended June 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	**5**	**—**	**5**
Change in fair value of net investment hedges	**(7)**	**1**	**(6)**
Change in fair value of cash flow hedges	**81**	**(26)**	**55**
Reclassification to net income of losses on cash flow hedges	**(56)**	**16**	**(40)**
Reclassification to net income of actuarial gains 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	**34**	**(12)**	**22**

three months ended June 30, 2015 (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	(135)	(2)	(137)
Change in fair value of net investment hedges	76	(18)	58
Change in fair value of cash flow hedges	(50)	14	(36)
Reclassification to net income of losses on cash flow hedges	(17)	6	(11)
Reclassification to net income of actuarial gains and prior service costs on pension and other post-retirement benefit plans	10	—	10
Other comprehensive income on equity investments	5	(1)	4
Other comprehensive loss	(111)	(1)	(112)

six months ended June 30, 2016 (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	**(205)**	**(2)**	**(207)**
Change in fair value of net investment hedges	**(10)**	**2**	**(8)**
Change in fair value of cash flow hedges	**27**	**(11)**	**16**
Reclassification to net income of gains on cash flow hedges	**64**	**(24)**	**40**
Reclassification to net income of actuarial gains and prior service costs on pension and other post-retirement benefit plans	**11**	**(3)**	**8**
Other comprehensive income on equity investments	**9**	**(2)**	**7**
Other comprehensive loss	**(104)**	**(40)**	**(144)**

six months ended June 30, 2015 (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	325	7	332
Change in fair value of net investment hedges	(283)	75	(208)
Change in fair value of cash flow hedges	(29)	8	(21)
Reclassification to net income of gains on cash flow hedges	56	(23)	33
Reclassification to net income of actuarial gains and prior service costs on pension and other post-retirement benefit plans	20	(3)	17
Other comprehensive income on equity investments	9	(2)	7
Other comprehensive income	98	62	160

The changes in AOCI by component are as follows:

three months ended June 30, 2016 (unaudited - millions of Canadian $)	**Currency translation adjustments**	**Cash flow hedges**	**Pension and OPEB plan adjustments**	**Equity investments**	**Total[1]**
AOCI balance at April 1, 2016	**(493)**	**(54)**	**(194)**	**(258)**	**(999)**
Other comprehensive (loss)/income before reclassifications[2]	**(4)**	**56**	**—**	**—**	**52**
Amounts reclassified from accumulated other comprehensive loss	**—**	**(40)**	**4**	**4**	**(32)**
Net current period other comprehensive (loss)/ income	**(4)**	**16**	**4**	**4**	**20**
AOCI balance at June 30, 2016	**(497)**	**(38)**	**(190)**	**(254)**	**(979)**

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 and cash flow hedges is net of non-controlling interest gains of $3 million and losses of $1 million, respectively.

six months ended June 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]	**(114)**	**19**	**—**	**—**	**(95)**
Amounts reclassified from accumulated other comprehensive loss	**—**	**40**	**8**	**7**	**55**
Net current period other comprehensive (loss)/ income[3]	**(114)**	**59**	**8**	**7**	**(40)**
AOCI balance at June 30, 2016	**(497)**	**(38)**	**(190)**	**(254)**	**(979)**

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 and cash flow hedges is net of non-controlling interest losses of $101 million and $3 million, respectively.

3 Losses related to cash flow hedges reported in AOCI and expected to be reclassified to net income in the next 12 months are estimated to be $22 million ($14 million, net of tax) at June 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 June 30		**six months ended June 30**		
(unaudited - millions of Canadian $)	**2016**	**2015**	**2016**	**2015**	
Cash flow hedges					
Commodities	**21**	21	**(61)**	(48)	Revenue (Energy)
Foreign exchange	**39**	_	**5**	_	Interest income and other
Interest	**(4)**	(4)	**(8)**	(8)	Interest expense
	56	17	**(64)**	(56)	Total before tax
	(16)	(6)	**24**	23	Income tax expense
	40	11	**(40)**	(33)	Net of tax
Pension and other post-retirement benefit plan adjustments					
Amortization of actuarial loss	**(6)**	(10)	**(11)**	(20)	[2]
	2	—	**3**	3	Income tax expense
	(4)	(10)	**(8)**	(17)	Net of tax
Equity investments					
Equity income	**(5)**	(5)	**(9)**	(9)	Income from equity investments
	1	1	**2**	2	Income tax expense
	(4)	(4)	**(7)**	(7)	Net of tax

