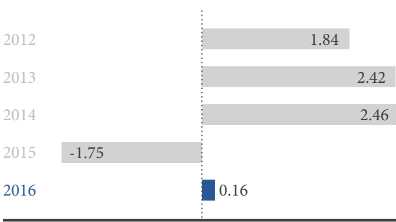
TransCanada
In business to deliver

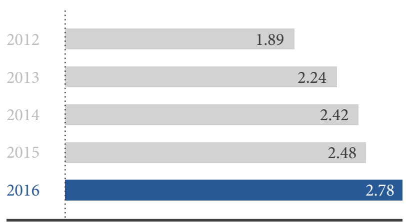
Annual Report 2016

FINANCIAL HIGHLIGHTS

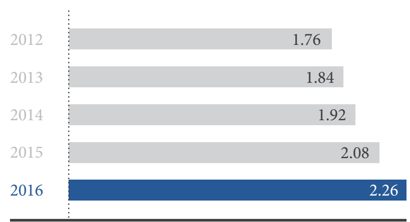
Net Income/(Loss) per Common Share (dollars)



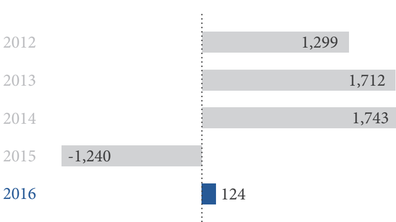
Comparable Earnings per Common Share[1] (dollars)



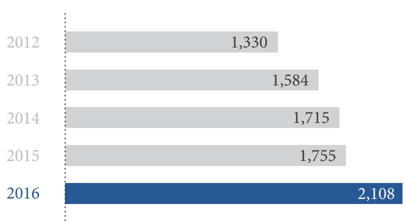
Dividends Declared per Common Share (dollars)



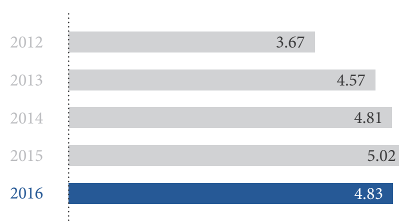
Net Income/(Loss) Attributable to Common Shares (millions of dollars)



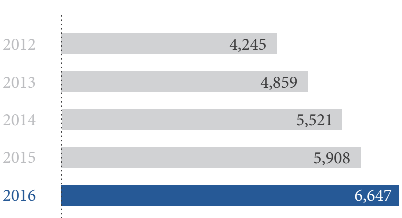
Comparable Earnings[1] (millions of dollars)



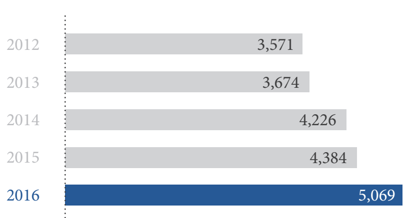
Comparable Distributable Cash Flow per Common Share[1] (dollars)



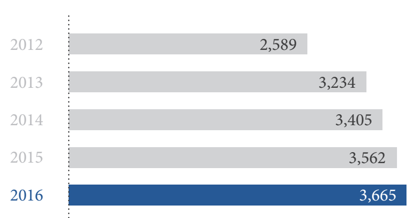
Comparable EBITDA[1] (millions of dollars)



Net Cash Provided by Operations (millions of dollars)



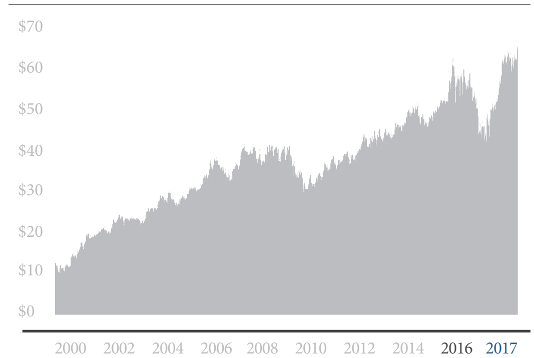
Comparable Distributable Cash Flow[1] (millions of dollars)



Track Record of Dividend Growth

* *Annualized based on first quarter declaration*

Common Share Price – Toronto Stock Exchange



TransCanada's shareholders have benefited from a 14% annual total return since 2000.

(1) Non-GAAP measures which do not have any standardized meanings prescribed by U.S. generally accepted accounting principles (GAAP). For more information, see non-GAAP measures in the Management Discussion and Analysis of the 2016 Annual Report.

Forward-Looking Information and Non-GAAP Measures
These pages contain certain forward-looking information and also contain references to certain non-GAAP measures that do not have any standardized meaning as prescribed by U.S. generally accepted accounting principles (GAAP) and therefore may not be comparable to similar measures presented by other entities. For more information on forward-looking information, the assumptions made, and the risks and uncertainties which could cause actual results to differ from the anticipated results, and reconciliations of non-GAAP measures to the most closely related GAAP measures, refer to TransCanada's 2016 Annual Report filed with Canadian securities regulators and the U.S. Securities and Exchange Commission and available at TransCanada.com.

ABOUT TRANSCANADA

For over 65 years, TransCanada has proudly delivered the energy that millions of North Americans rely on to heat and cool their homes, fuel transportation and power industry. Our facilities operate safely, reliably and with minimal impact on the environment, while our over 7,100 employees play an active part in the communities where they live in Canada, the United States and Mexico.

OUR VISION

To be the leading energy infrastructure company in North America, focusing on pipeline and power generation opportunities where we have, or can develop, a significant competitive advantage.

THREE COMPLEMENTARY ENERGY INFRASTRUCTURE BUSINESSES

Natural Gas Pipelines

Our 91,500-kilometre (56,900-mile) network of natural gas pipelines supplies more than 25 per cent of the clean-burning natural gas consumed daily across North America. This pipeline network strategically connects growing supply to key markets across our three operating geographies of Canada, the U.S. and Mexico. We are also the continent's largest provider of natural gas storage, with 653 billion cubic feet (Bcf) of regulated and unregulated storage capacity. Please visit the Natural Gas Pipelines Business section of the Management's Discussion and Analysis (MD&A) to learn more.

Liquids Pipelines

Our 4,300-kilometre (2,700-mile) Keystone Pipeline System transports 545,000 barrels of crude oil per day (bbl/d), or approximately 20 per cent of western Canadian exports to key refinery markets in the U.S. Midwest and Gulf Coast where it is converted into fuel and other useful petroleum products. Keystone has safely delivered more than 1.4 billion barrels since it began operation in June 2010. Please visit the Liquids Pipelines section of the MD&A to learn more.

Energy

TransCanada owns or has interests in 17 power generation facilities with capacity of 10,700 megawatts – enough to power more than 10 million homes. One-third of the power we provide is generated from emission-less sources including nuclear, hydro, wind and solar and we are leaders in the development and operation of high efficiency, natural gas-fired power facilities. Please visit the Energy section of the MD&A to learn more.

STRONG PERFORMANCE, ATTRACTIVE OPPORTUNITIES

- *Track record of delivering long-term shareholder value – 14 per cent average annual shareholder return since 2000.*
- *Visible growth portfolio – $23 billion in commercially secured near-term growth projects underway for completion by 2020. Advancing over $48 billion in medium to longer term projects.*
- *Attractive, growing dividend – Expect to grow our common share dividend at an average annual rate at the upper end of eight to ten per cent through 2020.*
- *Strong financial position – 'A' grade credit rating and predictable, low-risk businesses underpinned by long-term contracts or regulated cost-of-service models are expected to produce solid results in various market conditions.*
- *Committed to responsible development – We have an industry-leading safety record and have been recognized by numerous third-party rating agencies for excellence in balancing safety, profitability and social and environmental responsibility.*

A TRANSFORMATIONAL YEAR

DEAR FELLOW SHAREHOLDERS,

Last year was truly transformational for our company, as our portfolio of high-quality energy infrastructure assets performed very well at the same time as our long-term strategy and financial discipline allowed us to undertake unprecedented growth and achieve greater control over our destiny in ways that will reward our shareholders in the years ahead.

We are pleased to report that TransCanada has navigated the turbulent waters facing the energy industry over the last several years very well and has emerged a larger, stronger and more competitive enterprise as a result.

Strategy in Action – Columbia Acquisition

Our most significant initiative in 2016 unfolded near the end of the first quarter when we announced the acquisition of Columbia Pipeline Group for US$13 billion. This was the largest business transaction TransCanada has undertaken since our merger with Nova in 1998. It was a rare opportunity to diversify our regulated natural gas pipeline and storage operations and gave us an incumbency position in the Appalachian basin, one of the world's fastest growing and lowest cost natural gas production regions. The acquisition closed on July 1, adding 24,500 km (15,200 miles) of interstate natural gas pipelines between New York and the Gulf of Mexico to our already expansive network that now includes a broad footprint in the Marcellus and Utica shale gas plays. With the addition of Columbia's assets, TransCanada now transports 23 billion cubic feet per day (Bcf/d), or more than 25 per cent of North America's daily natural gas demand, and we are now the continent's largest natural gas storage provider.

The successful acquisition of Columbia was only possible due to our strategy of maintaining our financial strength and flexibility, including our 'A' grade credit rating that positions us to access capital on compelling terms at all points in the economic cycle. Financing the deal involved issuing $7.9 billion in equity through two bought deal share offerings and the decision to permanently divest our merchant power generation assets in the Northeastern United States. The addition of Columbia's regulated natural gas business has brought greater stability and predictability to our revenue streams. Looking forward, more than 95 per cent of our earnings before interest, taxes, depreciation and amortization (EBITDA) are expected to be generated by regulated or long-term contracted assets. Columbia also added meaningful near-term growth to our portfolio, bringing the total to $23 billion in projects that are expected to drive significant growth in earnings and cash flow and underpin our ability to deliver an annual average dividend growth at the upper end of an eight to 10 per cent range through the rest of the decade.

***Russ Girling**, President and Chief Executive Officer*
***S. Barry Jackson**, Chair of the Board*

Record Results in 2016

In 2016 we continued our unwavering focus of providing safe and reliable operations everywhere we do business. We are proud to have occupational and facility safety records that are among the best in the industry, and our pipeline and power facilities operated throughout 2016 without any major incidents, but we believe that no safety-related incidents are acceptable. While we continue to strive for top quartile performance and achieved a 50 per cent improvement in staff and contractor days away from work cases, we did not achieve the tough standards we set for ourselves. Last March, we experienced the tragic fatality of a contractor on one of our worksites. This is unacceptable and we have increased our already significant efforts to work with our contractors to ensure the safety of their workers on our sites. We have also reinforced our commitment to our goal of zero incidents by adopting safety as the first of our four corporate values. Moving forward, Safety, Integrity, Responsibility and Collaboration will be the guiding principles for everything we do.

TransCanada's share price reached all-time highs, reflecting our strategic repositioning, unparalleled growth prospects and strong operational performance.

The addition of Columbia along with the completion of several other growth projects has resulted in our asset base growing to $88 billion. TransCanada's share price reached all-time highs, reflecting our strategic repositioning, unparalleled growth prospects and strong operational performance. Comparable earnings per share increased by 12 per cent compared to 2015, while net cash provided by operations exceeded $5 billion for the first time in the company's history. Based on this sustainable growth, in February 2017 our Board of Directors approved our 17th consecutive annual increase in the common share dividend, increasing the annualized dividend from $2.26 to $2.50, an increase of 10.6 per cent.

Business Units Performing Well

Since July, we have made significant progress integrating Columbia's operations with our existing business and are well on track to realize the targeted US$250 million of annualized benefits by 2018. Also in our U.S. pipeline business, we reached a settlement with our customers that will result in higher rates on the ANR Pipeline and a three-year program to undertake long-term upgrades on the system. We realized higher contributions from our natural gas pipelines in Mexico in 2016, as we began collecting revenues on the Topolobampo and Mazatlan pipelines. Once the remaining three projects we have underway in the country enter service in 2018, we expect our Mexican assets to generate approximately US$575 million of annual EBITDA, more than triple the level of 2015. Similarly, the NGTL System in Alberta continues its steady growth with new facilities being added to meet demand and new contracts. NGTL now gathers most of the gas production in the Western Canada Sedimentary Basin and transported approximately 11.3 Bcf/day in 2016, up from 11 Bcf/d in 2015.

Our Liquids Pipelines business continues to perform well, with the Keystone Pipeline System generating in excess of $1 billion of EBITDA per year based on take-or-pay contracts to ship 545,000 bbl/d with an average remaining contract life of 15 years. Keystone extended its reach into the U.S. Gulf Coast refining centre with the completion of the Houston Lateral pipeline and tank terminal project in August, enhancing Keystone's short- and long-haul capabilities. With this addition, the Keystone system now provides access to approximately 6 million bbl/d of U.S. refining markets.

In our Energy business, our increased stake in the Bruce Power nuclear facility yielded higher earnings, while we took steps to dramatically reduce our exposure to the merchant power market through the planned sale of our power assets in the Northeastern U.S. and the termination of our power purchase agreements in Alberta. Our remaining power generation assets are underpinned primarily by long-term contracts with solid counterparties. We have also committed to significant long-term investments to extend the life of Bruce Power to the end of 2064, as this important facility provides approximately 30 per cent of Ontario's power supply and is an integral part of the province's Long Term Energy Plan. TransCanada is well positioned to capture new opportunities in North America's electricity market with the transition away from coal-fired power in favour of renewable and gas-fired generation.

Predictable, Low-Risk Growth

Looking forward, the stability of our base business is complemented by our portfolio of $23 billion in near-term growth projects scheduled for completion by the end of the decade. All of these projects are underpinned by long-term contracts or regulated business models and span our three business lines. More than $18 billion of these projects are natural gas pipelines and related facilities, including approximately US$7.1 billion in projects associated with Columbia, $5.4 billion in NGTL System expansions and three projects totaling US$2.5 billion of new investment underway in Mexico. Liquids pipelines projects totaling $2.1 billion are under construction to serve the needs of oil sands producers in moving their products within Alberta. Another $2.2 billion of investment is taking place in the Ontario power sector, where the Napanee Generating Station is on track to begin service in 2018, while asset management work is underway at Bruce Power in the first phase of its long-term life extension program.

Moving forward, Safety, Integrity, Responsibility and Collaboration will be the guiding principles for everything we do.

We continue to advance over $48 billion in medium to longer term projects that provide significant options for growth for our shareholders. This portfolio is underpinned by two major crude oil and two natural gas pipeline projects, any one of which would generate significant incremental annual EBITDA upon their successful completion. The Energy East and the Keystone XL crude oil pipeline projects could together provide 2 million bbl/d of long-haul capacity to move growing Canadian oil production to domestic and international markets. Meanwhile, in British Columbia our Prince Rupert Gas Transmission and Coastal GasLink projects could see us invest approximately $10 billion in bringing that province's emerging liquefied natural gas (LNG) industry to life. Combined, these pipelines would be capable of moving more than 4 Bcf/d of Canadian natural gas to international markets.

Positioned for Long-Term Success

It is clear that the strategy we put in place in 2000 continues to pay off and has proven resilient through a myriad of business conditions and economic cycles. We have built a solid foundation of complementary energy infrastructure assets that are critical for meeting North America's needs. Our growth plan is comprised of tangible, commercially secured projects in each of our business lines and geographies that align with long-term energy supply and demand. Our shareholders have been rewarded with growing dividends and an average annual total shareholder return of 14 per cent over that period.

How we conduct our business is important to our stakeholders across North America and we know that the continued success of our company depends on our ability to operate in an economically, socially and environmentally sustainable manner. We continue to consider every business decision in terms of our performance in these areas and we continue to receive recognition from highly regarded third-party agencies for our achievements. For the 15th year in a row, we were named to the Dow Jones Sustainability Index (DJSI) World Index and earned a place on DJSI's North American Index in 2016. We also improved our position in Newsweek's World Green Rankings and on Corporate Knights magazine's list of the Best 50 Corporate Citizens in Canada.

In 2016 we continued with our orderly succession of our Board of Directors, with the appointment of Siim A. Vanaselja as the next chair, subject to his re-election by shareholders at the 2017 annual meeting. Mr. Vanaselja has been a member of TransCanada's board since 2014 and has served as the chair of TransCanada's audit committee. We both look forward to working with him in the months ahead. We also look forward to working with Stéphan Crétier, who joins the board on February 17, 2017. Mr. Crétier's extensive experience as CEO of a multinational corporation, along with his leadership skills, strategic insight, and business acumen will be a valuable addition to our board. We would also like to extend our sincere thanks to John Richels, who will be retiring from the board on May 5, 2017. Mr. Richels served as a director for four years, during which time his industry knowledge and management experience provided context and perspective to the human resources committee and the health, safety and environment committee.

To conclude, 2016 was a remarkable year for TransCanada, but it also involved a lot of change and uncertainty for many of our employees, as we made significant organizational changes to accommodate our growth and to become more effective and efficient in how we conduct our business. By embracing change and adjusting the focus of our growth program, we are a stronger, more competitive company with an enhanced degree of confidence in our plans. The future remains bright for TransCanada and we would like to thank all of our employees and shareholders for their continued commitment to our long-term success.

Sincerely,

Russ Girling
President and Chief Executive Officer

S. Barry Jackson
Chair of the Board

Management's discussion and analysis

February 15, 2017

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 year ended December 31, 2016.

This MD&A should be read with our accompanying December 31, 2016 audited comparative consolidated financial statements and notes for the same period, which have been prepared in accordance with U.S. generally accepted accounting principles (GAAP).

Contents

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 the document are defined in the glossary on page 118. All information is as of February 15, 2017 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 include information about the following, among other things:

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

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

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

Assumptions

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

Risks and uncertainties

- our ability to realize the anticipated benefits from the acquisition of Columbia Pipeline Group, Inc. (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.

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

FOR MORE INFORMATION

See Supplementary information beginning on page 195 for other consolidated financial information on TransCanada for the last five years.

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

NON-GAAP MEASURES

This MD&A references the following non-GAAP measures:

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

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

Comparable measures

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

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

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

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

Comparable earnings

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

Comparable EBIT and comparable EBITDA

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

Funds generated from operations

Funds generated from operations includes net cash provided by operations before changes in operating working capital. We believe it is a useful measure of our consolidated operating cash flow because it does not include fluctuations from working capital balances, which do not necessarily reflect underlying operations in the same period, and is used to provide a consistent measure of the cash generating performance of our assets. See the Financial condition section for a reconciliation to net cash provided by operations.

Comparable distributable cash flow

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

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

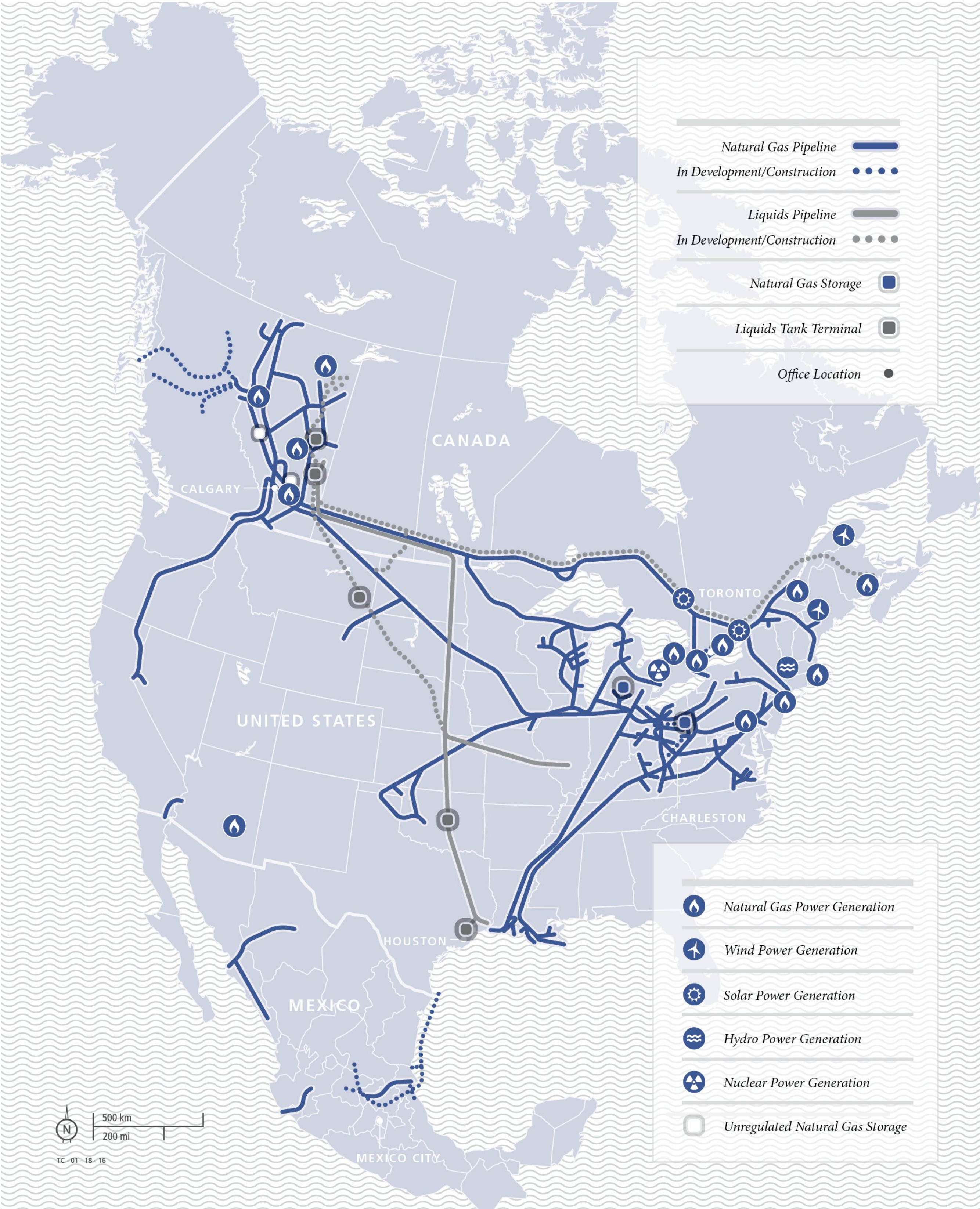
We believe comparable distributable cash flow is a useful supplemental measure of performance that defines cash available to common shareholders before capital allocation. See the Financial condition section for a reconciliation to net cash provided by operations.

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

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

About our business

With over 65 years of 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 natural gas storage facilities.



THREE CORE BUSINESSES

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

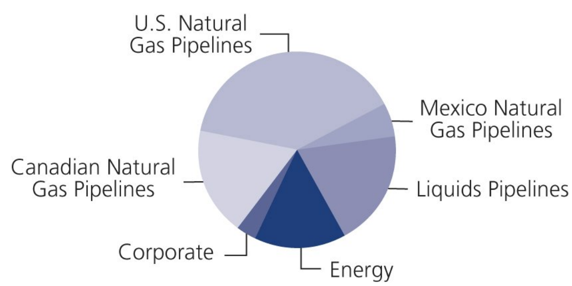
Our $88 billion portfolio of energy infrastructure assets meets the needs of people who rely on us to deliver their energy safely and reliably every day. We operate in seven Canadian provinces, 38 U.S. states and Mexico.

Year at a glance

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

1 2016 includes Columbia.
2 Includes the U.S. Northeast power assets held for sale.

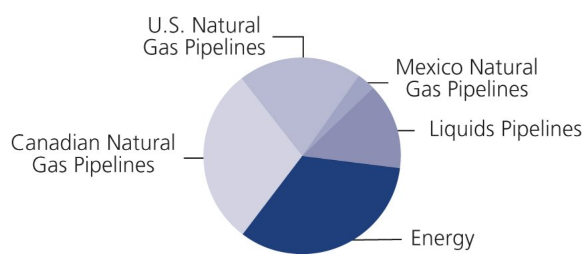
2016 Total assets



year ended December 31 (millions of $)	2016	2015
Total revenues		
Canadian Natural Gas Pipelines	**3,682**	3,680
U.S. Natural Gas Pipelines[1]	**2,526**	1,444
Mexico Natural Gas Pipelines	**378**	259
Liquids Pipelines	**1,755**	1,879
Energy	**4,164**	4,038
	12,505	11,300

1 Includes Columbia effective July 1, 2016.

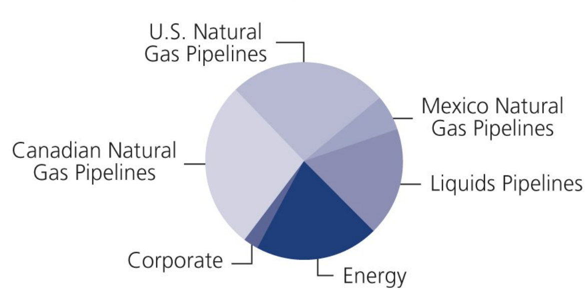
2016 Total revenues



year ended December 31 (millions of $)	2016	2015
Comparable EBIT		
Canadian Natural Gas Pipelines	**1,373**	1,413
U.S. Natural Gas Pipelines[1]	**1,286**	731
Mexico Natural Gas Pipelines	**290**	171
Liquids Pipelines	**881**	1,043
Energy	**996**	924
Corporate	**(118)**	(139)
	4,708	4,143

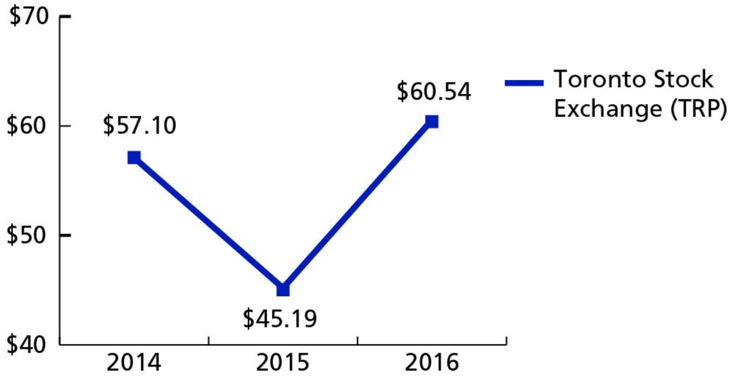
1 Includes Columbia effective July 1, 2016.

2016 Comparable EBIT



Common share price

at December 31



Common shares outstanding – average

(millions)	
2016	759
2015	709
2014	708

as at February 13, 2017 Common shares	issued and outstanding
	867 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
Series 15	40 million	Series 16 preferred shares

options to buy common shares	outstanding	exercisable
	11 million	6 million

OUR STRATEGY

Our energy infrastructure business is made up of pipeline and power generation assets that gather, transport, produce, store or deliver natural gas, crude oil and other petroleum products and electricity to support businesses and communities in North America.

Our vision is to be the leading energy infrastructure company in North America, focusing on pipeline and power generation opportunities in regions where we have or can develop a significant competitive advantage.

Key components of our strategy at a glance

1 Maximize the full-life value of our infrastructure assets and commercial positions

- Long-life infrastructure assets and long-term commercial arrangements are the cornerstones of our low risk business model.
- Our pipeline assets include large-scale natural gas and crude oil pipelines that connect long-life supply basins with stable and growing markets, generating predictable and sustainable cash flow and earnings.
- In Energy, long-term power sale agreements and shorter-term power sales to wholesale and load customers are used to manage and optimize our portfolio and to manage price volatility.

2 Commercially develop and build new asset investment programs

- We are developing high quality, long-life assets under our current $71 billion capital program, comprised of $23 billion in near-term projects and $48 billion in commercially-secured medium to long-term projects. These will contribute incremental earnings and cash flow over the near, medium and long terms as our investments are placed in service.
- Our expertise in project development, managing construction risks and maximizing capital productivity ensures a disciplined approach to reliability, cost and schedule, resulting in superior service for our customers and returns to shareholders.
- As part of our growth strategy, we rely on this experience and our regulatory, commercial, financial, legal and operational expertise to successfully build and integrate new pipeline and other energy facilities.
- Our investment in natural gas, nuclear, wind and solar generating facilities demonstrates our commitment to clean, sustainable energy.

3 Cultivate a focused portfolio of high quality development and investment options

- We assess opportunities to acquire and develop energy infrastructure that complements our existing portfolio and diversifies access to attractive supply and market regions.
- We focus on pipelines and energy growth initiatives in core regions of North America and prudently manage development costs, minimizing capital-at-risk in early stages of projects.
- We will advance selected opportunities to full development and construction when market conditions are appropriate and project risks and returns are acceptable.

4 Maximize our competitive strengths

- We are continually developing core competencies in areas such as safety, operational excellence, supply chain management, project execution and stakeholder management to ensure we provide maximum shareholder value over the short, medium and long terms.

A competitive advantage

Years of experience in the energy infrastructure business and a disciplined approach to project and operational management and capital investment give us our competitive edge.

- Strong leadership: scale, presence, operating capabilities and strategy development; expertise in regulatory, legal, commercial and financing support.
- High quality portfolio: a low-risk and enduring business model that maximizes the full-life value of our long-life assets and commercial positions throughout all points in the business cycle.
- Disciplined operations: highly skilled in designing, building and operating energy infrastructure; focus on operational excellence; and a commitment to health, safety and the environment are paramount parts of our core values.
- Financial positioning: consistently strong financial performance and long-term financial stability and profitability; disciplined approach to capital investment; ability to access sizable amounts of competitively priced capital to support our growth; ability to balance an increasing dividend on our common shares while preserving financial flexibility to fund our industry-leading capital program in all market conditions.
- Long-term relationships: long-term, transparent relationships with key customers and stakeholders; clear communication of our value to equity and debt investors – both the upside and the risks – to build trust and support.

ACQUISITION OF COLUMBIA PIPELINE GROUP, INC.

Acquisition

On July 1, 2016, we acquired 100 per cent ownership of Columbia for a purchase price of US$10.3 billion in cash. The acquisition was initially financed through proceeds of $4.4 billion from the sale of subscription receipts, draws on acquisition bridge facilities in the aggregate amount of US$6.9 billion and existing cash on hand. The sale of the subscription receipts was completed on April 1, 2016 through a public offering and, following the closing of the acquisition, were exchanged into 96.6 million TransCanada common shares. See Financial condition section for additional information on the acquisition bridge facilities and the subscription receipts.

Columbia operates a portfolio of approximately 24,500 km (15,200 miles) of regulated natural gas pipelines, 285 Bcf of natural gas storage facilities and related midstream assets. We acquired Columbia to expand our natural gas business in the U.S. market, positioning ourselves for additional long-term growth opportunities. The acquisition also includes a large portfolio of new capital growth projects which currently includes seven significant pipeline expansions designed to transport growing supply from the Marcellus / Utica production basins to markets as well as a scheduled program for modernization of existing infrastructure through 2020 to ensure the continuation of a safe, reliable and efficient system. We continue to execute on plans to ensure an effective integration of Columbia into the TransCanada organization, and remain on track to realizing our targeted US$250 million of annual cost, revenue and financing benefits by 2018.

Throughout this MD&A, we refer to Columbia as the overall corporate entity we acquired, however, we also make reference to specific businesses or assets within Columbia:

- Columbia Gas – We own and operate this interstate natural gas transportation pipeline and storage system which has largely operated as a means to transport gas from the Gulf Coast via Columbia Gulf, from various pipeline interconnects and from production areas in the Appalachian region to markets in the midwest, Atlantic, and northeast regions.
- Columbia Gulf – We own and operate this long-haul interstate natural gas transportation pipeline system that was originally designed to transport supply from the Gulf of Mexico to major supply markets in the U.S. Northeast. The pipeline is now transitioning and expanding to accommodate new supply in the Appalachian basin and its interconnect with Columbia Gas and other pipelines to deliver gas across various Gulf Coast markets.
- Millennium – We operate and own a 47.5 per cent ownership interest in Millennium which transports natural gas primarily sourced from the Marcellus shale to markets across southern New York and the lower Hudson Valley, as well as to the New York City market through its pipeline interconnections.
- Crossroads – We own and operate this interstate natural gas pipeline operating in Indiana and Ohio.
- Midstream – This midstream business provides natural gas producer services including gathering, treating, conditioning, processing, compression and liquids handling in the Appalachian Basin.

Columbia's wholly-owned natural gas storage business is one of North America’s largest and includes 37 storage fields in four states and is highly integrated with the Columbia pipeline assets.

- Hardy Storage – We also operate and own a 50 per cent interest in Hardy Storage, a natural gas storage field in Hardy and Hampshire counties in West Virginia.

The following table summarizes the acquisition related costs for Columbia that have been excluded from comparable earnings.

year ended December 31 (millions of $)	**2016**
Plant operating costs and other – U.S. Natural Gas Pipelines	63
Plant operating costs and other – Corporate	116
Interest expense	115
Interest income and other	(6)
Income tax expense	(10)
Net income attributable to non-controlling interests	(5)
Total excluded from comparable earnings	**273**

The $273 million of after-tax costs which were excluded from comparable earnings included $109 million of dividend equivalent payments on the subscription receipts issued as part of the permanent financing of the transaction, $90 million of retention, severance and integration costs, $36 million of acquisition costs and a $44 million deferred income tax adjustment upon acquisition, partially offset by $6 million of interest earned on the subscription receipt funds held in escrow pending their conversion to common shares.

As part of the initial financing plan for the Columbia acquisition, we announced the planned monetization of our U.S. Northeast power business and the sale of a minority interest in our Mexican pipelines.

Monetization of U.S. Northeast power business

On November 1, 2016, we announced the sale of Ravenswood, Ironwood, Ocean State Power and Kibby Wind to Helix Generation, LLC, an affiliate of LS Power Equity Advisors for US$2.2 billion and TC Hydro to Great River Hydro, LLC, an affiliate of ArcLight Capital Partners, LLC for US$1.065 billion. These two sale transactions are expected to close in the first half of 2017 subject to certain regulatory and other approvals and will include customary closing adjustments. These asset dispositions are expected to result in an approximate $1.1 billion after-tax net loss which is comprised of a $656 million after-tax goodwill impairment charge, an approximate $863 million after-tax net loss on the sale of the thermal and wind package and an approximate $440 million after-tax gain on the sale of the hydro assets to be recorded upon close of that transaction. We are also in the process of monetizing the U.S. Northeast power marketing business. Proceeds from these sales and future realization of value of the marketing business will be used to repay the remaining portion of the acquisition bridge facilities which were used to partially finance the Columbia acquisition.

Minority interest in Mexican pipelines

As part of the initial Columbia acquisition financing plan, we previously disclosed our intention to monetize a minority interest in our Mexico natural gas pipeline business. On November 1, 2016, we announced a decision to maintain our full ownership interest in this growing portfolio of natural gas pipeline assets in Mexico rather than sell a minority interest in six of these pipelines, which also is consistent with our strategy of maximizing shareholder value and maintaining a simplified corporate structure.

Common equity offering

On November 1, 2016, in conjunction with our decision to maintain our current ownership interest in our growing Mexican natural gas pipelines business, we entered into an agreement with a group of underwriters for a bought deal offering of common shares which included an over-allotment option. On November 16, 2016, including full exercise of the over-allotment option by the underwriters, we issued 60.2 million common shares at a price of $58.50 for total proceeds of approximately $3.5 billion. Proceeds from the offering were used to repay a portion of the US$6.9 billion acquisition bridge facilities which were used to partially finance the Columbia acquisition.

MLP Strategy/CPPL Acquisition

Following a review of our master limited partnership (MLP) strategy, on November 1, 2016, we announced an agreement and plan of merger through which our wholly-owned subsidiary, Columbia Pipeline Group, Inc., agreed to acquire, for cash, all of the outstanding publicly held common units of Columbia Pipeline Partners LP (CPPL). The acquisition is expected to close in first quarter 2017. TC PipeLines, LP remains a core element of our future strategy.

CAPITAL PROGRAM

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

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

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

Near-term projects

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

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

Medium to longer-term projects

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

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

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

2016 FINANCIAL HIGHLIGHTS

We use certain financial measures that do not have a standardized meaning under GAAP because we believe they improve our ability to compare results between reporting periods and enhance understanding of our operating performance. Known as non-GAAP measures, they may not be similar to measures provided by other companies.

Comparable EBITDA (comparable earnings before interest, taxes, depreciation and amortization), comparable EBIT (comparable earnings before interest and taxes), comparable earnings, comparable earnings per common share, comparable funds generated from operations, comparable distributable cash flow and comparable distributable cash flow per common share are all non-GAAP measures. See page 8 for more information about the non-GAAP measures we use and pages 80, 81 and 109 for a reconciliation to the GAAP equivalents.

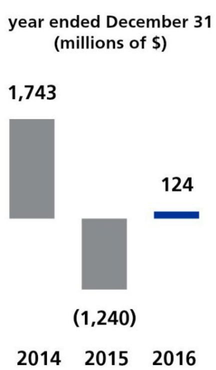
year ended December 31 (millions of $, except per share amounts)	**2016**	**2015**	**2014**
Income			
Revenues	**12,505**	11,300	10,185
Net income/(loss) attributable to common shares	**124**	(1,240)	1,743
per common share – basic & diluted	**$0.16**	($1.75)	$2.46
Comparable EBITDA	**6,647**	5,908	5,521
Comparable earnings	**2,108**	1,755	1,715
per common share	**$2.78**	$2.48	$2.42
Cash flows			
Net cash provided by operations	**5,069**	4,384	4,226
Comparable funds generated from operations	**5,171**	4,815	4,458
Comparable distributable cash flow	**3,665**	3,562	3,405
per common share	**$4.83**	$5.02	$4.81
Capital spending – capital expenditures	**5,007**	3,918	3,489
Capital spending – projects in development	**295**	511	848
Contributions to equity investments	**765**	493	256
Acquisitions, net of cash acquired	**13,608**	236	241
Proceeds from sale of assets, net of transaction costs	**6**	—	196
Balance sheet			
Total assets	**88,051**	64,398	58,525
Long-term debt	**40,150**	31,456	24,757
Junior subordinated notes	**3,931**	2,409	1,160
Preferred shares	**3,980**	2,499	2,255
Non-controlling interests	**1,726**	1,717	1,583
Common shareholders' equity	**20,277**	13,939	16,815
Dividends declared[1]			
per common share	**$2.26**	$2.08	$1.92
per Series 1 preferred share	**$0.8165**	$0.8165	$1.15
per Series 2 preferred share	**$0.60648**	$0.6299	—
per Series 3 preferred share	**$0.538**	$0.769	$1.00
per Series 4 preferred share	**$0.44648**	$0.2269	—
per Series 5 preferred share	**$0.56575**	$1.10	$1.10
per Series 6 preferred share	**$0.50648**	—	—
per Series 7 preferred share	**$1.00**	$1.00	$1.00
per Series 9 preferred share	**$1.0625**	$1.0625	$1.09
per Series 11 preferred share	**$1.1875**	$0.7040	—
per Series 13 preferred share	**$0.18525**	—	—
per Series 15 preferred share	**$0.3323**	—	—

1 See financial condition section on page 85 for details on the preferred share dividends.

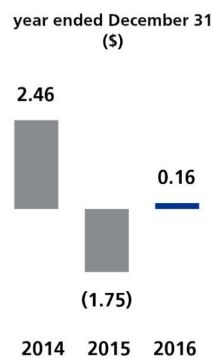
Consolidated results

year ended December 31 (millions of $, except per share amounts)	2016	2015	2014
Segmented earnings/(losses)			
Canadian Natural Gas Pipelines	**1,373**	1,413	1,454
U.S. Natural Gas Pipelines	**1,219**	606	556
Mexico Natural Gas Pipelines	**290**	171	142
Liquids Pipelines	**827**	(2,643)	830
Energy	**(1,140)**	792	1,036
Corporate	**(256)**	(238)	(87)
Total segmented earnings	**2,313**	101	3,931
Interest expense	**(1,998)**	(1,370)	(1,198)
Allowance for funds used during construction	**419**	295	136
Interest income and other	**103**	(132)	(45)
Income/(loss) before income taxes	**837**	(1,106)	2,824
Income tax expense	**(352)**	(34)	(831)
Net income/(loss)	**485**	(1,140)	1,993
Net income attributable to non-controlling interests	**(252)**	(6)	(153)
Net income/(loss) attributable to controlling interests	**233**	(1,146)	1,840
Preferred share dividends	**(109)**	(94)	(97)
Net income/(loss) attributable to common shares	**124**	(1,240)	1,743
Net income/(loss) per common share – basic and diluted	**$0.16**	($1.75)	$2.46

Net income/(loss) attributable to common shares



Net income/(loss) per share



Net income attributable to common shares in 2016 was $124 million or $0.16 per share (2015 – loss of $1,240 million or ($1.75) per share; 2014 – income of $1,743 million or $2.46 per share). On a per share basis, net income attributable to common shares in 2016 increased by $1.91 per share compared to 2015 due to the changes in net income as described below partially offset by the dilutive effect of issuing 161 million common shares in 2016.

The following specific items were recognized in net income/(loss) attributable to common shares in 2014 to 2016 and were excluded from comparable earnings for the relevant periods:

2016

- a $656 million after-tax impairment of Ravenswood goodwill. As a result of information received during the process to monetize our U.S. Northeast power business in third quarter 2016, it was determined that the fair value of Ravenswood no longer exceeds its carrying value
- an $873 million after-tax loss on U.S. Northeast power assets held for sale which included an $863 million after-tax loss on the thermal and wind package held for sale and $10 million of after-tax costs related to the monetization
- a $176 million after-tax impairment charge on the carrying value of our Alberta PPAs (both directly and through our equity investment in ASTC Power Partnership) as a result of our decision to terminate the PPAs and a $68 million after-tax loss on the transfer of environmental credits to the Balancing Pool upon final settlement of the PPA terminations
- costs associated with the acquisition of Columbia resulting in an after-tax charge of $273 million which included $109 million of dividend equivalent payments on the subscription receipts issued as part of the permanent financing of the transaction, $90 million of retention, severance and integration costs, $36 million of acquisition costs and a $44 million deferred income tax adjustment upon acquisition partially offset by $6 million of interest earned on the subscription receipt funds held in escrow prior to their conversion to common shares
- $28 million of income tax recoveries related to the realized loss on a third party sale of Keystone XL project assets. A provision for the expected pre-tax loss on these assets was included in our fourth quarter 2015 impairment charge, but the related income tax recoveries could not be recorded until realized
- an after-tax charge of $42 million related to Keystone XL costs for the maintenance and liquidation of project assets which are being expensed pending further advancement of the project
- an after-tax charge of $16 million for restructuring 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 in early 2016.

2015

- a $2,891 million after-tax impairment charge on the carrying value of our investment in Keystone XL and related projects
- an $86 million after-tax loss provision related to the sale of TC Offshore which closed in early 2016
- a net charge of $74 million after tax for restructuring comprised of $42 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 formed part of a restructuring initiative, which commenced in 2015, to maximize the effectiveness and efficiency of our existing operations and reduce overall costs
- a $43 million after-tax charge relating to an impairment in value on turbine equipment held for future use in our Energy business
- a $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
- 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.

2014

- a gain of $99 million after tax on the sale of Cancarb Limited and its related power generation business
- a net loss of $32 million after tax resulting from a termination payment to Niska Gas Storage for contract restructuring
- a gain of $8 million after tax on the sale of our 30 per cent interest in Gas Pacifico/INNERGY.

Certain unrealized fair value adjustments relating to risk management activities are also excluded from comparable earnings. The remainder of net income/(loss) is equivalent to comparable earnings. A reconciliation of net income/(loss) attributable to common shares to comparable earnings is shown in the following table.

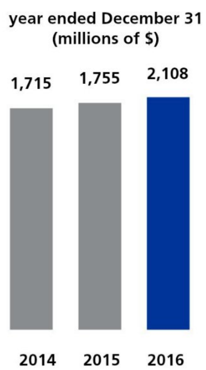
Refer to the Results section in each business segment and the Financial condition section of this MD&A for further discussion of these highlights.

Reconciliation of net income/(loss) to comparable earnings

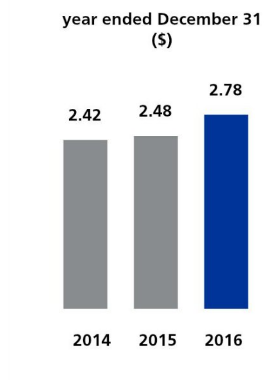
year ended December 31 (millions of $, except per share amounts)	2016	2015	2014
Net income/(loss) attributable to common shares	**124**	(1,240)	1,743
Specific items (net of tax):			
Ravenswood goodwill impairment	**656**	—	—
Loss on U.S. Northeast power assets held for sale	**873**	—	—
Alberta PPA terminations and settlement	**244**	—	—
Acquisition related costs – Columbia	**273**	—	—
Keystone XL income tax recoveries	**(28)**	—	—
Keystone XL asset costs	**42**	—	—
Restructuring costs	**16**	74	—
TC Offshore loss on sale	**3**	86	—
Keystone XL impairment charge	**—**	2,891	—
Turbine equipment impairment charge	**—**	43	—
Alberta corporate income tax rate increase	**—**	34	—
Bruce Power merger – debt retirement charge	**—**	27	—
Non-controlling interests (TC PipeLines, LP – Great Lakes impairment)	**—**	(199)	—
Cancarb gain on sale	**—**	—	(99)
Niska contract termination	**—**	—	32
Gas Pacifico/ INNERGY gain on sale	**—**	—	(8)
Risk management activities[1]	**(95)**	39	47
Comparable earnings	**2,108**	1,755	1,715
Net income/(loss) per common share	**$0.16**	$(1.75)	$2.46
Specific items (net of tax):			
Ravenswood goodwill impairment	**0.86**	—	—
Loss on U.S. Northeast power assets held for sale	**1.15**	—	—
Alberta PPA terminations and settlement	**0.32**	—	—
Acquisition related costs – Columbia	**0.37**	—	—
Keystone XL income tax recoveries	**(0.04)**	—	—
Keystone XL asset costs	**0.06**	—	—
Keystone XL impairment charge	**—**	4.08	—
TC Offshore loss on sale	**—**	0.12	—
Restructuring costs	**0.02**	0.10	—
Turbine equipment impairment charge	**—**	0.06	—
Alberta corporate income tax rate increase	**—**	0.05	—
Bruce Power merger – debt retirement charge	**—**	0.04	—
Non-controlling interests (TC PipeLines, LP – Great Lakes impairment)	**—**	(0.28)	—
Cancarb gain on sale	**—**	—	(0.14)
Niska contract termination	**—**	—	0.04
Gas Pacifico/ INNERGY gain on sale	**—**	—	(0.01)
Risk management activities	**(0.12)**	0.06	0.07
Comparable earnings per common share	**$2.78**	$2.48	$2.42

1	year ended December 31 (millions of $)	2016	2015	2014
	Canadian Power	**4**	(8)	(11)
	U.S. Power	**113**	(30)	(55)
	Liquids marketing	**(2)**	—	—
	Natural Gas Storage	**8**	1	13
	Foreign exchange	**26**	(21)	(21)
	Income taxes attributable to risk management activities	**(54)**	19	27
	Total unrealized gains/(losses) from risk management activities	**95**	(39)	(47)

Comparable earnings



Comparable earnings per share



Comparable earnings per share in 2016 were impacted by the dilutive effect of issuing 161 million common shares that year. See the Financial condition section of this MD&A for further information on the common share issuances.

Comparable earnings in 2016 were $353 million higher than in 2015. The 2016 increase in comparable earnings was primarily the net result of:

- higher earnings from our U.S. Natural Gas Pipelines due to incremental earnings from Columbia following the July 1, 2016 acquisition, higher ANR transportation revenue resulting from higher rates effective August 1, 2016, new contracts on ANR Southeast Mainline transportation revenues and lower OM&A expenses
- higher interest expense from debt issuances and lower capitalized interest
- higher interest income and other due to realized gains in 2016 compared to realized losses in 2015 on derivatives used to manage our net exposure to foreign exchange rate fluctuations on U.S. dollar denominated income
- lower earnings from Liquids Pipelines due to the net effect of higher contracted and lower uncontracted volumes on Keystone and lower volumes on Marketlink
- higher AFUDC on our rate-regulated projects including those for the NGTL System, Energy East, Columbia and Mexico pipelines
- higher contribution from Mexico Natural Gas Pipelines primarily due to earnings from Topolobampo beginning in July 2016
- higher earnings from Natural Gas Storage due to higher realized natural gas storage price spreads.

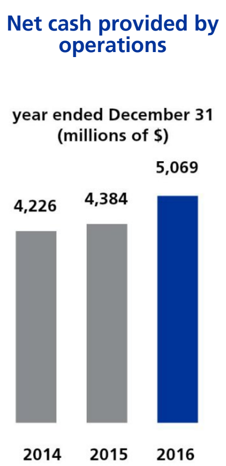
Comparable earnings in 2015 were $40 million higher than 2014, an increase of $0.06 per common share.

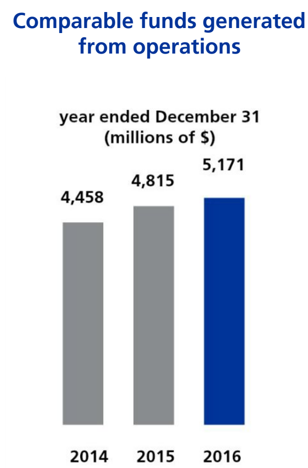
The 2015 increase in comparable earnings was primarily the net result of:

- higher earnings from Liquids Pipelines due to higher volumes on the Keystone Pipeline System
- lower earnings from Western Power as a result of lower realized power prices and lower PPA volumes
- higher interest expense as a result of long term debt issuances net of maturities
- higher interest income and other as a result of increased AFUDC related to our rate-regulated pipeline projects including Energy East and our Mexico pipelines

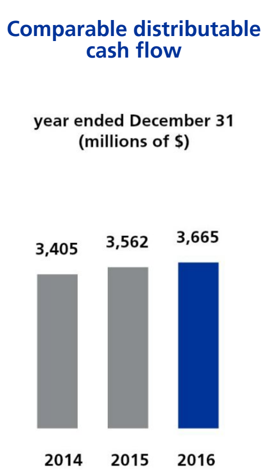
- higher earnings from U.S. Power due to increased margins and sales volumes to wholesale, commercial and industrial customers, partially offset by lower capacity revenue in New York and lower realized prices at our northeastern U.S. Power facilities
- higher earnings from U.S. Natural Gas Pipelines due to higher ANR, Great Lakes and GTN transportation revenues
- higher earnings from Eastern Power primarily due to four solar facilities acquired in 2014
- higher earnings from the Tamazunchale Extension which was placed in service in 2014.

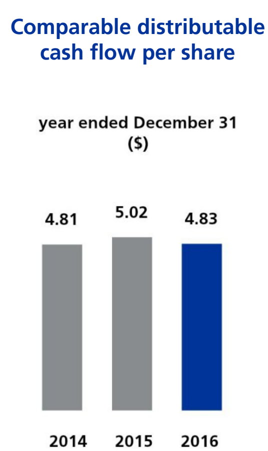
Cash flows





Net cash provided by operations was 16 per cent higher and comparable funds generated from operations were seven per cent higher in 2016 compared to 2015, primarily due to higher comparable earnings, as described above. In addition, net cash provided by operations was affected by the timing of working capital changes.





Comparable distributable cash flow increased in 2016 compared to 2015 primarily due to higher comparable earnings as described above, partially offset by higher maintenance capital expenditures in 2016. Comparable distributable cash flow per common share decreased year over year due to the common share issuances in 2016. See the Financial condition section for more information on the calculation of comparable distributable cash flow.

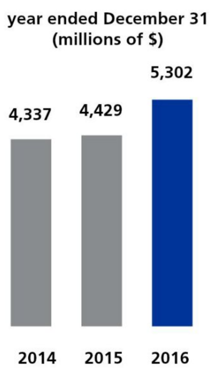
Funds used in investing activities

***Capital spending*[1]**

year ended December 31 (millions of $)	2016	2015	2014
Canadian Natural Gas Pipelines	**1,525**	1,596	1,141
U.S. Natural Gas Pipelines	**1,517**	537	277
Mexico Natural Gas Pipelines	**944**	566	718
Liquids Pipelines	**810**	1,290	1,949
Energy	**473**	376	206
Corporate	**33**	64	46
	5,302	4,429	4,337

1 Capital spending includes capacity capital expenditures, maintenance capital expenditures and capital projects in development.

Capital spending



We invested $5.3 billion in capital projects in 2016 to optimize the value of our existing assets and develop new, complementary assets in high demand areas that are expected to generate stable, predictable earnings and cash flow and to maximize returns to shareholders for years to come.

Other investing activities

In 2016, we made contributions of $765 million to our equity investments primarily related to our investment in Bruce Power, Grand Rapids and Sur de Texas.

In 2016, we acquired Columbia for a purchase price of US$10.3 billion in cash.

In 2016, Bruce Power issued bonds and borrowed under its bank credit facility as part of its financing program to fund its capital program and made distributions to its partners, including $725 million to us.

Balance sheet

We continue to maintain a solid financial position while growing our total assets by $29.5 billion since 2014. At December 31, 2016, common equity represented 32 per cent (30 per cent in 2015) of our capital structure, while other subordinated capital in the form of junior subordinated notes and preferred shares represented an additional 11 per cent. See page 79 for more information about our capital structure.

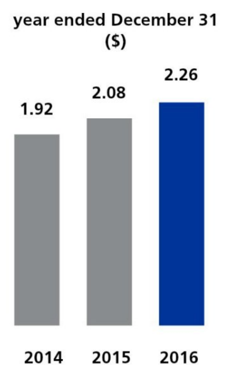
Common shares repurchased

In November 2015, we announced that the TSX had approved our normal course issuer bid (NCIB), which allowed for the repurchase and cancellation of up to 21.3 million of our common shares, representing three per cent of our 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. During that period, 7.1 million shares were repurchased at an average price of $43.36. The NCIB has now expired and has not been renewed. With the acquisition of Columbia, we do not anticipate further repurchases in the foreseeable future.

Dividends

We increased the quarterly dividend on our outstanding common shares by 10.6 per cent to $0.625 per common share for the quarter ending March 31, 2017 which equates to an annual dividend of $2.50 per common share and reflects our expectation of being able to grow our common share dividend at an average annual rate at the upper end of an eight to ten per cent range through the end of the decade. This is the 17th consecutive year we have increased the dividend on our common shares.

Dividends declared per common share



Dividend reinvestment plan

Under our DRP, eligible holders of common and preferred shares of TransCanada can reinvest their dividends and make optional cash payments to obtain additional 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 rather than purchased on the open markets to satisfy participation in the DRP.

Quarterly dividend on our common shares

$0.625 per common share (for the quarter ending March 31, 2017)

Annual dividends on our preferred shares[1]

Series 1 $0.8165

Series 2 $0.6045[2]

Series 3 $0.538

Series 4 $0.4445[2]

Series 5 $0.56575[3]

Series 6 $0.50925[2,4]

Series 7 $1.00

Series 9 $1.0625

Series 11 $0.95

Series 13 $1.375[5]

Series 15 $1.3292[6]

1 Annual dividend based on applicable fixed or quarterly floating rate as of February 15, 2017.
2 Floating quarterly dividend rate resets each quarter. See the Financial condition section for more information.
3 Series 5 preferred shares dividend rate changed in February 2016.
4 Series 6 preferred shares were issued February 2016.
5 Series 13 preferred shares were issued April 2016.
6 Series 15 preferred shares were issued November 2016.

Cash dividends paid

year ended December 31 (millions of $)	2016	2015	2014
Common shares	**1,436**	1,446	1,345
Preferred shares	**100**	92	94

OUTLOOK

Earnings

We anticipate our 2017 earnings, after excluding specific items, to be higher than 2016 mainly due to the following:

- Full year contribution from Columbia including new assets coming into service in late 2017
- Full year of operations from Topolobampo and Mazatlán in Mexico
- Growth in the average investment base for the NGTL System
- Higher expected Bruce Power equity income due to lower planned maintenance activity
- Expected earnings from new liquids pipeline interconnections and the Northern Courier and Grand Rapids projects being placed in service
- Full year impact of the ANR settlement

Partially offset by:

- Loss of operational earnings as a result of the monetization of U.S. Northeast power business in the first half of 2017.

In addition, on a per share basis, the full year impact of 2016 equity issuances is expected to have a partially dilutive effect on 2017 earnings.

Natural Gas Pipelines

Earnings from the Natural Gas Pipelines segments are primarily affected by regulatory decisions and the timing of these decisions. Earnings are also impacted by market conditions, which drive the level of demand and the rates we secure for our services.

Canadian Natural Gas Pipelines earnings in 2017 are expected to be higher than 2016 due to continued growth in the NGTL System as we continue to invest in connecting new natural gas supply in northeastern British Columbia and Alberta markets and respond to growing demand in intra-basin and export markets.

U.S. Natural Gas Pipelines earnings are expected to be higher in 2017 compared to 2016 as a result of a full year of earnings from our Columbia assets, the ANR settlement in 2016 and new long term contracts associated with the Leach XPress and Rayne XPress projects.

Mexico Natural Gas Pipelines earnings are expected to be higher in 2017 reflecting the addition of the Topolobampo and Mazatlán Pipeline assets in 2016 and AFUDC from our equity interest in the Sur de Texas pipeline project.

Liquids Pipelines

Earnings from the Liquids Pipelines business are mainly generated from offering pipeline capacity supported by long term contracts. Uncontracted capacity is offered to the market providing opportunities to generate incremental earnings.

Liquids Pipelines earnings in 2017 are expected to be slightly higher than 2016 as additional pipeline interconnections and the Northern Courier and Grand Rapids projects are placed into service.

Energy

Earnings in the Energy segment are generally maximized by maintaining and optimizing the operations of our power plants and through various marketing activities. The monetization of the U.S. Northeast power assets will result in the vast majority of Energy's remaining generation being sold under long-term contracts.

Overall we expect Energy earnings in 2017 to be lower compared to 2016 primarily as a result of the monetization of the U.S. Northeast power assets. Canadian Power earnings are expected to be higher in 2017 due to higher Bruce Power equity income resulting from lower planned maintenance activity.

Consolidated capital spending and equity investments

We expect to spend approximately $9 billion in 2017 on new and existing capital projects which includes capital expenditures on growth projects, maintenance activities and contributions to equity investments. The 2017 capital program primarily relates to Natural Gas Pipelines projects including Columbia projects, NGTL System expansions, Sur de Texas, ANR, Canadian Mainline, Tula and Villa de Reyes; Liquids Pipelines projects including Grand Rapids, Northern Courier and White Spruce; and Energy projects including Bruce Power and Napanee.

NATURAL GAS PIPELINES BUSINESS

Our natural gas pipeline network transports natural gas from supply basins to local distribution companies, power generation facilities, interconnecting pipelines and other businesses across Canada, the U.S. and Mexico. Our network of pipelines taps into virtually every major supply basin and transports over 25 per cent of continental daily natural gas needs through:

- Wholly-owned natural gas pipelines – 80,400 km (50,000 miles)
- Partially-owned natural gas pipelines – 11,100 km (6,900 miles).

In addition to our interstate natural gas pipelines, we also have regulated natural gas storage facilities in the U.S. with a total working gas capacity of 535 Bcf, making us one of the largest providers of natural gas storage and related services to key markets in North America. We also own and manage Columbia's midstream services which provides specific natural gas producer services including gathering, treatment, conditioning, processing and liquids handling with a focus on the Appalachian Basin.

Our Natural Gas Pipelines business is split into three operating segments representing its geographic diversity: Canadian Natural Gas Pipelines, U.S. Natural Gas Pipelines and Mexico Natural Gas Pipelines.

Strategy at a glance

Optimizing the value of our existing natural gas pipeline systems, while responding to the changing flow patterns of natural gas in North America, is a top priority.

We are also pursuing new pipeline opportunities to add incremental value to our business. Our key areas of focus include:

- Expansion and extension of our existing large North American natural gas pipeline footprint
- Connections to new and growing industrial, LDC, interconnect and electric power generation markets
- Connections to growing Canadian and U.S. shale gas and other supplies
- Additional new pipeline developments within Mexico
- Greenfield development projects, such as infrastructure for LNG exports from the west coast of Canada and the Gulf of Mexico

all of which play a critical role in meeting the transportation requirements for supply and demand for natural gas in North America.

Highlights

- Acquisition of Columbia: On July 1, 2016, we acquired Columbia for US$10.3 billion in cash, creating one of North America's largest regulated natural gas transmission and storage businesses
- Awarded Sur de Texas and Villa de Reyes pipeline projects in Mexico: Sur de Texas is a US$2.1 billion pipeline with a planned in-service date of late 2018, while Villa de Reyes is a US$0.6 billion pipeline with an anticipated in-service date of early 2018
- NGTL's $1.3 billion 2017 Facilities Application approved by the Government of Canada: Consists of five pipeline loops and two compressor stations
- ANR Section 4 Rate Case resolved through Settlement: FERC approved an uncontested settlement that resolved all issues in the Section 4 Rate Case filed by ANR
- NGTL Saddle West Project: The $0.6 billion commercially secured expansion is a combination of pipeline looping and five new compressor units at existing sites, which is subject to regulatory approval and planned to be in-service in 2019

UNDERSTANDING THE NATURAL GAS PIPELINES BUSINESS

Natural gas pipelines move natural gas from major sources of supply to locations or markets that use natural gas to meet their energy needs.

Our natural gas pipeline business builds, owns and operates a network of natural gas pipelines across North America that connects gas production to interconnects and end use markets. The network includes pipelines that are buried underground and transport natural gas predominantly under high pressure, compressor stations that act like pumps to move the large volumes of natural gas along the pipeline, meter stations that record the amount of natural gas coming on the network at receipt locations and leaving the network at delivery locations, and natural gas storage facilities that provide services to customers and help maintain the overall balance of the pipeline systems.

Our Major Pipeline Systems

The Natural Gas Pipelines map on page 30 shows our extensive pipeline network in North America that connects major supply sources and markets. Our major pipeline systems in Canada and the U.S. account for approximately 85 per cent of the total owned and operated pipe network within our extensive footprint.

NGTL System: This is our natural gas gathering and transportation system for the WCSB, connecting most of the natural gas production in western Canada to domestic and export markets. We believe we are very well positioned to connect growing supply in northeast B.C. and northwest Alberta and it is these two supply areas, along with growing demand for firm transportation in the oil sands area, that is driving our large capital program for new pipeline facilities on the NGTL System. The NGTL System is also well positioned to connect WCSB supply to potential LNG export facilities on the Canadian west coast.

Canadian Mainline: This is a major pipeline that was originally designed as a long haul delivery system transporting supply from the WCSB across Canada to Ontario and Québec to deliver gas to downstream Canadian and U.S. markets. The Canadian Mainline is also growing to accommodate additional supply connections closer to these markets.

Columbia Gas: This is our natural gas transportation system for the Appalachian basin, which contains the Marcellus and Utica shale plays. The Marcellus and Utica plays are two of the fastest growing natural gas shale plays in North America. Similar to our footprint in the WCSB, Columbia assets are very well positioned to connect growing supply and market in this area. This system also interconnects with other pipelines that provide access to key markets in the U.S. Northeast and south to the Gulf of Mexico and its growing demand for natural gas to serve LNG exports. Access to markets from producers in the region is driving the large capital program for new pipeline facilities on this system.

ANR Pipeline System: ANR is our pipeline system that connects supply basins and markets throughout the U.S. Midwest, and south to the Gulf of Mexico. This includes connecting supply in Texas, Oklahoma, the Appalachian basin and the Gulf of Mexico to markets in Wisconsin, Michigan, Illinois and Ohio.

Columbia Gulf: This is our pipeline system originally designed as a long haul delivery system transporting supply from the Gulf of Mexico to major supply markets in the U.S. Northeast. The pipeline is now transitioning and expanding to accommodate new supply in the Appalachian basin and its interconnect with Columbia Gas and other pipelines to deliver gas to various Gulf Coast markets.

Mexico Pipeline Network: In addition to the five major Canadian and U.S. pipeline systems above, we also have, in Mexico, a growing network of natural gas pipelines in service coupled with a large portfolio of projects under construction, including two on-shore pipeline projects, Tula and Villa de Reyes, that together consist of 720 km (445 miles) of 16, 24 and 36-inch pipelines, plus the Sur de Texas project, which is a 800 km (497 miles) 42-inch off-shore pipeline. We own 60 per cent of Sur de Texas through our joint venture with IEnova.

Regulation of tolls and cost recovery

Our natural gas pipelines are generally regulated by the NEB in Canada, by the FERC in the U.S. and by the CRE in Mexico. The regulators approve construction of new pipeline facilities and ongoing operations of the infrastructure.

Regulators in Canada, the U.S. and Mexico allow us to recover costs to operate the network by collecting tolls for services. These tolls generally include a return on our capital invested in the assets or rate base, as well as the recovery of the rate base over time through depreciation. Other costs recovered include OM&A costs, income and property taxes and interest on debt. The regulator reviews our costs to ensure they are reasonable and prudently incurred and approves tolls that provide us a reasonable opportunity to recover them.

Business environment and strategic priorities

The North American natural gas pipeline network has been developed to connect diverse supply regions to domestic markets and increasingly, to meet demand for LNG facilities. Use and growth of this infrastructure is affected by changes in the location and relative cost of natural gas supplies as well as changes in the location of markets and level of demand.

We have significant pipeline footprints that serve the two major supply regions of North America, which are the WCSB and the Appalachian basin. Our pipelines also source natural gas, to a lesser degree, from other significant basins including the Rockies, Williston, Haynesville, Fayetteville and Anadarko as well as the Gulf of Mexico. We expect continued growth in North American natural gas production to meet growing domestic markets, particularly in the electric generation and industrial sectors which benefit from a relatively low gas price. In addition, North American supply is expected to benefit from access to international markets via LNG exports. This view is consistent with those of independent third parties including the U.S. Energy Information Administration (EIA) in their Annual Energy Outlook 2017 and International Energy Outlook 2016 reports. According to these reports, North American gas demand for 2016 was nearly 90 Bcf/d and, with the growth in domestic markets and most particularly due to the addition of LNG markets, is expected to grow to approximately 100 Bcf/d by 2020.

This increased demand for natural gas, coupled with the annual decline rate of 15 per cent to 20 per cent for natural gas production, implies up to 25 Bcf/d of new production per year will be required to meet current and forecasted demand. That new production provides investment opportunities for pipeline infrastructure companies seeking to build new facilities to connect new supply and/or increase utilization of the existing footprint.

Changing demand

The growing supply of natural gas has resulted in relatively low natural gas prices in North America, which has supported increased demand particularly in the following areas:

- natural gas-fired power generation
- petrochemical and industrial facilities
- the production of Alberta oil sands, although new greenfield projects that have not begun construction may be delayed in the current low oil price environment
- exports to Mexico to fuel new power generation facilities.

Natural gas producers continue to progress opportunities to sell natural gas to global markets, which involves connecting natural gas supplies to new LNG export terminals being proposed primarily along the west coast of Canada and the U.S. Gulf of Mexico. The demand created by the addition of these new markets creates opportunities for us to build new pipeline infrastructure and to increase throughput on our existing pipelines.

Commodity prices

In general, the profitability of our gas pipelines business is not directly tied to commodity prices given we are a transporter of the commodity and the transportation costs are not tied to the price of natural gas. However, the cyclical supply and demand nature of commodities and related pricing can have an indirect impact on our business where producers may choose to accelerate or delay exploration or, similarly on the demand side, projects requiring natural gas may be accelerated or delayed depending on market or price conditions. Lower prices have allowed natural gas to gain market share versus coal in serving power generation markets. We continue to see record levels of natural gas consumed as the fuel source for electric power generation. In addition, U.S. LNG export levels continue to increase, primarily in the Gulf Coast area.

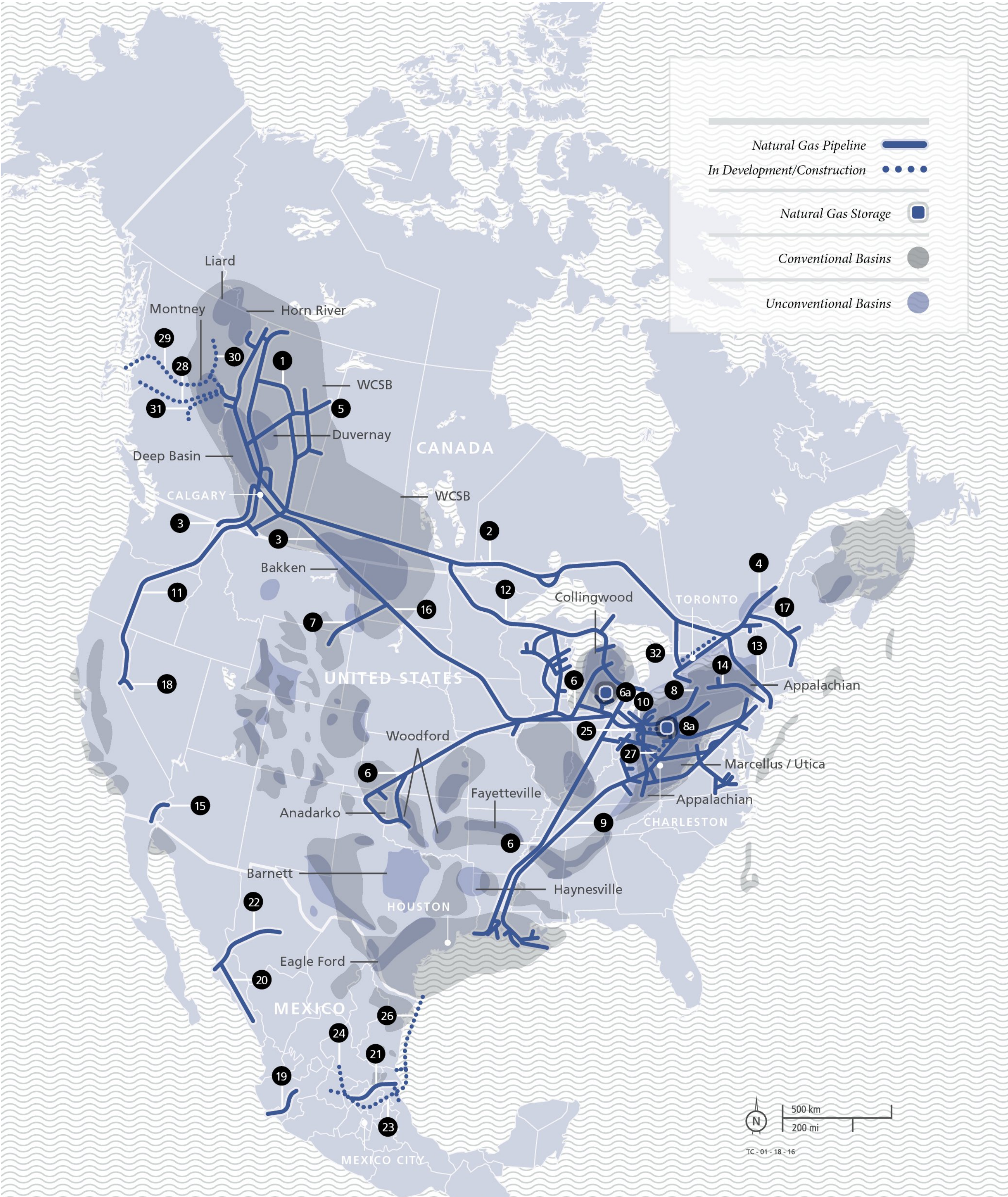
More competition

Changes in supply and demand levels and locations have resulted in increased competition for transportation services throughout North America. With our well distributed footprint of natural gas pipelines, and particularly our new presence in the growing Appalachian region, we are well positioned to compete. Along with other pipelines, we have and continue to assess further opportunities to restructure our tolls and service offerings to capture growing supply and North American demand that now includes access to world markets through LNG exports.

Strategic priorities

We are focused on capturing opportunities resulting from growing natural gas supply, and connecting new markets, while satisfying increasing demand for natural gas within existing markets. We are also focused on adapting our existing assets to the changing gas flow dynamics.

In 2017, one of our key focus areas will be on the continued execution of our large existing capital program that includes further expansion of the existing NGTL and Columbia systems and advancing several new natural gas pipeline projects in Mexico. Our near-term capital program in excess of $16 billion of projects, excluding North Montney, will see a continued progression of projects being placed in service over the next few years. Our goal is to ensure all of our projects are placed in service on time and on budget while ensuring the safety of our staff, contractors, and anyone impacted by the construction and operation of these facilities.



We are the operator of all of the following natural gas pipelines and regulated natural gas storage assets except for Iroquois.

		Length	Description	Effective ownership
	Canadian pipelines			
1	NGTL System	24,012 km (14,920 miles)	Receives, transports and delivers natural gas within Alberta and B.C., and connects with the Canadian Mainline, Foothills system and third-party pipelines.	100%
2	Canadian Mainline	14,125 km (8,777 miles)	Transports natural gas from the Alberta/Saskatchewan border and the Ontario/U.S. border to serve eastern Canada and interconnects to the U.S.	100%
3	Foothills	1,241 km (771 miles)	Transports natural gas from central Alberta to the U.S. border for export to the U.S. Midwest, Pacific northwest, California and Nevada.	100%
4	Trans Québec & Maritimes (TQM)	572 km (355 miles)	Connects with Canadian Mainline near the Ontario/Québec border to transport natural gas to the Montréal to Québec City corridor, and interconnects with the Portland pipeline system that serves the Northeast U.S.	50%
5	Ventures LP	161 km (100 miles)	Transports natural gas to the oil sands region near Fort McMurray, Alberta. It also includes a 27 km (17 miles) pipeline supplying natural gas to a petrochemical complex at Joffre, Alberta.	100%
	U.S. pipelines			
6	ANR	15,109 km (9,388 miles)	Transports natural gas from supply basins to markets throughout the mid-west and south to the Gulf of Mexico.	100%
6a	ANR Storage	250 Bcf	Provides regulated underground natural gas storage service from several facilities (not all shown) to customers in key mid-western markets.	
7	Bison	488 km (303 miles)	Transports natural gas from the Powder River Basin in Wyoming to Northern Border in North Dakota. We effectively own 26.8 per cent of the system through our interest in TC PipeLines, LP.	26.8%
8	Columbia Gas	18,113 km (11,255 miles)	Transports natural gas from supply primarily in the Appalachian basin to markets throughout the U.S. Northeast.	100% [1]
8a	Columbia Storage	285 Bcf	Provides regulated underground natural gas storage service from several facilities (not all shown) to customers in key eastern markets. We also own a 50 per cent interest in the 12 Bcf Hardy Storage facility.	100% [1]
8b	Midstream**	295 km (185 miles)	Provides infrastructure between the producer upstream well-head and the downstream (interstate pipeline and distribution) sector and includes a 47 per cent interest in Pennant Midstream.	100% [1]
9	Columbia Gulf	5,377 km (3,341 miles)	Transports natural gas to on-system customers and to pipeline interconnects serving markets in the U.S. Midwest and Southeast.	100% [1]
10	Crossroads	325 Km (202 miles)	Interstate natural gas pipeline operating in Indiana and Ohio with multiple interconnects to other pipelines.	100% [1]
11	Gas Transmission Northwest (GTN)	2,216 km (1,377 miles)	Transports natural gas from the WCSB and the Rocky Mountains to Washington, Oregon and California. Connects with Tuscarora and Foothills. We effectively own 26.8 per cent of the system through our interest in TC PipeLines, LP.	26.8%
12	Great Lakes	3,404 km (2,115 miles)	Connects with the Canadian Mainline near Emerson, Manitoba and St Clair, Ontario, plus interconnects with ANR at Crystal Falls and Farwell in Michigan, to transport natural gas to eastern Canada and the U.S. upper midwest. We effectively own 66 per cent of the system through the combination of our 53.6 per cent direct ownership interest and our 26.8 per cent interest in TC PipeLines, LP.	66%
13	Iroquois	669 km (416 miles)	Connects with Canadian Mainline near Waddington, New York to deliver natural gas to customers in the U.S. Northeast.	50%

		Length	Description	Effective ownership
14	Millennium	407 km (253 miles)	Natural gas pipeline supplied by local production, storage fields and interconnecting upstream pipelines to serve markets along its route and to the U.S. Northeast.	47.5% [1]
15	North Baja	138 km (86 miles)	Transports natural gas between Arizona and California, and connects with a third-party pipeline on the California/ Mexico border. We effectively own 26.8 per cent of the system through our interest in TC PipeLines, LP.	26.8%
16	Northern Border	2,272 km (1,412 miles)	Transports WCSB and Rockies natural gas with connections to Foothills and Bison to U.S. Midwest markets. We effectively own 13.4 per cent of the system through our 26.8 per cent interest in TC PipeLines, LP.	13.4%
17	Portland (PNGTS)	475 km (295 miles)	Connects with TQM near East Hereford, Québec to deliver natural gas to customers in the U.S. Northeast. We effectively own 25.2 per cent of the system through the combination of 11.8 per cent direct ownership and our 26.8 per cent interest in TC PipeLines, LP. Prior to January 1, 2016 we had direct ownership of 61.7 per cent.	25.2%
18	Tuscarora	491 km (305 miles)	Transports natural gas from GTN at Malin, Oregon to markets in northeastern California and northwestern Nevada. We effectively own 26.8 per cent of the system through our interest in TC PipeLines, LP.	26.8%
	Mexican pipelines			
19	Guadalajara	315 km (196 miles)	Transports natural gas from Manzanillo, Colima to Guadalajara, Jalisco.	100%
20	Mazatlán	413 km (257 miles)	Transports natural gas from El Oro to Mazatlán, Sinaloa in Mexico. Connects to the Topolobampo Pipeline at El Oro.	100%
21	Tamazunchale	359 km (223 miles)	Transports natural gas from Naranjos, Veracruz in east central Mexico to Tamazunchale, San Luis Potosi and on to El Sauz, Querétaro.	100%
22	Topolobampo	530 km (329 miles)	Transports natural gas to Topolobampo, Sinaloa, from interconnects with third-party pipelines in El Oro, Sinaloa and El Encino, Chihuahua in Mexico.	100%
	Under construction			
23	Tula	300 km* (186 miles)	The pipeline will originate in Tuxpan in the state of Veracruz and extend through the states of Puebla and Hidalgo, supplying natural gas to CFE combined-cycle power generating facilities in each of those jurisdictions as well as to the central and western regions of Mexico.	100%
24	Villa de Reyes	420 km* (261 miles)	The pipeline will deliver natural gas from Tula, Hildago to Villa de Reyes, and San Luis Potosi, connecting to the Tamazunchale and Tula pipelines.	100%
	NGTL 2016/17 Facilities**	540 km* (336 miles)	An expansion program comprised of 21 integrated projects of pipes, compression and metering to meet new incremental firm service requests received in 2014 on the NGTL System and expected to be completed between 2016 and 2018.	100%
	Gibraltar**	42 km* (26 miles)	A Midstream project designed to transport supply from the Marcellus and Utica shale plays into Columbia Gas and the Leach XPress pipeline project.	100% [1]
25	Leach XPress	260 km* (160 miles)	A Columbia Gas project designed to transport supply from the Marcellus and Utica shale plays to points along the system.	100% [1]
	Rayne XPress**		A Columbia Gulf project designed to transport supply from an interconnect with the Leach XPress pipeline project, plus another interconnect to markets along the system and to the Gulf Coast.	100% [1]
	Cameron Access**	55 km* (34 miles)	A Columbia Gulf pipeline to deliver natural gas from points along the Columbia Gulf system to the Cameron LNG facility.	100% [1]

		Length	Description	Effective ownership
	Permitting and pre-construction phase			
26	Sur de Texas	800 km* (497 miles)	The natural gas pipeline will begin offshore in the Gulf of Mexico at the border point near Brownsville Texas and end in Tuxpan, in the state of Veracruz, connecting with the Tamazunchale and Tula pipelines.	60%
27	Mountaineer XPress	275 km* (171 miles)	A Columbia Gas project designed to transport supply from the Marcellus and Utica shale plays to points along the system.	100% [1]
	NGTL 2018 Facilities**	88 km* (55 miles)	An expansion program comprised of multiple projects of 20- to 48-inch diameter pipelines, one new compressor unit and multiple meter stations to meet new incremental firm service requests received in 2015 on the NGTL System and expected to be completed by 2020.	100%
	NGTL Saddle West Expansion**	29 km* (18 miles)	An expansion program comprised of multiple projects including mainline looping, five compressor units at existing stations plus new metering facilities.	100%
	Gulf XPress**		A Columbia Gulf project designed to interconnect with the Mountaineer XPress pipeline project to markets along the pipelines and to the Gulf Coast.	100% [1]
	WB XPress**	47 km* (29 miles)	A Columbia Gas project designed to transport Marcellus supply both eastbound (to interconnects and mid-Atlantic markets) and westbound (to interconnect pipeline).	100% [1]
	In development			
28	Coastal GasLink	670 km* (416 miles)	To deliver natural gas from the Montney gas producing region at an expected interconnect on NGTL near Dawson Creek, B.C. to LNG Canada's proposed LNG facility near Kitimat, B.C.	100%
29	Prince Rupert Gas Transmission	900 km* (559 miles)	To deliver natural gas from the North Montney gas producing region at an expected interconnect on NGTL near Fort St. John, B.C. to the proposed Pacific Northwest LNG facility near Prince Rupert, B.C.	100%
30	North Montney	301 km* (187 miles)	An extension of the NGTL System to receive natural gas from the North Montney gas producing region and connect to NGTL's existing Groundbirch Mainline and the proposed Prince Rupert Gas Transmission project.	100%
31	Merrick Mainline	260 km* (161 miles)	To deliver natural gas from NGTL's existing Groundbirch Mainline near Dawson Creek, B.C. to its end point near the community of Summit Lake, B.C.	100%
32	Eastern Mainline	279 km* (173 miles)	Pipeline and compression facilities expected to be added in the Eastern Triangle of the Canadian Mainline to meet the requirements of the existing shippers as well as new firm service requirements following the conversion of components of the Mainline to facilitate the Energy East project.	100%

1 Effective ownership of Columbia assets assumes the first quarter 2017 expected close of the acquisition of the outstanding publicly held common units of CPPL.

* Final pipe lengths are subject to changes during construction and/or final design considerations.
** Facilities and some pipelines are not shown on the map

Canadian Natural Gas Pipelines

UNDERSTANDING THE CANADIAN NATURAL GAS PIPELINES SEGMENT

The Canadian natural gas business is subject to regulation by various federal and provincial governmental agencies. The NEB, however, has comprehensive jurisdiction over our Canadian gas business. The NEB approves tolls and services that are in the public interest and provides a reasonable opportunity for a pipeline to recover its costs to operate the pipeline. Included in the overall costs to operate the pipeline is a return on the investment the company has made in the assets, referred to as the return on equity. Typically tolls are based on the cost of providing service divided by a forecast of throughput volumes. Any variance in either costs or the actual volumes transported can result in an over-collection or under-collection of revenue that is normally trued up the following year in the calculation of the tolls for that period. The return on equity, however, would continue to be earned at the rate approved by the NEB.

We and our shippers can also establish settlement arrangements, subject to approval by the NEB, that may have elements that vary from the typical toll-setting process. Settlements can include longer terms and mechanisms such as incentive agreements that can have an impact on the actual return on equity achieved. Examples include fixing the OM&A component in determining revenue requirements, where variances are to the pipeline's account or shared in some fashion between the pipeline and shippers.

The NGTL System is currently in the second year of a two-year settlement arrangement that includes a fixed OM&A component with variances shared, depending on the amount, between the shippers and the pipeline. The Mainline system has a five-year fixed toll settlement in place, but has an incentive arrangement where it has discretion to price certain of its short term services, like Interruptible Transportation Service at market prices. Settlements of this nature provide the pipeline an incentive to either decrease costs and/or increase revenues on the pipeline with a beneficial sharing mechanism to both the shippers and us.

SIGNIFICANT EVENTS

Canadian Regulated Pipelines

NGTL System

On October 6, 2016, the NEB recommended government approval of the $0.4 billion Towerbirch Project. This project consists of a 55 km (34 miles) 36-inch pipeline loop and a 32 km (20 miles) 30-inch pipeline extension of the NGTL System in northwest Alberta and northeast B.C. The NEB approved the continued use of the existing rolled-in toll methodology for this project.

On October 31, 2016, the Government of Canada approved our $1.3 billion NGTL 2017 Facilities Application, which is a major component of the 2016/2017 Facilities program. This NGTL expansion program consists of five pipeline loops ranging in size from 24-inch up to 48-inch pipe of approximately 230 km (143 miles) in length, plus two compressor station unit additions of approximately 46.5 MW (62,360 HP).

On December 7, 2016, we announced the $0.6 billion Saddle West expansion of the NGTL System to increase natural gas transportation capacity on the northwest portion of our system. The project will consist of 29 km (18 miles) of 36-inch pipeline looping of existing mainlines, the addition of five compressor units at existing station sites and new metering facilities. The project is underpinned by incremental firm service contracts and is expected to be in-service in 2019.

NGTL currently has a $3.7 billion near-term capital program for completion to 2020, including the Saddle West expansion and excluding the $1.7 billion North Montney and $1.9 billion Merrick pipeline projects. In 2016, we have placed in service approximately $0.5 billion of facilities. We currently have regulatory approval for $2.0 billion of facilities and plan to place in service $1.6 billion of new facilities in 2017.

North Montney

On December 9, 2016, the Canadian Government approved the sunset clause extension for the North Montney project Certificate of Public Convenience and Necessity for one year to June 10, 2017. The extension continues to be subject to the condition that construction shall not begin until a positive FID has been made on the Pacific NorthWest LNG Project (PNW LNG). NGTL continues to work with our customers and stakeholders to be ready to initiate construction of the $1.7 billion North Montney facilities, however, the in-service date will be finalized once a FID has been made.

Canadian Mainline – Kings North and Station 130 Facilities

In fourth quarter 2016, we placed in service the approximate $310 million Kings North Connector and the approximate $75 million compressor unit addition at Station 130 on the Canadian Mainline system. These two projects are consistent with our current 2015-2020 Mainline Settlement with our shippers and provide optionality to access alternative supply sources while contracting for increased short haul transportation service within the Eastern Triangle area of the Canadian Mainline system.

Canadian Mainline – Eastern Mainline Project

This $2 billion project consists of new gas facilities in southeastern Ontario that will be required as a result of the proposed Energy East project that includes a planned transfer of a portion of Canadian Mainline from natural gas service to crude oil service. The Eastern Mainline Project is conditioned on the approval and construction of the Energy East pipeline. See the Liquids Pipelines section for an update on Energy East .