1 All amounts in parentheses indicate expenses to the condensed consolidated statement of income.

2 These accumulated other comprehensive loss components are included in the computation of net benefit cost. Refer to Note 10 for additional detail.

10. Employee post-retirement benefits

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

	three months ended June 30				six months ended June 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	**25**	27	**—**	—	**51**	54	**1**	1
Interest cost	**29**	29	**3**	3	**59**	57	**5**	5
Expected return on plan assets	**(39)**	(39)	**(1)**	(1)	**(79)**	(77)	**(1)**	(1)
Amortization of actuarial loss	**6**	8	**—**	1	**10**	17	**1**	2
Amortization of past service cost	**—**	1	**—**	—	**—**	1	**—**	—
Amortization of regulatory asset	**5**	6	**—**	—	**9**	12	**—**	—
Amortization of transitional obligation related to regulated business	**—**	—	**1**	1	**—**	—	**1**	1
Net benefit cost recognized	**26**	32	**3**	4	**50**	64	**7**	8

11. Risk management and financial instruments

RISK MANAGEMENT OVERVIEW

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

COUNTERPARTY CREDIT RISK

TransCanada's maximum counterparty credit exposure with respect to financial instruments at June 30, 2016, without taking into account security held, consisted of cash and cash equivalents, restricted cash, 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 June 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 $187 million (US$144 million) at June 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)	June 30, 2016	December 31, 2015
Notional amount	**28,400 (US 21,800)**	23,100 (US 16,700)
Fair value	**31,200 (US 24,000)**	23,800 (US 17,200)

Derivatives designated as a net investment hedge

(unaudited - millions of Canadian $, unless noted otherwise)	June 30, 2016 Fair value[1]	June 30, 2016 Notional or principal amount	December 31, 2015 Fair value[1]	December 31, 2015 Notional or principal amount
Asset/(liability)				
U.S. dollar cross-currency interest rate swaps (maturing 2016 to 2019)[2]	**(499)**	**US 2,650**	(730)	US 3,150
U.S. dollar foreign exchange forward contracts (maturing 2016 to 2017)	**(37)**	**US 450**	50	US 1,800
	(536)	**US 3,100**	(680)	US 4,950

1 Fair values equal carrying values.

2 In the three and six months ended June 30, 2016, net realized gains of $2 million and $4 million, respectively, (2015 - gains of $2 million and $5 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, restricted cash, 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 $)	June 30, 2016 Carrying amount	June 30, 2016 Fair value	December 31, 2015 Carrying amount	December 31, 2015 Fair value
Notes receivable[1]	**158**	**209**	214	265
Current and long-term debt[2,3]	**(39,925)**	**(45,490)**	(31,456)	(34,309)
Junior subordinated notes	**(2,264)**	**(1,833)**	(2,409)	(2,011)
	(42,031)	**(47,114)**	(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 six months ended June 30, 2016 included unrealized losses of $1 million and $13 million, respectively, (2015 - gains of $3 million and nil, 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 June 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:

	June 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)	**—**	**111**	—	90
Fixed income securities (maturing after 10 years)	**428**	**—**	261	—
	428	**111**	261	90

1 Available for sale assets are recorded at fair value and included in intangible and other assets 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.