Canadian Mainline – Other Expansions

In addition to the Eastern Mainline Project, new facilities investments in the Eastern Triangle portion of the Canadian Mainline are planned for 2017. Including the Vaughan Loop, with a planned in-service date of November 2017, we have approximately $300 million of additional investment to meet contractual commitments from shippers.

LNG Pipeline Projects

Prince Rupert Gas Transmission (PRGT)

On September 27, 2016, PNW LNG received an environmental certificate from the Government of Canada for a proposed LNG plant at Prince Rupert, B.C. PNW LNG has indicated they will conduct a total project review over the coming months prior to announcing next steps for the project. The project has key approvals in place and construction will advance following direction from PNW LNG as the in-service date for PRGT will be aligned with PNW LNG's liquefaction facility timeline.

On December 21, 2016, PNW LNG received an LNG export license from the NEB which extended the export term from 25 years to 40 years.

We are continuing our engagement with Indigenous groups and have now signed project agreements with 14 First Nation groups along the pipeline route. Project agreements outline financial and other benefits and commitments that will be provided to each First Nation for as long as the project is in service.

PRGT is a 900 km (559 mile) natural gas pipeline that will deliver gas from the North Montney producing region at an expected interconnect on the NGTL System near Fort St. John, B.C. to PNW LNG's proposed LNG facility near Prince Rupert, B.C. Should the project not proceed, our project costs (including carrying charges) are fully recoverable.

Coastal GasLink

On July 11, 2016, the LNG Canada joint venture participants announced a delay to their FID for the proposed liquefied natural gas facility in Kitimat, B.C. A future FID date has not been disclosed. We are working with LNG Canada to maintain the appropriate pace of the Coastal GasLink development schedule and work activities.

We are continuing our engagement with Indigenous groups along our pipeline route and have now concluded long-term project agreements with 17 First Nation communities. We look to continue discussions with the remaining First Nations who have not signed Project Agreements.

Coastal GasLink is a 670 km (416 mile) pipeline that will deliver natural gas from the Dawson Creek, B.C. area, to LNG Canada’s proposed gas liquefaction facility near Kitimat, BC. Should the project not proceed, our project costs (including carrying charges) are fully recoverable.

FINANCIAL RESULTS

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented earnings (the equivalent GAAP measure). See page 8 for more information on non-GAAP measures we use. 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 and 2014 results have been adjusted to reflect this change.

year ended December 31 (millions of $)	2016	2015	2014
NGTL System	**998**	920	844
Canadian Mainline	**1,137**	1,216	1,320
Other Canadian pipelines[1]	**118**	133	122
Business development	**(7)**	(11)	(11)
Comparable EBITDA	**2,246**	2,258	2,275
Depreciation and amortization	**(873)**	(845)	(821)
Comparable EBIT and segmented earnings	**1,373**	1,413	1,454

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

Canadian Natural Gas Pipelines comparable EBIT and segmented earnings decreased by $40 million in 2016 compared to 2015 and by $41 million in 2015 compared to 2014.

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

year ended December 31 (millions of $)	2016	2015	2014
Net income			
NGTL System	**318**	269	241
Canadian Mainline	**208**	213	300
Average investment base			
NGTL System	**7,451**	6,698	6,236
Canadian Mainline	**4,441**	4,784	5,690

Net income for the NGTL System was $49 million higher in 2016 compared to 2015 mainly due to a higher average investment base and increased OM&A incentive earnings recorded in 2016. Net income in 2015 was $28 million higher than 2014 due to a higher average investment base and OM&A incentive losses realized in 2014. The two-year 2016-2017 Revenue Requirement Settlement includes an ROE of 10.1 per cent on 40 per cent deemed equity and a mechanism for sharing variances above and below a fixed annual OM&A amount with flow-through treatment of all other costs. The 2015 NGTL Settlement included a 10.1 per cent ROE on deemed common equity of 40 per cent and a mechanism for sharing variances between actual and a fixed OM&A cost amount that was based on an escalation of 2014 actual costs. The 2013-2014 NGTL Settlement included an ROE of 10.1 per cent on deemed common equity of 40 per cent and fixed annual OM&A costs with any variance between actual and fixed OM&A accruing to us.

Canadian Mainline's net income in 2016 decreased by $5 million compared to 2015 mainly due to a lower average investment base and higher carrying charges to shippers on the 2016 net revenue surplus, partially offset by higher incentive earnings in 2016. Net income in 2015 was $87 million lower than 2014 due to a lower approved ROE on a lower average investment base, lower incentive earnings and a $20 million after-tax contribution from us in accordance with the terms of the NEB 2014 Decision as described below. The lower average investment base in 2016 and 2015 was mainly due to depreciation and the inclusion of the 2015 and 2014 net revenue surpluses and deferrals, associated with fixing tolls during the settlement term, in the investment base.

In 2016 and 2015, the Canadian Mainline operated under the NEB 2014 Decision which was approved by the NEB in 2014 and superseded the NEB 2013 Decision. The NEB 2014 Decision included an approved ROE of 10.1 per cent with a possible range of achieved ROE outcomes between 8.7 per cent and 11.5 per cent. This decision also included an incentive mechanism that has both upside and downside risk and a $20 million annual after-tax contribution from us. Toll stabilization is achieved through the continued use of deferral accounts to capture the surplus or shortfall between our revenues and cost of service for each year over the six-year fixed toll term.

In 2014, the Canadian Mainline operated under the NEB 2013 Decision, which included an approved ROE of 11.5 per cent on deemed common equity of 40 per cent and an incentive mechanism based on total net revenues.

Business development expenses in 2016 were $4 million lower compared to 2015 primarily due to decreased business development activity.

Depreciation and amortization

Depreciation and amortization was $28 million higher in 2016 compared to 2015, and $24 million higher in 2015 compared to 2014, primarily due to new NGTL System facilities that were placed in service in both 2016 and 2015.

OUTLOOK

Earnings

Net income for rate-regulated pipelines is affected by changes in investment base, ROE and regulated capital structure, and also by the terms of toll settlements or other toll proposals approved by the NEB.

Canadian Natural Gas Pipelines earnings in 2017 are expected to be higher than 2016 due to continued growth in the NGTL System. We expect the NGTL System investment base to continue to grow as we extend and expand the northwest portion in response to continued growth in market demand and that this will have a positive impact on NGTL System earnings in 2017. The terms of the NGTL 2016-2017 Revenue Requirement Settlement included a continuation of the 2015 approved ROE and depreciation rates and a mechanism for sharing variances above and below a fixed annual OM&A cost amount and flow-through treatment of all other costs.

In 2017, the Canadian Mainline will continue to operate under the terms of the NEB 2014 Decision. We expect Canadian Mainline 2017 earnings to be slightly lower than 2016 due to a declining investment base.

We also anticipate a modest level of investment in our other Canadian rate-regulated natural gas pipelines, but expect the average investment bases of these pipelines to continue to decline as annual depreciation outpaces capital investment, reducing their year-over-year earnings.

Under the current regulatory model, earnings from Canadian rate-regulated natural gas pipelines are not materially affected by short-term fluctuations in the commodity price of natural gas, changes in throughput volumes or changes in contracted capacity levels.

Capital spending

We spent a total of $1.5 billion in 2016 for our Canadian Natural Gas Pipelines and expect to spend approximately $2.1 billion in 2017 primarily on the NGTL System expansion projects, Canadian Mainline capacity projects and maintenance capital.

U.S. Natural Gas Pipelines

UNDERSTANDING THE U.S. NATURAL GAS PIPELINES SEGMENT

The U.S. interstate natural gas pipeline business is subject to regulation by various federal, state and local governmental agencies. The FERC, however, has comprehensive jurisdiction over our U.S. natural gas business.The FERC approves maximum transportation rates that are cost based and are designed to recover the pipeline's investment, operating expenses and a reasonable return for our investors. In the U.S., we have the ability to contract for negotiated or discounted rates with shippers.

The FERC does not require U.S. interstate pipelines to calculate rates annually, nor do they generally allow for the collection or refund of the variance between actual and expected revenue and costs into future years. This difference in U.S. regulation from the Canadian regulatory environment puts our U.S. pipelines at risk for the difference in expected and actual costs and revenues between rate cases. If revenues no longer provide a reasonable opportunity to recover costs, we can file with the FERC for a new determination of rates, subject to any moratorium in effect. Similarly, the FERC may institute proceedings to lower rates if they consider the return on the capital invested to be too high.

Similar to Canada, we can also establish settlement arrangements with our U.S. shippers, that are ultimately subject to approval by the FERC. Rate case moratoriums for a period of time before either we or the shippers can file for a rate review are common for a settlement in that it provides some certainty for shippers in terms of rates, eliminates the costs associated with a toll proceeding for all parties and can provide an incentive for pipelines to lower costs.

TransCanada's Master Limited Partnership

We own, through subsidiaries, a 26.8 per cent effective ownership in TC PipeLines, LP, a MLP which trades on the New York Stock Exchange under the symbol TCP. TC PipeLines, LP has ownership interests in GTN, Northern Border, Bison, Great Lakes, North Baja, Tuscarora and the PNGTS pipeline systems. Our overall effective ownership for each of these assets with consideration of the ownership through the MLP is provided in the asset listing of our major pipelines starting on page 31.

SIGNIFICANT EVENTS

Columbia Capital Projects

The July 1, 2016 acquisition of Columbia included a capital expansion program that was underway for new facilities planned to be in service in 2016 through 2018 as well as modernization programs for existing assets to be completed through 2020. The large capital expansion program, excluding portions completed in 2016, consists of US$6.8 billion related to our regulated pipeline business and US$0.3 billion related to our midstream business. The estimated project costs exclude AFUDC. The following summarizes the key capital projects for this new set of assets that are now part of our overall U.S. Natural Gas Pipelines footprint.

Leach XPress

This Columbia Gas project is designed to transport approximately 1.5 Bcf/d of Marcellus and Utica gas supply to delivery points along the pipeline and to the Leach interconnect with Columbia Gulf. The project consists of 219 km (136 miles) of 36-inch greenfield pipe, 39 km (24 miles) of 36-inch loop, three km (two miles) of 30-inch greenfield pipe, 82.8 MW (111,000 hp) of greenfield compression and 24.6 MW (33,000 hp) of brownfield compression. We expect the project, with an estimated capital investment of US$1.4 billion, to be in service in fourth quarter 2017. The FERC 7(C) application was filed in June 2015 and on January 19, 2017, FERC issued the order approving construction of the facility. The Final Environmental Impact Statement (FEIS) was received September 1, 2016. Once remaining regulatory approvals are obtained, we plan to begin right-of-way preparation and construction activities in February 2017, for a planned in-service date of November 1, 2017.

Rayne XPress

This Columbia Gulf project is designed to transport approximately 1.1 Bcf/d of southwest Marcellus and Utica production associated with the Leach XPress expansion and an interconnect with the Texas Eastern System to various delivery points on the Columbia Gulf and the Gulf Coast. The project consists of bi-directional compressor station modifications along Columbia Gulf, 38.8 MW (52,000 hp) of greenfield compression, 20.1 MW (27,000 hp) of replacement compression and six km (four miles) of 30-inch pipe replacement. We expect the project, with an estimated capital investment of US$0.4 billion, to be in service on November 1, 2017. The FERC 7(C) application was filed in July 2015 and on January 19, 2017, FERC issued the order approving construction of the facility.The FEIS was received September 1, 2016. Once remaining regulatory approvals are obtained, we plan to begin right-of-way preparation and construction activities in February 2017, for a planned in-service date of November 1, 2017.

Mountaineer XPress

This Columbia Gas project is designed to transport approximately 2.7 Bcf/d of Marcellus and Utica gas supply to delivery points along the pipeline and to the Leach interconnect with Columbia Gulf. The project consists of 264 km (164 miles) of 36-inch greenfield pipeline, ten km (six miles) of 24-inch lateral pipeline, 0.6 km (0.4 miles) of 30-inch replacement pipeline, 114.1 MW (153,000 hp) of greenfield compression and 55.9 MW (75,000 hp) of brownfield compression. We expect this project, with an estimated capital investment of US$2.0 billion, to be in service in fourth quarter 2018. The FERC 7(C) application was filed in April 2016.

Gulf XPress

This Columbia Gulf project is designed to transport approximately 0.9 Bcf/d associated with the Mountaineer XPress expansion to various delivery points on Columbia Gulf and the Gulf Coast. The project consists of adding seven greenfield midpoint compressor stations along the Columbia Gulf route totaling 182.7 MW (254,000 hp). We expect this project, with an estimated capital investment of US$0.6 billion, to be placed in service in fourth quarter 2018. The FERC 7(C) application was filed in April 2016.

Cameron Access Project

This Columbia Gulf project is designed to transport approximately 0.8 Bcf/d of gas supply to the Cameron LNG export terminal in Louisiana. The project consists of 44 km (27 miles) of 36-inch greenfield pipeline, 11 km (seven miles) of 30-inch looping and 9.7 MW (13,000 hp) of greenfield compression. We expect this project, with an estimated capital investment of US$0.3 billion, to be in service in first quarter 2018. The FERC certificate was received in September 2015.

WB XPress

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

Modernization I & II

Columbia Gas and its customers have entered into a settlement arrangement, approved by FERC, which provides recovery and return on investment to modernize its system, improve system integrity and enhance service reliability and flexibility. The modernization program includes, among other things, replacement of aging pipeline and compressor facilities, enhancements to system inspection capabilities and improvements in control systems. Modernization I has been approved for up to US$0.6 billion of work with approximately US$0.2 billion remaining to be spent in 2017. Modernization II has been approved for up to US$1.1 billion of work to be completed through 2020. As per terms of the arrangements, facilities in service by October 31 collect revenues effective February 1 of the following year.

Midstream – Gibraltar Pipeline Project

We expect to complete the US$0.3 billion investment to construct an approximate 1,000 TJ/d dry gas header pipeline in southwest Pennsylvania by the end of 2017. The first phase of the multi-phase project was completed in December 2016.

Rate Case Settlements

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

In addition to ANR's rate case settlement, FERC approvals were obtained for settlements with shippers for our Iroquois, Tuscarora and Columbia Gulf pipelines.

Acquisition of CPPL

On November 1, 2016, we announced that we entered into an agreement and plan of merger through which our wholly-owned subsidiary, Columbia Pipeline Group, Inc., agreed to acquire, for cash, all of the outstanding publicly held common units of CPPL at a price of US$17.00 per common unit for an aggregate transaction value of approximately US$915 million. The transaction is expected to close in first quarter 2017.

FINANCIAL RESULTS

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented earnings (the equivalent GAAP measure). See page 8 for more information on non-GAAP measures we use. 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 and 2014 results have been adjusted to reflect this change. In addition, Columbia results are included from its acquisition on July 1, 2016. Comparative periods do not include Columbia.

year ended December 31 (millions of US$, unless otherwise noted)	2016	2015	2014
Columbia Gas[1]	**269**	—	—
ANR	**324**	225	181
TC PipeLines, LP[2, 3]	**118**	106	88
Great Lakes[3, 4]	**59**	63	49
Midstream[1]	**40**	—	—
Columbia Gulf[1]	**25**	—	—
Other U.S. pipelines[1,2,3,5]	**73**	85	131
Non-controlling interests[6]	**365**	292	241
Business development	**(3)**	(12)	3
Comparable EBITDA	**1,270**	759	693
Depreciation and amortization	**(300)**	(190)	(191)
Comparable EBIT	**970**	569	502
Foreign exchange impact	**316**	162	54
Comparable EBIT (Cdn$)	**1,286**	731	556
Specific items:			
Acquisition related costs - Columbia	**(63)**	—	—
TC Offshore loss on sale	**(4)**	(125)	—
Segmented earnings (Cdn$)	**1,219**	606	556

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

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

3 TC PipeLines, LP periodically conducts at-the-market equity issuances which decrease our ownership in TC PipeLines, LP. On January 1, 2016, we sold a 49.9 per cent direct interest in PNGTS to TC PipeLines, LP and continue to hold 11.8 per cent direct ownership. On April 1, 2015, we sold our remaining 30 per cent direct interest in GTN to TC PipeLines, LP. On October 1, 2014, we sold our remaining 30 per cent direct interest in Bison to TC PipeLines, LP. The following shows our ownership interest in TC PipeLines, LP and our effective ownership interest of GTN, Bison, Great Lakes and PNGTS through our ownership interest in TC PipeLines, LP for the periods presented.

	Effective ownership percentage as of		
	December 31, 2016	December 31, 2015	December 31, 2014
TC PipeLines, LP	26.8	28.0	28.3
Effective ownership through TC PipeLines, LP:			
Bison	26.8	28.0	28.3
GTN	26.8	28.0	19.8
Great Lakes	12.5	13.0	13.1
PNGTS	13.4	—	—

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

5 Includes our direct ownership in Iroquois, PNGTS, GTN (until April 1, 2015) and Bison (until October 1, 2014); our effective ownership in Millennium and Hardy Storage; and general and administrative costs related to U.S. natural gas assets.

6 Comparable EBITDA for the portions of TC PipeLines, LP, PNGTS, and CPPL we do not own.

U.S. Natural Gas Pipelines segmented earnings in 2016 increased by $613 million compared to 2015 and $50 million in 2015 compared to 2014. Segmented earnings in 2016 included $63 million before tax mainly related to retention and severance expenses resulting from the Columbia acquisition and an additional $4 million pre-tax loss on the sale of TC Offshore. Segmented earnings in 2015 included a $125 million pre-tax loss provision ($86 million after tax) as a result of a December 2015 agreement to sell TC Offshore, which closed in March 2016. These amounts have been excluded from our calculation of comparable EBIT and comparable earnings.

Earnings from our U.S. Natural Gas Pipelines operations, which include Columbia effective July 1, 2016, are generally affected by contracted volume levels, volumes delivered and the rates charged as well as by the cost of providing services. Columbia and ANR results are also affected by the contracting and pricing of its storage capacity and incidental commodity sales. Pipeline and storage volumes and revenues are generally higher in the winter months because of the seasonal nature of the business.

Comparable EBITDA for the U.S. Natural Gas Pipelines was US$511 million higher in 2016 than 2015. This was due to the net effect of:

- US$357 million of earnings from Columbia as a result of the acquisition on July 1, 2016
- higher ANR transportation revenue resulting from a FERC-approved rate settlement, effective August 1, 2016, higher Southeast Mainline transportation revenues and lower pipeline integrity work on ANR, partially offset by lower incidental commodity sales and a one time settlement in 2015 with an owner of adjacent facilities for commercial interruption of ANR's service
- higher contributions from TC PipeLines, LP mainly due to higher GTN transportation revenues
- lower business development activity.

Comparable EBITDA for the U.S. Natural Gas Pipelines was US$66 million higher in 2015 than 2014. This was due to the net effect of:

- higher ANR Southeast Mainline transportation revenues, incidental commodity sales and ANR's first quarter 2015 settlement with an owner of adjacent facilities for commercial interruption of ANR's service, partially offset by increased spending on ANR pipeline integrity work
- lower contributions from Other U.S. Pipelines as ownership interests in GTN and Bison were sold to TC PipeLines, LP in April 2015 and October 2014, respectively. These drop downs increased comparable EBITDA from TC PipeLines, LP but also increased the offsetting non-controlling interests
- recovery of amounts from partners for 2013 Alaska Gasline Inducement Act costs.

Depreciation and amortization

Depreciation and amortization was US$110 million higher in 2016 compared to 2015 primarily due to our acquisition of Columbia on July 1, 2016 and increased depreciation rates on ANR following its rate settlement effective August 1, 2016.

OUTLOOK

Earnings

U.S. Natural Gas Pipelines earnings are affected by the level of contracted capacity and the rates charged to customers. Our ability to recontract or sell capacity at favourable rates is influenced by prevailing market conditions and competitive factors, including alternatives available to end use customers in the form of competing natural gas pipelines and supply sources, in addition to broader conditions that might impact demand from certain customers or market segments. Earnings are also affected by the level of OM&A and other costs, which includes the impact of safety, environmental and other regulators' decisions.

Many of our U.S. natural gas pipelines are backed by long-term take-or-pay contracts that are expected to deliver stable and consistent financial performance.

We expect the U.S. Natural Gas Pipelines earnings to be higher in 2017 than in 2016 due to, among other factors, a full year of Columbia earnings. We also expect our Columbia businesses to benefit from increased revenues associated with their recently completed and planned expansion projects. These projects provide our customers with increased access to new sources of supply while extending their market reach. Further, we continue to pursue expansions across Columbia's geographical footprint that will allow for the transport of constrained natural gas production in the Marcellus and Utica producing regions to areas of demand.

ANR has secured new long term contracts and extended terms at maximum recourse rates for significant volumes originating from the Utica/Marcellus shale plays. We believe that the new contracts combined with the 2016 settlement agreement will provide an increased level of stable earnings from ANR in 2017.

Great Lakes, Northern Border and GTN have benefited from market conditions through 2016 that has maintained the value of their services. We continue to seek opportunities to expand upon this success along with those opportunities associated with continued growth in end use markets for natural gas as we examine commercial, regulatory and operational changes to continue to optimize our pipelines' positions in response to positive developments in supply fundamentals.

Capital spending

We spent a total of US$1.1 billion in 2016 for our U.S. Natural Gas Pipelines and expect to spend approximately US$3.1 billion in 2017 primarily on Columbia expansion projects and ANR maintenance capital.

Mexico Natural Gas Pipelines

UNDERSTANDING THE MEXICO NATURAL GAS PIPELINES SEGMENT

For over a decade, Mexico has been undergoing a large transition from using oil to using natural gas as its energy source for electric generation. New large natural gas pipeline infrastructure is required to meet the growing demand for natural gas. Large natural gas pipelines in Mexico have been developed primarily through a competitive bid process whereby pipeline companies propose a cash flow stream over a 25 year contract based on their estimate of construction and ongoing operating costs. The revenues in these 25-year contracts are predominately denominated in U.S. dollars and are underpinned by the CFE, Mexico's electric utility. The pipeline operator is at risk for the construction and ongoing operating costs and is subject to penalties, excluding force majeure claims, if the project is not ready for in-service by a specific date.

Our Mexican pipelines have approved tariffs, services and related rates for other potential users of the pipeline. Most of the contracts that currently underpin the construction and operation of the facilities in Mexico are long-term, fixed-rate contracts designed to recover the cost of our service.

SIGNIFICANT EVENTS

Topolobampo

The Topolobampo project is a 530 km (329 miles), 30-inch pipeline with a cost of US$1.0 billion that will receive natural gas from upstream pipelines near El Encino in the state of Chihuahua. The pipeline will deliver natural gas from these interconnecting pipelines to delivery points along the pipeline route including our Mazatlán pipeline at El Oro in the state of Sinaloa. Construction of the pipeline is supported by a 25-year natural gas Transportation Service Agreement (TSA) for 670 MMcf/d with the CFE. Completion of construction is delayed into 2017 due to delays with Indigenous consultations by others. Under the terms of the TSA, this delay is recognized as a force majeure event with provisions allowing for the collection of revenue as per the original TSA service commencement date of July 2016.

Mazatlán

The Mazatlán project is a 413 km (257 miles), 24-inch diameter pipeline running from El Oro to Mazatlán within the state of Sinaloa with an estimated cost of US$0.4 billion. This pipeline is supported by a 25-year natural gas TSA for 200 MMcf/d with the CFE. Physical construction is complete and is awaiting natural gas supply from upstream interconnecting pipelines. We have met our contractual obligations and thus the collection and recognition of revenue began as per terms of the TSA in December 2016.

Tula

The Tula project is a US$0.6 billion, 36-inch, 300 km (186 miles) pipeline supported by a 25-year natural gas TSA for 886 MMcf/d with the CFE. The pipeline will transport natural gas from Tuxpan, Veracruz to markets near Tula, Querétaro extending through the states of Puebla and Hidalgo. Construction has commenced in certain regions, however, expected completion of construction is revised to 2018 due to delays with Indigenous consultations.

Villa de Reyes

On April 11, 2016, we announced that we were awarded the contract to build, own and operate the Villa de Reyes pipeline in Mexico. Construction of the pipeline is supported by a 25-year natural gas transportation service contract for 886 MMcf/d with the CFE. We expect to invest approximately US$0.6 billion to construct 36- and 24-inch diameter pipelines totaling 420 km (261 miles) with an anticipated in-service date of early 2018. The bi-directional pipeline will transport natural gas between Tula, in the state of Hidalgo, and Villa de Reyes, in the state of San Luis Potosí. The project will interconnect with our Tamazunchale and Tula pipelines as well as with other transporters in the region.

Sur de Texas

On June 13, 2016, we announced that our joint venture with IEnova had been chosen to build, own and operate the US$2.1 billion Sur de Texas pipeline in Mexico. We will have a 60 per cent interest in this project. Construction of the pipeline is supported by a 25-year natural gas transportation service contract for 2.6 bcf/d with the CFE. We expect to invest approximately US$1.3 billion in the joint venture to construct the 42-inch diameter, approximately 800 km (497 miles) pipeline with an anticipated in-service date of late 2018. The pipeline will start offshore in the Gulf of Mexico, at the border point near Brownsville, Texas, and end in Tuxpan, Mexico in the state of Veracruz. The project will deliver natural gas to our Tamazunchale and Tula pipelines and to other transporters in the region.

FINANCIAL RESULTS

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented earnings (the equivalent GAAP measure). See page 8 for more information on non-GAAP measures we use. 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 and 2014 results have been adjusted to reflect this change.

year ended December 31 (millions of US$, unless otherwise noted)	2016	2015	2014
Tamazunchale	**106**	109	91
Topolobampo	**81**	(3)	—
Guadalajara	**68**	70	69
Mazatlán	**5**	(2)	—
Other[1, 2]	**(4)**	4	(6)
Business development	**(5)**	(12)	(7)
Comparable EBITDA	**251**	166	147
Depreciation and amortization	**(33)**	(34)	(28)
Comparable EBIT	**218**	132	119
Foreign exchange impact	**72**	39	14
Comparable EBIT (Cdn$)	**290**	171	133
Specific item:			
Gas Pacifico/INNERGY gain on sale	**—**	—	9
Segmented earnings (Cdn$)	**290**	171	142

1 Includes our share of the equity income from TransGas and Gas Pacifico/INNERGY located in South America. In November 2014, we sold our interest in Gas Pacifico/INNERGY.

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

Mexico Natural Gas Pipelines segmented earnings in 2016 increased by $119 million compared to 2015 and increased by $29 million in 2015 compared to 2014. Segmented earnings in 2014 included $9 million pre-tax related to the gain on sale of Gas Pacifico/INNERGY in November 2014.

Comparable EBITDA for the Mexico Natural Gas Pipelines was US$85 million higher in 2016 than 2015. This was the net effect of:

- incremental earnings from Topolobampo. The Topolobampo project experienced a delay in construction which, under the terms of our TSA with the CFE, constitutes a force majeure event with provisions allowing for the collection and recognition of revenue as per the original TSA service commencement date of July 2016
- incremental earnings from Mazatlán. Construction is complete and the collection and recognition of revenue began per the terms of the TSA in December 2016
- lower business development costs expensed in 2016 due to the capitalization of costs for work on projects successfully awarded and under construction.

Comparable EBITDA for the Mexico Natural Gas Pipelines was US$19 million higher in 2015 than 2014. This was the net effect of:

- higher earnings from the Tamazunchale Extension which was placed in service in late 2014
- increased business development activity in 2015.

Depreciation and amortization

Depreciation and amortization was US$1 million lower in 2016 compared to 2015 and US$6 million higher in 2015 compared to 2014. The increase in 2015 was primarily due to the Tamazunchale Extension being placed in service in 2014.

OUTLOOK

Earnings

Mexico Natural Gas Pipelines earnings reflect long-term stable revenue contracts that are affected by the cost of providing service and include our share of equity income from our 60 per cent effective interest in the Sur de Texas pipeline project.

Overall, we expect the Mexico Natural Gas Pipelines earnings to increase in 2017 due to a full year of earnings for Topolobampo and Mazatlán. We also anticipate higher equity earnings through AFUDC earned on our 60 per cent interest in the Sur de Texas pipeline project. The 2017 earnings from the Tamazunchale and Guadalajara pipelines are expected to remain consistent with 2016 due to the long-term nature of the revenue contracts.

Capital spending

We spent a total of US$0.8 billion in 2016 for our Mexican natural gas pipelines and expect to spend approximately US$1.2 billion in 2017 primarily on construction of projects awarded in late 2015 and the first half of 2016.

NATURAL GAS PIPELINES – BUSINESS RISKS

The following are risks specific to our natural gas pipelines business. See page 92 for information about general risks that affect the company as a whole, including other operational risks, HSE risks and financial risks.

WCSB supply for downstream connecting pipelines

Our pipelines downstream of the NGTL System depend largely on supply from the WCSB. We continue to monitor any changes in our customers' gas production plans and how these changes may impact our existing assets and new project schedules. There is competition for this supply from several pipelines within the basin. An overall decrease in production and/or competing demand for supply could impact throughput on WCSB connected pipelines that, in turn, could impact overall revenues generated. The WCSB has considerable natural gas reserves, but the amount actually produced depends on many variables, including the price of natural gas, basin-on-basin competition, downstream pipeline tolls, demand within the basin and the overall value of the reserves, including liquids content.

Market access

We compete for market share with other natural gas pipelines. New supply basins being developed closer to markets we have historically served may reduce the throughput and/or distance of haul on our existing pipelines and impact revenue. New markets created by LNG export facilities developed to access worldwide natural gas demand can lead to increased revenue through higher utilization of existing facilities and/or demand for new infrastructure. The long-term competitiveness of our pipeline systems and the avoidance of bypass pipelines will depend on our ability to adapt to changing flow patterns by offering alternative transportation services at prices that are acceptable to the market.

Competition for greenfield expansion

We face competition from other pipeline companies seeking opportunities to invest in greenfield natural gas pipeline development opportunities. This competition could result in fewer projects being available that meet our investment hurdles or projects that proceed with lower overall financial returns.

Demand for pipeline capacity

Demand for pipeline capacity is ultimately the key driver that enables pipeline transportation services to be sold. Demand for pipeline capacity is created by supply and market competition, variations in economic activity, weather variability, natural gas pipeline and storage competition and pricing of alternative fuels. Renewal of expiring contracts and the opportunity to charge and collect a toll that the market accepts depends on the overall demand for transportation service. A change in the level of demand for our pipeline transportation services could impact revenues.

Commodity prices

The cyclical supply and demand nature of commodities and related pricing can have a secondary impact on our business where our shippers may choose to accelerate or delay certain projects. This can impact the timing for the demand of transportation services and/or new gas pipeline infrastructure. As well, sustained low gas prices could impact our shippers' financial situation and their ability to meet their transportation service cost obligations.

Regulatory risk

Decisions by regulators can have an impact on the approval, timing, construction, operation and financial performance of our natural gas pipelines. There is a risk that decisions are delayed or are not favourable and therefore could impact revenues and the opportunity to further invest capital in our systems. There is also risk of a regulator disallowing a portion of our prudently incurred costs, now or at some point in the future.

The regulatory approval process for larger infrastructure projects, including the time it takes to receive a decision, could be slowed or unfavorable due to the influence from the evolving role of activists and their impact on public opinion and government policy related to natural gas pipeline infrastructure development.

Increased scrutiny of operating processes by the regulator or other enforcing agencies has the potential to increase operating costs or require additional capital investment. There is a risk of an impact to income if these costs are not fully recoverable.

We continuously monitor regulatory developments and decisions to determine the possible impact on our gas pipelines business. We also work closely with our stakeholders in the development of rate, facility and tariff applications and negotiated settlements, where possible.

Construction and operations

Constructing and operating our pipelines to ensure transportation services are provided safely and reliably is essential to the success of our business. Interruptions in our pipeline operations impacting our throughput capacity may result in reduced revenue and can affect corporate reputation as well as customer and public confidence in our operations. We manage this by investing in a highly skilled workforce, hiring third party inspectors during construction, operating prudently, monitoring our pipeline systems 24 hours a day every day, using risk-based preventive maintenance programs and making effective capital investments. We use pipeline inspection equipment to regularly check the integrity of our pipelines, and repair or replace sections whenever necessary. We also calibrate the meters regularly to ensure accuracy, and continuously maintain compression equipment to ensure safe and reliable operation.

Liquids Pipelines

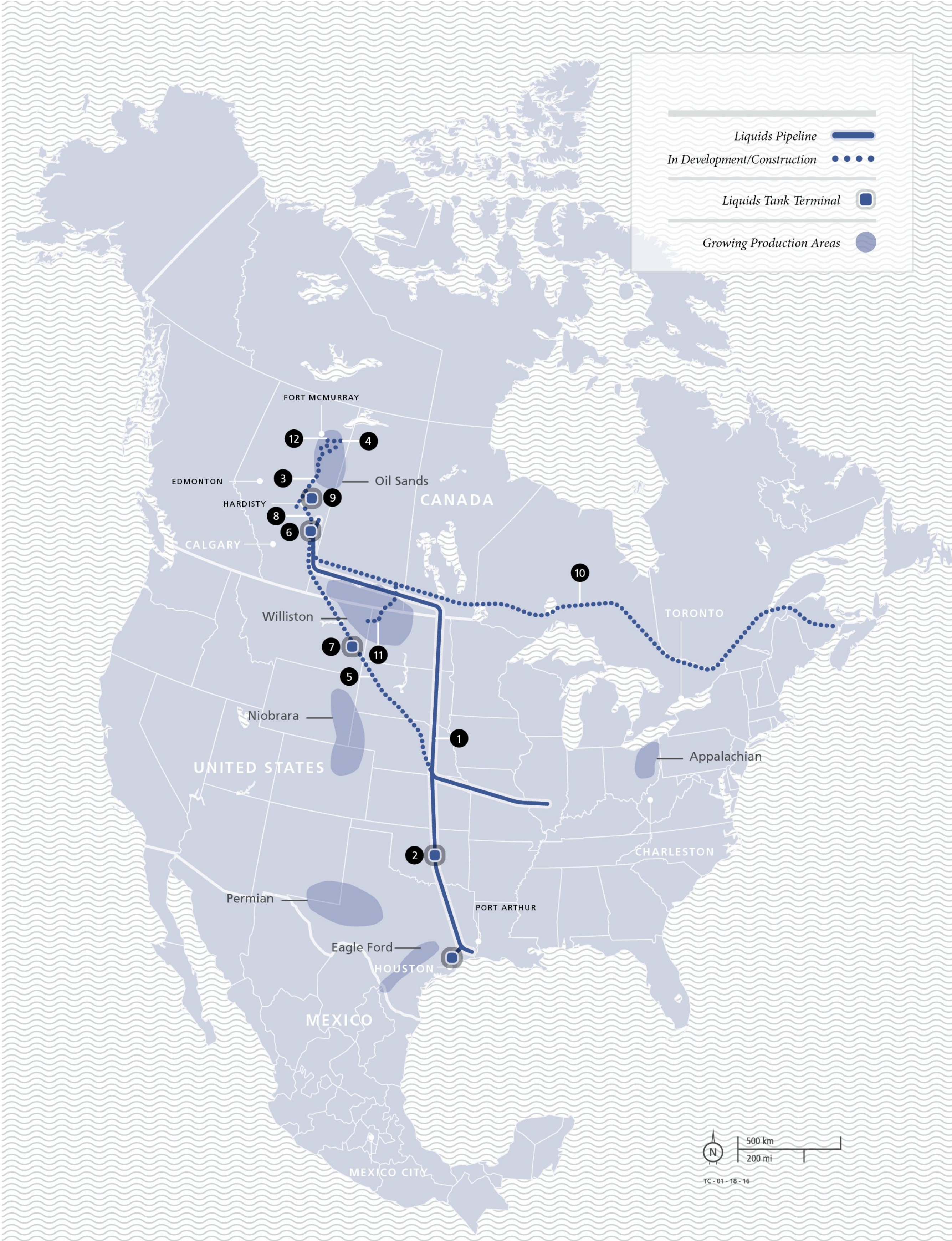
Our existing liquids pipeline infrastructure connects Alberta crude oil supplies to U.S. refining markets in Illinois, Oklahoma and Texas, as well as connecting U.S. crude oil supplies from the Cushing, Oklahoma hub to refining markets in the U.S Gulf Coast. Our proposed future pipeline infrastructure would also connect Canadian and U.S. crude oil supplies to refining markets in eastern Canada and overseas export markets, and expand capacity for Canadian and U.S. crude oil to access U.S. markets. We will also pursue enhancing our transportation service offerings to other areas of the liquids pipelines business value chain.

Strategy at a glance

- Focus on accessing and delivering growing North American liquids supply to key markets by expanding our liquids pipelines infrastructure to deliver directly from supply regions seamlessly along a contiguous path to the market
- Focus on maximizing the value from our current operating assets, securing organic growth around these assets, identifying acquisition opportunities in the current lower crude oil price environment and positioning our business development activities to capture opportunities when the environment recovers
- Expand transportation service offerings to other areas of the liquids pipelines business value chain including condensate transportation and ancillary services such as short and long term storage of liquids and liquids marketing, which complement our pipeline transportation infrastructure
- Continued development and construction of our proposed infrastructure projects will provide North America with a crucial liquids transportation network to transport growing supply directly to key markets and provide opportunities for us to further expand our liquids pipelines business.

Highlights

- Transported over 1.4 billion barrels of crude oil on the Keystone Pipeline System since operations began in 2010
- Expanded market access in the U.S. Gulf Coast with Houston Lateral and Terminal and CITGO Sour Lake pipeline connections, and completion of the HoustonLink pipeline, which form part of the Keystone Pipeline System
- Filed a consolidated application with the NEB for the proposed Energy East project
- Finalized a long term transportation agreement with a major oil sands producer to develop and construct the White Spruce pipeline and increase contract volumes on Grand Rapids
- Filed a U.S. Presidential Permit application with the U.S. Department of State for Keystone XL


Liquids Pipeline
In Development/Construction
Liquids Tank Terminal
Growing Production Areas
FORT MCMURRAY
EDMONTON
HARDISTY
CALGARY
Oil Sands
CANADA
Williston
Niobrara
UNITED STATES
Appalachian
TORONTO
CHARLESTON
PORT ARTHUR
Permian
Eagle Ford
HOUSTON
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We are the operator of all of the following pipelines and properties.

		Length	Description	Ownership
	Liquids pipelines			
1	Keystone Pipeline System	4,324 km (2,687 miles)	Transports crude oil from Hardisty, Alberta, to U.S. markets at Wood River and Patoka, Illinois, Cushing, Oklahoma, and Houston and Port Arthur, Texas	100%
2	Marketlink		Terminal and pipeline facilities to transport crude oil from the market hub at Cushing, Oklahoma to the Houston and Port Arthur, Texas refining markets on facilities that form part of the Keystone Pipeline System	100%
	Under construction			
3	Grand Rapids	460 km (287 miles)	To transport crude oil and diluent between the producing area northwest of Fort McMurray, Alberta and the Edmonton/Heartland, Alberta market region	50%
4	Northern Courier	90 km (56 miles)	To transport bitumen and diluent between the Fort Hills mine site and Suncor Energy's terminal located north of Fort McMurray, Alberta	100%
	In development			
5	Keystone XL	1,897 km (1,179 miles)	To transport crude oil from Hardisty, Alberta to Steele City, Nebraska to expand capacity of the Keystone Pipeline System	100%
6	Keystone Hardisty Terminal		Crude oil terminal located at Hardisty, Alberta, providing western Canadian producers with crude oil batch accumulation tankage and access to the Keystone Pipeline System	100%
7	Bakken Marketlink		To transport crude oil from the Williston Basin producing region in North Dakota and Montana to Cushing, Oklahoma on facilities that form part of Keystone XL	100%
8 9	Heartland Pipeline and TC Terminals	200 km (125 miles)	Terminal and pipeline facilities to transport crude oil from the Edmonton/Heartland, Alberta region to facilities in Hardisty, Alberta	100%
10	Energy East	4,600 km (2,850 miles)	To transport crude oil from western Canada to eastern Canadian refineries and export markets	100%
11	Upland	400 km (240 miles)	To transport crude oil from, and between, multiple points in North Dakota and interconnect with Energy East at Moosomin, Saskatchewan	100%
12	White Spruce	72 km (45 miles)	To transport crude oil from northeast Alberta into Grand Rapids.	100%

UNDERSTANDING THE LIQUIDS PIPELINES BUSINESS

Our liquids business consists of pipelines which efficiently move crude oil from major supply sources to markets where crude oil can be refined into various petroleum products, ancillary services such as short and long term storage of liquids at terminals and a liquids marketing business to expand into other areas of the liquids business value chain. The Keystone Pipeline System, our largest liquids pipelines asset, moves approximately 20 per cent of western Canadian crude oil exports to key refining markets in the U.S. Midwest and the U.S. Gulf Coast and has transported over 1.4 billion barrels of crude oil since operations began in 2010.

We provide pipeline capacity to shippers supported by long term contracts with fixed monthly payments that are not linked to actual throughput volumes or to the price of the commodity, generating stable earnings over the contract term. Uncontracted capacity is offered to the market on a spot basis which provides opportunities to generate incremental earnings. Storage of liquids is offered to our customers in return for fixed fee payments, which are not linked to actual storage volumes or to the price of the commodity.

The terms of service and fixed monthly payments are determined by transportation service arrangements negotiated with shippers. These long term arrangements provide for the recovery of costs we incur to construct and operate the system.

Business environment

Crude oil continues to drive the modern economy, with people's need for efficient and reliable transportation and products developed from petroleum generating the majority of global crude oil demand. Despite the emergence of new technologies that have made vehicles more fuel efficient, demand for crude oil and the products derived from it is projected by the International Energy Agency to increase between eight million Bbl/d and 21 million Bbl/d between now and 2040, driven primarily by growth in Asia and developing countries.

OPEC's market share strategy in late 2014 created an oversupply situation in the global crude oil market putting downward pressure on crude oil prices. This lower crude oil price environment prompted producers to significantly reduce capital investment which will impact supply growth in the near and longer term. With the recently agreed crude oil production cuts by OPEC and non-OPEC producers, natural production declines and continued global crude oil demand growth, it is expected that crude oil supply and demand will balance in the near term. As the market comes into balance, crude oil prices are expected to recover to a range which will support further investment and supply growth.

Our liquids pipelines business is well positioned to endure the impact of short term commodity price fluctuations and supply adjustments. Our existing operations and development projects are supported by long term contracts where we have agreed to provide pipeline capacity to our customers in exchange for fixed monthly payments, irrespective of commodity prices or supply. The cyclical supply and demand nature of commodities and their price movements can have a secondary impact on our business where our shippers may choose to accelerate or delay certain new projects. This can impact the timing for the demand of transportation services and/or new liquids infrastructure.

We continue to advance a number of growth opportunities in the near term and monitor the marketplace for strategic asset acquisition opportunities. Commodity price fluctuations are a normal part of the business cycle. Longer-term, we expect global demand for crude oil will continue to grow, ultimately resulting in continued growth in North American crude oil supply production and demand for new pipeline infrastructure. Our current position and growth opportunities in the liquids transportation business provide a significant platform to capture these future opportunities.

Supply outlook

Canada

Canada has the world's third largest supply of crude oil and has the potential to become a key world supplier as crude oil production from mature oil fields around the world decline. Alberta produces the majority of the crude oil in the WCSB, which is the primary source of crude oil supply for the Keystone Pipeline System. In its 2016 Crude Oil Forecast, Markets and Transportation report, the Canadian Association of Petroleum Producers (CAPP) estimates 2017 WCSB crude oil supply will reach 0.9 million Bbl/d of conventional crude oil and condensate and 3.3 million Bbl/d of oil sands crude oil, for a total of approximately 4.2 million Bbl/d. The report also forecasts WCSB crude oil supply will increase to 4.9 million Bbl/d by 2025 and to 5.5 million Bbl/d by 2030.