	June 30, 2016		June 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	**16**	**—**	(3)	—
six months ended	**21**	**1**	(3)	—

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 June 30, 2016 is as follows:

at June 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]	**22**	**—**	**—**	**390**	**412**
Foreign exchange	**5**	**—**	**6**	**15**	**26**
Interest rate	**—**	**6**	**—**	**1**	**7**
	27	**6**	**6**	**406**	**445**
Intangible and other assets					
Commodities[2]	**3**	**—**	**—**	**177**	**180**
Foreign exchange	**—**	**—**	**6**	**—**	**6**
Interest rate	**—**	**8**	**—**	**1**	**9**
	3	**8**	**6**	**178**	**195**
Total Derivative Assets	**30**	**14**	**12**	**584**	**640**
Accounts payable and other					
Commodities[2]	**(54)**	**—**	**—**	**(356)**	**(410)**
Foreign exchange	**—**	**—**	**(301)**	**(20)**	**(321)**
Interest rate	**(3)**	**—**	**—**	**—**	**(3)**
	(57)	**—**	**(301)**	**(376)**	**(734)**
Other long-term liabilities					
Commodities[2]	**—**	**—**	**—**	**(182)**	**(182)**
Foreign exchange	**—**	**—**	**(247)**	**—**	**(247)**
Interest rate	**(3)**	**—**	**—**	**—**	**(3)**
	(3)	**—**	**(247)**	**(182)**	**(432)**
Total Derivative Liabilities	**(60)**	**—**	**(548)**	**(558)**	**(1,166)**

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 June 30, 2016	Power	Natural Gas	Liquids	Foreign Exchange	Interest
Purchases[1]	**103,576**	**242**	**1**	**—**	**—**
Sales[1]	**74,963**	**174**	**3**	**—**	**—**
Millions of dollars	**—**	**—**	**—**	**US 2,367**	**US 1,400**
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 June 30		six months ended June 30	
(unaudited - millions of Canadian $)	2016	2015	2016	2015
Derivative instruments held for trading[1]				
Amount of unrealized gains/(losses) in the period				
Commodities[2]	**187**	23	**120**	(3)
Foreign exchange	**20**	30	**47**	1
Amount of realized (losses)/gains in the period				
Commodities	**(47)**	(33)	**(142)**	(32)
Foreign exchange	**13**	(10)	**57**	(53)
Derivative instruments in hedging relationships				
Amount of realized (losses)/gains in the period				
Commodities	**(67)**	(113)	**(140)**	(97)
Foreign exchange	**(43)**	—	**(106)**	—
Interest rate	**1**	2	**3**	4

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 merchant 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 9) related to derivatives in cash flow hedging relationships are as follows:

	three months ended June 30		six months ended June 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	**42**	(50)	**26**	(29)
Foreign exchange	**40**	—	**5**	—
Interest rate	**—**	—	**(1)**	—
	82	(50)	**30**	(29)
Reclassification of (losses)/gains on derivative instruments from AOCI to net income (effective portion)[1]				
Commodities[2]	**(21)**	(21)	**61**	48
Foreign exchange[3]	**(39)**	—	**(5)**	—
Interest rate[4]	**4**	4	**8**	8
	(56)	(17)	**64**	56
Gains/(losses) on derivative instruments recognized in net income (ineffective portion)				
Commodities[2]	**43**	56	**(15)**	(7)
	43	56	**(15)**	(7)

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 June 30, 2016 (unaudited - millions of Canadian $)	**Gross derivative instruments presented on the balance sheet**	**Amounts available for offset[1]**	**Net amounts**
Derivative - Asset			
Commodities	**592**	**(475)**	**117**
Foreign exchange	**32**	**(32)**	**—**
Interest rate	**16**	**(3)**	**13**
Total	**640**	**(510)**	**130**
Derivative - Liability			
Commodities	**(592)**	**475**	**(117)**
Foreign exchange	**(568)**	**32**	**(536)**
Interest rate	**(6)**	**3**	**(3)**
Total	**(1,166)**	**510**	**(656)**