According to the 2016 publication entitled Alberta's Energy Reserves 2015 and Supply/Demand Outlook 2016-2025, the Alberta Energy Regulator estimates there is approximately 165 billion barrels of economically and technically recoverable conventional and oil sands reserves in Alberta. Oil sands projects have a long reserve life with steady production after ramping up. In its 2014 Responsible Canadian Energy report, CAPP estimates a typical oil sands mine has a 25 to 50 year lifespan, while an in-situ operation will run 10 to 15 years on average. This longevity aligns with the producer's desire to secure long term market connectivity for their reserves. The Keystone Pipeline System, as well as projects under development such as the proposed Energy East pipeline, are underpinned by long term contracts.

U.S.

The U.S. is also among the world's largest crude oil producers, with average production estimated at 8.8 million Bbl/d in 2016 as a result of significant growth in light tight oil (LTO) production. The U.S. EIA forecasts 1.6 million Bbl/d of U.S. production growth from 2016 to 2025, peaking at 10.5 million Bbl/d by 2027. However, U.S. production is expected to fall slightly to approximately 8.7 million Bbl/d in 2017, which will contribute to balancing global supply and demand and support a recovery in crude oil prices.

Most continental U.S. crude oil is produced from five growing production areas: Williston, Eagle Ford, Niobrara, Permian and Appalachian. These LTO production areas represent some of the sources of crude oil supply for our Marketlink system at Cushing, Oklahoma. The Marketlink system, with connectivity to Houston and Port Arthur, Texas and Lake Charles, Louisiana refining markets, is well positioned to transport this growing supply.

The rise in LTO production also contributed to the recent lift on the decades old U.S. domestic crude oil export ban. Our completed Houston Lateral and Terminal and delivery points at Port Arthur, Texas that form part of the Keystone Pipeline System are well positioned to capture the growing demand for the export market.

The U.S. is the world's biggest crude oil consumer where crude oil demand is forecasted to grow slightly from approximately 16 million Bbl/d to over 17 million Bbl/d by 2040. U.S. Gulf Coast refineries are mainly configured to process heavy and medium crude oil and cannot easily switch to processing LTO in large quantities without significant capital investments. U.S. Gulf Coast refineries currently require approximately 8.6 million Bbl/d of crude oil, of which approximately 3.2 million Bbl/d is heavy and medium supplied by offshore imports. This level of demand is not expected to change significantly in the near or longer term. The Keystone Pipeline System is well positioned to deliver Canadian crude oil to this significant market.

Strategic priorities

Notwithstanding the current economic conditions, we remain committed to advancing our portfolio of commercially secured projects to connect growing Canadian and U.S. crude oil supply to key markets, maximizing the value from our current operating assets, leveraging existing infrastructure and expanding across our liquids pipelines business value chain in the near term.

We continue to extend the Keystone Pipeline System's access in the U.S. Gulf Coast market to over 4.5 million Bbl/d of regional refinery centres in Houston and Port Arthur, Texas and Lake Charles, Louisiana. Expanding the Keystone Pipeline System's market reach is expected to enhance both short and long haul volumes. Our HoustonLink joint venture with Magellan Midstream Partners, L.P. (Magellan) which provides a connection between our Houston Lateral and Terminal and Magellan's Houston and Texas City, Texas delivery system, will enhance our crude oil connectivity in the Houston area. In December 2016, we completed construction of a lateral to the CITGO Petroleum (CITGO) Sour Lake, Texas terminal which supplies the Lake Charles, Louisiana marketplace.

Within Alberta, we are leveraging our extensive natural gas pipeline footprint and experience to develop a regional liquids pipelines business. Growth in oil sands production is driving the need for new intra-Alberta pipelines, such as our 50 per cent owned Grand Rapids project, that can move crude oil production from the source to the market hub at Edmonton, Alberta. Our joint venture with Keyera Corp. will enhance our ability to access a reliable and cost effective source of diluent for Grand Rapids. Our White Spruce pipeline, which will transport crude oil from a major oil sands plant in northeast Alberta into Grand Rapids, will further expand our regional footprint. In addition, Northern Courier will facilitate supply from the Fort Hills Energy Partners' mine to market. When supported by market conditions, the Heartland pipeline and TC Terminals and Keystone Hardisty Terminal projects will support these market hubs, allowing shippers to seamlessly connect with the Keystone Pipeline System, Energy East and other pipelines that transport crude oil outside of Alberta, and ultimately provide our customers with a contiguous seamless path from production to market.

In the longer term, our focus remains on securing regulatory approval for the Energy East pipeline. The project will serve the three eastern Canadian refineries along the route in Montréal and Québec City, Québec and Saint John, New Brunswick, and meet global market demand. In addition, we filed a U.S. Presidential Permit application with the U.S. Department of State for the Keystone XL project which will begin in Hardisty, Alberta, and extend south to Steele City, Nebraska.

In this challenging crude oil price environment, we will closely monitor the market place for strategic asset acquisitions to enhance our system connectivity or expand our footprint within North America. We remain disciplined in our approach and will position our business development activities strategically to capture the opportunities as the business environment recovers.

SIGNIFICANT EVENTS

Keystone Pipeline System

In August 2016, the Houston Lateral and Terminal were placed into service, which extends the Keystone Pipeline System to the Houston, Texas refinery market. The HoustonLink pipeline which connects the Houston Terminal to Magellan's Houston and Texas City, Texas delivery system was completed in December 2016. In addition, the CITGO Sour Lake pipeline connection between the Keystone Pipeline System and CITGO's Sour Lake, Texas terminal was placed into service in December 2016.

On April 2, 2016, we shut down the Keystone Pipeline System 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 and the pipeline was restarted by mid-April 2016. Shortly thereafter in early May 2016, permanent pipeline repairs were completed and restoration work was completed by early July 2016. Corrective measures required by PHMSA were completed in September 2016. This shutdown did not significantly impact our 2016 earnings.

Keystone XL

In June 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 Keystone XL. 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. This arbitration is in a preliminary stage and the likelihood of success and resulting impact on the Company's financial position or results of operations is unknown at this time.

On January 24, 2017, the U.S. President signed a Presidential Memorandum inviting TransCanada to refile an application for the U.S. Presidential Permit. On January 26, 2017, we filed a Presidential Permit application with the U.S. Department of State for the project. The pipeline will begin in Hardisty, Alberta, and extend south to Steele City, Nebraska.

Given the passage of time since the November 6, 2015 denial of the Presidential Permit, we are updating our shipping contracts and some shippers may increase or decrease their volume commitments. We expect the project to retain sufficient commercial support for us to make a final investment decision.

Energy East

In May 2016, we filed a consolidated application with the NEB for the Energy East pipeline. In June 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. However, in August 2016, panel sessions were cancelled as three NEB panelists recused themselves from continuing to sit on the panel to review the project due to allegations of reasonable apprehension of bias. The Chair of the NEB and the Vice Chair, who is also a panel member, have recused themselves of any further duties related to the project. As a result, all hearings for the project were adjourned until further notice.

On January 9, 2017, the NEB appointed three new panel members to undertake the review of the Energy East and Eastern Mainline projects. On January 27, 2017, the new NEB panel members voided all decisions made by the previous hearing panel members and the new panel members will decide how to move forward with the hearing. We are not required to refile the application and parties will not be required to reapply for intervener status. However, all other proceedings and associated deadlines are no longer applicable. If the new panel members determine that the project application is complete, the 21-month NEB review period will commence.

White Spruce

In December 2016, we finalized a long term transportation agreement to develop and construct the 20-inch diameter White Spruce pipeline, which will transport crude oil from a major oil sands plant in northeast Alberta, into the Grand Rapids pipeline system. The total capital cost for the project is approximately $200 million and is expected to be in service in 2018 subject to regulatory approvals.

Northern Courier

Construction continues on the Northern Courier pipeline to transport bitumen and diluent between the Fort Hills mine site and Suncor Energy's terminal located north of Fort McMurray, Alberta. The project is fully underpinned by long term contracts with the Fort Hills partnership. We expect to begin commercial operation in fourth quarter 2017.

Grand Rapids

Construction continues on the Grand Rapids pipeline which will connect producing areas northwest of Fort McMurray to terminals in the Edmonton/Heartland, Alberta region. We have a joint partnership with Brion Energy to develop Grand Rapids with each party owning 50 per cent of the pipeline project. Our partner has also entered into a long-term transportation service contract in support of the project. We will operate Grand Rapids once it is complete and we expect crude oil transportation to begin in the second half of 2017.

Construction is also progressing on the 20-inch diameter diluent joint venture pipeline between Edmonton and Fort Saskatchewan, Alberta. The joint venture between Grand Rapids and Keyera Corp. will be incorporated into Grand Rapids and will provide enhanced diluent supply alternatives to our shippers. We anticipate the pipeline to be in service in late 2017.

FINANCIAL RESULTS

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented earnings (the equivalent GAAP measure). See page 8 for more information on non-GAAP measures we use. 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 and 2014 results have been adjusted to reflect this change.

year ended December 31 (millions of $)	**2016**	**2015**	**2014**
Keystone Pipeline System	**1,169**	1,333	1,061
Business Development and Other	**(3)**	(24)	(15)
Comparable EBITDA	**1,166**	1,309	1,046
Depreciation and amortization	**(285)**	(266)	(216)
Comparable EBIT	**881**	1,043	830
Specific items:			
Keystone XL asset costs	**(52)**	—	—
Keystone XL impairment charge	**—**	(3,686)	—
Risk management activities	**(2)**	—	—
Segmented earnings/(loss)	**827**	(2,643)	830
Comparable EBIT denominated as follows:			
Canadian dollars	**228**	232	212
U.S. dollars	**493**	633	561
Foreign exchange impact	**160**	178	57
Comparable EBIT	**881**	1,043	830

Liquids Pipelines segmented earnings were $3,470 million higher in 2016 compared to 2015 and $3,473 million lower in 2015 than 2014. Segmented earnings in 2016 included $52 million of pre-tax costs related to Keystone XL for the maintenance and liquidation of project assets which are being expensed pending further advancement of the project and $2 million of unrealized losses from changes in the fair value of derivatives related to our liquids marketing business. The segmented loss in 2015 included a $3,686 million pre-tax impairment charge related to Keystone XL and related projects. See Critical accounting estimates on page 97 for more information. 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.Comparable EBITDA for Liquids Pipelines was $143 million lower in 2016 compared to 2015. This decrease was due to the net effect of:

- lower uncontracted volumes on Keystone pipeline
- lower volumes on Marketlink
- higher contracted volumes on Keystone pipeline
- a growing contribution from liquids marketing
- lower business development activities
- a stronger U.S. dollar which had a positive impact on the Canadian dollar equivalent comparable earnings from our U.S. operations.

Comparable EBITDA for Liquids Pipelines was $263 million higher in 2015 than in 2014. This increase was primarily due to:

- higher volumes
- incremental earnings from the Keystone Gulf Coast extension which was placed in service in January 2014
- a stronger U.S. dollar which had a positive impact on the Canadian dollar equivalent comparable earnings from our U.S. operations.

Depreciation and amortization

Depreciation and amortization was $19 million higher in 2016 than in 2015 as result of new facilities being placed in service and the effect of a stronger U.S. dollar. Depreciation and amortization was $50 million higher in 2015 than in 2014 mainly due to the effect of a stronger U.S. dollar.

OUTLOOK

Earnings

Excluding specified items, our 2017 earnings are expected to be higher than our 2016 earnings as a result of new pipeline interconnections and the Northern Courier and Grand Rapids pipelines being placed into service in 2017.

Capital spending

We spent a total of $0.8 billion in 2016 for our Liquids Pipelines and expect to spend approximately $0.5 billion in 2017, primarily on Grand Rapids, Northern Courier and White Spruce.

BUSINESS RISKS

The following are risks specific to our liquids pipelines business. See page 92 for information about general risks that affect the company as a whole, including other operational risks, HSE risks, and financial risks.

Operational

Optimizing and maintaining availability of our liquids pipelines is essential to the success of our Liquids Pipelines business. Interruptions in our pipeline operations impact our throughput capacity and may result in reduced fixed payment revenues and spot volume opportunities. We manage this by investing in a highly skilled workforce, operating prudently, using risk-based preventive maintenance programs and making effective capital investments. We use internal inspection equipment to check our pipelines regularly and repair them whenever necessary.

While the majority of the costs to operate the Keystone Pipeline System are passed through to our shippers, a portion of our volume is moved under an all-in fixed toll structure where we are exposed to changing costs which may impact our earnings.

Regulatory and government

Rates for our liquids pipelines are regulated by the NEB in Canada, and by the FERC in the U.S. They regulate the terms of service and rates to ensure they are just and reasonable and that there is no unjust discrimination in rates, tariffs or services. A shipper can submit concerns to the regulator at any time, however the majority of the pipeline's capacity is underpinned by long term transportation agreements which minimizes the risk of complaints in respect of the regulation of such rates and associated cost recovery.

Decisions by Canadian and U.S. regulators can have a significant impact on the approval, construction, operation and financial performance of our liquids pipelines. Public opinion about crude oil development and production may also have an adverse impact on the regulatory process. In conjunction with this, there are some individuals and interest groups that are expressing their opposition to crude oil production by lobbying against the construction of liquids pipelines. Changing environmental requirements or revisions to current regulatory process may impact the timing to obtain permit approvals for our liquids pipelines. We manage these risks by continuously monitoring regulatory and government developments and decisions to determine their possible impact on our liquids pipelines business and by working closely with our stakeholders in the development and operation of the assets.

Execution, capital costs and permitting

We make substantial capital commitments in large infrastructure projects based on the assumption that the new assets will offer an attractive return on investment in the future. Under some contracts, we share the cost of these risks with customers and while we carefully consider the expected cost of our capital projects, under some contracts we bear greater capital cost risk which may impact our return on these projects. Our capital projects are also subject to permitting risk which may result in construction delays, increased capital cost and, potentially, reduced investment returns.

Crude oil supply and demand for pipeline capacity

A decrease in demand for refined crude oil products could adversely impact the price that crude oil producers receive for their product. Lower crude oil prices could mean producers may curtail their investment in the further development of crude oil supplies. Depending on the severity, these factors would negatively impact opportunities to expand our liquids pipelines infrastructure and, in the longer term, to re-contract with shippers as current agreements expire.

Competition

As we continue to develop a competitive position in the North American liquids transportation market to transport growing crude oil and condensate supplies between key North American producing regions and refining and export markets, we face competition from other midstream companies which also seek to transport these crude oil and condensate supplies to the same markets. Our success is dependent on our ability to offer and contract transportation services on terms that are market competitive.

Liquids marketing

Our liquids marketing business generates revenue by capitalizing on asset utilization opportunities by entering into short-term or long-term pipeline or storage terminal capacity contracts.

Volatility in commodity prices and changing market conditions could impact the value of those capacity contracts. Availability of alternative pipeline systems that can deliver into the same areas can also impact contract value. The liquids marketing business complies with our risk management policies which are described in Other information – Risks and risk management.

Energy

Our Energy business includes a portfolio of power generation assets in Canada and the U.S., and unregulated natural gas storage assets in Alberta. The two sale transactions to monetize our U.S. Northeast power assets are expected to close in the first half of 2017. See the Significant Events section for more information.

We will continue to own, control and develop approximately 7,050 MW of generation capacity powered by natural gas, nuclear, wind and solar upon closing of the U.S. Northeast power asset sales.

Our ongoing business will consist of power facilities located in Alberta, Ontario, Québec, New Brunswick and Arizona. The majority of these assets are supported by long-term contracts.

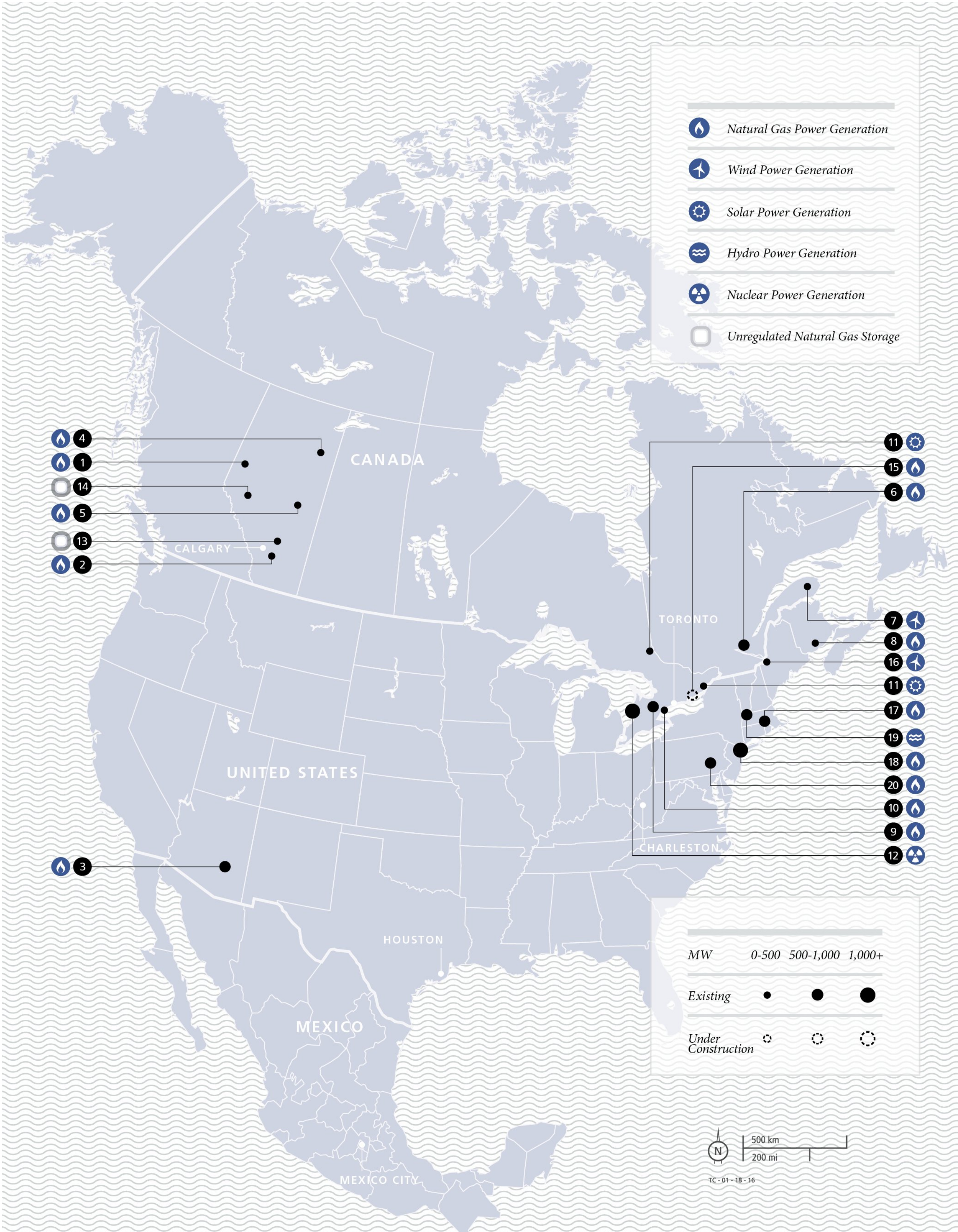
We own and operate approximately 118 Bcf of unregulated natural gas storage capacity in Alberta and hold a contract with a third party for additional storage, in total accounting for approximately one-third of all storage capacity in the province.

Strategy at a glance

- Maximize the value of our diverse portfolio of contracted and low cost power generation assets through safe and reliable operations
- Execute capital programs on time and on budget
- Pursue growth in contracted power infrastructure as electric systems move to become less carbon intensive and absorb growing amounts of intermittent renewable capacity
- Maximize the value of our existing unregulated Alberta natural gas storage assets in an expanding gas marketplace that requires storage to balance and provide gas system reliability

Highlights

- Bruce Power: Strong results at Bruce Power and increase of site output by 100 MW to 6,400 MW as a result of extended life program work
- Napanee 900 MW natural gas-fired power plant: Construction continues and nears 50 per cent completion
- Alberta PPA termination settlement finalized with the Government of Alberta and the Balancing Pool
- Monetization of the U.S. Northeast power assets expected to close in first half of 2017


Natural Gas Power Generation
Wind Power Generation
Solar Power Generation
Hydro Power Generation
Nuclear Power Generation
Unregulated Natural Gas Storage
CANADA
CALGARY
TORONTO
UNITED STATES
CHARLESTON
HOUSTON
MEXICO
MEXICO CITY
4
1
14
5
13
2
3
11
15
6
7
8
16
11
17
19
18
20
10
9
12
MW
0-500
500-1,000
1,000+
Existing
Under Construction
N
500 km
200 mi
TC - 01 - 18 - 16

We are the operator of all of our Energy assets, except for Cartier Wind, Bruce Power and Portlands Energy.

		Generating capacity (MW)	Type of fuel	Description	Ownership
	Canadian Power 7,056 MW of power generation capacity (including facilities under construction)				
	Western Power 1,013 MW of power generation capacity in Alberta and the western U.S.				
1	Bear Creek	100	natural gas	Cogeneration plant in Grande Prairie, Alberta.	100%
2	Carseland	95	natural gas	Cogeneration plant in Carseland, Alberta.	100%
3	Coolidge	575	natural gas	Simple-cycle peaking facility in Coolidge, Arizona. Power sold under a 20-year PPA with the Salt River Project Agricultural Improvements & Power District which expires in 2031.	100%
4	Mackay River	197	natural gas	Cogeneration plant in Fort McMurray, Alberta.	100%
5	Redwater	46	natural gas	Cogeneration plant in Redwater, Alberta.	100%
	Eastern Power 2,939 MW of power generation capacity (including facilities under construction)				
6	Bécancour	550	natural gas	Cogeneration plant in Trois-Rivières, Québec. Power sold under a 20-year PPA with Hydro-Québec which expires in 2026. Steam sold to an industrial customer. Power generation has been suspended since 2008. We continue to receive capacity payments while generation is suspended.	100%
7	Cartier Wind	365[1]	wind	Five wind power facilities in Gaspésie, Québec. Power sold under 20-year PPAs with Hydro-Québec which expire between 2026-2032.	62%
8	Grandview	90	natural gas	Cogeneration plant in Saint John, New Brunswick. Power sold under a 20-year tolling agreement to buy 100 per cent of heat and electricity output with Irving Oil which expires in 2024.	100%
9	Halton Hills	683	natural gas	Combined-cycle plant in Halton Hills, Ontario. Power sold under a 20-year Clean Energy Supply contract with the IESO which expires in 2030.	100%
10	Portlands Energy	275[1]	natural gas	Combined-cycle plant in Toronto, Ontario. Power sold under a 20-year Clean Energy Supply contract with the IESO which expires in 2029.	50%
11	Ontario Solar	76	solar	Eight solar facilities in Southern Ontario and New Liskeard, Ontario. Power sold under 20-year FIT contracts with the IESO which expire between 2032-2034.	100%
	Bruce Power 3,104 MW of power generation capacity				
12	Bruce Power	3,104[1]	nuclear	Eight operating reactors in Tiverton, Ontario. Bruce Power leases the eight nuclear facilities from Ontario Power Generation (OPG).	48.5%
	Unregulated natural gas storage 118 Bcf of non-regulated natural gas storage capacity				
13	CrossAlta	68 Bcf		Underground facility connected to the NGTL System in Crossfield, Alberta.	100%
14	Edson	50 Bcf		Underground facility connected to the NGTL System near Edson, Alberta.	100%
	Under construction				
15	Napanee	900	natural gas	Combined-cycle plant in Greater Napanee, Ontario. Power sold under a 20-year Clean Energy Supply contract with the IESO which expires 20 years from in-service date. Expected in-service date is 2018.	100%

1 Our share of power generation capacity.

Assets Held for Sale

		Generating capacity (MW)	Type of fuel	Description	Ownership
	U.S. Power 4,533 MW of power generation capacity				
16	Kibby Wind	132	wind	Wind farm in Kibby and Skinner Townships, Maine.	100%
17	Ocean State Power	560	natural gas	Combined-cycle plant in Burrillville, Rhode Island.	100%
18	Ravenswood	2,480	natural gas and oil	Multiple-unit generating facility using dual fuel-capable steam turbine, combined-cycle and combustion turbine technology in Queens, New York.	100%
19	TC Hydro	583	hydro	13 hydroelectric facilities, including stations and associated dams and reservoirs in New Hampshire, Vermont and Massachusetts (on the Connecticut and Deerfield rivers).	100%
20	Ironwood[1]	778	natural gas	Combined-cycle plant in Lebanon, Pennsylvania.	100%

1 Acquired February 1, 2016.

UNDERSTANDING THE ENERGY BUSINESS

Our Energy business is made up of three groups:

- Canadian Power
- Natural Gas Storage (Canadian, non-regulated)
- U.S. Power (monetization expected to close in the first half of 2017).

Canadian Power

Western Power

We own approximately 1,000 MW of power supply through four natural gas-fired cogeneration facilities in Alberta and the Coolidge simple-cycle, natural gas peaking facility in Arizona.

A disciplined operational strategy is critical to maximizing output and revenue at our cogeneration facilities and maximizing Coolidge earnings, where revenue is based on plant availability rather than a function of market price.

Our marketing group sells uncommitted volumes from the cogeneration plants, and buys and sells power and natural gas to maximize earnings from our assets. To reduce exposure associated with uncontracted volumes, we sell a portion of our power in forward sales markets when acceptable contract terms are available. A portion of our power is retained to be sold in the spot market or under shorter-term forward arrangements. This ensures we have adequate power supply to fulfill our sales obligations if we have unexpected plant outages and provides the opportunity to increase earnings in periods of high spot prices.

In November 2016, the Government of Alberta announced plans to fully implement a process to procure additional renewable energy along with significant changes to the current energy-only market design and implement a capacity market by 2021. We will continue to monitor and participate in the industry and Government discussions on the Alberta power market to identify the impacts to our existing cogeneration facilities and opportunities for potential growth.

Eastern Power

We own or are developing approximately 3,000 MW of power generation capacity in Eastern Canada. All of the power produced by these assets is sold under long-term contracts.

Disciplined maintenance of plant operations is critical to the results of our Eastern Power assets, where earnings are based on plant availability and performance.

Bruce Power

Bruce Power is a nuclear power generation facility located near Tiverton, Ontario and is comprised of eight nuclear units with a combined capacity of approximately 6,400 MW. Bruce Power leases the eight nuclear facilities from Ontario Power Generation (OPG). We hold a 48.5 per cent ownership interest in Bruce Power.

Results from Bruce Power fluctuate primarily due to the frequency, scope and duration of planned and unplanned maintenance outages.

In December 2015, Bruce Power entered into an agreement with the IESO to extend the operating life of the Bruce Power facility to 2064. This new agreement represents an extension and material amendment to the earlier agreement that led to the refurbishment of Units 1 and 2 at the site.

The amended agreement, which took economic effect in January 2016, allows Bruce Power to immediately begin investing in life extension activities for Units 3 through 8 to support the long-term refurbishment program. This early investment in the Asset Management program will result in near-term life extension up to the major refurbishment outages and beyond. Major Component Replacement work is currently underway and will continue through 2033 with major refurbishment outages beginning in 2020.

As part of the life extension and refurbishment agreement, Bruce Power began receiving a uniform price of $65.73 per MWh for all units in January 2016, which includes certain flow-through items such as fuel and lease expense recovery. The contract 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 uniform price. Bruce Power also enters into fixed-price contracts under which it receives or pays the difference between the contract price and the spot price.

Over time, the uniform price will be subject to adjustments for the return of and on capital invested at Bruce Power under the Asset Management and Major Component Replacement capital programs, along with various other pricing adjustments that allow for a better matching of revenues and costs over the long term.

Our estimated share of investment related to the Asset Management program to be completed over the life of the agreement is approximately $2.5 billion (2014 dollars). Our estimated share of investment in the Major Component Replacement work for Units 3 through 8 over the 2020 to 2033 timeframe is approximately a further $4 billion (2014 dollars).

Under certain conditions, Bruce Power and the IESO can elect to not proceed with the remaining Major Component Replacement investments should the cost exceed certain thresholds or prove to not provide sufficient economic benefits.

Natural Gas Storage

We own and operate 118 Bcf of non-regulated natural gas storage capacity in Alberta. This business operates independently from our regulated natural gas transmission business and our regulated storage businesses. We also hold a contract for additional Alberta-based storage capacity with a third party.

Our natural gas storage business helps balance seasonal and short-term supply and demand, and adds flexibility to the delivery of natural gas to markets in Alberta and the rest of North America. Market volatility creates arbitrage opportunities and our natural gas storage facilities also give customers the ability to capture value from short-term price movements. The natural gas storage business is affected by the change in seasonal natural gas price spreads which are generally determined by the differential in natural gas prices between the traditional summer injection and winter withdrawal seasons.

Our gas storage business contracts with third parties, typically participants in the Alberta and interconnected gas markets, for a fixed fee to provide gas storage services on a short, medium, and/or long term basis.

We also enter into proprietary natural gas storage transactions, which include a forward purchase of our own natural gas to be injected into storage and a simultaneous forward sale of natural gas for withdrawal at a later period, typically during the winter withdrawal season. By matching purchase and sales volumes on a back-to-back basis, we lock in future positive margins, effectively eliminating our exposure to changes in gas prices.

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

We are currently in the process of selling 4,500 MW of power generation capacity in New York, New England and Pennsylvania. Results from our U.S. Power business will continue to be included in our earnings until the monetization of the U.S. Northeast power business is complete. The two sale transactions to monetize our U.S. Northeast power assets are expected to close in the first half of 2017 and a process is underway to monetize our marketing business.

We earn revenues in New York, PJM and New England by providing generation capacity and by selling energy. Capacity markets compensate power suppliers for being available to provide power, and are intended to promote investment in new and existing power resources needed to meet customer demand and maintain a reliable power system. Capacity revenue in New York, PJM and New England are a function of two factors, capacity prices and plant availability. The energy markets compensate power providers for the actual energy they supply.

We focus on selling power under short- and long-term contracts to wholesale, commercial and industrial customers in the following power markets:

- New York, operated by the New York ISO
- New England, operated by the New England ISO
- PJM Interconnection area (PJM).

We also earn additional revenues by bundling power sales with other energy services.

We meet our power sales commitments using power we generate ourselves or acquire at fixed prices, thereby reducing our exposure to changes in commodity prices.

SIGNIFICANT EVENTS

Canadian Power

Alberta PPAs

On March 7, 2016, we issued notice to the Balancing Pool to terminate our Alberta PPAs. On July 22, 2016, we, along with the ASTC Power Partnership, issued a notice referring 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 could have affected resolution of the arbitration of the Sheerness, Sundance A and Sundance B PPAs. In December 2016, management engaged in settlement negotiations with the Government of Alberta and finalized terms of the settlement of all legal disputes related to the PPA terminations. The Government and the Balancing Pool agreed to our termination of the PPAs resulting in the transfer of all our obligations under the PPAs to the Balancing Pool.

Upon final settlement of the PPA terminations, we transferred to the Balancing Pool a package of environmental credits held to offset the PPA emissions costs and recorded a non-cash charge of $92 million before tax ($68 million after tax) related to the carrying value of our environmental credits. In first quarter 2016, 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 previously held the Sundance B PPA.

Ontario Cap and Trade

In May 2016, legislation enabling Ontario's cap and trade program was signed into law with the new regulation taking effect July 1, 2016. This regulation sets a limit on annual province-wide greenhouse gas emissions beginning in January 2017 and introduces a market to administer the purchase and trading of emissions allowances. The regulation places the compliance obligation for emissions from our natural gas-fired power facilities on local gas distributors, with the distributors then flowing the associated costs to the facilities themselves. The IESO has proposed contract amendments for contract holders to address costs and other issues associated with this change in law. We continue to work with the IESO to finalize these amendments. We do not expect a significant overall impact to our Energy business as a result of this new regulation.

Napanee

Construction continues on a 900 MW natural gas-fired power plant at Ontario Power Generation's Lennox site in eastern Ontario in the town of Greater Napanee. We expect to invest approximately $1.1 billion in the Napanee facility during construction and commercial operations are expected to begin in 2018. Production from the facility is fully contracted with the IESO.

Bécancour

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. In November 2016, HQ released a new ten year supply plan indicating additional peak winter capacity from Bécancour is not required at this time. Prior to this development, the regulator in Québec, Régie de l'énergie, reversed its initial decision to approve this agreement. Management does not expect further developments at Bécancour until November 2019 when the next ten year supply plan is filed.

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. In February 2017, Bruce Power issued additional bonds under its financing program and distributed $362 million to TransCanada.

U.S. Power

Monetization of U.S. Northeast power business

On November 1, 2016, we announced the sale of Ravenswood, Ironwood, Ocean State Power and Kibby Wind to Helix Generation, LLC, an affiliate of LS Power Equity Advisors for US$2.2 billion and the sale of TC Hydro to Great River Hydro, LLC, an affiliate of ArcLight Capital Partners, LLC for US$1.065 billion. These two sale transactions are expected to close in the first half of 2017 subject to certain regulatory and other approvals and will include closing adjustments. These sales are expected to result in an approximate net loss of $1.2 billion before tax ($1.1 billion after tax) which is comprised of a $1,085 million goodwill impairment charge ($656 million after tax), a net loss of $829 million ($863 million after tax) on the sale of the thermal and wind package and an approximate gain of $710 million ($440 million after tax) on sale of the hydro assets to be recorded upon the close of that transaction. A process to monetize our remaining marketing business, TCPM, is underway.

FINANCIAL RESULTS

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented earnings (the equivalent GAAP measure). See page 8 for more information on non-GAAP measures we use. 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 and 2014 results have been adjusted to reflect this change.

year ended December 31 (millions of $)	**2016**	**2015**	**2014**
Canadian Power			
Western Power[1]	**75**	72	252
Eastern Power[2]	**353**	390	345
Bruce Power	**293**	285	314
Canadian Power – comparable EBITDA[1,2,3]	**721**	747	911
Depreciation and amortization	**(142)**	(190)	(179)
Canadian Power – comparable EBIT[1,2,3]	**579**	557	732
U.S. Power (US$)			
U.S. Power – comparable EBITDA	**396**	414	371
Depreciation and amortization	**(105)**	(105)	(107)
U.S. Power – comparable EBIT	**291**	309	264
Foreign exchange impact	**94**	86	27
U.S. Power – comparable EBIT (Cdn$)	**385**	395	291
Natural Gas Storage and other			
Natural Gas Storage and other – comparable EBITDA	**59**	14	43
Depreciation and amortization	**(12)**	(12)	(12)
Natural Gas Storage and other – comparable EBIT	**47**	2	31
Business Development comparable EBITDA and EBIT	**(15)**	(30)	(30)
Energy – comparable EBIT[1,2,3]	**996**	924	1,024
Specific items:			
Ravenswood goodwill impairment	**(1,085)**	—	—
Loss on U.S. Northeast power assets held for sale	**(844)**	—	—
Alberta PPA terminations and settlement	**(332)**	—	—
Turbine equipment impairment charge	**—**	(59)	—
Bruce Power merger – debt retirement charge	**—**	(36)	—
Cancarb gain on sale	**—**	—	108
Niska contract termination	**—**	—	(43)
Risk management activities	**125**	(37)	(53)
Segmented (loss)/earnings	**(1,140)**	792	1,036

1 Included Sundance A and Sheerness PPAs, and the Sundance B PPA held through our investment in ASTC Power Partnership up to March 7, 2016.
2 Includes three solar facilities acquired in September 2014 and one solar facility acquired in December 2014.
3 Includes our share of equity income from our investments in Portlands Energy and Bruce Power, and ASTC Power Partnership up to March 7, 2016.

Energy segmented earnings were $1,932 million lower in 2016 than in 2015 and $244 million lower in 2015 than in 2014 and included the following specific items:

- a $1,085 million impairment of Ravenswood goodwill in 2016. As a result of information received during the process to monetize our U.S. Northeast power business in third quarter 2016, it was determined that the fair value of Ravenswood no longer exceeds its carrying value
- a loss of $844 million before tax in 2016 which included an $829 million net loss on the thermal and wind package assets held for sale and $15 million of costs related to the monetization of our U.S. Northeast power business. See Significant Events section for more details
- a $332 million pre-tax charge in 2016 which included a $211 million impairment charge on the carrying value of our Alberta PPAs, a $29 million impairment of our equity investment in ASTC Power Partnership, and a $92 million loss on the transfer of environmental credits to the Balancing Pool upon final settlement of the PPA terminations
- a loss in 2015 of $59 million before tax relating to an impairment in value on turbine equipment previously purchased for a new power development project that did not proceed
- a charge in 2015 of $36 million before tax related to Bruce Power's retirement of debt in conjunction with the merger of the Bruce A and Bruce B partnerships
- a gain in 2014 of $108 million before tax on the sale of Cancarb Limited and its related power generation business, which closed in April 2014
- a net loss in 2014 of $43 million before tax resulting from the contract termination payment to Niska Gas Storage effective April 2014
- 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 (millions of $, pre-tax)	**2016**	**2015**	**2014**
Canadian Power	**4**	(8)	(11)
U.S. Power	**113**	(30)	(55)
Natural Gas Storage	**8**	1	13
Total unrealized gains/(losses) from risk management activities	**125**	(37)	(53)

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 particular 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 representative of our underlying operations.

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

The specific items noted above have been excluded in our calculation of comparable EBIT. The remainder of the Energy segmented earnings are equivalent to comparable EBIT which, along with comparable EBITDA, are discussed below.

Comparable EBITDA for Energy was $1,289 million in 2016 compared to $1,260 million in 2015, an increase of $29 million . The increase was the net effect of:

- higher earnings from Natural Gas Storage due to higher realized natural gas storage price spreads
- lower earnings from Eastern Power due to lower contractual earnings at Bécancour and lower contributions from the sale of unused natural gas transportation
- lower earnings from U.S. Power due to lower capacity revenues in New York and lower realized prices at our New England facilities, partially offset by higher earnings due to our acquisition of the Ironwood power plant on February 1, 2016
- lower business development expenses primarily due to decreased business development activity
- higher earnings from Bruce Power mainly due to lower depreciation as a result of the operating life extensions, our increased ownership interest and higher realized sales price, partially offset by lower volumes and higher operating costs from increased outage days
- a stronger U.S. dollar and its positive effect on the foreign exchange impact.

Comparable EBITDA for Energy was $1,260 million in 2015 compared to $1,333 million in 2014, a decrease of $73 million. This decrease was the net effect of:

- lower earnings from Western Power as a result of lower realized prices and lower PPA volumes
- higher earnings from U.S. Power due to increased margins and sales volumes to wholesale, commercial and industrial customers, partially offset by lower capacity revenue in New York and lower realized prices at our U.S. Northeast power facilities
- higher earnings from Eastern Power primarily due to four solar facilities acquired in 2014
- lower earnings from Bruce Power due to higher operating expenses mostly offset by fewer unplanned outage days at Bruce A, as well as higher operating expenses and lower gains from contracting activities, partially offset by lower lease expense at Bruce B
- lower earnings from Natural Gas Storage due to lower realized natural gas storage price spreads
- a stronger U.S. dollar and its positive effect on the foreign exchange impact.

Western and Eastern Power results

Comparable EBITDA and comparable EBIT are non-GAAP measures. See page 8 for more information. The following are the components of comparable EBITDA and comparable EBIT.

year ended December 31 (millions of $)	2016	2015	2014
Revenue[1]			
Western Power	**216**	542	747
Eastern Power[2]	**411**	455	428
Other[3]	**43**	62	85
	670	1,059	1,260
Income from equity investments[4]	**24**	8	45
Commodity purchases resold	**(60)**	(353)	(404)
Plant operating costs and other	**(206)**	(252)	(304)
Comparable EBITDA[5]	**428**	462	597
Depreciation and amortization	**(142)**	(190)	(179)
Comparable EBIT[5]	**286**	272	418
Breakdown of comparable EBITDA			
Western Power[5]	**75**	72	252
Eastern Power	**353**	390	345
Comparable EBITDA[5]	**428**	462	597
Plant availability[6]			
Western Power	**93%**	97%	96%
Eastern Power[7]	**91%**	97%	91%

1 Includes the realized gains and losses from financial derivatives used to manage Canadian Power's assets and are presented on a net basis in Western and Eastern Power revenues. The unrealized gains and losses from financial derivatives have been excluded to arrive at Comparable EBITDA.
2 Includes three solar facilities acquired in September 2014 and one solar facility acquired in December 2014.
3 Includes Revenue from the sale of unused natural gas transportation, sale of excess natural gas purchased for generation and Cancarb sales of thermal carbon black up to April 15, 2014 when it was sold.
4 Includes our share of equity income from our investments in ASTC Power Partnership, which held the Sundance B PPA, and Portlands Energy. 2016 excludes a $29 million charge related to the Sundance B PPA termination which was held in ASTC Power Partnership.
5 Included Sundance A, Sundance B and Sheerness PPAs up to March 7, 2016.
6 The percentage of time the plant was available to generate power, regardless of whether it was running.
7 Does not include Bécancour because power generation has been suspended since 2008.

Western Power

Western Power's comparable EBITDA in 2016 was $3 million higher than in 2015. The increase was due to higher realized prices on generated volumes offset by PPA losses realized in first quarter 2016.

Results from the Alberta PPAs are included up to March 7, 2016 when we sent notice to the Balancing Pool to terminate the PPAs for the Sundance A, Sundance B and Sheerness facilities. Income from equity investments included earnings from the ASTC Power Partnership which held our 50 per cent ownership in the Sundance B PPA. See the Significant Events section for more information on the PPA terminations.

Alberta power prices are impacted by several factors including the prevailing supply and demand conditions and natural gas price levels. Average spot market power prices in Alberta decreased by 45 per cent from approximately $33/MWh in 2015 to approximately $18/MWh in 2016. The average AECO natural gas price decreased by 20 per cent from approximately $2.55/GJ in 2015 to approximately $2.05/GJ in 2016. The Alberta power market remained well-supplied and power consumption was down in 2016 due to a weak economy.

Depreciation and amortization decreased by $48 million in 2016 compared to 2015 following the termination of the Alberta PPAs.

Western Power's comparable EBITDA in 2015 was $180 million lower than in 2014. The decrease was due to lower realized power prices and lower PPA volumes. Average spot market power prices in Alberta decreased by 34 per cent from approximately

$50/MWh in 2014 to approximately $33/MWh in 2015. The average AECO natural gas price decreased by 40 per cent from approximately $4.27/GJ in 2014 to approximately $2.55/GJ in 2015.

Eastern Power

Eastern Power's comparable EBITDA in 2016 was $37 million lower than 2015 due to lower contractual earnings at Bécancour and lower earnings on the sale of unused natural gas transportation.

In 2015, Eastern Power's comparable EBITDA was $45 million higher than 2014 due to the net effect of incremental earnings from solar facilities acquired in 2014, higher contractual earnings at Bécancour and lower earnings on the sale of unused natural gas transportation.

Bruce Power results

Bruce Power results reflect our proportionate share. Bruce A and B were merged in December 2015 and comparative information for 2015 and 2014 is reported on a combined basis to reflect the merged entity. Comparable EBITDA and comparable EBIT are non-GAAP measures. See page 8 for more information on non-GAAP measures we use. The following is our proportionate share of the components of comparable EBITDA and comparable EBIT.

year ended December 31 (millions of $, unless noted otherwise)	**2016**	**2015**	**2014**
Equity income included in comparable EBITDA and EBIT comprised of:			
Revenues	**1,470**	1,301	1,256
Operating expenses	**(849)**	(691)	(623)
Depreciation and other	**(328)**	(325)	(319)
Comparable EBITDA and comparable EBIT[1]	**293**	285	314
Bruce Power – other information			
Plant availability[2]	**83%**	87%	86%
Planned outage days	**415**	327	245
Unplanned outage days	**76**	45	127
Sales volumes (GWh)[1]	**22,178**	19,358	18,723
Realized sales price per MWh[3,4]	**$67**	$65	$65

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

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

3 Calculation based on actual and deemed generation. Realized sales price per MWh includes realized gains and losses from contracting activities and cost flow-through items.

4 Excludes unrealized gains and losses on contracting activities and non-electricity revenues.

Comparable EBITDA from Bruce Power in 2016 was $8 million higher than 2015. The increase was mainly due to lower depreciation as a result of the Bruce Power facility's operating life extension, our increased ownership and higher realized sales prices, partially offset by lower volumes and higher operating costs from increased outage days compared to 2015.

Comparable EBITDA from Bruce A in 2015 was $4 million lower than 2014. The decrease was mainly due to higher operating expenses, partially offset by higher volumes resulting from fewer unplanned outage days.

Comparable EBITDA from Bruce B in 2015 was $25 million lower than 2014. The decrease was mainly due to higher operating expenses and lower gains from contracting activities, partially offset by lower lease expense based on the terms of the lease agreement with OPG. All Bruce B units were removed from service in April 2015 to allow for inspection of the Bruce B vacuum building as mandated by the Canadian Nuclear Safety Commission to occur approximately once every decade.

Natural Gas Storage and other results

Comparable EBITDA in 2016 was $45 million higher than 2015, mainly due to increased third party storage revenues as a result of higher realized natural gas storage price spreads.

In 2015, comparable EBITDA was $29 million lower than 2014, mainly due to decreased proprietary and third party storage revenues as a result of lower realized natural gas storage price spreads as well as extreme natural gas price volatility experienced in first quarter 2014.

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

Comparable EBITDA and comparable EBIT are non-GAAP measures. See page 8 for more information. The following are the components of comparable EBITDA and comparable EBIT.

year ended December 31 (millions of US$)	2016	2015	2014
Revenue[1]			
Power[2]	**2,192**	1,997	1,840
Capacity	**278**	317	362
	2,470	2,314	2,202
Commodity purchases resold	**(1,595)**	(1,474)	(1,297)
Plant operating costs and other[3]	**(479)**	(426)	(534)
Comparable EBITDA[1]	**396**	414	371
Depreciation and amortization[4]	**(105)**	(105)	(107)
Comparable EBIT[1]	**291**	309	264

1 Includes Ironwood acquisition commencing February 1, 2016.
2 Includes the realized gains and losses from financial derivatives used to manage U.S. Power's assets and are presented on a net basis in power revenues. The unrealized gains and losses from financial derivatives are excluded to arrive at Comparable EBITDA.
3 Includes the costs of fuel consumed in generation.
4 U.S. Power assets held for sale no longer depreciated beginning in November 2016.

Sales volumes and plant availability

year ended December 31	2016	2015	2014
Physical sales volumes (GWh)			
Supply			
Generation[1]	**12,752**	7,849	7,742
Purchased	**26,613**	20,937	13,798
	39,365	28,786	21,540
Plant availability[2,3]	**81%**	78%	82%

1 Increase primarily due to Ironwood acquisition.
2 The percentage of time the plant was available to generate power, regardless of whether it is running.
3 Plant availability was lower in 2015 due to an unplanned outage at the Ravenswood facility. The unit returned to service in May 2015.

U.S. Power – other information

year ended December 31	2016	2015	2014
Average Spot Power Prices (US$ per MWh)			
New England[1]	**30**	42	65
New York[2]	**29**	39	61
PJM[3]	**25**	n/a	n/a
Average New York[2] Zone J Spot Capacity Prices (US$ per KW-M)	**8.65**	11.44	13.96

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

U.S. Power's comparable EBITDA in 2016 was US$18 million lower than 2015. This reflected the net effect of:

- lower capacity revenues due to lower realized capacity prices in New York and the impact of lower availability as a result of a unit outage from September 2014 to May 2015, partially offset by insurance recoveries, net of deductibles at Ravenswood
- lower realized power prices and lower generation at our facilities in New England, partially offset by lower fuel costs
- lower margins on sales to wholesale, commercial and industrial customers partially offset by higher sales to customers in the PJM market
- higher earnings due to our acquisition of the Ironwood power plant in February 2016
- insurance recoveries related to an unplanned outage at the Ravenswood facility that occurred in 2008.

In 2015, U.S. Power's comparable EBITDA was US$43 million higher than 2014. This reflected the net effect of:

- higher margins and higher sales to wholesale, commercial and industrial customers in both the PJM and New England markets
- lower realized power prices at our facilities in New York and New England, partially offset by lower fuel costs
- lower capacity revenue at Ravenswood due to lower realized capacity prices in New York and the impact of lower availability at the facility.

Average New York Zone J spot capacity prices were approximately 24 per cent lower in 2016 than in 2015. The decrease in spot prices and the impact of hedging activities resulted in lower realized capacity prices in New York. This was primarily due to an increase in demonstrated capability from existing resources in New York City's Zone J market. The impact of lower capacity prices in New York was partially offset by capacity revenues earned by our Ironwood power plant.

Capacity revenues were also negatively impacted by an outage at Unit 30 from September 2014 to May 2015 at Ravenswood. The calculation used by the NYISO to determine the capacity volume for which a generator is compensated utilizes a rolling average forced outage rate. As a result of this methodology, outages impact capacity volumes and associated revenues on a lagged basis. Accordingly, capacity revenues for the year ended December 31, 2016 were negatively impacted compared to the same period in 2015. Although the impacts of the outage continued to be included in the rolling average forced outage rate calculation throughout 2016, it will have a smaller impact in 2017 based on the calculation formula. Insurance recoveries, net of deductibles, for this event have been received and are being recognized in capacity revenues to offset amounts lost during the periods impacted by the lower forced outage rate. As a result of these insurance recoveries, the Unit 30 unplanned outage has not had a significant impact on our earnings, although the recording of earnings has not coincided exactly with lost revenues due to timing of the insurance proceeds. In addition, insurance recoveries related to an unplanned outage at the Ravenswood facility that occurred in 2008 were recognized in power revenues in second quarter 2016 and fourth quarter 2015.

Average spot power prices in 2016 in New England decreased approximately 29 per cent and in New York spot power prices decreased approximately 26 per cent compared to 2015 due to unseasonably warm weather in first quarter 2016 and lower natural gas commodity prices.

Although sales to customers in the PJM and New England wholesale utility market were higher in 2016 compared to the same period in 2015, the earnings in both markets were lower as the supply costs to serve these customers have increased.

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

OUTLOOK

Earnings

Excluding specified items, our 2017 earnings for the Energy segment are expected to be lower than 2016 primarily due to the monetization of our U.S. Northeast power business, expected to be completed in the first half of 2017, partially offset by higher equity income from Bruce Power due to lower planned maintenance activity.

The monetization of the U.S. Northeast power business results in the vast majority of Energy's remaining output being sold under long-term contracts.

Excluding specified items, Western Power earnings in 2017 are expected to be slightly higher than in 2016 due to a modest recovery of average spot power prices from low prices experienced in 2016 and the termination of the Alberta PPAs.

Eastern Power earnings in 2017 are expected to be slightly lower than in 2016 mainly due to reduced earnings from the optimization of natural gas transportation capacity. All of our energy assets in Eastern Canada are fully contracted.

Bruce Power equity income in 2017 is expected to be higher than in 2016 due to lower planned maintenance activity. Planned maintenance is expected to occur on Bruce Unit 5 in the first half of 2017 and Units 3 and 6 in the second half of 2017. The overall average plant availability percentages in 2017 are expected to be approximately 90 per cent compared to the low 80s in 2016.

Natural Gas Storage earnings in 2017 are expected to be slightly lower than in 2016 due to a forecasted return to normal winter weather conditions resulting in lower seasonal natural gas storage price spreads. The opportunity to hedge available storage capacity at higher natural gas storage price spreads is expected to partially mitigate the impact of lower spreads.

Capital spending

We spent a total of $0.5 billion in 2016 and expect to spend approximately $0.4 billion on capital projects in Energy in 2017, primarily on Napanee.

Equity investments

We invested $0.2 billion for capital projects at Bruce Power in 2016 and expect to invest approximately $0.4 billion in 2017.

BUSINESS RISKS

The following are risks specific to our Energy business. See page 92 for information about general risks that affect the Company as a whole, including other operational risks, HSE risks, and financial risks.

Fluctuating power and natural gas market prices

Power and natural gas prices are affected by fluctuations in supply and demand, weather, and by general economic conditions. The power generation facilities in our Western Power operations in Alberta are exposed to commodity price volatility. Earnings from these businesses are generally correlated to the prevailing power supply and demand conditions.

Our portfolio of assets in Eastern Canada and our Coolidge facility are fully contracted, and are therefore not materially impacted by fluctuating commodity prices. As these contracts expire in the long term, it is uncertain if we will be able to re-contract on similar terms.

To mitigate the impact of power price volatility in Alberta and the U.S. Northeast, we sell a portion of our supply under contracts where terms are acceptable. A portion of our power is retained to be sold in the spot market or under shorter-term forward arrangements to ensure we have adequate power supply to fulfill sales obligations if unexpected plant outages occur. This unsold supply is exposed to fluctuating power and natural gas market prices. As power sales contracts expire, new forward contracts are entered into at prevailing market prices.

Our natural gas storage business is subject to fluctuating seasonal natural gas price spreads which are generally determined by the differential in natural gas prices between the traditional summer injection and winter withdrawal seasons.

Plant availability

Optimizing and maintaining plant availability is essential to the continued success of our Energy business. Unexpected outages or extended planned outages at our power plants can increase maintenance costs, lower plant output and sales revenue, and lower capacity payments and margins. We may also have to buy power or natural gas on the spot market to meet our delivery obligations.

We manage this risk by investing in a highly skilled workforce, operating prudently, running comprehensive, risk-based preventive maintenance programs and making effective capital investments.

Execution and capital costs

We make substantial capital commitments developing power generation infrastructure based on the assumption that these assets will deliver an attractive return on investment. While we carefully consider the scope and expected costs of our capital projects, we are exposed to execution and capital cost overrun risk which may impact our return on these projects. We mitigate this risk by implementing comprehensive project governance and oversight processes and through the structuring of commercial arrangements where certain execution and capital cost risks may be shared with counterparties.

Regulatory

We operate in both regulated and deregulated power markets in both the United States and Canada. These markets are subject to various federal, state and provincial regulations in both countries. As power markets evolve across North America, there is the potential for regulatory bodies to implement new rules that could negatively affect us as a generator and marketer of electricity.

These may be in the form of market rule changes, changes in the interpretation and application of market rules by regulators, price caps, emission controls, emissions costs, cost allocations to generators and out-of-market actions taken by others to build excess generation, all of which negatively affect the price of power or capacity, or both. In addition, our development projects rely on an orderly permitting process and any disruption to that process can have negative effects on project schedules and costs. We are an active participant in formal and informal regulatory proceedings and take legal action where required.

Weather

Significant changes in temperature and other weather events have many effects on our business, ranging from the impact on demand, availability and commodity prices, to efficiency and output capability. Extreme temperature and weather can affect market demand for power and natural gas and can lead to significant price volatility. Extreme weather can also restrict the availability of natural gas and power if demand is higher than supply. Seasonal changes in temperature can reduce the efficiency of our natural gas-fired power plants, and the amount of power they produce. Variable wind speeds affect earnings from our wind assets, and sun-light hours and intensity affects earnings from our solar assets.

Competition

We face various competitive forces that impact our existing assets and prospects for growth. For instance, our existing power plants in Alberta will compete over time with new power capacity. New supply could come in several forms including supply that employs more efficient power generation technologies, additional supply from regional power transmission interconnections and new supply in the form of distributed generation. We also face competition from other power companies in the greenfield power plant development arena.

U.S. Power capacity payments

A significant portion of revenues earned by our U.S. Northeast operations come from capacity payments where prices are determined in various competitive auctions. Fluctuations in capacity prices can have a material impact on these businesses. Auction pricing results are impacted by the prevailing supply and demand conditions for capacity and other factors. All three U.S. Northeast capacity markets where we have assets feature demand curve price setting processes driven by a number of established parameters and other rules that are subject to periodic review and revisions by the respective ISOs and FERC.

Hydrology

Our hydroelectric power generation facilities in the U.S. Northeast are subject to hydrology risks that can impact the volume of water available for generation at these facilities including weather changes and events, local river management and potential dam failures at these plants or upstream facilities.

Corporate

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented losses (the equivalent GAAP measure). See page 8 for more information on non-GAAP measures we use. 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 and 2014 results have been adjusted to reflect this change.

year ended December 31 (millions of $)	**2016**	**2015**	**2014**
Comparable EBITDA	**(70)**	(108)	(64)
Depreciation and amortization	**(48)**	(31)	(23)
Comparable EBIT	**(118)**	(139)	(87)
Specific items:			
Acquisition related costs – Columbia	**(116)**	—	—
Restructuring costs	**(22)**	(99)	—
Segmented losses	**(256)**	(238)	(87)

Corporate segmented losses in 2016 increased by $18 million compared to 2015 and included the following specific items that have been excluded in comparable EBIT:

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

Corporate segmented losses in 2015 increased by $151 million compared to 2014 due to severance costs and expected future losses under lease commitments that have been excluded in comparable EBIT.

Comparable EBITDA in 2015 included the portion of our corporate restructuring costs that were recovered through our tolling mechanisms.

The increase in Corporate depreciation in 2016 compared to 2015 reflected incremental depreciation on our Corporate capital additions in 2016, including in Columbia.

Corporate restructuring and business transformation

In mid-2015, we commenced a business restructuring and transformation initiative. While there was no change to our corporate strategy, we undertook this initiative to reduce overall costs and maximize the effectiveness and efficiency of our existing operations.

Restructuring costs consist primarily of severance and expected future losses under lease commitments. In 2015, we incurred $122 million before tax of restructuring costs and recorded a provision of $87 million before tax related to planned severance costs in 2016 and 2017 and expected future losses under lease commitments.

In 2016, an additional provision of $44 million before tax was recorded related to changes to the expected future losses under lease commitments. Approximately $157 million and $22 million was recorded in plant operating costs and other in the consolidated statement of income for the years ended December 31, 2015 and 2016, respectively. In 2015, $58 million was recorded in revenues in the consolidated statement of income related to costs that were recoverable through regulatory and tolling structures. In addition, $44 million and $22 million was recorded as a regulatory asset on the consolidated balance sheet at December 31, 2015 and 2016, respectively, as these amounts are expected to be recovered through regulatory and tolling structures in future periods, and $8 million was capitalized in 2015 to projects impacted by the corporate restructuring.

Changes in the restructuring liability were as follows:

(millions of $)	**Employee Severance**	**Lease Commitments**	**Total**
Restructuring liability at December 31, 2015	60	27	87
Restructuring charges	—	44	44
Cash payments	(24)	(8)	(32)
Restructuring liability at December 31, 2016	**36**	**63**	**99**

As a result of the Columbia acquisition, our restructuring and business transformation initiative has been extended into 2017, and will be broadened to include additional synergies expected from cost saving efforts related to the acquisition. Benefits, in the form of enhanced business efficiencies and effectiveness, will be reflected in savings related to the execution of our capital programs, flow-through amounts to customers under established regulatory and commercial arrangements, and increased earnings.

OTHER INCOME STATEMENT ITEMS

Interest Expense

year ended December 31 (millions of $)	**2016**	**2015**	**2014**
Interest on long-term debt and junior subordinated notes			
Canadian dollar-denominated	**(452)**	(437)	(443)
U.S. dollar-denominated	**(1,127)**	(911)	(854)
Foreign exchange impact	**(366)**	(255)	(90)
	(1,945)	(1,603)	(1,387)
Other interest and amortization expense	**(114)**	(47)	(70)
Capitalized interest	**176**	280	259
Interest expense included in comparable earnings	**(1,883)**	(1,370)	(1,198)
Specific item:			
Acquisition related costs – Columbia	**(115)**	—	—
Interest expense	**(1,998)**	(1,370)	(1,198)

Interest expense in 2016 was $628 million higher than in 2015 due to the net effect of:

- the specific item of $115 million included the dividend equivalent payments of $109 million on the subscription receipts issued to partially fund the Columbia acquisition and $6 million of other acquisitions related costs. See the Financial condition section for more information.
- long term debt issuances in 2016 and 2015 partially offset by Canadian and U.S. dollar-denominated debt maturities. See the Financial condition section on page 78 for details on long term debt
- debt acquired in the acquisition of Columbia on July 1, 2016
- higher foreign exchange on interest expense related to U.S. dollar-denominated debt
- amortization expense on debt issuance costs related to the acquisition bridge facilities
- higher carrying charges to shippers in 2016 on the net revenue variance for Canadian Mainline
- 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 Napanee.

Interest expense in 2015 was $172 million higher than 2014 due to the net effect of:

- long term debt issuances in 2015 and 2014 partially offset by Canadian and U.S. dollar-denominated debt maturities
- a stronger U.S dollar and its effect on interest expense related to U.S. dollar-denominated debt
- lower carrying charges to shippers in 2015 on the net revenue variance for Canadian Mainline
- higher capitalized interest primarily due to capital spending on liquids projects, LNG projects and Napanee, partially offset by lower capitalized interest on the completion of the Gulf Coast expansion of the Keystone Pipeline System in first quarter 2014.

Allowance for funds used during construction

year ended December 31 (millions of $)	2016	2015	2014
Allowance for funds used during construction			
Canadian dollar-denominated	**181**	119	61
U.S. dollar-denominated	**181**	137	67
Foreign exchange impact	**57**	39	8
Allowance for funds used during construction	**419**	295	136

In 2016, AFUDC was $124 million higher than 2015 due to capital expenditures on our NGTL System expansion, Energy East, Columbia and Mexico pipelines projects.

In 2015, AFUDC was $159 million higher than 2014 due to capital expenditures on our Mexico pipelines, Energy East and NGTL System expansion projects.

Interest income and other

year ended December 31 (millions of $)	2016	2015	2014
Interest income and other included in comparable earnings	**71**	(111)	(24)
Specific items:			
Acquisition related costs – Columbia	**6**	—	—
Risk management activities	**26**	(21)	(21)
Interest income and other	**103**	(132)	(45)

In 2016 interest income and other was $235 million higher than 2015 due to a net effect of:

- interest income on the gross proceeds of the subscription receipts issued to partially fund the Columbia acquisition. See the Financial condition section for more information
- unrealized gains on risk management activities in 2016 compared to losses in 2015. These amounts have been excluded from comparable earnings
- realized gains in 2016 compared to realized losses in 2015 on derivatives used to manage our net exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income
- the impact of a fluctuating U.S. dollar on the translation of foreign currency denominated working capital.

In 2015, interest income and other was $87 million lower than 2014 due to a net effect of:

- higher realized losses in 2015 compared to 2014 on derivatives used to manage our net exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income
- the impact of a fluctuating U.S dollar on the translation of foreign currency denominated working capital.

Income tax expense

year ended December 31 (millions of $)	2016	2015	2014
Income tax expense included in comparable earnings	**(841)**	(903)	(859)
Specific items:			
Ravenswood goodwill impairment	**429**	—	—
Loss on U.S. Northeast power assets held for sale	**(29)**	—	—
Alberta PPA terminations and settlement	**88**	—	—
Acquisition related costs – Columbia	**10**	—	—
Keystone XL income tax recoveries	**28**	—	—
Keystone XL asset costs	**10**	—	—
Restructuring costs	**6**	25	—
TC Offshore loss on sale	**1**	39	—
Keystone XL impairment charge	**—**	795	—
Turbine equipment impairment charge	**—**	16	—
Bruce Power merger – debt retirement charge	**—**	9	—
Alberta corporate income tax rate increase	**—**	(34)	—
Cancarb gain on sale	**—**	—	(9)
Niska contract termination	**—**	—	11
Gas Pacifico/INNERGY gain on sale	**—**	—	(1)
Risk management activities	**(54)**	19	27
Income tax expense	**(352)**	(34)	(831)

Income tax expense included in comparable earnings decreased $62 million in 2016 compared to 2015 mainly because of lower flow-through taxes in 2016 on Canadian regulated pipelines and changes in the proportion of income earned between Canadian and foreign jurisdictions partially offset by higher pre-tax earnings in 2016 compared to 2015.

Income tax expense included in comparable earnings increased $44 million in 2015 compared to 2014 because of higher pre-tax earnings in 2015 compared to 2014 and changes in the proportion of income earned between Canadian and foreign jurisdictions.

Net income attributable to non-controlling interests

year ended December 31 (millions of $)	2016	2015	2014
Net income attributable to non-controlling interests included in comparable earnings	**(257)**	(205)	(153)
Specific items:			
Acquisition related costs – Columbia	**5**	—	—
TC PipeLines, LP – Great Lakes impairment	**—**	199	—
Net income attributable to non-controlling interests	**(252)**	(6)	(153)

Net income attributable to non-controlling interests increased by $246 million in 2016 compared to 2015 due to the net effect of a $5 million charge in 2016 related to the non-controlling interests portion of retention and severance expenses resulting from the Columbia acquisition and a US$199 million impairment charge recorded by TC PipeLines, LP in 2015 related to their equity investment goodwill in Great Lakes. Both of these items have been excluded in the calculation of comparable earnings. On consolidation, we recorded the non-controlling interests' 72 per cent of this TC PipeLines, LP impairment charge, which was US $143 million, or $199 million (in Canadian dollars). TC PipeLines, LP's impairment charge is not recognized at the TransCanada consolidation level as a result of our lower carrying value of Great Lakes. See Critical accounting estimates section on page 100 for more information on our goodwill impairment testing.

Net income attributable to non-controlling interests included in comparable earnings increased by $52 million in 2016 compared to 2015 primarily due to the acquisition of Columbia which included a non-controlling interest in CPPL. In addition, the sale of our 30 per cent direct interest in GTN in April 2015 and a 49.9 per cent interest in PNGTS in January 2016 to TC PipeLines, LP along with the impact of a stronger U.S. dollar on the Canadian dollar equivalent earnings from TC PipeLines, LP increased net income attributable to non-controlling interests year-over-year.

Net income attributable to non-controlling interests included in comparable earnings increased $52 million in 2015 compared to 2014 due to higher earnings resulting from the sale of our remaining 30 per cent direct interests in GTN in April 2015 and Bison in October 2014 to TC PipeLines, LP along with the impact of a stronger U.S. dollar on the Canadian dollar equivalent earnings from TC PipeLines, LP.

Preferred share dividends

year ended December 31 (millions of $)	**2016**	**2015**	**2014**
Preferred share dividends	**(109)**	(94)	(97)

Preferred share dividends increased $15 million to $109 million in 2016 compared to $94 million in 2015 due to the issuance of Series 13 and Series 15 preferred shares in April 2016 and November 2016. See Financial condition section on page 78 for more information.

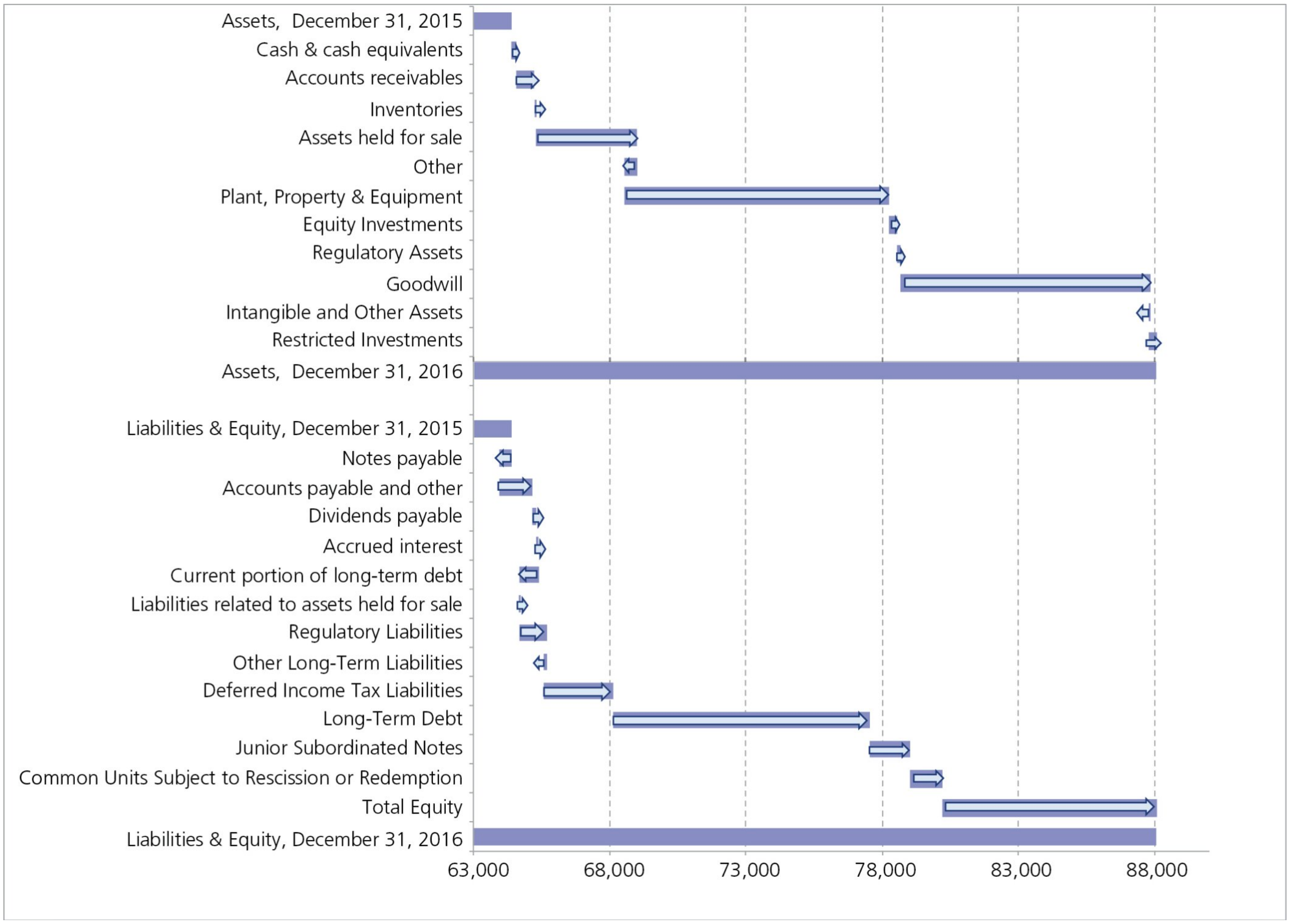
Financial condition

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 predictable and growing cash flow from operations, access to capital markets, DRP, portfolio management including proceeds from the drop down of natural gas pipeline assets to TC PipeLines, LP, cash on hand and substantial committed credit facilities.

Balance sheet analysis

As of December 31, 2016, assets increased by $24 billion, liabilities increased by $15 billion and equity, including common units subject to rescission or redemption, increased by $9 billion compared to December 31, 2015.

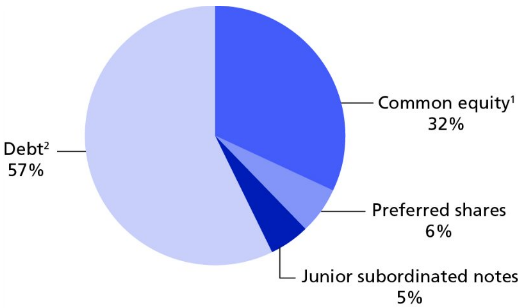


The acquisition of Columbia on July 1, 2016 and related financing activities resulted in significant increases to our assets, liabilities and equity. Also impacting the balance sheet in 2016 was the pending sales of our U.S. Northeast power assets as we have classified these as assets held for sale. Aside from the Columbia acquisition, the increase in liabilities was mainly due to the 2016 issuances of long-term debt and junior subordinated debt exceeding repayments and increased regulatory liabilities for the Canadian Mainline.

The increase in equity in 2016 was mainly due to common equity issuances to finance the acquisition of Columbia, and additional preferred share issuances.

Consolidated capital structure

at December 31, 2016



1 Includes non-controlling interests in TC PipeLines, LP and Portland.

2 Net of cash.

As at December 31, 2016, we had unused capacity of $2.0 billion, $1.0 billion and US$2.8 billion under our equity, Canadian debt and U.S. debt shelf prospectuses, respectively, to facilitate future access to the debt and equity markets.

We were in compliance with all of our financial covenants at December 31, 2016. Provisions of various trust indentures and credit arrangements with certain of our subsidiaries can restrict those subsidiaries' ability to declare and pay dividends or make distributions under certain circumstances. If such restrictions apply, they may, in turn, have an impact on our ability to declare and pay dividends on our common and preferred shares. In the opinion of management, these provisions do not currently restrict or alter our ability to declare or pay dividends. These trust indentures and credit arrangements also require us to comply with various affirmative and negative covenants and maintain certain financial ratios.

Cash flow

The following tables summarize the consolidated cash flow of our business.

year ended December 31 (millions of $)	**2016**	**2015**	**2014**
Net cash provided by operations	**5,069**	4,384	4,226
Net cash used in investing activities	**(18,783)**	(4,879)	(4,291)
	(13,714)	(495)	(65)
Net cash provided by/(used in) financing activities	**14,007**	744	(373)
	293	249	(438)
Effect of foreign exchange rate changes on Cash and Cash Equivalents	**(127)**	112	—
Net change in Cash and Cash Equivalents	**166**	361	(438)

We continue to fund our capital program through cash flow from operations, capital market financing activities, DRP proceeds and portfolio management including the drop down of our U.S. natural gas pipeline assets to TC PipeLines, LP.

Liquidity will continue to be comprised of predictable cash flow from operations, committed credit facilities, our ability to access debt and equity markets, portfolio management including additional drop downs of our U.S. natural gas pipeline assets into TC PipeLines, LP and cash on hand.

The drop down of our U.S. natural gas pipeline assets into TC PipeLines, LP remains an important financing lever for us as we execute our capital growth program, subject to actual funding needs, market conditions, the relative attractiveness of alternate capital sources and the approvals of TC PipeLines, LP's board and our board.

Net cash provided by operations

year ended December 31 (millions of $)	2016	2015	2014
Net cash provided by operations	**5,069**	4,384	4,226
(Decrease)/increase in operating working capital	**(248)**	346	189
Funds generated from operations	**4,821**	4,730	4,415
Specific items:			
Acquisition related costs - Columbia	**283**	—	—
Keystone XL asset costs	**52**	—	—
Loss on U.S. Northeast power assets held for sale	**15**	—	—
Restructuring costs	**—**	85	—
Niska contract termination	**—**	—	43
Comparable funds generated from operations	**5,171**	4,815	4,458
Dividends on preferred shares	**(100)**	(92)	(94)
Distributions paid to non-controlling interests	**(279)**	(224)	(178)
Maintenance capital expenditures including equity investments	**(1,127)**	(937)	(781)
Comparable distributable cash flow	**3,665**	3,562	3,405
Comparable distributable cash flow per common share	**$4.83**	$5.02	$4.81

Net cash provided by operations

Net cash provided by operations increased in 2016 compared to 2015 due to higher comparable earnings (as discussed in Financial highlights on page 18) and the timing of working capital changes.

Comparable funds generated from operations

Comparable funds generated from operations, a non-GAAP measure, helps us assess the cash generating ability of our operations excluding the timing effects of working capital changes. See page 8 for more information about non-GAAP measures. The increase in 2016 compared to 2015 was driven by the increase in comparable earnings (as discussed in Financial highlights on page 18) adjusted for the following non-cash items: increased deferred income tax expense, increased depreciation, higher equity AFUDC income and higher equity earnings. Comparable funds generated from operations also reflected higher distributions from operating activities of equity investments, primarily from our U.S. natural gas pipelines.

At December 31, 2016, our current assets were higher than our current liabilities, leaving us with a working capital surplus of $0.4 billion. This short-term surplus is primarily the result of the pending sale of our U.S. Northeast power assets which have been reclassified to assets held for sale. Without the assets held for sale classified as current on the balance sheet, we would be in a working capital deficit which is considered to be in the normal course of a growing business and is managed through:

- our ability to generate predictable and growing cash flow from operations
- our access to capital markets
- approximately $9.6 billion of unutilized unsecured credit facilities.

Comparable distributable cash flow

Comparable distributable cash flow, a non-GAAP measure, helps us assess the cash available to common shareholders before capital allocation. The increases from 2015 to 2016 as well as 2014 to 2015 were driven by increases in funds generated from operations, as described above, partially offset by higher maintenance capital expenditures primarily on Columbia pipelines since the acquisition on July 1, 2016 and on ANR in 2016 and 2015. See page 8 for more information on non-GAAP measures we use.

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

year ended December 31 (millions of $)	2016	2015	2014
Canadian Natural Gas Pipelines	344	347	355
U.S. Natural Gas Pipelines	464	298	151
Other	319	292	275
Maintenance capital expenditures including equity investments	1,127	937	781

Net cash used in investing activities

year ended December 31 (millions of $)	2016	2015	2014
Capital spending			
Capital expenditures	**(5,007)**	(3,918)	(3,489)
Capital projects in development	**(295)**	(511)	(848)
	(5,302)	(4,429)	(4,337)
Contributions to equity investments	**(765)**	(493)	(256)
Acquisitions, net of cash acquired	**(13,608)**	(236)	(241)
Proceeds from sale of assets, net of transaction costs	**6**	—	196
Other distributions from equity investments	**727**	9	12
Deferred amounts and other	**159**	270	335
Net cash used in investing activities	**(18,783)**	(4,879)	(4,291)

Our 2016 capital expenditures were incurred primarily for:

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

Our 2015 capital expenditures were incurred primarily for expanding the NGTL System, Canadian Mainline and ANR plus construction of our Mexican pipelines, Northern Courier and the Napanee power generating facility.

Our 2014 capital expenditures were incurred primarily for expanding the NGTL System and ANR plus construction of our Mexican pipelines and Houston Lateral and Tank Terminal.

Costs incurred on capital projects in development from 2014 to 2016 primarily related to the Energy East and LNG pipeline projects.

Contributions to equity investments increased in 2016 compared to 2015 primarily due to our investments in Bruce Power, Grand Rapids and Sur de Texas. Contributions increased in 2015 compared to 2014 primarily due to our investments in Bruce Power and Grand Rapids.

On July 1, 2016, we acquired 100 per cent ownership of Columbia for US$10.3 billion in cash.

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

On March 31, 2016, we sold TC Offshore for $6 million.

On February 1, 2016, we acquired the Ironwood power plant for US$653 million in cash after post-acquisition adjustments.

In 2015, we acquired an additional ownership interest in Bruce Power. In 2014, we acquired an additional four solar facilities in Ontario and sold Cancarb and its related power generation facilities.

The increase from 2015 to 2016 in Other distributions from equity investments is primarily due to distributions from Bruce Power. In second quarter 2016, Bruce Power issued bonds and borrowed under its bank credit facility as part of its financing program to fund its capital program and make distributions to its partners which resulted in $725 million being received by us.

Net cash provided by/(used in) financing activities

year ended December 31 (millions of $)	2016	2015	2014
Notes payable (repaid)/issued, net	**(329)**	(1,382)	544
Long-term debt issued, net of issue costs	**12,333**	5,045	1,403
Long-term debt repaid	**(7,153)**	(2,105)	(1,069)
Junior subordinated notes issued, net of issue costs	**1,549**	917	—
Dividends and distributions paid	**(1,815)**	(1,762)	(1,617)
Common shares issued, net of issue costs	**7,747**	27	47
Common shares repurchased	**(14)**	(294)	—
Preferred shares issued, net of issue costs	**1,474**	243	440
Partnership units of subsidiary issued, net of issue costs	**215**	55	79
Preferred shares of subsidiary redeemed	**—**	—	(200)
Net cash provided by/(used in) financing activities	**14,007**	744	(373)

Cash provided by financing activities was $14 billion in 2016 mainly due to the common share issuances and acquisition bridge facilities to finance the Columbia acquisition. The details of our financing activities are outlined below.

Long-term debt issued

(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	3.69% [2]
	June 2016	Medium Term Notes	June 2046	700	4.35%
	January 2016	Senior Unsecured Notes	January 2026	US 850	4.875%
	January 2016	Senior Unsecured Notes	January 2019	US 400	3.125%
	November 2015	Senior Unsecured Notes	November 2017	US 1,000	1.625%
	October 2015	Medium Term Notes	November 2041	400	4.55%
	July 2015	Medium Term Notes	July 2025	750	3.3%
	March 2015	Senior Unsecured Notes	March 2045	US 750	4.6%
	January 2015	Senior Unsecured Notes	January 2018	US 500	1.875%
	January 2015	Senior Unsecured Notes	January 2018	US 250	Floating
	February 2014	Senior Unsecured Notes	March 2034	US 1,250	4.63%
TRANSCANADA PIPELINE USA LTD.					
	June 2016	Acquisition Bridge Facility[1]	June 2018	US 1,700	Floating
ANR PIPELINE COMPANY					
	June 2016	Senior Unsecured Notes	June 2026	US 240	4.14%
TUSCARORA GAS TRANSMISSION COMPANY					
	April 2016	Term Loan	April 2019	US 10	Floating
TC PIPELINES, LP					
	September 2015	Unsecured Term Loan	October 2018	US 170	Floating
	March 2015	Senior Unsecured Notes	March 2025	US 350	4.375%
GAS TRANSMISSION NORTHWEST LLC					
	June 2015	Unsecured Term Loan	June 2019	US 75	Floating

1 These facilities were put in place to finance a portion of the Columbia acquisition and bear interest at LIBOR plus an applicable margin. Proceeds from the monetization of the U.S. Northeast power business will be used to repay these facilities.

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

The net proceeds of the above debt, other than the acquisition bridge facilities, were used for general corporate purposes, to fund our capital program and to repay existing debt.

Long-term debt retired/repaid

(millions of $) Company	Retirement/ repayment date	Type	Amount	Interest rate
TRANSCANADA PIPELINES LIMITED				
	February 2017	Acquisition Bridge Facility	US 500	Floating
	January 2017	Medium Term Notes	300	5.1%
	November 2016	Acquisition Bridge Facility[1]	US 3,200	Floating
	October 2016	Medium Term Notes	400	4.65%
	June 2016	Senior Unsecured Notes	US 84	7.69%
	June 2016	Senior Unsecured Notes	US 500	Floating
	January 2016	Senior Unsecured Notes	US 750	0.75%
	August 2015	Debentures	150	11.9%
	June 2015	Senior Unsecured Notes	US 500	3.4%
	March 2015	Senior Unsecured Notes	US 500	0.875%
	January 2015	Senior Unsecured Notes	US 300	4.875%
	June 2014	Debentures	125	11.1%
	February 2014	Medium Term Notes	300	5.05%
	January 2014	Medium Term Notes	450	5.65%
NOVA GAS TRANSMISSION LTD.				
	February 2016	Debentures	225	12.2%
	June 2014	Debentures	53	11.2%
GAS TRANSMISSION NORTHWEST LLC				
	June 2015	Senior Unsecured Notes	US 75	5.09%

1 Proceeds from the November 2016 common equity offering were used to partially repay the acquisition bridge facilities.

Junior subordinated notes issued

(millions of $) Company	Issue date	Type	Maturity date	Amount	Interest rate
TRANSCANADA PIPELINES LIMITED					
	August 2016	Junior subordinated notes[1,2]	August 2076	US 1,200	6.125% [3]
	May 2015	Junior subordinated notes[1,4]	May 2075	US 750	5.875% [5]

1 The Junior subordinated notes are subordinated in right of payment to existing and future senior indebtedness or other obligations of TCPL. The Junior subordinated notes were issued to TransCanada Trust (the Trust), a financing trust subsidiary wholly-owned by TCPL. While the obligations of the Trust are fully and unconditionally guaranteed by TCPL on a subordinated basis, the Trust is not consolidated in TransCanada's financial statements because TCPL does not have a variable interest in the Trust and the only substantive assets of the Trust are junior subordinated notes of TCPL.

2 The Junior subordinated notes are callable at TCPL's option at any time on or after August 15, 2026 at 100 per cent of the principal amount plus accrued and unpaid interest to the date of redemption.

3 The interest rate is fixed at 6.125 per cent per annum and will reset starting August 2026 until August 2046 to the three month LIBOR plus 4.89 per cent per annum; from August 2046 to August 2076 the interest rate will reset to the three month LIBOR plus 5.64 per cent per annum.

4 The Junior subordinated notes are callable at TCPL's option at any time on or after May 20, 2025 at 100 per cent of the principal amount plus accrued and unpaid interest to the date of redemption.

5 The interest rate is fixed at 5.875 per cent per annum and will reset starting May 2025 until May 2045 to the three month LIBOR plus 3.778 per cent per annum; from May 2045 to May 2075 the interest rate will reset to the three month LIBOR plus 4.528 per cent per annum.

On August 15, 2016, the Trust, a wholly owned financing trust subsidiary of TCPL, issued US$1.2 billion of Trust Notes to third party investors with a fixed interest rate of 5.875 per cent for the first ten years converting to a floating rate thereafter. The proceeds of the Trust Notes were loaned to TCPL through the subscription for US$1.2 billion of junior subordinated notes of TCPL at an initial fixed rate of 6.125 per cent, which includes a 0.25 per cent administration charge.

In May 2015, the Trust issued US$750 million of Trust Notes to third party investors with a fixed interest rate of 5.625 per cent for the first ten years converting to a floating rate thereafter. The proceeds of the the Trust Notes were loaned to TCPL through the subscription for US$750 million of junior subordinated notes of TCPL at an initial fixed rate of 5.875 per cent, which includes a 0.25 per cent administration charge.

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

Dividend reinvestment plan

Under our DRP, eligible holders of common and preferred shares of TransCanada can reinvest their dividends and make optional cash payments to obtain additional 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. Currently, approximately 39 per cent of common share dividends declared are designated to be reinvested in TransCanada common shares under the DRP.

Common shares issued under public offerings and subscription receipts

On November 16, 2016, we issued 60.2 million common shares at a price of $58.50 each for total proceeds of approximately $3.5 billion. Proceeds from the offering were used to repay a portion of the US$6.9 billion acquisition bridge facilities which were drawn to partially finance the closing of the Columbia acquisition.

On April 1, 2016, we issued 96.6 million subscription receipts to partially fund the Columbia acquisition at a price of $45.75 each for total proceeds of $4.4 billion. Each subscription receipt holder received one common share upon closing of the Columbia acquisition. Holders received dividend equivalent payments per subscription receipt equal to dividends declared on each common share, with the first payment on April 29, 2016 for holders of record at close of business on April 15, 2016. The second dividend equivalent payment was made on July 29, 2016 to holders of record at the close of business on June 30, 2016. For the twelve months ended December 31, 2016, $109 million of dividend equivalent payments were recorded as interest expense and have been excluded from comparable earnings.