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 (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 June 30, 2016, the Company provided cash collateral of $259 million (December 31, 2015 - $482 million) and letters of credit of $19 million (December 31, 2015 - $41 million) to its counterparties. The Company held nil (December 31, 2015 - nil) in cash collateral and $11 million (December 31, 2015 - $2 million) in letters of credit from counterparties on asset exposures at June 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 June 30, 2016, the aggregate fair value of all derivative instruments with credit-risk-related contingent features that were in a net liability position was $17 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 June 30, 2016, the Company would have been required to provide additional collateral of $17 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. Inputs include published exchange rates, interest rates, interest rate swap curves, yield curves and broker quotes from external data service providers. This category includes interest rate and foreign exchange derivative assets and liabilities where fair value is determined using the income approach and commodity derivatives where fair value is determined using the market approach. Transfers between Level I and Level II would occur when there is a change in market circumstances.
Level III	Valuation of assets and liabilities are measured using a market approach based on extrapolation of inputs that are unobservable or where observable data does not support a significant portion of the derivative's fair value. This category mainly includes long-dated commodity transactions in certain markets where liquidity is low and the Company uses the most observable inputs available or, if not available, long-term broker quotes to estimate the fair value for these transactions. Valuation of options is based on the Black-Scholes pricing model. Assets and liabilities measured at fair value can fluctuate between Level II and Level III depending on the proportion of the value of the contract that extends beyond the time frame for which significant inputs are considered to be observable. As contracts near maturity and observable market data 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 June 30, 2016 (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	**106**	**463**	**23**	**592**
Foreign exchange	**—**	**32**	**—**	**32**
Interest rate	**—**	**16**	**—**	**16**
Derivative instrument liabilities:				
Commodities	**(99)**	**(482)**	**(11)**	**(592)**
Foreign exchange	**—**	**(568)**	**—**	**(568)**
Interest rate	**—**	**(6)**	**—**	**(6)**
	7	**(545)**	**12**	**(526)**

1 There were no transfers from Level I to Level II or from Level II to Level III for the six months ended June 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 (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 June 30		**six months ended June 30**	
(unaudited - millions of Canadian $, pre-tax)	**2016**	**2015**	**2016**	**2015**
Balance at beginning of period	**9**	2	**9**	4
Total gains included in net income	**7**	8	**10**	5
Transfers into/(out of) Level III	**—**	3	**(3)**	3
Settlements	**(4)**	—	**(3)**	—
Sales	**—**	—	**(1)**	—
Total losses included in OCI	**—**	(2)	**—**	(1)
Balance at end of period[1]	**12**	11	**12**	11

1 For the three and six months ended June 30, 2016, revenues include unrealized gains of $6 million and $8 million attributed to derivatives in the Level III category that were still held at June 30, 2016 (2015 - gains of $11 million and $8 million, respectively).

A 10 per cent increase or decrease in commodity prices, with all other variables held constant, would result in a less than $1 million change in the fair value of outstanding derivative instruments included in Level III as at June 30, 2016.

12. 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.

Columbia Pipeline Group, Inc.

On March 17, 2016, TransCanada entered into an agreement to acquire Columbia for a purchase price of US$10.3 billion in cash. The acquisition closed on July 1, 2016. Refer to Note 15, Subsequent event for additional information on this acquisition.

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 on 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$657 million in cash before 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 is ongoing, however, preliminary findings indicate that the transaction will result in no goodwill. The Company began consolidating Ironwood as of the date of acquisition which has not had a material impact on the consolidated results of the Company. In addition, the pro forma incremental impact on the Company's consolidated results for each of the periods presented is not material.

13. 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 $300 million as a result of the extension of premise leases in second quarter 2016.

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.