Interest income of $6 million relating to the subscription receipts proceeds while held in escrow has also been excluded from comparable earnings.

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.

Common shares repurchased

In November 2015, we announced that the TSX approved our NCIB, which allowed for the repurchase and cancellation of up to 21.3 million of our 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. During December 2015 and January 2016, 7.1 million shares were repurchased at an average price of $43.36. The NCIB has now expired and has not been renewed. With the acquisition of Columbia, we do not anticipate further repurchases in the foreseeable future.

Preferred share issuance, redemption and conversion

In November 2016, we completed a public offering of 40 million Series 15 cumulative redeemable minimum rate reset first preferred shares at $25 per share resulting in gross proceeds of $1.0 billion. The Series 15 preferred shareholders will have the right to convert their Series 15 preferred shares into Series 16 cumulative redeemable first preferred shares on May 31, 2022 and on the last business day of May of every fifth year thereafter. The holders of Series 16 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 3.85 per cent. The fixed dividend rate on the Series 15 preferred shares was set for its initial period at 4.9 per cent per annum and will reset every five years to a rate equal to the sum of the then applicable five-year Government of Canada bond yield plus 3.85 per cent subject to a floor of not less than 4.9 per cent per annum.

In April 2016, we completed a public offering of 20 million Series 13 cumulative redeemable minimum rate reset 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.

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.

The following table summarizes the above issuance and conversion of preferred shares for the year ended December 31, 2016**:**

	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	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	5.50%	$1.375	$25.00	May 31, 2021	Series 14
Series 15	40,000	4.90%	$1.3292	$25.00	May 31, 2022	Series 16

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 date for $25.50 per share plus all accrued and unpaid dividends on such redemption date, in which case they are redeemable at $25.00 per share plus all accrued and unpaid dividends.

3 The floating quarterly dividend rate for the Series 6 preferred shares is 2.073 per cent at December 31, 2016 and will reset every quarter going forward. The dividend rate was reset, effective January 30, 2017, to 2.013 per cent up to but excluding April 29, 2017.

In June 2015, holders of 5.5 million Series 3 cumulative redeemable first preferred shares exercised their option to convert to Series 4 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 1.28 per cent which will reset every quarter going forward. The fixed dividend rate on the remaining Series 3 preferred shares was reset for five years at 2.152 per cent per annum. Such rate will reset every five years.

In March 2015, we completed a public offering of 10 million Series 11 cumulative redeemable first preferred shares at $25 per share resulting in gross proceeds of $250 million. The Series 11 preferred shareholders will have the right to convert their Series 11 preferred shares into Series 12 cumulative redeemable first preferred shares on November 30, 2020 and on November 30 of every fifth year thereafter. The holders of Series 12 preferred shares will be entitled to receive quarterly floating rate cumulative dividends at an annual rate equal to the applicable 90-day Government of Canada treasury bill rate plus 2.96 per cent. The fixed dividend rate on the Series 11 preferred shares was set for its initial period at 3.8 per cent per annum.

In December 2014, holders of 12.5 million Series 1 cumulative redeemable first preferred shares exercised their option to convert to Series 2 cumulative redeemable first preferred shares and receive quarterly floating quarterly dividend at an annual rate equal to the applicable 90-day Government of Canada treasury bill rate and 1.92 per cent which will reset every quarter going forward. The fixed dividend rate on the remaining Series 1 preferred shares was reset for five years at 3.266 per cent per annum. Such rate will reset every five years.

In March 2014, TCPL redeemed all four million of its Series Y preferred shares at a price of $50 per share plus $0.2455 representing accrued and unpaid dividends. The total face value of the outstanding Series Y shares was $200 million and they carried an aggregate of $11 million in annualized dividends.

In January 2014, we completed a public offering of 18 million Series 9 cumulative redeemable first preferred shares at $25 per share resulting in gross proceeds of $450 million. The Series 9 preferred shareholders will have the right to convert their Series 9 preferred shares into Series 10 cumulative preferred shares on October 30, 2019 and on October 30 of every fifth year thereafter. The holders of Series 10 preferred shares will be entitled to receive quarterly floating rate cumulative dividends at an annual rate equal to the applicable 90-day Government of Canada bond treasury bill plus 2.35 per cent. The fixed dividend rate on the Series 9 preferred shares was set for its initial period at 4.25 per cent per annum.

The net proceeds of the above preferred share offerings were used for general corporate purposes and to reduce short-term indebtedness which was used to fund our capital program.

TC PipeLines, LP

At-the-market equity issuance program

Under the TC PipeLines, LP at-the-market equity issuance program (ATM program), TC PipeLines, LP is authorized to offer and sell common units having an aggregate offering price of up to US$200 million. Our ownership interest in TC PipeLines, LP decreases as a result of equity issuances under the ATM program.

In 2016, 3.1 million common units were issued under the TC PipeLines, LP ATM program generating net proceeds of approximately US$164 million. At December 31, 2016, our ownership interest in TC PipeLines, LP had decreased to 26.8 per cent as a result of issuances under the ATM program.

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.

Asset drop downs

On January 1, 2016, we closed the sale of a 49.9 per cent interest of our total 61.7 per cent interest in PNGTS to TC PipeLines, LP for US$223 million including the assumption of US$35 million of proportional PNGTS debt.

In April 2015, we closed the sale of our remaining 30 per cent directly held interest in GTN to TC PipeLines, LP, for an aggregate purchase price of US$457 million. Proceeds were comprised of US$264 million in cash, the assumption of US$98 million in proportional GTN debt and US$95 million of new Class B units of TC PipeLines, LP.

In October 2014, we closed the sale of our remaining 30 per cent directly held interest in Bison to TC PipeLines, LP, for cash proceeds of US$215 million.

Credit facilities

We have several committed credit facilities that support our commercial paper programs and provide short-term liquidity for general corporate purposes as well as acquisition bridge facilities to support the interim financing of the Columbia acquisition. In addition, we have demand credit facilities that are also used for general corporate purposes, including issuing letters of credit and providing additional liquidity.

At December 31, 2016, we had a total of $11.1 billion (2015 – $8.9 billion) of committed revolving and demand credit facilities and $4.9 billion of acquisition bridge facilities including:

Amount	Unused capacity	Borrower	Description	Matures
$3 billion	$3 billion	TCPL	Committed, syndicated, revolving, extendible credit facility that supports TCPL's Canadian commercial paper program and for general corporate purposes	December 2021
US$2 billion	—	TCPL	Committed, syndicated, senior asset bridge term loan commitment that supports the acquisition of Columbia	June 2018
US$2 billion	US$2 billion	TCPL	Committed, syndicated, revolving, extendible credit facility that supports TCPL's U.S. commercial paper program	December 2017
US$1.7 billion	—	TCPL USA	Committed, syndicated, senior asset bridge term loan commitment that supports the acquisition of Columbia	June 2018
US$1 billion	US$0.9 billion	TCPL USA	Committed, syndicated, revolving, extendible credit facility that is used for TCPL USA general corporate purposes, guaranteed by TCPL	December 2017
US$1 billion	US$1 billion	Columbia	Committed, syndicated, revolving, extendible credit facility that is issued for Columbia's general corporate purposes and provides additional liquidity, guaranteed by TCPL	December 2017
US$0.5 billion	US$0.5 billion	TAIL	Committed, syndicated, revolving, extendible credit facility that supports TAIL's commercial paper program, guaranteed by TCPL	December 2017
$2.1 billion	$0.7 billion	TCPL/TCPL USA	Supports the issuance of letters of credit and provides additional liquidity	Demand

At December 31, 2016, our operated affiliates had an additional $0.6 billion (2015 – $0.6 billion) of undrawn capacity on committed credit facilities.

Contractual obligations

Our contractual obligations include our long-term debt, operating leases, purchase obligations and other liabilities incurred in our business such as environmental liability funds and employee retirement and post-retirement benefit plans.

Payments due (by period)

at December 31, 2016 (millions of $)	Total	less than 12 months	12 – 36 months	37 – 60 months	more than 60 months
Notes payable	774	774	—	—	—
Long-term debt (includes junior subordinated notes)	44,301	1,838	10,683	4,927	26,853
Operating leases (future payments for various premises, services and equipment, less sub-lease receipts)	1,099	124	222	135	618
Purchase obligations	6,191	3,602	1,398	397	794
Other long-term liabilities reflected on the balance sheet	195	19	39	40	97
	52,560	6,357	12,342	5,499	28,362

Long-term debt

At the end of 2016, we had $40.2 billion of long-term debt and $3.9 billion of junior subordinated notes outstanding, compared to $31.5 billion of long-term debt and $2.4 billion of junior subordinated notes at December 31, 2015.

Total notes payable were $0.8 billion at the end of 2016 compared to $1.2 billion at the end of 2015.

We attempt to spread out the maturity profile of our debt. The weighted-average maturity of our long-term debt is 17 years, with the majority maturing beyond five years.

Interest payments

At December 31, 2016, scheduled interest payments related to our long-term debt and junior subordinated notes were as follows:

at December 31, 2016 (millions of $)	**Total**	**less than 12 months**	**12 – 36 months**	**37 – 60 months**	**more than 60 months**
Long-term debt	29,033	1,940	3,450	2,955	20,688
Junior subordinated notes	7,767	144	289	289	7,045
	36,800	2,084	3,739	3,244	27,733

Operating leases

Our operating leases for premises, services and equipment expire at different times between now and 2052. Some of our operating leases include the option to renew the agreement for one to 25 years.

Our commitments at December 31, 2016 include future payments related to our U.S. Northeast power business. At the close of the sale of Ravenswood, our commitments are expected to decrease by $54 million in 2017 and 2018, $35 million in 2019 and $106 million in 2022 and beyond.

Purchase obligations

We have purchase obligations that are transacted at market prices and in the normal course of business, including long-term natural gas transportation and purchase arrangements.

Capital expenditure commitments include obligations related to the construction of growth projects and are based on the projects proceeding as planned. Changes to these projects, including cancellation, would reduce or possibly eliminate these commitments as a result of cost mitigation efforts.

Payments due (by period)[1]

at December 31, 2016 (millions of $)	Total	less than 12 months	12 – 36 months	37 – 60 months	more than 60 months
Canadian Natural Gas Pipelines					
Transportation by others[2]	267	77	102	63	25
Capital spending[3]	755	737	17	1	—
Other	2	2	—	—	—
U.S. Natural Gas Pipelines					
Transportation by others[2]	925	179	221	136	389
Capital spending[3]	77	77	—	—	—
Mexico Natural Gas Pipelines					
Capital spending[3]	2,060	1,555	505	—	—
Liquids Pipelines					
Capital spending[3]	167	167	—	—	—
Other	30	6	9	6	9
Energy					
Commodity purchases	485	245	221	19	—
Capital spending[3]	510	407	95	8	—
Other[4]	720	75	145	129	371
Corporate					
Information technology and other	193	75	83	35	—
	6,191	3,602	1,398	397	794

1 The amounts in this table exclude funding contributions to our pension plans.
2 Demand rates are subject to change. The contractual obligations in the table are based on demand volumes only and exclude commodity charges incurred when volumes flow.
3 Amounts include capital expenditures, capital projects under development and contribution to equity investments for capital projects, are estimates and are subject to variability based on timing of construction and project enhancements.
4 Includes estimates of certain amounts which are subject to change depending on plant-fired hours, use of natural gas storage facilities, the consumer price index, actual plant maintenance costs, plant salaries as well as changes in regulated rates for transportation.

Outlook

We are developing quality projects under our long-term $71 billion capital program. These long-life infrastructure assets are supported by long-term commercial arrangements and, once completed, are expected to generate significant growth in earnings and cash flow.

Our $71 billion capital program is comprised of $23 billion of near-term projects and $48 billion of commercially secured medium and longer-term projects, each of which are subject to key commercial or regulatory approvals. The portfolio is expected to be financed through our growing internally generated cash flow, common shares issued under our DRP and a combination of funding options including:

- senior debt
- project financing
- preferred shares
- hybrid securities
- additional drop downs of our U.S. natural gas pipeline assets to TC PipeLines, LP
- asset sales
- potential involvement of strategic or financial partners
- portfolio management.

Additional financing alternatives available include the establishment of a TransCanada Corporation ATM program, if appropriate, or, lastly, discrete common equity issuances.

GUARANTEES

Bruce Power

We and our partner, BPC Generation Infrastructure Trust, have each severally guaranteed a Bruce Power contingent financial obligation related to a lease agreement. The Bruce Power guarantee has a term to 2018.

At December 31, 2016, our share of the potential exposure under the Bruce Power guarantee was estimated to be $88 million. The carrying amount of the guarantee was estimated to be $1 million.

Sur de Texas and other jointly owned entities

We and our partners in certain other jointly owned entities have also guaranteed (jointly, severally, or jointly and severally) 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. The guarantees have terms ranging to 2040.

Our share of the potential exposure under these assurances was estimated at December 31, 2016 to be a maximum of $892 million. The carrying amount of these guarantees was $81 million, and is included in other long-term liabilities. In some cases, if we make a payment that exceeds our ownership interest, the additional amount must be reimbursed by our partners.

OBLIGATIONS – PENSION AND OTHER POST-RETIREMENT PLANS

In 2017, we expect to make funding contributions of approximately $100 million for the defined benefit pension plans, approximately $7 million for the other post-retirement benefit plans and approximately $51 million for the savings plan and defined contribution pension plans. In addition, we expect to provide a $20 million letter of credit to the Canadian defined benefit plan for the funding of solvency requirements.

In 2016, we made funding contributions of $111 million to our defined benefit pension plans, $8 million for the other post-retirement benefit plans and $52 million for the savings plan and defined contribution pension plans. We also provided a $20 million letter of credit to a defined benefit plan in lieu of cash funding.

Outlook

The next actuarial valuation for our pension and other post-retirement benefit plans will be carried out as at January 1, 2017. Based on current market conditions, we expect funding requirements for these plans to approximate 2016 levels for several years. This will allow us to amortize solvency deficiencies in the plans, in addition to normal funding costs.

Our net benefit cost for our defined benefit and other post-retirement plans decreased to $116 million in 2016 from $146 million in 2015, mainly due to a higher expected returns on increased plan assets.

Future net benefit costs and the amount we will need to contribute to fund our plans will depend on a range of factors, including:

- interest rates
- actual returns on plan assets
- changes to actuarial assumptions and plan design
- actual plan experience versus projections
- amendments to pension plan regulations and legislation.

We do not expect future increases in the level of funding needed to maintain our plans to have a material impact on our liquidity.

Other information

RISKS AND RISK MANAGEMENT

The following is a summary of general risks that affect our company. You can find risks specific to each operating business segment in the business segment discussions.

Risk management is integral to the successful operation of our business. Our strategy is to ensure that our risks and related exposures are in line with our business objectives and risk tolerance.

We build risk assessment into our decision-making processes at all levels.

The Board's Governance Committee oversees our risk management activities, which includes ensuring that there are appropriate management systems in place to manage our risks, including adequate Board oversight of our risk management policies, programs and practices. Other Board committees oversee specific types of risk: the Audit Committee oversees management's role in monitoring financial risk, the Human Resources Committee oversees executive resourcing and compensation, organizational capabilities and compensation risk, and the Health, Safety and Environment Committee oversees operational, safety and environmental risk through regular reporting from management.

Our executive leadership team is accountable for developing and implementing risk management plans and actions, and effective risk management is reflected in their compensation.

Operational risks

Risk and Description	Impact	Monitoring and Mitigation
Business interruption		
Operational risks, including labour disputes, equipment malfunctions or breakdowns, acts of terror and sabotage, or natural disasters and other catastrophic events.	Decrease in revenues, increase in operating costs or legal proceedings or other expenses all of which could reduce our earnings. Losses not covered by insurance could have an adverse effect on operations, cash flow and financial position.	We have incident, emergency and crisis management systems to ensure an effective response to minimize further loss or injuries and to enhance our ability to resume operations. We also have a Business Continuity Program that determines critical business processes and develops resumption plans to ensure process continuity. We have comprehensive insurance to mitigate certain of these risks, but insurance does not cover all events in all circumstances.
Reputation and relationships		
Our reputation and relationship with Indigenous communities and our stakeholders including other communities, landowners, governments and government agencies, and environmental non-governmental organizations is very important.	These Indigenous communities and stakeholders can have a significant impact on our operations, infrastructure development and overall reputation.	Our Stakeholder Engagement Framework is our formal commitment to stakeholder engagement. Our four core values – safety, integrity, responsibility and collaboration – are at the heart of our commitment to stakeholder engagement, and guide us in our interactions with stakeholders. Additionally, our Indigenous Relations and Native American Relations Policies guide our engagement with Indigenous communities. We also have specific stakeholder programs that set requirements, assess risks and ensure compliance with legal and policy requirements.
Execution and capital costs		
Investing in large infrastructure projects involves substantial capital commitments and associated execution risks based on the assumption that these assets will deliver an attractive return on investment in the future.	While we carefully consider the expected cost of our capital projects, under some contracts we bear capital cost overrun and schedule risk which may decrease our return on these projects.	Under some contracts, we share the cost of execution risks with customers, in exchange for the potential benefit they will realize when the project is finished.

Risk and Description	Impact	Monitoring and Mitigation
Cyber security		
We rely on our information technology to process, transmit and store electronic information, including information we use to safely operate our assets. TransCanada and other energy infrastructure companies in jurisdictions where we do business and around the globe, continue to face cyber security risks. Cyber security events could be directed against companies in the energy infrastructure industry.	A breach in the security of our information technology could expose our business to a risk of loss, misuse or interruption of critical information and functions. This could affect our operations, damage our assets, result in safety incidents, damage to the environment, reputational harm, competitive disadvantage, regulatory enforcement actions and potential litigation, which could have a material adverse effect on our operations, financial position and results of operations.	We have a comprehensive cyber security strategy which aligns with industry and recognized standards for cyber security. This strategy includes cyber security risk assessments, continuous monitoring of networks and other information sources for threats to the organization, comprehensive incident response plans/processes and a cyber security awareness program for employees. We have insurance which covers reasonably foreseeable losses due to damage to our facilities, and losses incurred by others, as a result of a cyber security event. These polices do not, however, cover losses that may result from a cyber security event that prevents us from operating our facilities but does not result in any physical damage.

Health, safety and environment

The Health, Safety and Environment (HSE) committee of TransCanada's Board of Directors (the Board) oversees operational risk, people and process safety, security of personnel and environmental risks, and monitors compliance with our HSE corporate policy through regular reporting from management. We have a management system that establishes a framework for managing HSE issues that is used to capture, organize, document, monitor and improve our related policies, programs and procedures.

Our management system for HSE is modeled after international standards, conforms to external industry consensus standards and voluntary programs, and complies with applicable legislative requirements and various other internal management systems. It follows a continuous improvement cycle organized into four key areas:

- planning – risk and regulatory assessment, objectives and targets, and structure and responsibility
- implementing – development and implementation of programs, plans, procedures and practices aimed at operational risk management
- reporting – document and records management, communication and reporting
- action – ongoing audit and review of HSE performance.

The HSE committee reviews HSE performance and risk management. It receives detailed reports on:

- overall HSE corporate governance
- operational performance and preventive maintenance metrics
- asset integrity programs
- emergency preparedness, incident response and evaluation
- people and process safety performance metrics
- developments in and compliance with applicable legislation and regulations.

The HSE committee also receives updates on any specific areas of operational and construction risk management review being conducted by management and the results and corrective action plans emanating from internal and third party audits.

The safety of our employees, contractors and the public, as well as the integrity of our existing and newly-developed infrastructure is a top priority. All assets are designed, constructed and commissioned with full consideration given to safety and integrity, and are brought into service only after all necessary requirements have been satisfied. In 2016, we spent $809 million for pipeline integrity on the natural gas and liquids pipelines we operate, a $6 million increase over 2015. The 2016 integrity spending is inclusive of assets acquired as part of the Columbia acquisition in 2016 as well as spending related to the 2016 repair and remediation of a leak on the Keystone Pipeline System in South Dakota. Pipeline integrity spending will fluctuate due to annual risk assessments that are conducted of the pipeline system along with evaluating information obtained from recent inspections and maintenance activities. Under the approved regulatory models in Canada, non-capital pipeline integrity expenditures on NEB-regulated pipelines are generally treated on a flow-through basis and, as a result, these expenditures have minimal impact on our earnings. Under Keystone Pipeline System contracts, pipeline integrity expenditures are recovered through the tolling mechanism and, as a result, these expenditures generally have no impact on our earnings.

Our Energy operations spending associated with process safety and our various integrity programs is used to minimize risk to employees and the public, process equipment, the surrounding environment, and to prevent disruptions to serving the energy needs of our customers.

Our main environmental risks are:

- changing regulations and costs associated with our emissions of air pollutants and GHG
- product releases, including crude oil and natural gas, into the environment (land, water and air)
- use, storage and disposal of chemicals and hazardous materials
- conformance and compliance with corporate and regulatory policies and requirements and new regulations.

As described in the Business interruption section above, we have a set of procedures in place to manage our response to natural disasters which include catastrophic events such as forest fires, tornadoes, earthquakes, floods, volcanic eruptions and hurricanes. The procedures, which are included in our Emergency Management Program, are designed to help protect the health and safety of our employees, minimize risk to the public and limit any adverse impacts on the environment.

Environmental compliance and liabilities

Our facilities are subject to federal, state, provincial and local environmental statutes and regulations governing environmental protection, including air and GHG emissions, water quality, wastewater discharges and waste management. Our facilities are required to obtain and comply with a wide variety of environmental registrations, licenses, permits and other approvals and requirements. Failure to comply could result in administrative, civil or criminal penalties, remedial requirements or orders affecting future operations.

Through implementing our Environment Program, we continually monitor our facilities to ensure compliance with all environmental requirements. We routinely monitor proposed changes in environmental policy, legislation and regulation, and where the risks are potentially large or uncertain, we comment on proposals independently or through industry associations.

We are not aware of any material outstanding orders, claims or lawsuits against us related to releasing or discharging any material into the environment or in connection with environmental protection.

Compliance obligations can result in significant costs associated with installing and maintaining pollution controls, fines and penalties resulting from any failure to comply, and potential limitations on operations.

Remediation obligations can result in significant costs associated with the investigation and remediation of contaminated properties, and with damage claims arising from the contamination of properties.

It is very difficult to estimate the amount and timing of all our future expenditures related to environmental matters because:

- environmental laws and regulations (and interpretation and enforcement of them) change
- new claims can be brought against our existing or discontinued assets
- our pollution control and clean up cost estimates may change, especially when our current estimates are based on preliminary site investigation or agreements
- we may find new contaminated sites, or what we know about existing sites could change
- where there is potentially more than one responsible party involved in litigation, we cannot estimate our joint and several liability with certainty.

At December 31, 2016, we had accrued approximately $39 million related to these obligations (2015 - $32 million). This represents the amount that we have estimated that we will need to manage our currently known environmental liabilities. We believe that we have considered all necessary contingencies and established appropriate reserves for environmental liabilities; however, there is the risk that unforeseen matters may arise requiring us to set aside additional amounts. We adjust reserves regularly to account for changes in liabilities.

Greenhouse gas emissions regulation risk

We own assets and have business interests in a number of regions where there are regulations to address industrial GHG emissions, including GHG pricing policies. We recorded $62 million of expenses under existing GHG pricing programs in 2016 (2015 - $59 million). Across North America there are a variety of new and evolving initiatives in development at the federal, regional, state and provincial level aimed at achieving GHG emission reductions through direct or indirect means. We actively monitor and submit comments to regulators as these new and evolving initiatives are undertaken. We expect that, over time, most of our facilities will be subject to some form of regulation to manage GHG emissions.

Existing policies

- the U.S. Environmental Protection Agency published regulations related to fugitive methane emissions for new and modified compressor stations in the natural gas transmission and storage sector in 2015. We will continue to monitor this matter
- B.C. has a tax on GHG emissions from fossil fuel combustion. We recover the compliance costs through the tolls our customers pay
- under the SGER in Alberta, established industrial facilities with GHG emissions above a certain threshold have to reduce their emissions below an intensity baseline. The SGER program covers our natural gas pipelines and energy assets, which included our Sundance and Sheerness PPAs up to March 7, 2016. Natural gas pipeline compliance costs are recovered through the tolls our customers pay. A portion of the compliance costs for the Energy assets are recovered through market pricing and hedging activities. We announced plans to terminate the Alberta PPAs in 2016 and the transfer to the Balancing Pool occurred on January 10, 2017
- Québec and California have GHG cap and trade programs linked under the Western Climate Initiative (WCI) GHG emissions market. In Québec, the Bécancour cogeneration plant is required to cover its GHG emissions. The government allocates free emission units for the majority of Bécancour's compliance requirements. The remaining requirements were met with GHG instruments purchased at auctions or secondary markets. The costs of these emissions units were recovered through commercial contracts. The Canadian Mainline natural gas pipeline facilities in Québec are also covered under this program and have purchased compliance instruments. In California, TransCanada has costs associated with the cap and trade program from our power marketing activities
- U.S. northeastern states that are members of the RGGI have implemented a CO_2 cap and trade program for electricity generators. This program applies to both the Ravenswood and Ocean State Power generation facilities. We expect to monetize our U.S. Northeast power business in the first half of 2017, subject to regulatory and other approvals.

Anticipated policies

- future legislative and regulatory programs could significantly restrict emissions of GHGs including methane across our operations
- the Government of Canada has proposed a federal plan to have carbon pricing in place in all Canadian jurisdictions in 2018. The plan may expand GHG pricing coverage of TransCanada assets to Saskatchewan, Manitoba and New Brunswick and is within the bounds of our previously anticipated changes to GHG regulations
- the Alberta government announced a new climate change policy, the Climate Leadership Plan (CLP), in 2015. This policy is expected to see the replacement of the SGER program with a performance standard-based GHG pricing program in 2018. Alberta’s carbon levy, introduced in January 2017, is another component of the CLP. Sites covered under the requirements of the SGER or performance standard are exempt from paying the carbon levy
- Ontario launched a cap and trade program under the WCI on January 1, 2017. The Canadian Mainline assets in the province and Bruce Power LP are required by law to participate in the program
- Washington State adopted emission standards to cap and reduce GHGs from certain stationary sources in September 2016. Gas Transmission Northwest compressor stations in Washington are potentially eligible parties to the standards in 2017.

Financial risks

We are exposed to market risk, counterparty credit risk and liquidity risk, and have strategies, policies and limits in place to mitigate their impact on our earnings, cash flow and, ultimately, shareholder value.

These strategies, policies and limits are designed to ensure our risks and related exposures are in line with our business objectives and risk tolerance. We manage market risk and counterparty credit risk within limits that are ultimately established by the Board, implemented by senior management and monitored by our risk management and internal audit groups. Management monitors compliance with market and counterparty risk management policies and procedures, and reviews the adequacy of the risk management framework, overseen by the Audit Committee. Our internal audit group assists the Audit Committee by carrying out regular and ad-hoc reviews of risk management controls and procedures, and reporting up to the Audit Committee.

Market risk

We build and invest in energy infrastructure projects, buy and sell energy commodities, issue short-term and long-term debt (including amounts in foreign currencies) and invest in foreign operations. Certain of these activities expose us to market risk from changes in commodity prices and foreign exchange and interest rates which may affect our earnings and the value of the financial instruments we hold. We assess contracts used to manage market risk to determine whether all, or a portion, meets the definition of a derivative.

Derivative contracts we use to assist in managing our exposure to market risk include:

- forwards and futures contracts – agreements to buy or sell a financial instrument or commodity at a specified price and date in the future. We use foreign exchange and commodity forwards and futures to manage the impact of changes in interest rates, foreign exchange rates and commodity prices
- swaps – agreements between two parties to exchange streams of payments over time according to specified terms. We use interest rate, cross-currency and commodity swaps to manage the impact of changes in interest rates, foreign exchange rates and commodity prices
- options – agreements that give the purchaser the right (but not the obligation) to buy or sell a specific amount of a financial instrument or commodity at a fixed price, either at a fixed date or at any time within a specified period. We use option agreements to manage the impact of changes in interest rates, foreign exchange rates and commodity prices.

Commodity price risk

We are exposed to changes in commodity prices which may affect our earnings. We use several strategies to reduce this exposure, including:

- committing a portion of expected power supply to fixed price sales contracts of varying terms while reserving a portion of our unsold power supply to mitigate operational and price risk in our asset portfolio
- purchasing a portion of the natural gas we need to fuel our natural gas-fired power plants in advance or entering into contracts that base the sale price of our electricity on the cost of the natural gas, effectively locking in a margin
- meeting our power sales commitments using power we generate ourselves or with power we buy at fixed prices, reducing our exposure to changes in commodity prices
- using derivative instruments to enter into offsetting or back-to-back positions to manage commodity price risk created by certain fixed and variable prices in arrangements for different pricing indices and delivery points.

Foreign exchange and interest rate risk

We generate revenues and incur expenses that are denominated in currencies other than Canadian dollars. As as result, our earnings and cash flows are exposed to fluctuations.

A portion of our businesses generate earnings in U.S. dollars, but since we report our financial results 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. We manage this using a combination of interest rate swaps and options.

Average exchange rate – U.S. to Canadian dollars

2016	**1.33**
2015	1.28
2014	1.10

The impact of changes in the value of the U.S. dollar on our U.S. 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 page 8 for more information.

Significant U.S. dollar-denominated amounts

year ended December 31 (millions of US$)	2016	2015	2014
U.S. Natural Gas Pipelines comparable EBIT	**970**	569	502
Mexico Natural Gas Pipelines comparable EBIT	**218**	132	119
U.S. Liquids Pipelines comparable EBIT	**493**	633	561
U.S. Power comparable EBIT	**291**	309	264
U.S. dollar-denominated allowance for funds used during construction	**181**	137	67
Interest on U.S. dollar-denominated long-term debt	**(1,127)**	(911)	(854)
Capitalized interest on U.S. dollar-denominated capital expenditures	**22**	109	154
U.S. non-controlling interests and other	**189**	16	137
	1,237	994	950

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:

	2016		2015	
at December 31 (millions of $)	Fair value[1]	Notional or principal amount	Fair value[1]	Notional or principal amount
U.S. dollar cross-currency interest rate swaps (maturing 2017 to 2019)[2]	**(425)**	**US 2,350**	(730)	US 3,150
U.S. dollar foreign exchange forward contracts (maturing 2017)	**(7)**	**US 150**	50	US 1,800
	(432)	**US 2,500**	(680)	US 4,950

1 Fair values equal carrying values.

2 Consolidated net income in 2016 included net realized gains of $6 million (2015 – gains of $8 million) related to the interest component of cross-currency swap settlements.

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

The notional amounts and fair value of U.S. dollar-denominated debt designated as a net investment hedge were as follows:

at December 31 (millions of $)	2016	2015
Notional amount	**26,600 (US 19,800)**	23,100 (US 16,700)
Fair value	**29,400 (US 21,900)**	23,800 (US 17,200)

Counterparty credit risk

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

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

If a counterparty fails to meet its financial obligations to us according to the terms and conditions of the financial instrument, we could experience a financial loss. We manage our exposure to this potential loss using recognized credit management techniques, including:

- dealing with creditworthy counterparties – a significant amount of our credit exposure is with investment grade counterparties or, if not, is generally partially supported by financial assurances from investment grade parties
- setting limits on the amount we can transact with any one counterparty – we monitor and manage the concentration of risk exposure with any one counterparty, and reduce our exposure when we feel we need to and when it is allowed under the terms of our contracts
- using contract netting arrangements and obtaining financial assurances, such as guarantees and letters of credit or cash, when we believe it is necessary.

There is no guarantee that these techniques will protect us from material losses.

We review our accounts receivable regularly and record allowances for doubtful accounts using the specific identification method. We had no significant credit losses in 2016 and no significant amounts past due or impaired at year end. We had a credit risk concentration of $200 million (US$149 million) at December 31, 2016 with one counterparty (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.

For our Canadian regulated gas pipeline assets, counterparty credit risk is managed through application of tariff provisions as approved by the NEB.

Liquidity risk

Liquidity risk is the risk that we will not be able to meet our financial obligations as they come due. We manage our liquidity by continuously forecasting our cash flow for a 12 month period and making sure 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. See page 78 Financial condition for more information about our liquidity.

Legal proceedings

Legal proceedings, arbitrations and actions are part of doing business. While we cannot predict the final outcomes of proceedings and actions with certainty, management does not expect any current proceeding or action to have a material impact on our consolidated financial position or results of operations. Other than the Keystone XL legal proceedings described on page 52, we are not aware of any potential legal proceeding or action that would have a material impact on our consolidated financial position or results of operations.

CONTROLS AND PROCEDURES

We meet Canadian and U.S. regulatory requirements for disclosure controls and procedures, internal control over financial reporting and related CEO and CFO certifications.

Disclosure controls and procedures

Under the supervision and with the participation of management, including our President and CEO and our CFO, we carried out quarterly evaluations of the effectiveness of our disclosure controls and procedures, including for the period ended December 31, 2016, as required by the Canadian securities regulatory authorities and by the SEC. Based on this evaluation, our President and CEO and our CFO have concluded that the disclosure controls and procedures are effective in that they are designed to ensure that the information we are required to disclose in reports we file with or send to securities regulatory authorities is recorded, processed, summarized and reported within the time periods specified under Canadian and U.S. securities laws.

Management's annual report on internal control over financial reporting

We are responsible for establishing and maintaining adequate internal control over financial reporting, which is a process designed by, or under the supervision of, our President and CEO and our CFO, and effected by our board of directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with GAAP.

Under the supervision and with the participation of management, including our President and CEO and our CFO, an evaluation of the effectiveness of the internal control over financial reporting was conducted as of December 31, 2016 based on the criteria described in "Internal Control - Integrated Framework" issued in 2013 by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, management determined that, as of December 31, 2016, the internal control over financial reporting was effective.

Our evaluation did not include internal controls over financial reporting at Columbia, which we acquired July 1, 2016. The decision to exclude Columbia from our assessment in the year of acquisition is consistent with SEC guidance and is considered to be a common practice for newly acquired entities.

Assets attributable to Columbia as of December 31, 2016 represented approximately 13 per cent of our total assets as of December 31, 2016, and revenues attributable to Columbia for the period July 1, 2016 to December 31, 2016 represented approximately 7 per cent of our total revenues for the year ended December 31, 2016.

Our internal control over financial reporting as of December 31, 2016 has been audited by KPMG LLP, an independent registered public accounting firm, as stated in their attestation report which is included in this document.

CEO and CFO Certifications

Our President and CEO and our CFO have attested to the quality of the public disclosure in our fiscal 2016 reports filed with Canadian securities regulators and the SEC, and have filed certifications with them.

Changes in internal control over financial reporting

Our internal controls over financial reporting now include Columbia's systems, processes and controls, as well as additional controls designed to result in complete and accurate consolidation of Columbia's results. Other than this change, there has been no change in our internal control over financial reporting that occurred during the year covered by this annual report that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

CRITICAL ACCOUNTING ESTIMATES

When we prepare financial statements that conform with GAAP, we are required to make certain 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 judgment. We also regularly assess the assets and liabilities themselves.

The following accounting estimates require us to make the most significant assumptions when preparing our financial statements and changes in these assumptions could have a material impact on the financial statements from those estimates.

Rate-regulated accounting

Under GAAP, an asset qualifies to use RRA when it meets three criteria:

- a regulator must establish or approve the rates for the regulated services or activities
- the regulated rates must be designed to recover the cost of providing the services or products
- it is reasonable to assume that rates set at levels to recover the cost can be charged to (and collected from) customers because of the demand for services or products and the level of direct and indirect competition.

We believe that the regulated natural gas pipelines and certain liquids pipelines projects we account for using RRA meet these criteria. The most significant impact of using these principles is the timing of when we recognize certain expenses and revenues, which is based on the economic impact of the regulators' decisions about our revenues and tolls, and may be different from what would otherwise be expected under GAAP. Regulatory assets represent costs that are expected to be recovered in customer rates in future periods. Regulatory liabilities are amounts that are expected to be refunded through customer rates in future periods.

Regulatory assets and liabilities

at December 31 (millions of $)	**2016**	**2015**
Regulatory assets		
Long-term assets	**1,322**	1,184
Short-term assets (included in Other current assets)	**33**	85
Regulatory liabilities		
Long-term liabilities	**2,121**	1,159
Short-term liabilities (included in Accounts payable and other)	**178**	44

Impairment of long-lived assets and goodwill

We review long-lived assets (such as plant, property and equipment) and intangible assets for impairment whenever events or changes in circumstances lead us to believe we might not be able to recover an asset's carrying value. If the total of the undiscounted future cash flows we estimate for an asset is less than its carrying value, we consider its fair value to be less than its carrying value and we calculate and record an impairment loss to recognize this.

In 2016, the following impairments were recorded:

- a goodwill impairment charge on the full carrying value of Ravenswood goodwill of $656 million after tax
- a $244 million after-tax charge with respect to the Alberta PPA terminations.

In 2015, the following impairments were recorded:

- a $2,891 million after-tax charge on the carrying value of our investment in Keystone XL and related projects
- a loss of $43 million after tax relating to certain Energy turbine equipment.

Alberta PPA terminations

On March 7, 2016, we issued notice to the Balancing Pool of the decision to terminate our 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 SGER, we expected increasing costs related to carbon emissions to continue throughout the remaining terms of the PPAs resulting in increasing unprofitability. As such, in 2016, we recognized a non-cash impairment charge of $155 million after tax, which represented the carrying value of the PPAs. Upon final settlement of the Alberta PPA terminations in December 2016, we transferred to the Balancing Pool a package of environmental credits that were being held to offset the PPA emissions costs and recorded a non-cash charge of $68 million after tax related to the carrying value of these environmental credits.

We also recognized a non-cash impairment charge of $21 million after tax in income from equity investments which represented the carrying value of the equity investment in ASTC Partnership.

Keystone XL

At December 31, 2016, we reviewed our remaining investment in Keystone XL and related projects with a carrying value of $526 million (2015 – $621 million) and found no events or changes in circumstance indicating that the carrying value may not be recoverable.

At December 31, 2015, in connection with the denial of the U.S. Presidential permit, we evaluated our $4.3 billion investment in Keystone XL and related projects, including Keystone Hardisty Terminal, for impairment. As a result of our analysis, we determined that the carrying amount of these assets was no longer recoverable, and recognized a total non-cash impairment charge of $3.7 billion ($2.9 billion after tax). The impairment charge was based on the excess of the carrying value over the estimated fair value of $621 million.

The estimated fair value related to plant and equipment at December 31, 2015 was based on the price that would be received to sell the assets in their current condition. Key assumptions used in the determination of selling price included an estimated two year disposal period and the then current weak energy market conditions. The valuation considered a variety of potential selling prices that were based on the various markets that could be used in order to dispose of these assets.

The estimated fair value of the terminals at December 31, 2015 was determined using a discounted cash flow approach as a measure of fair value. We recorded a full impairment charge on capitalized interest and other intangible assets as these costs were no longer probable to be recovered. The impairment charge also included certain cancellation fees that will be incurred in the future if the project is ultimately abandoned.

Energy Turbine impairment

Following the evaluation of specific capital project opportunities in 2015, it was determined that the carrying value of certain Energy turbine equipment was not fully recoverable. These turbines had been previously purchased for a power development project that did not proceed. Various other projects have recently been evaluated for possible use of this equipment and we have determined there is not an appropriate operation or project in which we currently expect to economically utilize this asset. As a result, at December 31, 2015, we recognized a non-cash impairment charge of $59 million ($43 million after tax) based on the excess of the carrying value over the estimated fair value of the turbines, which was determined using a third party valuation based on a comparison to similar assets available for sale in the market.

Goodwill

We test goodwill for impairment annually or more frequently if events or changes in circumstances lead us to believe it might be impaired. We first assess qualitative factors to determine whether events or changes in circumstances indicate that goodwill might be impaired, and if we conclude that it is not more likely than not that the fair value of the reporting unit is greater than its carrying value, we use a two-step process to test for impairment:

1. First, we compare the fair value of the reporting unit to its book value, including its goodwill. If fair value is less than book value, we consider our goodwill to be impaired.
2. Next, we measure the amount of the impairment by calculating the implied fair value of the reporting unit's goodwill. We do this by deducting the fair value of the tangible and intangible net assets of the reporting unit from the fair value we calculated in the first step. If the goodwill's carrying value exceeds its implied fair value, we record an impairment charge.

We base these valuations on our projections of future cash flows, which involves making estimates and assumptions about:

- discount rates
- commodity and capacity prices
- market supply and demand assumptions
- growth opportunities
- output levels
- competition from other companies
- regulatory changes.

If our assumptions change significantly, our requirement to record an impairment charge could also change.

As a result of information received during the process to monetize our U.S. Northeast power business it was determined that the fair value of Ravenswood did not exceed its carrying value, including goodwill. The fair value of the reporting unit was determined using a combination of methods including a discounted cash flow approach and a range of expected consideration from a potential sale. The expected cash flows were discounted using a risk-adjusted discount rate to determine the fair value. As a result, we recorded a goodwill impairment charge on the full carrying value of Ravenswood goodwill of $1,085 million ($656 million after tax) within the Energy segment. The impairment charge was recorded prior to reclassification to assets held for sale.

The estimated fair value of Great Lakes' natural gas transportation business exceeded its carrying value by less than 10 per cent. The fair value of this reporting unit was measured using a discounted cash flow analysis in its most recent valuation. Assumptions used in the analysis regarding Great Lakes' ability to realize long-term value in the North American energy market included the impact of changing natural gas flows in its market region as well as a change in our view of other strategic alternatives to increase utilization of Great Lakes. Although evolving market conditions and other factors relevant to Great Lakes' long-term financial performance have remained relatively stable, there is a risk that reductions in future cash flow forecasts or adverse changes in other key assumptions could result in a future impairment of a portion of the goodwill balance relating to Great Lakes. Our share of the goodwill related to Great Lakes, net of non-controlling interests, was US$386 million at December 31, 2016 (2015 – US $386 million).

At December 31, 2016, the estimated fair value of ANR exceeded its carrying value by less than 10 per cent. The fair value of this reporting unit was measured using a discounted cash flow analysis. Assumptions regarding ANR's ability to realize long-term value depend upon trends in value for its storage services, continued growth in its asset base and favourable outcomes of future rate proceedings. We reduced long-term forecast cash flows from the reporting unit as compared to those utilized in previous impairment tests thereby reflecting the continued changes in the business environment. There is a risk that continued reductions in future cash flow forecasts and adverse changes in other key assumptions could result in a future impairment of a portion of the goodwill balance relating to ANR. The goodwill balance related to ANR at December 31, 2016 was US$1.9 billion (2015 – US$1.9 billion).

Asset retirement obligations

When there is a legal obligation to set aside funds to cover future abandonment costs, and we can reasonably estimate them, we recognize the fair value of the ARO in our financial statements.

We cannot determine when we will retire many of our hydro-electric power plants, oil pipelines, natural gas pipelines and transportation facilities and regulated natural gas storage systems because we intend to operate them as long as there is supply and demand, and so we have not recorded obligations for them.

For those we do record, we use the following assumptions:

- when we expect to retire the asset
- the scope of abandonment and reclamation activities that are required
- inflation and discount rates.

The ARO is initially recorded when the obligation exists and is subsequently accreted through charges to operating expenses.

We continue to evaluate our future abandonment obligations and costs and monitor developments that could affect the amounts we record.

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 normal 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.

Non-derivative financial instruments

Fair value of non-derivative financial instruments

The fair value of our 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 has been 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 including cash and cash equivalents, accounts receivable, intangibles and other assets, notes payable, accounts payable and other, accrued interest and other long-term liabilities have carrying amounts that equal their fair value due to the nature of the item or the short time to maturity and would 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 financial instruments.

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 effective portion of the change in the fair value of hedging derivatives for cash flow hedges and hedges of our net investment in foreign operations are recorded in OCI in the period of change. Any ineffective portion is recognized in net income in the same financial category as the underlying transaction. The change in the fair value of derivative instruments that have been designated as fair value hedges are recorded in net income in interest income and other and interest expense.

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.

The recognition of gains and losses on derivatives for Canadian natural gas regulated pipelines exposures is determined through the regulatory process. Gains and losses arising from changes in the fair value of derivatives accounted for as part of RRA, including those that qualify for hedge accounting treatment, can be recovered or refunded through the tolls charged by us. As a result, these gains and losses are deferred as regulatory assets or regulatory liabilities and are refunded to or collected from the ratepayers in subsequent years when the derivative settles.

Fair value of derivative instruments

The fair value of foreign exchange and interest rate derivatives has been calculated using the income approach which uses year-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. Credit risk has been taken into consideration when calculating the fair value of derivative instruments.

Balance sheet presentation of derivative instruments

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

at December 31 (millions of $)	**2016**	**2015**
Other current assets	**376**	442
Intangible and other assets	**133**	168
Accounts payable and other	**(607)**	(926)
Other long-term liabilities	**(330)**	(625)
	(428)	(941)

Anticipated timing of settlement – derivative instruments

The anticipated timing of settlement for derivative instruments assumes constant commodity prices, interest rates and foreign exchange rates. Settlements will vary based on the actual value of these factors at the date of settlement.

at December 31, 2016 (millions of $)	Total fair value	2017	2018 and 2019	2020 and 2021
Derivative instruments held for trading				
Assets	480	362	103	15
Liabilities	(486)	(368)	(115)	(3)
Derivative instruments in hedging relationships				
Assets	29	14	15	—
Liabilities	(451)	(239)	(212)	—
	(428)	(231)	(209)	12

Unrealized and realized gains/(losses) of derivative instruments

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

year ended December 31 (millions of $)	2016	2015
Derivative instruments held for trading[1]		
Amount of unrealized gains/(losses) in the year		
Commodities[2]	**123**	(37)
Foreign exchange	**25**	(21)
Amount of realized (losses)/gains in the year		
Commodities	**(204)**	(151)
Foreign exchange	**62**	(112)
Derivative instruments in hedging relationships		
Amount of realized (losses)/gains in the year		
Commodities	**(167)**	(179)
Foreign exchange	**(101)**	—
Interest rate	**4**	8

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 2016 announcement of our intention to sell the U.S. Northeast power assets, losses of $49 million and gains of $7 million (2015 – nil) were recorded in net income in 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 consolidated statement of OCI related to derivatives in cash flow hedging relationships including the portion attributable to non-controlling interests is as follows:

year ended December 31 (millions of $, pre-tax)	**2016**	**2015**
Change in fair value of derivative instruments recognized in OCI (effective portion)[1]		
Commodities	**39**	(92)
Interest rate	**5**	—
	44	(92)
Reclassification of gains/(losses) on derivative instruments from AOCI to net income (effective portion)[1]		
Commodities[2]	**57**	128
Interest rate[3]	**14**	16
	71	144
Losses on derivative instruments recognized in net income (ineffective portion)		
Commodities[2]	**—**	—

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 consolidated statement of income.

3 Reported within interest expense on the 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 December 31, 2016, the aggregate fair value of all derivative contracts with credit-risk-related contingent features that were in a net liability position was $19 million (2015 – $32 million), with collateral provided in the normal course of business of nil (2015 – nil). If the credit-risk-related contingent features in these agreements were triggered on December 31, 2016, we would have been required to provide additional collateral of $19 million (2015 – $32 million) to our counterparties. Collateral may also need to be provided should the fair value of derivative instruments exceed pre-defined contractual exposure limit thresholds.

We have sufficient liquidity in the form of cash and undrawn committed revolving bank lines to meet these contingent obligations should they arise.

ACCOUNTING CHANGES

Changes in accounting policies for 2016

Extraordinary and unusual income statement items

In January 2015, the Financial Accounting Standards Board (FASB) issued new guidance on extraordinary and unusual income statement items. This update eliminates the concept of extraordinary items from GAAP. This new guidance was effective January 1, 2016, was applied prospectively and did not have an impact on our consolidated financial statements.

Consolidation

In February 2015, the FASB issued new guidance on consolidation. This guidance 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 our consolidation conclusions. Disclosure requirements outlined in the new guidance are included in the notes to our consolidated financial statements.

Imputation of interest

In April 2015, the FASB issued new guidance on simplifying the accounting for debt issuance costs. This guidance requires that debt issuance costs be presented on the balance sheet as a direct deduction from the carrying amount of the related 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.

Classification of certain cash receipts and cash payments

In August 2016, the FASB issued new guidance to clarify how entities should classify certain cash receipts and cash payments on the statement of cash flows. This new guidance is effective January 1, 2018, however, since early adoption is permitted, the Company elected to retrospectively apply this guidance effective December 31, 2016. The application of this guidance did not have a material impact on the classification of debt pre-payments or extinguishment costs, contingent consideration payments made after a business combination, proceeds from the settlement of insurance claims and proceeds from the settlement of corporate owned life insurance. We have elected to classify distributions received from equity method investments using the nature of distributions approach as it is more representative of the nature of the underlying activities of the investments that generated the distributions. As a result, certain comparative period distributions received from equity method investments have been reclassified from investing activities to cash generated from operations in the consolidated statement of cash flows.

Future accounting changes

Revenue from contracts with customers

In 2014, the FASB issued new guidance on revenue from contracts with customers. Current guidance allows for revenue recognition when certain criteria are met. The new guidance requires that an entity recognize revenue in accordance with a five-step model. This model is used to depict the transfer of promised goods or services to customers in an amount that reflects the total consideration to which it expects to be entitled,during the term of the contract, in exchange for those goods or services. We will adopt this new standard on the effective date of January 1, 2018. There are two methods in which the new standard 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 evaluating both methods of adoption as we work through our analysis. We have identified all existing customer contracts that are within the scope of the new guidance and have begun to analyze individual contracts or groups of contracts to identify any significant differences and the impact on revenues as a result of implementing the new standard. As we continue our contract analysis, we will also quantify the impact, if any, on prior period revenues.

We will address any system and process changes necessary to compile the information to meet the disclosure requirements of the new standard. As we are currently evaluating the impact of this guidance, we have not yet determined the effect on our consolidated financial statements.

Inventory

In July 2015, the FASB issued new guidance on simplifying the measurement of inventory. The new guidance specifies 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 guidance 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 their 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, however we are evaluating the option to early adopt. We are currently identifying existing lease agreements that may have an impact on our consolidated financial statements as a result of adopting this new guidance.

Derivatives and hedging

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

Equity method investments

In March 2016, the FASB issued new guidance that simplifies the transition to equity method accounting. In these situations, when an increase in ownership interest in an investment qualifies it for equity method accounting, the new guidance eliminates the requirement to retroactively apply the equity method of accounting. This new guidance is effective January 1, 2017 and will be applied prospectively. We do not expect the adoption of this new guidance 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 guidance 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.

Consolidation

In October 2016, the FASB issued new guidance on consolidation relating to interests held through related parties that are under common control. The new guidance amends the consolidation requirements such that if a single decision maker is required to evaluate whether it is the primary beneficiary of a variable interest entity (VIE), it will need to consider only its proportionate indirect interest in the VIE held through a common control party. The new guidance is effective January 1, 2017 and we do not expect the adoption of this new guidance to have a material impact on our consolidated financial statements.

Income taxes

In October 2016, the FASB issued new guidance on income tax effects of intra-entity transfers of assets other than inventory. The new guidance requires the recognition of deferred and current income taxes for an intra-entity asset transfer when the transfer occurs. The new guidance is effective January 1, 2018 and will be applied on a modified retrospective basis. Early adoption is permitted. We are currently evaluating the impact of the adoption of this guidance and have not yet determined the effect on our consolidated financial statements.

Restricted cash

In November 2016, the FASB issued new guidance on restricted cash and cash equivalents on the statement of cash flows. The new guidance requires that the statement of cash flows explain the change during the period in the total cash and cash equivalents, and amounts generally described as restricted cash or restricted cash equivalents. The amounts of restricted cash and cash equivalents will be included cash and cash equivalents when reconciling the beginning-of-year and end-of-year total amounts on the statement of cash flows. This new guidance is effective January 1, 2018 and will be applied retrospectively. Early adoption is permitted. 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 COMPARABLE EBITDA AND COMPARABLE EBIT TO SEGMENTED EARNINGS

year ended December 31 (millions of $, except per share amounts)	2016	2015	2014
Comparable EBITDA			
Canadian Natural Gas Pipelines	**2,246**	2,258	2,275
U.S. Natural Gas Pipelines	**1,683**	974	767
Mexico Natural Gas Pipelines	**333**	215	164
Liquids Pipelines	**1,166**	1,309	1,046
Energy	**1,289**	1,260	1,333
Corporate	**(70)**	(108)	(64)
Comparable EBITDA	**6,647**	5,908	5,521
Depreciation and amortization	**(1,939)**	(1,765)	(1,611)
Comparable EBIT	**4,708**	4,143	3,910
Specific items:			
Ravenswood goodwill impairment	**(1,085)**	—	—
Loss on U.S. Northeast power assets held for sale	**(844)**	—	—
Alberta PPA terminations and settlement	**(332)**	—	—
Acquisition related costs – Columbia	**(179)**	—	—
Keystone XL asset costs	**(52)**	—	—
Restructuring costs	**(22)**	(99)	—
TC Offshore loss on sale	**(4)**	(125)	—
Keystone XL impairment charge	**—**	(3,686)	—
Turbine equipment impairment charge	**—**	(59)	—
Bruce Power merger – debt retirement charge	**—**	(36)	—
Cancarb gain on sale	**—**	—	108
Niska contract termination	**—**	—	(43)
Gas Pacifico/ INNERGY gain on sale	**—**	—	9
Risk management activities[1]	**123**	(37)	(53)
Segmented earnings	**2,313**	**101**	**3,931**

1

year ended December 31 (millions of $)	2016	2015	2014
Canadian Power	**4**	(8)	(11)
U.S. Power	**113**	(30)	(55)
Liquids	**(2)**	—	—
Natural Gas Storage	**8**	1	13
Total unrealized gains/(losses) from risk management activities	**123**	(37)	(53)

QUARTERLY RESULTS

Selected quarterly consolidated financial data

(unaudited, millions of $, except per share amounts)

2016	Fourth	Third	Second	First
Revenues	**3,619**	**3,632**	**2,751**	**2,503**
Net (loss)/income attributable to common shares	**(358)**	**(135)**	**365**	**252**
Comparable earnings	**626**	**622**	**366**	**494**
Comparable earnings per common share	**$0.75**	**$0.78**	**$0.52**	**$0.70**
Share statistics				
Net (loss)/income per common share – basic and diluted	**($0.43)**	**($0.17)**	**$0.52**	**$0.36**
Dividends declared per common share	**$0.565**	**$0.565**	**$0.565**	**$0.565**

2015	Fourth	Third	Second	First
Revenues	2,851	2,944	2,631	2,874
Net (loss)/income attributable to common shares	(2,458)	402	429	387
Comparable earnings	453	440	397	465
Comparable earnings per common share	$0.64	$0.62	$0.56	$0.66
Share statistics				
Net (loss)/income per common share – basic and diluted	($3.47)	$0.57	$0.60	$0.55
Dividends declared per common share	$0.52	$0.52	$0.52	$0.52

Factors affecting quarterly financial information by business segment

Quarter-over-quarter revenues and net income fluctuate for reasons that vary across our business segments.

In our Canadian Natural Gas Pipelines, U.S. Natural Gas Pipelines and Mexico Natural Gas Pipelines segments, except for seasonal fluctuations in short-term throughput volumes on U.S. pipelines, quarter-over-quarter revenues and net income generally remain relatively stable during any fiscal year. Over the long term, however, they fluctuate because of:

- regulators' 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, annual revenues and net income are based on contracted crude oil transportation and uncommitted spot transportation. Quarter-over-quarter revenues and net income are 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 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 fourth quarter 2016, comparable earnings excluded:

- an $870 million after-tax charge related to the loss on U.S. Northeast power assets held for sale which included an $863 million after-tax loss on the thermal and wind package held for sale and $7 million of after-tax costs related to the monetization
- an additional $68 million after-tax loss on the transfer of environmental credits to the Balancing Pool upon final settlement of the Alberta PPA terminations
- an after-tax charge of $67 million for costs associated with the acquisition of Columbia which included a $44 million deferred tax adjustment upon acquisition and $23 million of retention, severance and integration costs
- an after-tax charge of $18 million related to Keystone XL costs for the maintenance and liquidation of project assets which are being expensed pending further advancement of the project
- an after-tax restructuring charge of $6 million for additional expected future losses under lease commitments. These charges form part of a restructuring initiative, which commenced in 2015, to maximize the effectiveness and efficiency of our existing operations and reduce overall costs.

In third quarter 2016, comparable earnings excluded:

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

In second quarter 2016, comparable earnings excluded:

- a charge of $113 million related to costs associated with the acquisition of Columbia which included $109 million related to dividend equivalent payments on the subscription receipts
- 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 which closed in early 2016
- a net charge of $60 million after tax for our business restructuring and transformation initiative comprised of $28 million mainly related to 2015 severance costs and a provision of $32 million for 2016 planned severance costs and expected future losses under lease commitments. These charges form part of a restructuring initiative, which commenced in 2015 to maximize the effectiveness and efficiency of our existing operations and reduce overall costs
- a $43 million after-tax charge relating to an impairment in value 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.

FOURTH QUARTER 2016 HIGHLIGHTS

Consolidated results

three months ended December 31 (millions of $, except per share amounts)	2016	2015
Canadian Natural Gas Pipelines	**379**	423
U.S. Natural Gas Pipelines	**416**	99
Mexico Natural Gas Pipelines	**105**	41
Liquids Pipelines	**218**	(3,416)
Energy	**(571)**	77
Corporate	**(71)**	(144)
Total segmented earnings/(losses)	**476**	(2,920)
Interest expense	**(542)**	(380)
Allowance for funds used during construction	**97**	91
Interest income and other	**(15)**	(11)
Income/(loss) before income taxes	**16**	(3,220)
Income tax (expense)/recovery	**(274)**	646
Net loss	**(258)**	(2,574)
Net (loss)/income attributable to non-controlling interests	**(68)**	139
Net loss attributable to controlling interests	**(326)**	(2,435)
Preferred share dividends	**(32)**	(23)
Net loss attributable to common shares	**(358)**	(2,458)
Net loss per common share – basic and diluted	**($0.43)**	($3.47)

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

The 2016 results included:

- an $870 million after-tax charge related to the loss on U.S. Northeast power assets held for sale which included an $863 million after-tax loss on the thermal and wind package held for sale and $7 million of after-tax costs related to the monetization
- an additional $68 million after-tax loss on the transfer of environmental credits to the Balancing Pool upon final settlement of the Alberta PPA terminations
- an after-tax charge of $67 million for costs associated with the acquisition of Columbia which included a $44 million deferred tax adjustment upon acquisition and $23 million of retention, severance and integration costs
- an after-tax charge of $18 million related to Keystone XL costs for the maintenance and liquidation of project assets which are being expensed pending further advancement of the project
- an after-tax restructuring charge of $6 million for additional expected future losses under lease commitments. These charges form part of a restructuring initiative, which commenced in 2015, to maximize the effectiveness and efficiency of our existing operations and reduce overall costs.

The 2015 results included:

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

- a $199 million positive income adjustment related to the impact on our net income from non-controlling interests of TC PipeLines, LP's impairment of their equity investment in Great Lakes.

Net loss 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.

Reconciliation of net loss to comparable earnings

three months ended December 31 (millions of $, except per share amounts)	**2016**	**2015**
Net loss attributable to common shares	**(358)**	(2,458)
Specific items (net of tax):		
Loss on U.S. Northeast power assets held for sale	**870**	—
Alberta PPA terminations and settlement	**68**	—
Acquisition related costs – Columbia	**67**	—
Keystone XL asset costs	**18**	—
Restructuring costs	**6**	60
TC Offshore loss on sale	**—**	86
Keystone XL impairment charge	**—**	2,891
Turbine equipment impairment charge	**—**	43
Bruce Power merger – debt retirement charge	**—**	27
Non-controlling interests – (TC PipeLines, LP - Great Lakes impairment)	**—**	(199)
Risk management activities[1]	**(45)**	3
Comparable earnings	**626**	453
Net loss per common share	**($0.43)**	($3.47)
Specific items (net of tax):		
Loss on U.S. Northeast power assets held for sale	**1.05**	—
Alberta PPA terminations and settlement	**0.08**	—
Acquisition related costs – Columbia	**0.08**	—
Keystone XL asset costs	**0.02**	—
Restructuring costs	**0.01**	0.08
TC Offshore loss on sale	**—**	0.12
Keystone XL impairment charge	**—**	4.08
Turbine equipment impairment charge	**—**	0.06
Bruce Power merger – debt retirement charge	**—**	0.04
Non-controlling interests – (TC PipeLines, LP – Great Lakes impairment)	**—**	(0.28)
Risk management activities	**(0.06)**	0.01
Comparable earnings per common share	**$0.75**	$0.64

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three months ended December 31 (millions of $)	**2016**	**2015**
Canadian Power	**1**	(1)
U.S. Power	**97**	(8)
Liquids marketing	**4**	—
Natural Gas Storage	**(1)**	(1)
Foreign exchange	**(23)**	4
Income tax attributable to risk management activities	**(33)**	3
Total unrealized gains/(losses) from risk management activities	**45**	(3)

Comparable earnings

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

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

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

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

Highlights by business segment

Canadian Natural Gas Pipelines

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

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

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

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

U.S. Natural Gas Pipelines

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

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

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

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

Mexico Natural Gas Pipelines

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

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

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

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

Liquids Pipelines

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

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

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

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

Energy

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

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

Risk management activities	**three months ended December 31**	
(millions of $, pre-tax)	**2016**	**2015**
Canadian Power	**1**	(1)
U.S. Power	**97**	(8)
Natural Gas Storage	**(1)**	(1)
Total unrealized gains/(losses) from risk management activities	**97**	(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 impacts of other derivative and non-derivative transactions that make up our business as a whole. As a result, we do not consider them reflective of our underlying operations.

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

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

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

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

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

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

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

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

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

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

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

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

Glossary

Units of measure

Bbl/d	Barrel(s) per day
Bcf	Billion cubic feet
Bcf/d	Billion cubic feet per day
GWh	Gigawatt hours
km	Kilometres
KW-M	Kilowatt month
MMcf/d	Million cubic feet per day
MW	Megawatt(s)
MWh	Megawatt hours
TJ/d	Terajoule per day

General terms and terms related to our operations

bitumen	A thick, heavy oil that must be diluted to flow (also see: diluent). One of the components of the oil sands, along with sand, water and clay
cogeneration facilities	Facilities that produce both electricity and useful heat at the same time
diluent	A thinning agent made up of organic compounds. Used to dilute bitumen so it can be transported through pipelines
Eastern Triangle	Canadian Mainline region between North Bay, Toronto and Montréal
FID	Final investment decision
FIT	Feed-in tariff
force majeure	Unforeseeable circumstances that prevent a party to a contract from fulfilling it
GHG	Greenhouse gas
HSE	Health, safety and environment
investment base	Includes rate base as well as assets under construction
LNG	Liquefied natural gas
NEB 2014 Decision	In response to the RH-01-2014 Decision on the Canadian Mainline's 2015-2030 Tolls Application.
OM&A	Operating, maintenance and administration
PJM Interconnection area (PJM)	A regional transmission organization that coordinates the movement of wholesale electricity in all or parts of 13 states and the District of Columbia
PPA	Power purchase arrangement
rate base	Our annual average investment used
TSA	Transportation Service Agreements
WCSB	Western Canada Sedimentary Basin

Accounting terms

AFUDC	Allowance for funds used during construction
AOCI	Accumulated other comprehensive (loss)/income
ARO	Asset retirement obligations
DRP	Dividend reinvestment plan
GAAP	U.S. generally accepted accounting principles
FASB	Financial Accounting Standards Board (U.S.)
OCI	Other comprehensive (loss)/income
RRA	Rate-regulated accounting
ROE	Rate of return on common equity
Specific Item	Items we believe are significant but not reflective of our underlying operations in the period

Government and regulatory bodies terms

CFE	Comisión Federal de Electricidad (Mexico)
CRE	Comisión Reguladora de Energia, or Energy Regulatory Commission (Mexico)
FERC	Federal Energy Regulatory Commission (U.S.)
IESO	Independent Electricity System Operator
ISO	Independent System Operator
NAFTA	North American Free Trade Agreement
NEB	National Energy Board (Canada)
OPEC	Organization of the Petroleum Exporting Countries
OPG	Ontario Power Generation
RGGI	Regional Greenhouse Gas Initiative (northeastern U.S.)
SEC	U.S. Securities and Exchange Commission
SGER	Specified Gas Emitters Regulations

Management's Report on Internal Control over Financial Reporting

The consolidated financial statements and Management's Discussion and Analysis (MD&A) included in this Annual Report are the responsibility of the management of TransCanada Corporation (TransCanada or the Company) and have been approved by the Board of Directors of the Company. The consolidated financial statements have been prepared by management in accordance with United States generally accepted accounting principles (GAAP) and include amounts that are based on estimates and judgments. The MD&A is based on the Company's financial results. It compares the Company's financial and operating performance in 2016 to that in 2015, and highlights significant changes between 2015 and 2014. The MD&A should be read in conjunction with the consolidated financial statements and accompanying notes. Financial information contained elsewhere in this Annual Report is consistent with the consolidated financial statements.

Management is responsible for establishing and maintaining adequate internal control over financial reporting for the Company. Management has designed and maintains a system of internal control over financial reporting, including a program of internal audits to carry out its responsibility. Management believes these controls provide reasonable assurance that financial records are reliable and form a proper basis for the preparation of financial statements. The internal control over financial reporting include management's communication to employees of policies that govern ethical business conduct.

Under the supervision and with the participation of the President and Chief Executive Officer and the Chief Financial Officer, management conducted an evaluation of the effectiveness of its internal control over financial reporting based on the framework in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Management concluded, based on its evaluation, that internal control over financial reporting was effective as of December 31, 2016, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external reporting purposes.

TransCanada acquired Columbia Pipeline Group, Inc. (Columbia) on July 1, 2016. As a result, management's assessment and conclusion on the effectiveness of its internal control over financial reporting did not include internal controls over financial reporting at Columbia. These exclusions are consistent with SEC Commission Staff's guidance that the assessment of recently a acquired business may be omitted from the scope of its assessment of the effectiveness of internal control over financial reporting in the year of the acquisition. Assets attributable to Columbia represented approximately 13 per cent of TransCanada's total assets as at December 31, 2016, and revenues attributable to Columbia for the period July 1, 2016 to December 31, 2016 represented approximately 7 per cent of TransCanada's total revenues for the year ended December 31, 2016.

The Board of Directors is responsible for reviewing and approving the financial statements and MD&A and ensuring that management fulfills its responsibilities for financial reporting and internal control. The Board of Directors carries out these responsibilities primarily through the Audit Committee, which consists of independent, non-management directors. The Audit Committee meets with management at least five times a year and meets independently with internal and external auditors and as a group to review any significant accounting, internal control and auditing matters in accordance with the terms of the Charter of the Audit Committee, which is set out in the Annual Information Form. The Audit Committee's responsibilities include overseeing management's performance in carrying out its financial reporting responsibilities and reviewing the Annual Report, including the consolidated financial statements and MD&A, before these documents are submitted to the Board of Directors for approval. The internal and independent external auditors have access to the Audit Committee without the requirement to obtain prior management approval.

The Audit Committee approves the terms of engagement of the independent external auditors and reviews the annual audit plan, the Auditors' Report and the results of the audit. It also recommends to the Board of Directors the firm of external auditors to be appointed by the shareholders.

The shareholders have appointed KPMG LLP as independent external auditors to express an opinion as to whether the consolidated financial statements present fairly, in all material respects, the Company's consolidated financial position, results of operations and cash flows in accordance with GAAP. The reports of KPMG LLP outline the scope of its examinations and its opinions on the consolidated financial statements and the effectiveness of the Company's internal control over financial reporting.

Russell K. Girling
President and
Chief Executive Officer

Donald R. Marchand
Executive Vice-President and
Chief Financial Officer

February 15, 2017

Independent Auditors' Report of Registered Public Accounting Firm

To the Shareholders of TransCanada Corporation

We have audited the accompanying consolidated financial statements of TransCanada Corporation, which comprise the Consolidated balance sheets as at December 31, 2016 and December 31, 2015, the Consolidated statements of income, comprehensive income, cash flows and equity for each of the years in the three-year period ended December 31, 2016, and Notes, comprising a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with U.S. generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the Consolidated financial statements present fairly, in all material respects, the consolidated financial position of TransCanada Corporation as at December 31, 2016 and December 31, 2015, and its consolidated results of operations and its consolidated cash flows for each of the years in the three-year period ended December 31, 2016 in accordance with U.S. generally accepted accounting principles.

Other Matter

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), TransCanada Corporation's internal control over financial reporting as of December 31, 2016, based on the criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 15, 2017 expressed an unmodified (unqualified) opinion on the effectiveness of TransCanada Corporation's internal control over financial reporting.

KPMG LLP

Chartered Professional Accountants
February 15, 2017
Calgary, Canada

Report of Independent Registered Public Accounting Firm

To the Shareholders of TransCanada Corporation

We have audited TransCanada Corporation's internal control over financial reporting as of December 31, 2016, based on criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). TransCanada Corporation's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, TransCanada Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2016, based on criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

TransCanada Corporation acquired Columbia Pipeline Group, Inc. (Columbia) on July 1, 2016, and management excluded from its assessment of the effectiveness of TransCanada Corporation's internal control over financial reporting as of December 31, 2016. Columbia's internal control over financial reporting associated with total assets of $11,496 million and total revenues of $929 million included in the consolidated financial statements of TransCanada Corporation as of and for the year ended December 31, 2016. Our audit of internal control over financial reporting of TransCanada Corporation also excluded an evaluation of the internal control over financial reporting of Columbia.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Consolidated balance sheets of TransCanada Corporation as of December 31, 2016 and 2015, and the related Consolidated statements of income, comprehensive income, cash flows, and equity for each of the years in the three-year period ended December 31, 2016 and our report dated February 15, 2017 expressed an unmodified (unqualified) opinion on those consolidated financial statements.

KPMG LLP

Chartered Professional Accountants
February 15, 2017
Calgary, Canada

Consolidated statement of income

year ended December 31 (millions of Canadian $, except per share amounts)	2016	2015	2014
Revenues (Note 1)			
Canadian Natural Gas Pipelines	**3,682**	3,680	3,557
U.S. Natural Gas Pipelines	**2,526**	1,444	1,159
Mexico Natural Gas Pipelines	**378**	259	197
Liquids Pipelines	**1,755**	1,879	1,547
Energy	**4,164**	4,038	3,725
	12,505	11,300	10,185
Income from Equity Investments (Note 9)	**514**	440	522
Operating and Other Expenses			
Plant operating costs and other	**3,819**	3,250	2,973
Commodity purchases resold	**2,172**	2,237	1,836
Property taxes	**555**	517	473
Depreciation and amortization	**1,939**	1,765	1,611
Goodwill and other asset impairment charges (Note 8, 11 and 12)	**1,388**	3,745	—
	9,873	11,514	6,893
(Loss)/Gain on Assets Held for Sale/Sold (Notes 6 and 26)	**(833)**	(125)	117
Financial Charges			
Interest expense (Note 17)	**1,998**	1,370	1,198
Allowance for funds used during construction	**(419)**	(295)	(136)
Interest income and other	**(103)**	132	45
	1,476	1,207	1,107
Income/(Loss) before Income Taxes	**837**	(1,106)	2,824
Income Tax Expense/(Recovery) (Note 16)			
Current	**156**	136	145
Deferred	**196**	(102)	686
	352	34	831
Net Income/(Loss)	**485**	(1,140)	1,993
Net Income attributable to non-controlling interests (Note 19)	**252**	6	153
Net Income/(Loss) Attributable to Controlling Interests	**233**	(1,146)	1,840
Preferred share dividends	**109**	94	97
Net Income/(Loss) Attributable to Common Shares	**124**	(1,240)	1,743
Net Income/(Loss) per Common Share (Note 20)			
Basic and diluted	**$0.16**	($1.75)	$2.46
Dividends Declared per Common Share	**$2.26**	$2.08	$1.92
Weighted Average Number of Common Shares (millions) (Note 20)			
Basic	**759**	709	708
Diluted	**760**	709	710

The accompanying Notes to the consolidated financial statements are an integral part of these statements.

Consolidated statement of comprehensive income

year ended December 31 (millions of Canadian $)	2016	2015	2014
Net Income/(Loss)	**485**	(1,140)	1,993
Other Comprehensive (Loss)/Income, Net of Income Taxes			
Foreign currency translation gains on net investment in foreign operations	**3**	813	517
Change in fair value of net investment hedges	**(10)**	(372)	(276)
Change in fair value of cash flow hedges	**30**	(57)	(69)
Reclassification to net income of gains and losses on cash flow hedges	**42**	88	(55)
Unrealized actuarial losses and gains on pension and other post-retirement benefit plans	**(26)**	51	(102)
Reclassification to net income of actuarial loss and prior service costs on pension and other post-retirement benefit plans	**16**	32	18
Other comprehensive (loss)/income on equity investments	**(87)**	47	(204)
Other comprehensive (loss)/income (Note 22)	**(32)**	602	(171)
Comprehensive Income/(Loss)	**453**	(538)	1,822
Comprehensive income attributable to non-controlling interests	**241**	312	283
Comprehensive Income/(Loss) Attributable to Controlling Interests	**212**	(850)	1,539
Preferred share dividends	**109**	94	97
Comprehensive Income/(Loss) Attributable to Common Shares	**103**	(944)	1,442

The accompanying Notes to the consolidated financial statements are an integral part of these statements.

Consolidated statement of cash flows

year ended December 31 (millions of Canadian $)	2016	2015	2014
Cash Generated from Operations			
Net income/(loss)	**485**	(1,140)	1,993
Depreciation and amortization	**1,939**	1,765	1,611
Goodwill and other asset impairment charges (Notes 8, 11 and 12)	**1,388**	3,745	—
Deferred income taxes (Note 16)	**196**	(102)	686
Income from equity investments (Note 9)	**(514)**	(440)	(522)
Distributions received from operating activities of equity investments (Note 9)	**844**	793	726
Employee post-retirement benefits expense, net of funding (Note 23)	**(3)**	44	37
Loss/(gain) on assets held for sale/sold (Notes 6 and 26)	**833**	125	(117)
Equity allowance for funds used during construction	**(253)**	(165)	(95)
Unrealized (gains)/losses on financial instruments	**(149)**	58	74
Other	**55**	47	22
Decrease/(increase) in operating working capital (Note 25)	**248**	(346)	(189)
Net cash provided by operations	**5,069**	4,384	4,226
Investing Activities			
Capital expenditures (Note 4)	**(5,007)**	(3,918)	(3,489)
Capital projects in development (Note 4)	**(295)**	(511)	(848)
Contributions to equity investments (Note 9)	**(765)**	(493)	(256)
Acquisitions, net of cash acquired (Note 5 and 26)	**(13,608)**	(236)	(241)
Proceeds from sale of assets, net of transaction costs (Note 26)	**6**	—	196
Other distributions from equity investments (Note 9)	**727**	9	12
Deferred amounts and other	**159**	270	335
Net cash used in investing activities	**(18,783)**	(4,879)	(4,291)
Financing Activities			
Notes payable (repaid)/issued, net	**(329)**	(1,382)	544
Long-term debt issued, net of issue costs	**12,333**	5,045	1,403
Long-term debt repaid	**(7,153)**	(2,105)	(1,069)
Junior subordinated notes issued, net of issue costs	**1,549**	917	—
Dividends on common shares	**(1,436)**	(1,446)	(1,345)
Dividends on preferred shares	**(100)**	(92)	(94)
Distributions paid to non-controlling interests	**(279)**	(224)	(178)
Common shares issued, net of issue costs	**7,747**	27	47
Common shares repurchased (Note 20)	**(14)**	(294)	—
Preferred shares issued, net of issue costs	**1,474**	243	440
Partnership units of subsidiary issued, net of issue costs	**215**	55	79
Preferred shares of subsidiary redeemed (Note 19)	**—**	—	(200)
Net cash provided by/(used in) financing activities	**14,007**	744	(373)
Effect of Foreign Exchange Rate Changes on Cash and Cash Equivalents	**(127)**	112	—
Increase/(Decrease) in Cash and Cash Equivalents	**166**	361	(438)
Cash and Cash Equivalents			
Beginning of year	**850**	489	927
Cash and Cash Equivalents			
End of year	**1,016**	850	489

The accompanying Notes to the consolidated financial statements are an integral part of these statements.

Consolidated balance sheet

at December 31 (millions of Canadian $)		2016	2015
ASSETS			
Current Assets			
Cash and cash equivalents		**1,016**	850
Accounts receivable		**2,075**	1,387
Inventories		**368**	323
Assets held for sale (Note 6)		**3,717**	20
Other (Note 7)		**908**	1,338
		8,084	3,918
Plant, Property and Equipment (Note 8)		**54,475**	44,817
Equity Investments (Note 9)		**6,544**	6,214
Regulatory Assets (Note 10)		**1,322**	1,184
Goodwill (Note 11)		**13,958**	4,812
Intangible and Other Assets (Note 12)		**3,026**	3,102
Restricted Investments		**642**	351
		88,051	64,398
LIABILITIES			
Current Liabilities			
Notes payable (Note 13)		**774**	1,218
Accounts payable and other (Note 14)		**3,861**	2,653
Dividends payable		**526**	385
Accrued interest		**595**	520
Liabilities related to assets held for sale (Note 6)		**86**	39
Current portion of long-term debt (Note 17)		**1,838**	2,547
		7,680	7,362
Regulatory Liabilities (Note 10)		**2,121**	1,159
Other Long-Term Liabilities (Note 15)		**1,183**	1,260
Deferred Income Tax Liabilities (Note 16)		**7,662**	5,144
Long-Term Debt (Note 17)		**38,312**	28,909
Junior Subordinated Notes (Note 18)		**3,931**	2,409
		60,889	46,243
Common Units Subject to Rescission or Redemption (Note 19)		**1,179**	—
EQUITY			
Common shares, no par value (Note 20)		**20,099**	12,102
Issued and outstanding:	December 31, 2016 – 864 million shares		
	December 31, 2015 – 703 million shares		
Preferred shares (Note 21)		**3,980**	2,499
Additional paid-in capital		**—**	7
Retained earnings		**1,138**	2,769
Accumulated other comprehensive loss (Note 22)		**(960)**	(939)
Controlling Interests		**24,257**	16,438
Non-controlling interests (Note 19)		**1,726**	1,717
		25,983	18,155
		88,051	64,398

Commitments, Contingencies and Guarantees (Note 27)
Corporate Restructuring Costs (Note 28)
Variable Interest Entities (Note 29)

The accompanying Notes to the consolidated financial statements are an integral part of these statements.

On behalf of the Board:

Russell K. Girling
Director

Siim A. Vanaselja
Director

Consolidated statement of equity

year ended December 31 (millions of Canadian $)	2016	2015	2014
Common Shares			
Balance at beginning of year	**12,102**	12,202	12,149
Shares issued under public offerings, net of issue costs (Note 20)	**7,752**	—	—
Shares issued under dividend reinvestment and share purchase plan (Note 20)	**177**	—	—
Shares issued on exercise of stock options (Note 20)	**74**	30	53
Shares repurchased (Note 20)	**(6)**	(130)	—
Balance at end of year	**20,099**	12,102	12,202
Preferred Shares			
Balance at beginning of year	**2,499**	2,255	1,813
Shares issued under public offering, net of issue costs (Note 21)	**1,481**	244	442
Balance at end of year	**3,980**	2,499	2,255
Additional Paid-In Capital			
Balance at beginning of year	**7**	370	401
Issuance of stock options, net of exercises	**6**	8	3
Dilution impact from TC PipeLines, LP units issued	**24**	6	9
Redemption of subsidiary's preferred shares	**—**	—	(6)
Impact of common shares repurchased (Note 20)	**(8)**	(164)	—
Impact of asset drop downs to TC PipeLines, LP (Note 26)	**(38)**	(213)	(37)
Reclassification of additional paid-in capital deficit to retained earnings	**9**	—	—
Balance at end of year	**—**	7	370
Retained Earnings			
Balance at beginning of year	**2,769**	5,478	5,096
Net income/(loss) attributable to controlling interests	**233**	(1,146)	1,840
Common share dividends	**(1,733)**	(1,471)	(1,360)
Preferred share dividends	**(122)**	(92)	(98)
Reclassification of additional paid-in capital deficit to retained earnings	**(9)**	—	—
Balance at end of year	**1,138**	2,769	5,478
Accumulated Other Comprehensive Loss			
Balance at beginning of year	**(939)**	(1,235)	(934)
Other comprehensive (loss)/income attributable to controlling interests (Note 22)	**(21)**	296	(301)
Balance at end of year	**(960)**	(939)	(1,235)
Equity Attributable to Controlling Interests	**24,257**	16,438	19,070
Equity Attributable to Non-Controlling Interests			
Balance at beginning of year	**1,717**	1,583	1,611
Acquisition of non-controlling interests in Columbia Pipeline Partners LP	**1,051**	—	—
Net income/(loss) attributable to non-controlling interests			
TC PipeLines, LP	**215**	(13)	136
Portland Natural Gas Transmission System	**20**	19	15
Columbia Pipeline Partners LP	**17**	—	—
Preferred share dividends of TCPL	**—**	—	2
Other comprehensive (loss)/income attributable to non-controlling interests	**(11)**	306	130
Issuance of TC PipeLines, LP units			
Proceeds, net of issue costs	**215**	55	79
Decrease in TransCanada's ownership of TC PipeLines, LP	**(40)**	(11)	(14)
Distributions declared to non-controlling interests	**(279)**	(222)	(182)
Reclassification to common units subject to rescission or redemption (Note 19)	**(1,179)**	—	—
Redemption of subsidiary's preferred shares	**—**	—	(194)
Balance at end of year	**1,726**	1,717	1,583
Total Equity	**25,983**	18,155	20,653

The accompanying Notes to the consolidated financial statements are an integral part of these statements.

Notes to consolidated financial statements

1. DESCRIPTION OF TRANSCANADA'S BUSINESS

TransCanada Corporation (TransCanada or the Company) is a leading North American energy infrastructure company which operates in three core businesses, Natural Gas Pipelines, Liquids Pipelines and Energy, each of which offers different products and services. As a result of the acquisition of Columbia Pipeline Group, Inc. (Columbia) and the pending monetization of the United States (U.S.) Northeast power business, the Company has revised its reporting segments from Natural Gas Pipelines, Liquids Pipelines, Energy and Corporate, to Canadian Natural Gas Pipelines, U.S. Natural Gas Pipelines, Mexico Natural Gas Pipelines, Liquids Pipelines, Energy and Corporate as at December 31, 2016. The Corporate segment is non-operational, consisting of corporate and administrative functions. The revised structure aligns with the information reviewed by the Chief Operating Decision Maker (CODM). Historical financial results for the years ended December 31, 2015 and 2014 have been adjusted to align with this change in the Company's segmented reporting.

Canadian Natural Gas Pipelines

The Canadian Natural Gas Pipelines segment consists of the Company's investments in 40,111 km (24,923 miles) of regulated natural gas pipelines.

U.S. Natural Gas Pipelines

The U.S. Natural Gas Pipelines segment consists of the Company's investments in 49,776 km (30,933 miles) of regulated natural gas pipelines, 535 Bcf of regulated natural gas storage facilities, midstream and other assets.

Acquired as part of Columbia on July 1, 2016, the Company owns and operates:

- Columbia Gas – an interstate natural gas transportation pipeline and storage system, which has largely operated as a means to transport gas from the Gulf Coast, via Columbia Gulf, from various pipeline interconnects and from production areas in the Appalachian region to markets in the midwest, Atlantic, and northeast regions.
- Columbia Gulf – a long-haul interstate natural gas transportation pipeline system that was originally designed to transport supply from the Gulf of Mexico to major supply markets in the U.S. Northeast. The pipeline is now transitioning and expanding to accommodate new supply from the Appalachian basin at its interconnect with Columbia Gas and other pipelines to deliver natural gas across various Gulf Coast markets.
- Millennium – a 47.5 per cent ownership interest in Millennium Pipeline, which transports natural gas primarily sourced from the Marcellus shale to markets across southern New York and the lower Hudson Valley, as well as to New York City through its pipeline interconnections.
- Crossroads – an interstate natural gas pipeline operating in Indiana and Ohio.
- Midstream – this business provides natural gas producer services including gathering, treating, conditioning, processing, compression and liquids handling in the Appalachian Basin, and includes a 47 per cent interest in Pennant Midstream.

Mexico Natural Gas Pipelines

The Mexico Natural Gas Pipelines segment consists of the Company's investments in 1,617 km (1,005 miles) of regulated natural gas pipelines in Mexico. This segment also includes the Company's 46.5 percent interest in the TransGas pipeline located in Colombia and prior to its sale in November 2014, the Company's interest in Gas Pacifico/INNERGY in South America.

Liquids Pipelines

The Liquids Pipelines segment consists of the Company's investment in 4,324 km (2,687 miles) of crude oil pipeline systems which connect Alberta and U.S. crude oil supplies to U.S. refining markets in Illinois, Oklahoma and Texas.

Energy

The Energy segment primarily consists of the Company's investments in 18 power generation plants and 118 Bcf of non-regulated natural gas storage facilities. These include Canadian plants in Alberta, Ontario, Québec and New Brunswick, and U.S. plants in New York, New England, Pennsylvania and Arizona. At December 31, 2016, five power generation plants in New York and New England, Pennsylvania are classified as Assets held for sale. Refer to Note 6, Assets held for sale, for further information.

2. ACCOUNTING POLICIES

The Company's consolidated financial statements have been prepared by management in accordance with U.S. generally accepted accounting principles (GAAP). Amounts are stated in Canadian dollars unless otherwise indicated.

Basis of Presentation

These consolidated financial statements include the accounts of TransCanada and its subsidiaries. The Company consolidates its interest in entities over which it is able to exercise control. To the extent there are interests owned by other parties, these interests are included in Non-controlling interests. TransCanada uses the equity method of accounting for joint ventures in which the Company is able to exercise joint control and for investments in which the Company is able to exercise significant influence. TransCanada records its proportionate share of undivided interests in certain assets. Certain prior year amounts have been reclassified to conform to current year presentation.