In addition to the guarantees for Bruce Power, 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 June 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 2019[2]	**88**	**1**	88	2
Sur de Texas-Tuxpan	ranging to 2040	**689**	**46**	—	—
Other jointly owned entities	ranging to 2040	**116**	**30**	139	24
		893	**77**	227	26

1 TransCanada's share of the potential estimated current or contingent exposure.

2 Except for one guarantee with no termination date.

14. 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 $)	June 30, 2016	December 31, 2015
ASSETS		
Current Assets		
Cash and cash equivalents	**61**	54
Accounts receivable	**51**	55
Inventories	**23**	25
Other	**8**	6
	143	140
Plant, Property and Equipment	**3,623**	3,704
Equity Investments	**592**	664
Goodwill	**509**	541
	4,867	5,049
LIABILITIES		
Current Liabilities		
Accounts payable and other	**64**	74
Accrued interest	**20**	21
Current portion of long-term debt	**59**	45
	143	140
Regulatory Liabilities	**32**	33
Other Long-Term Liabilities	**6**	4
Deferred Income Tax Liabilities	**2**	—
Long-Term Debt	**2,893**	2,998
	3,076	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 $)	June 30, 2016	December 31, 2015
Balance sheet		
Equity investments	**4,854**	5,410
Off-balance sheet		
Potential exposure to guarantees	**204**	227
Maximum exposure to loss	**5,058**	5,637

15. Subsequent event

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 6, Long-term debt for additional information on the bridge term loan credit facilities and Note 8, Equity and share capital for additional information on the subscription receipts.

Columbia operates a portfolio of 24,250 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 long-term growth opportunities.

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 preliminary purchase price equation reflects management's current best estimate of the fair value of Columbia's assets and liabilities based on the analysis of information obtained to date. As management completes its analysis, the final purchase price equation may differ materially from the preliminary purchase price equation discussed below.

(unaudited - millions of Canadian $)	**July 1, 2016**
Purchase Price Consideration	**13,392**
Fair Value Assigned to Net Assets	
Current Assets	856
Plant, Property and Equipment	9,927
Regulatory Assets	238
Other non-current assets	763
Current Liabilities	(933)
Regulatory Liabilities	(385)
Deferred Income Tax Liabilities	(2,117)
Long-Term Debt	(3,847)
Other Long-Term Liabilities	(182)
Non-controlling interests	(1,051)
Fair Value of Net Assets Acquired	**3,269**
Goodwill	**10,123**

The fair values of cash and cash equivalents, accounts receivable, inventories, other current assets and accrued interest approximate their carrying values due to their short-term nature, however, certain adjustments are expected to accounts payable and other.

Columbia's natural gas pipelines are subject to FERC regulations and, as a result, their rate base is expected to be recovered with a reasonable rate of return over the life of the assets. These assets are expected to 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 third party valuation report, resulting in a fair value increase of $325 million. The fair value of base gas included in Columbia's plant, property and equipment was estimated by using quoted market prices which resulted in a fair value increase of $839 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 $300 million increase from its carrying value. Temporary differences created as a result of fair value changes described above will result in deferred tax assets and liabilities that will be 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 (Columbia MLP) common units outstanding to the public as of June 30, 2016, and valued at Columbia MLP's June 30, 2016 closing price of US$15.00 per common unit.

The preliminary purchase price equation includes Goodwill of $10.1 billion. Factors that contributed to the Goodwill include the opportunity 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.

Acquisition-related expenses were approximately $10 million and $36 million for the three and six months ended June 30, 2016, respectively. These amounts are included in Plant operating costs and other in the condensed consolidated statement of income.

Upon acquisition, the Company began consolidating Columbia. The following supplemental unaudited, pro forma consolidated financial information of the Company for the three and six months ended June 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 June 30		**six months ended June 30**	
(unaudited - millions of Canadian $, except per share amounts)	**2016**	**2015**	**2016**	**2015**
Revenues	**3,155**	3,020	**6,148**	6,315
Net Income	**486**	549	**932**	1,117
Net Income Attributable to Common Shares	**394**	473	**718**	950
Net Income per Common Share	**$0.49**	$0.59	**$0.90**	$1.18