Use of Estimates and Judgments

In preparing these consolidated 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 judgment in making these estimates and assumptions. Significant estimates and judgments used in the preparation of the consolidated financial statements include, but are not limited to:

- fair value of assets and liabilities acquired in a business combination (Note 5)
- fair value and depreciation rates of plant, property and equipment (Note 8)
- carrying value of regulatory assets and liabilities (Note 10)
- fair value of goodwill (Note 11)
- fair value of intangible assets (Note 12)
- carrying value of asset retirement obligations (Note 15)
- provisions for income taxes (Note 16)
- assumptions used to measure retirement and other post-retirement obligations (Note 23)
- fair value of financial instruments (Note 24) and
- provision for commitments, contingencies, guarantees (Note 27) and restructuring (Note 28).

Actual results could differ from these estimates.

Regulation

In Canada, regulated natural gas pipelines and liquids pipelines are subject to the authority of the National Energy Board (NEB). In the U.S., natural gas pipelines, liquids pipelines and regulated natural gas storage assets are subject to the authority of the Federal Energy Regulatory Commission (FERC). In Mexico, natural gas pipelines are subject to the authority of the Energy Regulatory Commission (CRE). The Company's Canadian, U.S. and Mexican natural gas transmission operations are regulated with respect to construction, operations and the determination of tolls. Rate-regulated accounting (RRA) standards may impact the timing of the recognition of certain revenues and expenses in TransCanada's rate-regulated businesses which may differ from that otherwise expected in non-rate-regulated businesses to appropriately reflect the economic impact of the regulators' decisions regarding revenues and tolls. TransCanada's businesses that apply RRA currently include Canadian, U.S. and Mexican natural gas pipelines, regulated U.S. natural gas storage and certain of its liquids pipelines projects. RRA is not applicable to the Keystone Pipeline System as the regulators' decisions regarding operations and tolls on that system generally do not have an impact on timing of recognition of revenues and expenses.

Revenue Recognition

Natural Gas Pipelines and Liquids Pipelines

Transportation

Revenues from the Company's natural gas and liquids pipelines, with the exception of Canadian natural gas pipelines which are subject to RRA, are generated from contractual arrangements for committed capacity and from the transportation of natural gas or crude oil. Revenues earned from firm contracted capacity arrangements are recognized ratably over the contract period regardless of the amount of natural gas or crude oil that is transported. Transportation revenues for interruptible or volumetric-based services are recognized when physical deliveries of natural gas or crude oil are made.

Revenues from Canadian natural gas pipelines subject to RRA are recognized in accordance with decisions made by the NEB. The Company's Canadian natural gas pipeline tolls are based on revenue requirements designed to recover the costs of providing natural gas transportation services, which include a return of and return on capital, as approved by the NEB. The Company's Canadian natural gas pipelines generally are not subject to risks related to variances in revenues and most costs. These variances are generally subject to deferral treatment and are recovered or refunded in future rates. The Company's Canadian natural gas pipelines, at times, are subject to incentive mechanisms, as negotiated with shippers and approved by the NEB. These mechanisms can result in the Company recognizing more or less revenue than required to recover the costs that are subject to incentives. Revenues are recognized on firm contracted capacity ratably over the contract period. Revenues from interruptible or volumetric-based services are recorded when physical delivery is made. Revenues recognized prior to an NEB decision on rates for that period reflect the NEB's last approved rate of return on common equity (ROE) assumptions. Adjustments to revenue are recorded when the NEB decision is received.

The Company's U.S. natural gas pipelines are subject to FERC regulations and, as a result, revenues collected may be subject to refund during a rate proceeding. Allowances for these potential refunds are recognized using management's best estimate based on the facts and circumstances of the proceeding. Any allowances that are recognized during the proceeding process are refunded or retained at the time a regulatory decision becomes final.

Revenues from the Company's Mexican natural gas pipelines are primarily collected based on CRE-approved negotiated firm capacity contracts and recognized ratably over the contract period. Other volumes shipped on these pipelines are subject to CRE-approved tariffs.

The Company does not take ownership of the gas that it transports for others.

Regulated Natural Gas Storage

Revenues from the Company's regulated natural gas storage services are recognized ratably over the contract period for firm committed capacity regardless of the amount of natural gas that is stored, and when gas is injected or withdrawn for interruptible or volumetric-based services. The Company does not take ownership of the gas that it stores for others.

Midstream and Other

Revenues from the Company's midstream natural gas services, including gathering, treating, conditioning, processing, compression and liquids handling services, are generated from volumetric based contractual arrangements and are recognized ratably over the contract period regardless of the amount of natural gas that is subject to these services. The Company also owns mineral rights in association with certain storage facilities. These mineral rights can be leased or contributed to producers of natural gas in return for a royalty interest. Royalties from mineral interests are recognized when product is produced.

Energy

Power

Revenues from the Company's Energy business are primarily derived from the sale of electricity and from the sale of unutilized natural gas fuel, which are recorded at the time of delivery. Revenues also include capacity payments and ancillary services, as well as gains and losses resulting from the use of commodity derivative contracts. The accounting for derivative contracts is described in the Derivative instruments and hedging activities policy in this note.

Non-Regulated Natural Gas Storage

Revenues earned from providing non-regulated natural gas storage services are recognized in accordance with the terms of the natural gas storage contracts, which is generally over the term of the contract. Revenues earned on the sale of proprietary natural gas are recorded in the month of delivery. Derivative contracts for the purchase or sale of natural gas are recorded at fair value with changes in fair value recorded in Revenues.

Cash and Cash Equivalents

The Company's Cash and cash equivalents consist of cash and highly liquid short-term investments with original maturities of three months or less and are recorded at cost, which approximates fair value.

Inventories

Inventories primarily consist of natural gas inventory in storage, crude oil in transit, materials and supplies including spare parts and fuel. Inventories are all carried at the lower of weighted average cost or market.

Plant, Property and Equipment

Natural Gas Pipelines

Plant, property and equipment for natural gas pipelines are carried at cost. Depreciation is calculated on a straight-line basis once the assets are ready for their intended use. Pipeline and compression equipment are depreciated at annual rates ranging from one per cent to six per cent, and metering and other plant equipment are depreciated at various rates reflecting their estimated useful lives. The cost of major overhauls of equipment is capitalized and depreciated over the estimated service lives of the overhauls. The cost of regulated natural gas pipelines includes an allowance for funds used during construction (AFUDC) consisting of a debt component and an equity component based on the rate of return on rate base approved by regulators. AFUDC is reflected as an increase in the cost of the assets in plant, property and equipment and the equity component of AFUDC is a non-cash expenditure with a corresponding credit recognized in Allowance for funds used during construction in the Consolidated statement of income. Interest is capitalized during construction of non-regulated natural gas pipelines.

Natural gas storage base gas, which is valued at cost, represents storage volumes that are maintained to ensure that adequate well pressure exists to deliver current gas inventory. Natural gas storage base gas is not depreciated.

When regulated natural gas pipelines retire plant, property and equipment from service, the original book cost is removed from the gross plant amount and recorded as a reduction to accumulated depreciation. Costs incurred to remove a plant from service, net of any salvage proceeds, are also recorded in accumulated depreciation.

Midstream and Other

Plant, property and equipment for midstream assets are carried at cost. Depreciation is calculated on a straight-line basis once the assets are ready for their intended use. Gathering and processing facilities are depreciated at annual rates ranging from 1.7 per cent to 2.5 per cent, and other plant and equipment are depreciated at various rates. When these assets are retired from plant, property and equipment, the original book cost and related accumulated depreciation and amortization are derecognized and any gain or loss is recorded in net income.

The Company participates as a working interest partner in the development of Marcellus and Utica acreage. The working interest allows the Company to invest in the drilling activities in addition to a royalty interest in well production. The Company uses the successful efforts method of accounting for natural gas and crude oil resulting from its portion of drilling activities. Capitalized well costs are depleted based on the units of production method.

Liquids Pipelines

Plant, property and equipment for liquids pipelines are carried at cost. Depreciation is calculated on a straight-line basis once the assets are ready for their intended use. Pipeline and pumping equipment are depreciated at annual rates ranging from two per cent to 2.5 per cent, and other plant and equipment are depreciated at various rates. The cost of these assets includes interest capitalized during construction for non-regulated liquids pipelines and AFUDC for regulated pipelines. When liquids pipelines retire plant, property and equipment from service, the original book cost and related accumulated depreciation and amortization are derecognized and any gain or loss is recorded in net income.

Energy

Power generation and natural gas storage plant, equipment and structures are recorded at cost and, once the assets are ready for their intended use, depreciated by major component on a straight-line basis over their estimated service lives at average annual rates ranging from two per cent to 20 per cent. Other equipment is depreciated at various rates. The cost of major overhauls of equipment is capitalized and depreciated over the estimated service lives of the overhauls. Interest is capitalized on facilities under construction. When these assets are retired from plant, property and equipment, the original book cost and related accumulated depreciation and amortization are derecognized and any gain or loss is recorded in net income. Natural gas storage base gas, which is valued at original cost, represents storage volumes that are maintained to ensure that adequate well pressure exists to deliver current gas inventory. Natural gas storage base gas is not depreciated.

Corporate

Corporate plant, property and equipment are recorded at cost and depreciated on a straight-line basis over their estimated useful lives at average annual rates ranging from three per cent to 20 per cent.

Capitalized Project Costs

The Company capitalizes project costs once advancement to a construction stage is probable or costs are otherwise likely to be recoverable. The Company also capitalizes interest for non-regulated projects in development and AFUDC for regulated projects. Capital projects in development are included in Intangible and other assets. These represent larger projects that generally require regulatory or other approvals before physical construction can begin. Once approvals are received, projects are moved to Plant, property and equipment under construction. When the asset is ready for its intended use and available for operations, capitalized project costs are depreciated in accordance with the Company's depreciation policies.

Assets Held For Sale

The Company classifies assets as held for sale when management approves and commits to a formal plan to actively market a disposal group and expects the sale to close within the next twelve months. Upon classifying an asset as held for sale, the asset is recorded at the lower of its carrying amount or its estimated fair value, reduced for selling costs, and any losses are recognized in Net income. Depreciation expense is no longer recorded once assets are classified as held for sale.

Impairment of Long-Lived Assets

The Company reviews long-lived assets, such as Plant, property and equipment and Intangible assets for impairment whenever events or changes in circumstances indicate the carrying value may not be recoverable. If the total of the estimated undiscounted future cash flows or the estimated sale price is less than the carrying value of an asset, an impairment loss is recognized for the excess of the carrying value over the estimated fair value of the asset.

Acquisitions and Goodwill

The Company accounts for business acquisitions using the acquisition method of accounting and, accordingly, the assets and liabilities of the acquired entities are primarily measured at their estimated fair values at the date of acquisition. The excess of the fair value of the consideration transferred over the estimated fair value of the net assets acquired is classified as goodwill. Goodwill is not amortized and is tested for impairment on an annual basis or more frequently if events or changes in circumstances indicate that it might be impaired. The annual review for goodwill impairment is performed at the reporting unit level which is one level below the Company's operating segments. The Company initially assesses qualitative factors to determine whether events or changes in circumstances indicate that goodwill might be impaired. If the Company concludes that it is not more likely than not that the fair value of the reporting unit is greater than its carrying value, the first step of the two-step impairment test is performed by comparing the fair value of the reporting unit to its carrying value, which includes goodwill. If the fair value of the reporting unit is less than its carrying value, an impairment is indicated and a second step is performed to measure the amount of the impairment. In the second step, the implied fair value of goodwill is calculated by deducting the recognized amounts of all tangible and intangible net assets of the reporting unit from the fair value determined in the initial assessment. If the carrying value of goodwill exceeds the calculated implied fair value of goodwill, an impairment charge is recorded in an amount equal to the difference.

Power Purchase Arrangements

A power purchase arrangement (PPA) is a long-term contract for the purchase or sale of power on a predetermined basis. TransCanada has PPAs for the sale of power that are accounted for as operating leases. Prior to their termination, substantially all the PPAs under which TransCanada purchased power were also accounted for as operating leases, and initial payments to acquire these PPAs were recognized in Intangible and other assets and amortized on a straight-line basis over the term of the contracts. A portion of these PPAs were subleased to third parties under terms and conditions similar to the PPAs, and were also accounted for as operating leases with the margin earned from the subleases recorded in Revenues. During 2016, the Company terminated these PPAs and recorded an impairment charge. Refer to Note 12, Intangible and other assets, for further information.

Restricted Investments

The Company has certain investments that are restricted as to their withdrawal and use. These restricted investments are classified as available for sale and are recorded at fair value on the Consolidated balance sheet.

As a result of the NEB's Land Matters Consultation Initiative (LMCI), TransCanada is required to collect funds to cover estimated future pipeline abandonment costs for all NEB regulated Canadian pipelines. Funds collected are placed in trusts that hold and invest the funds and are accounted for as restricted investments. LMCI restricted investments may only be used to fund the abandonment of the NEB regulated pipeline facilities; therefore, a corresponding regulatory liability is recorded on the Consolidated balance sheet. The Company also has other restricted investments that have been set aside to fund insurance claim losses to be paid by the Company's wholly-owned captive insurance subsidiary.

Income Taxes

The Company uses the asset and liability method of accounting for income taxes. This method requires the recognition of deferred income tax assets and liabilities for future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Deferred income tax assets and liabilities are measured using enacted tax rates at the balance sheet date that are anticipated to apply to taxable income in the years in which temporary differences are expected to be reversed or settled. Changes to these balances are recognized in net income in the period during which they occur except for changes in balances related to the Canadian regulated natural gas pipelines which are deferred until they are refunded or recovered in tolls, as permitted by the NEB. Deferred income tax assets and liabilities are classified as non-current on the Consolidated balance sheet.

Canadian income taxes are not provided on the unremitted earnings of foreign investments that the Company does not intend to repatriate in the foreseeable future.

Asset Retirement Obligations

The Company recognizes the fair value of a liability for asset retirement obligations (ARO) in the period in which it is incurred, when a legal obligation exists and a reasonable estimate of fair value can be made. The fair value is added to the carrying amount of the associated asset and the liability is accreted through charges to Operating and other expenses.

The Company has recorded ARO related to its non-regulated natural gas storage operations, mineral rights and certain power generation facilities. The scope and timing of asset retirements related to most of the Company's natural gas pipelines, liquids pipelines and hydroelectric power plants is indeterminable. As a result, the Company has not recorded an amount for ARO related to these assets, with the exception of certain abandoned facilities and certain facilities expected to be retired as part of an ongoing modernization program that will improve system integrity and enhance service reliability and flexibility on Columbia Gas.

Environmental Liabilities

The Company records liabilities on an undiscounted basis for environmental remediation efforts that are likely to occur and where the cost can be reasonably estimated. The estimates, including associated legal costs, are based on available information using existing technology and enacted laws and regulations. The estimates are subject to revision in future periods based on actual costs incurred or new circumstances. Amounts expected to be recovered from other parties, including insurers, are recorded as an asset separate from the associated liability.

Emission allowances or credits purchased for compliance are recorded on the Consolidated balance sheet at historical cost and expensed when they are utilized. Compliance costs are expensed when incurred. Allowances granted to or internally generated by TransCanada are not attributed a value for accounting purposes. When required, TransCanada accrues emission liabilities on the Consolidated balance sheet upon the generation or sale of power using the best estimate of the amount required to settle the obligation. Allowances and credits not used for compliance are sold and any gain or loss is recorded in Revenues.

Stock Options and Other Compensation Programs

TransCanada's Stock Option Plan permits options for the purchase of common shares to be awarded to certain employees, including officers. Stock options granted are recorded using the fair value method. Under this method, compensation expense is measured at the grant date based on the fair value as calculated using a binomial model and is recognized on a straight-line basis over the vesting period with an offset to Additional paid-in capital. Upon exercise of stock options, amounts originally recorded against Additional paid-in capital are reclassified to Common shares.

The Company has medium-term incentive plans, under which payments are made to eligible employees. The expense related to these incentive plans is accounted for on an accrual basis. Under these plans, benefits vest when certain conditions are met, including the employees' continued employment during a specified period and achievement of specified corporate performance targets.

Employee Post-Retirement Benefits

The Company sponsors defined benefit pension plans (DB Plans), defined contribution plans (DC Plans), a savings plan and other post-retirement benefit plans. Contributions made by the Company to the DC Plans and savings plan are expensed in the period in which contributions are made. The cost of the DB Plans and other post-retirement benefits received by employees is actuarially determined using the projected benefit method pro-rated based on service and management's best estimate of expected plan investment performance, salary escalation, retirement age of employees and expected health care costs.

The DB Plans' assets are measured at fair value at December 31 of each year. The expected return on the DB Plans' assets is determined using market-related values based on a five-year moving average value for all of the DB Plans' assets. Past service costs are amortized over the expected average remaining service life of the employees. Adjustments arising from plan amendments are amortized on a straight-line basis over the average remaining service life of employees active at the date of amendment. The Company recognizes the overfunded or underfunded status of its DB Plans as an asset or liability, respectively, on its Consolidated balance sheet and recognizes changes in that funded status through Other comprehensive income/(loss) (OCI) in the year in which the change occurs. The excess of net actuarial gains or losses over 10 per cent of the greater of the benefit obligation and the market-related value of the DB Plans' assets, if any, is amortized out of Accumulated other comprehensive income/(loss) (AOCI) and into Net income over the average remaining service life of the active employees. When the restructuring of a benefit plan gives rise to both a curtailment and a settlement, the curtailment is accounted for prior to the settlement.

For certain regulated operations, post-retirement benefit amounts are recoverable through tolls as benefits are funded. The Company records any unrecognized gains or losses or changes in actuarial assumptions related to these post-retirement benefit plans as either regulatory assets or liabilities. The regulatory assets or liabilities are amortized on a straight-line basis over the expected average remaining service life of active employees.

Foreign Currency Transactions and Translation

Foreign currency transactions are those transactions whose terms are denominated in a currency other than the currency of the primary economic environment in which the Company or reporting subsidiary operates, referred to as the functional currency. Transactions denominated in foreign currencies are translated into the functional currency using the exchange rate prevailing at the date of the transaction. Monetary assets and liabilities denominated in foreign currencies are translated to the functional currency using the rate of exchange in effect at the balance sheet date whereas non-monetary assets and liabilities are translated at the historical rate of exchange in effect on the date of the transaction. Exchange gains and losses resulting from translation of monetary assets and liabilities are recorded in Net income except for exchange gains and losses of the foreign currency debt related to Canadian regulated natural gas pipelines, which are deferred until they are refunded or recovered in tolls, as permitted by the NEB.

Gains and losses arising from translation of foreign operations' functional currencies to the Company's Canadian dollar reporting currency are reflected in OCI until the operations are sold at which time, the gains and losses are reclassified to Net income. Asset and liability accounts are translated at the period-end exchange rates while revenues, expenses, gains and losses are translated at the exchange rates in effect at the time of the transaction. The Company's U.S. dollar-denominated debt and certain derivative hedging instruments have been designated as a hedge of the net investment in foreign subsidiaries and, as a result, the unrealized foreign exchange gains and losses on the U.S. dollar denominated debt are also reflected in OCI.

Derivative Instruments and Hedging Activities

All derivative instruments are recorded on the Consolidated balance sheet at fair value, unless they qualify for and are designated under a normal purchase and normal sales exemption, or are considered to meet other permitted exemptions.

The Company applies hedge accounting to arrangements that qualify and are designated for hedge accounting treatment, which includes fair value and cash flow hedges, and hedges of foreign currency exposures of net investments in foreign operations. Hedge accounting is discontinued prospectively if the hedging relationship ceases to be effective or the hedging or hedged items cease to exist as a result of maturity, expiry, sale, termination, cancellation or exercise.

In a fair value hedging relationship, the carrying value of the hedged item is adjusted for changes in fair value attributable to the hedged risk and these changes are recognized in Net income. Changes in the fair value of the hedged item, to the extent that the hedging relationship is effective, are offset by changes in the fair value of the hedging item, which are also recorded in Net income. Changes in the fair value of foreign exchange and interest rate fair value hedges are recorded in Interest income and other and Interest expense, respectively. If hedge accounting is discontinued, the carrying value of the hedged item is no longer adjusted and the cumulative fair value adjustments to the carrying value of the hedged item are amortized to Net income over the remaining term of the original hedging relationship.

In a cash flow hedging relationship, the effective portion of the change in the fair value of the hedging derivative is initially recognized in OCI, while any ineffective portion is recognized in Net income in the same financial statement category as the underlying transaction. When hedge accounting is discontinued, the amounts recognized previously in AOCI are reclassified to Revenues, Interest expense and Interest income and other, as appropriate, during the periods when the variability in cash flows of the hedged item affects Net income or as the original hedged item settles. Gains and losses on derivatives are reclassified immediately to Net income from AOCI when the hedged item is sold or terminated early, or when it becomes probable that the anticipated transaction will not occur.

In hedging the foreign currency exposure of a net investment in a foreign operation, the effective portion of foreign exchange gains and losses on the hedging instruments is recognized in OCI and the ineffective portion is recognized in Net income. The amounts recognized previously in AOCI are reclassified to Net income in the event the Company reduces its net investment in a foreign operation.

In some cases, derivatives do not meet the specific criteria for hedge accounting treatment. In these instances, the changes in fair value are recorded in Net income in the period of change.

The recognition of gains and losses on derivatives for Canadian natural gas regulated pipelines exposures is determined through the regulatory process. Gains and losses arising from changes in the fair value of derivatives accounted for as part of RRA, including those that qualify for hedge accounting treatment, are refunded or recovered through the tolls charged by the Company. As a result, these gains and losses are deferred as Regulatory assets or Regulatory liabilities and are refunded to or collected from the ratepayers, in subsequent years when the derivative settles.

Derivatives embedded in other financial instruments or contracts (host instrument) are recorded as separate derivatives. Embedded derivatives are measured at fair value if their economic characteristics are not clearly and closely related to those of the host instrument, their terms are the same as those of a stand-alone derivative and the total contract is not held for trading or accounted for at fair value. When changes in the fair value of embedded derivatives are measured separately, they are included in Net income.

Long-Term Debt Transaction Costs

The Company records long-term debt transaction costs as a deduction from the carrying amount of the related debt and amortizes these costs using the effective interest method for all costs except those related to the Canadian natural gas regulated pipelines, which continue to be amortized on a straight-line basis in accordance with the provisions of regulatory tolling mechanisms.

Guarantees

Upon issuance, the Company records the fair value of certain guarantees entered into by the Company or partially owned entities for which contingent payments may be made. The fair value of these guarantees is estimated by discounting the cash flows that would be incurred by the Company if letters of credit were used in place of the guarantees as appropriate in the circumstances. Guarantees are recorded as an increase to Equity investments, Plant, property and equipment, or a charge to Net income, and a corresponding liability is recorded in Other long-term liabilities. The release from the obligation is recognized either over the term of the guarantee or upon expiration or settlement.

3. ACCOUNTING CHANGES

Changes in Accounting Policies for 2016

Extraordinary and unusual income statement items

In January 2015, the Financial Accounting Standards Board (FASB) issued new guidance on extraordinary and unusual income statement items. This update eliminates the concept of extraordinary items from GAAP. This new guidance was effective January 1, 2016, was applied prospectively and did not have an impact on the Company's consolidated financial statements.

Consolidation

In February 2015, the FASB issued new guidance on consolidation. This guidance 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 29, Variable interest entities.

Imputation of interest

In April 2015, the FASB issued new guidance on simplifying the accounting for debt issuance costs. This guidance requires that debt issuance costs be presented on the balance sheet as a direct deduction from the carrying amount of the related 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.

Classification of certain cash receipts and cash payments

In August 2016, the FASB issued new guidance to clarify how entities should classify certain cash receipts and cash payments on the statement of cash flows. This new guidance is effective January 1, 2018, however, since early adoption is permitted, the Company elected to retrospectively apply this guidance effective December 31, 2016. The application of this guidance did not have a material impact on the classification of debt pre-payments or extinguishment costs, contingent consideration payments made after a business combination, proceeds from the settlement of insurance claims and proceeds from the settlement of corporate owned life insurance. The Company has elected to classify distributions received from equity method investments using the nature of distributions approach as it is more representative of the nature of the underlying activities of the investments that generated the distributions. As a result, certain comparative period distributions received from equity method investments have been reclassified from investing activities to cash generated from operations in the Consolidated statement of cash flows.

Future Accounting Changes

Revenue from contracts with customers

In 2014, the FASB issued new guidance on revenue from contracts with customers. Current guidance allows for revenue recognition when certain criteria are met. The new guidance requires that an entity recognize revenue in accordance with a five-step model. This model is used to depict the transfer of promised goods or services to customers in an amount that reflects the total consideration to which it expects to be entitled during the term of the contract in exchange for those goods or services. The Company will adopt the new standard on the effective date of January 1, 2018. There are two methods in which the new standard 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 evaluating both methods of adoption as it works through its analysis. The Company has identified all existing customer contracts that are within the scope of the new guidance and has begun to analyze individual contracts or groups of contracts to identify any significant differences and the impact on revenues as a result of implementing the new standard. As the Company continues its contract analysis, it will also quantify the impact, if any, on prior period revenues. The Company will address any system and process changes necessary to compile the information to meet the disclosure requirements of the new standard. As the Company is currently evaluating the impact of this standard, it has not yet determined the effect on its consolidated financial statements.

Inventory

In July 2015, the FASB issued new guidance on simplifying the measurement of inventory. The new guidance specifies 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, however, the Company is evaluating the option to early adopt. The Company is currently identifying existing lease agreements that may have an impact on the Company's consolidated financial statements as a result of adopting this new guidance.

Derivatives and hedging

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

Equity method investments

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

Measurement of credit losses on financial instruments

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

Consolidation

In October 2016, the FASB issued new guidance on consolidation relating to interests held through related parties that are under common control. The new guidance amends the consolidation requirements such that if a decision maker is required to evaluate whether it is the primary beneficiary of a variable interest entity (VIE), it will need to consider only its proportionate indirect interest in the VIE held through a common control party. The new guidance is effective January 1, 2017 and the Company does not expect the adoption of this new guidance to have a material impact on its consolidated financial statements.

Income taxes

In October 2016, the FASB issued new guidance on income tax effects of intra-entity transfers of assets other than inventory. The new guidance requires the recognition of deferred and current income taxes for an intra-entity asset transfer when the transfer occurs. The new guidance is effective January 1, 2018 and will be applied on a modified retrospective basis. Early adoption is permitted. 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.

Restricted cash

In November 2016, the FASB issued new guidance on restricted cash and cash equivalents on the statement of cash flows. The new guidance requires that the statement of cash flows explain the change during the period in the total cash and cash equivalents, and amounts generally described as restricted cash or restricted cash equivalents. The amounts of restricted cash and cash equivalents will be included in Cash and cash equivalents when reconciling the beginning of year and end of year total amounts on the statement of cash flows. This new guidance is effective January 1, 2018 and will be applied retrospectively. Early adoption is permitted. 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.

4. SEGMENTED INFORMATION

As a result of the acquisition of Columbia and the pending monetization of the U.S. Northeast power business, the Company has changed its reporting segments. TransCanada has six reportable segments, namely, Canadian Natural Gas Pipelines, U.S. Natural Gas Pipelines, Mexico Natural Gas Pipelines, Liquids Pipelines, Energy and Corporate. The Corporate segment is non-operational, consisting of corporate and administrative functions. This provides information that is aligned with the CODM's review of business performance and how decisions about business segments are made. Historical financial results for the years ended December 31, 2015 and 2014 have been adjusted to align with this change in the Company's segmented reporting.

year ended December 31, 2016 (millions of Canadian $)	**Canadian Natural Gas Pipelines**	**U.S. Natural Gas Pipelines**	**Mexico Natural Gas Pipelines**	**Liquids Pipelines**	**Energy**	**Corporate**	**Total**
Revenues	**3,682**	**2,526**	**378**	**1,755**	**4,164**	**—**	**12,505**
Income from equity investments	**12**	**214**	**(3)**	**(1)**	**292**	**—**	**514**
Plant operating costs and other	**(1,181)**	**(1,000)**	**(42)**	**(554)**	**(834)**	**(208)**	**(3,819)**
Commodity purchases resold	**—**	**—**	**—**	**—**	**(2,172)**	**—**	**(2,172)**
Property taxes	**(267)**	**(120)**	**—**	**(88)**	**(80)**	**—**	**(555)**
Depreciation and amortization	**(873)**	**(397)**	**(43)**	**(285)**	**(293)**	**(48)**	**(1,939)**
Goodwill and other asset impairment charges	**—**	**—**	**—**	**—**	**(1,388)**	**—**	**(1,388)**
Loss on assets held for sale/sold	**—**	**(4)**	**—**	**—**	**(829)**	**—**	**(833)**
Segmented earnings/(losses)	**1,373**	**1,219**	**290**	**827**	**(1,140)**	**(256)**	**2,313**
Interest expense							**(1,998)**
Allowance for funds used during construction							**419**
Interest income and other							**103**
Income before income taxes							**837**
Income tax expense							**(352)**
Net income							**485**
Net income attributable to non-controlling interests							**(252)**
Net income attributable to controlling interests							**233**
Preferred share dividends							**(109)**
Net income attributable to common shares							**124**
Capital spending							
Capital expenditures	**1,372**	**1,517**	**944**	**668**	**473**	**33**	**5,007**
Capital projects in development	**153**	**—**	**—**	**142**	**—**	**—**	**295**
	1,525	**1,517**	**944**	**810**	**473**	**33**	**5,302**

year ended December 31, 2015 (millions of Canadian $)	Canadian Natural Gas Pipelines	U.S. Natural Gas Pipelines	Mexico Natural Gas Pipelines	Liquids Pipelines	Energy	Corporate	Total
Revenues	3,680	1,444	259	1,879	4,038	—	11,300
Income from equity investments	12	162	5	—	261	—	440
Plant operating costs and other	(1,162)	(555)	(49)	(491)	(786)	(207)	(3,250)
Commodity purchases resold	—	—	—	—	(2,237)	—	(2,237)
Property taxes	(272)	(77)	—	(79)	(89)	—	(517)
Depreciation and amortization	(845)	(243)	(44)	(266)	(336)	(31)	(1,765)
Asset impairment charges	—	—	—	(3,686)	(59)	—	(3,745)
Loss on assets held for sale/sold	—	(125)	—	—	—	—	(125)
Segmented earnings/(losses)	1,413	606	171	(2,643)	792	(238)	101
Interest expense							(1,370)
Allowance for funds used during construction							295
Interest income and other							(132)
Loss before income taxes							(1,106)
Income tax expense							(34)
Net loss							(1,140)
Net income attributable to non-controlling interests							(6)
Net loss attributable to controlling interests							(1,146)
Preferred share dividends							(94)
Net loss attributable to common shares							(1,240)
Capital spending							
Capital expenditures	1,366	534	566	1,012	376	64	3,918
Capital projects in development	230	3	—	278	—	—	511
	1,596	537	566	1,290	376	64	4,429

year ended December 31, 2014 (millions of Canadian $)	**Canadian Natural Gas Pipelines**	**U.S. Natural Gas Pipelines**	**Mexico Natural Gas Pipelines**	**Liquids Pipelines**	**Energy**	**Corporate**	**Total**
Revenues	3,557	1,159	197	1,547	3,725	—	10,185
Income from equity investments	12	143	8	—	359	—	522
Plant operating costs and other	(1,028)	(467)	(41)	(439)	(934)	(64)	(2,973)
Commodity purchases resold	—	—	—	—	(1,836)	—	(1,836)
Property taxes	(266)	(68)	—	(62)	(77)	—	(473)
Depreciation and amortization	(821)	(211)	(31)	(216)	(309)	(23)	(1,611)
Gain on assets held for sale/sold	—	—	9	—	108	—	117
Segmented earnings/(losses)	1,454	556	142	830	1,036	(87)	3,931
Interest expense							(1,198)
Allowance for funds used during construction							136
Interest income and other							(45)
Income before income taxes							2,824
Income tax expense							(831)
Net income							1,993
Net income attributable to non-controlling interests							(153)
Net income attributable to controlling interests							1,840
Preferred share dividends							(97)
Net income attributable to common shares							1,743
Capital spending							
Capital expenditures	814	237	717	1,469	206	46	3,489
Capital projects in development	327	40	1	480	—	—	848
	1,141	277	718	1,949	206	46	4,337

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

Geographic Information

year ended December 31 (millions of Canadian $)	2016	2015	2014
Revenues			
Canada – domestic	**3,655**	3,877	3,956
Canada – export	**1,177**	1,292	1,314
United States	**7,295**	5,872	4,718
Mexico	**378**	259	197
	12,505	11,300	10,185

at December 31 (millions of Canadian $)	2016	2015
Plant, Property and Equipment		
Canada	**20,531**	19,287
United States	**29,414**	21,899
Mexico	**4,530**	3,631
	54,475	44,817

5. 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 all outstanding restricted and performance stock units. The acquisition was financed through proceeds of approximately $4.4 billion from the sale of subscription receipts, draws on acquisition bridge 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 upon closing of the acquisition were exchanged into approximately 96.6 million common shares of TransCanada. Refer to Note 17, Long-term debt for additional information on the acquisition bridge facilities and Note 20, Common shares for additional information on the subscription receipts.

Columbia operates a portfolio of approximately 24,500 km (15,200 miles) of regulated natural gas pipelines, 285 Bcf of natural gas storage facilities and midstream and other assets in various regions in the U.S. TransCanada acquired Columbia to expand the Company's natural gas business in the U.S. market, positioning the Company for additional long-term growth opportunities.

The goodwill of $10.1 billion (US$7.7 billion) arising from the acquisition principally reflects the opportunities to expand the Company's U.S. Natural Gas Pipelines segment and to gain a stronger competitive position in the North American natural gas business. The goodwill resulting from the acquisition is not deductible for income tax purposes.

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

	July 1, 2016	
(millions of $)	**U.S.**	**Canadian**[1]
Purchase Price Consideration	**10,294**	**13,392**
Fair Value of Net Assets Acquired		
Current assets	658	856
Plant, property and equipment	7,560	9,835
Equity investments	441	574
Regulatory assets	190	248
Intangibles and other assets	135	175
Current liabilities	(597)	(777)
Regulatory liabilities	(294)	(383)
Other long-term liabilities	(144)	(187)
Deferred income tax liabilities	(1,613)	(2,098)
Long-term debt	(2,981)	(3,878)
Non-controlling interests	(808)	(1,051)
Fair Value of Net Assets Acquired	**2,547**	**3,314**
Goodwill (Note 11)	**7,747**	**10,078**

1 At July 1, 2016 exchange rate of $1.30.

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

Columbia's natural gas pipelines are subject to FERC regulations and, as a result, their rate bases are expected to be recovered with a reasonable rate of return over the life of the assets. These assets, as well as related regulatory assets and liabilities, have fair values equal to their carrying values. The fair value of mineral rights included in Columbia's plant, property and equipment was determined using a discounted cash flow approach which resulted in a fair value increase of $241 million (US$185 million). The fair value of base gas included in Columbia's plant, property and equipment was determined by using a quoted market price multiplied by the volume of gas in place which resulted in a fair value increase of $840 million (US$646 million). The fair value of base gas is based on preliminary information obtained and is subject to change as the Company completes it's work on the volume acquired. An adjustment to the fair value of base gas would impact the purchase price equation.

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

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

(millions of $)	Maturity Date	Type	Fair Value	Interest Rate
COLUMBIA PIPELINE GROUP INC.				
	June 2018	Senior Unsecured Notes (US$500)	US$506	2.45%
	June 2020	Senior Unsecured Notes (US$750)	US$779	3.30%
	June 2025	Senior Unsecured Notes (US$1000)	US$1,092	4.50%
	June 2045	Senior Unsecured Notes (US$500)	US$604	5.80%
			US$2,981	

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

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

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

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

Upon completing the acquisition, the Company began consolidating Columbia. Columbia's significant accounting policies are consistent with TransCanada's and continue to be applied. Columbia contributed $929 million to the Company's Revenues and $132 million to the Company's Net income from the acquisition date to December 31, 2016.

The following supplemental pro forma consolidated financial information of the Company for the years ended December 31, 2016 and 2015 includes the results of operations for Columbia as if the acquisition had been completed on January 1, 2015.

year ended December 31 (millions of Canadian $)	**2016**	**2015**
Revenues	**13,404**	13,007
Net Income/(Loss)	**627**	(820)
Net Income/(Loss) Attributable to Common Shares	**234**	(971)

6. ASSETS HELD FOR SALE

U.S. Northeast Power Assets

The Company's planned monetization of its U.S. Northeast power business, for the purposes of permanently financing the Columbia acquisition, includes the sale of Ravenswood, Ironwood, Kibby Wind, Ocean State Power, TC Hydro and the marketing business, TransCanada Power Marketing (TCPM).

On November 1, 2016, the Company entered into agreements to sell all of these assets except TCPM.

The sale of Ravenswood, Ironwood, Kibby Wind and Ocean State Power to a third party for proceeds of approximately US$2.2 billion is expected to close in the first half of 2017. As a result, a loss of approximately $829 million ($863 million after tax) was recorded in 2016 and was included in (Loss)/gain on assets held for sale/sold in the Consolidated statement of income and included the impact of an estimated $70 million of foreign currency translation gains to be reclassified from AOCI to Net income on close. At December 31, 2016, the related assets and liabilities were classified as held for sale in the Energy segment and were recorded at their fair values less costs to sell based on the proceeds expected on the close of this sale.

The sale of TC Hydro to another third party for proceeds of approximately US$1.1 billion is also expected to close in the first half of 2017, and is expected to result in an estimated gain of $710 million ($440 million after tax) including the impact of an estimated $5 million of foreign currency translation gains. This gain will be recognized upon closing of the sale transaction. At December 31, 2016, the related assets and liabilities were classified as held for sale in the Energy segment.

As of December 31, 2016, TCPM did not meet the criteria to be classified as held for sale.

The following table details the assets and liabilities held for sale at December 31, 2016.

(millions of $)	U.S.	Canadian[1]
Assets held for sale		
Accounts receivable	**13**	**18**
Inventories	**56**	**75**
Other current assets	**90**	**121**
Plant, property and equipment	**2,229**	**2,993** [2]
Intangible and other assets	**328**	**440**
Foreign currency translation gains	**—**	**70** [3]
Total assets held for sale	**2,716**	**3,717**
Liabilities related to assets held for sale		
Accounts payable and other	**32**	**43**
Other long-term liabilities	**32**	**43**
Total liabilities related to assets held for sale	**64**	**86**

1 At December 31, 2016 exchange rate of $1.34.

2 Includes $17 million (US$13 million) for a gas plant held for sale in the U.S. Natural Gas Pipelines segment.

3 Foreign currency translation gains related to the investments in Ravenswood, Ironwood, Kibby Wind and Ocean State Power will be reclassified from AOCI to Net Income on close of the sale.

TC Offshore LLC

On March 1, 2016, the Company closed the sale of TC Offshore LLC. This resulted in an additional loss on disposal of $4 million pre-tax which is included in (Loss)/gain on assets held for sale/sold in the Consolidated statement of income.

On December 18, 2015, the Company entered into an agreement to sell TC Offshore LLC to a third party. At December 31, 2015, the related assets and liabilities were classified as held for sale in the U.S. Natural Gas Pipelines segment and were recorded at their fair values less costs to sell. This resulted in a loss of $125 million pre-tax in 2015 which was included in (Loss)/gain on assets held for sale/sold in the Consolidated statement of income. The estimated fair value of these assets was based on the proceeds expected on the close of this sale.

7. OTHER CURRENT ASSETS

at December 31 (millions of Canadian $)	**2016**	**2015**
Fair value of derivative contracts (Note 24)	**376**	442
Cash provided as collateral	**313**	590
Prepaid expenses	**131**	132
Regulatory assets (Note 10)	**33**	85
Other[1]	**55**	89
	908	1,338

1 Includes current portion of note receivable from the seller of Ravenswood of $55 million (US$40 million) at December 31, 2015. As of November 1, 2016, all Ravenswood assets including the current portion of the note receivable have been reclassified to Assets held for sale (Note 6).

8. PLANT, PROPERTY AND EQUIPMENT

at December 31 (millions of Canadian $)	2016 Cost	2016 Accumulated Depreciation	2016 Net Book Value	2015 Cost	2015 Accumulated Depreciation	2015 Net Book Value
Canadian Natural Gas Pipelines						
NGTL System						
Pipeline	**8,814**	**3,951**	**4,863**	8,456	3,820	4,636
Compression	**2,447**	**1,499**	**948**	2,188	1,404	784
Metering and other	**1,124**	**519**	**605**	1,096	489	607
	12,385	**5,969**	**6,416**	11,740	5,713	6,027
Under construction	**1,151**	**—**	**1,151**	969	—	969
	13,536	**5,969**	**7,567**	12,709	5,713	6,996
Canadian Mainline						
Pipeline	**9,502**	**6,221**	**3,281**	9,164	5,966	3,198
Compression	**3,537**	**2,361**	**1,176**	3,433	2,220	1,213
Metering and other	**605**	**198**	**407**	499	192	307
	13,644	**8,780**	**4,864**	13,096	8,378	4,718
Under construction	**219**	**—**	**219**	257	—	257
	13,863	**8,780**	**5,083**	13,353	8,378	4,975
Other Canadian Natural Gas Pipelines						
Other[1]	**1,728**	**1,273**	**455**	1,705	1,213	492
Under construction	**112**	**—**	**112**	63	—	63
	1,840	**1,273**	**567**	1,768	1,213	555
	29,239	**16,022**	**13,217**	27,830	15,304	12,526
U.S. Natural Gas Pipelines						
Columbia Gas[2]						
Pipeline	**3,072**	**13**	**3,059**	—	—	—
Compression	**1,864**	**7**	**1,857**	—	—	—
Metering and other	**2,542**	**34**	**2,508**	—	—	—
	7,478	**54**	**7,424**	—	—	—
Under construction	**1,127**	**—**	**1,127**	—	—	—
	8,605	**54**	**8,551**	—	—	—
ANR						
Pipeline	**1,468**	**349**	**1,119**	1,449	350	1,099
Compression	**1,494**	**260**	**1,234**	1,101	187	914
Metering and other	**988**	**254**	**734**	977	252	725
	3,950	**863**	**3,087**	3,527	789	2,738
Under construction	**232**	**—**	**232**	304	—	304
	4,182	**863**	**3,319**	3,831	789	3,042

at December 31 (millions of Canadian $)	2016 Cost	2016 Accumulated Depreciation	2016 Net Book Value	2015 Cost	2015 Accumulated Depreciation	2015 Net Book Value
Other U.S. Natural Gas Pipelines						
GTN	**2,221**	**810**	**1,411**	2,278	765	1,513
Great Lakes	**2,106**	**1,155**	**951**	2,157	1,155	1,002
Midstream[2,3]	**1,072**	**23**	**1,049**	—	—	—
Columbia Gulf[2]	**880**	**5**	**875**	—	—	—
Other[2,4]	**2,120**	**567**	**1,553**	2,124	521	1,603
	8,399	**2,560**	**5,839**	6,559	2,441	4,118
Under construction	**346**	**—**	**346**	8	—	8
	8,745	**2,560**	**6,185**	6,567	2,441	4,126
	21,532	**3,477**	**18,055**	10,398	3,230	7,168
Mexico Natural Gas Pipelines						
Pipeline	**2,734**	**180**	**2,554**	1,296	162	1,134
Compression	**422**	**19**	**403**	183	14	169
Metering and other	**502**	**40**	**462**	388	27	361
	3,658	**239**	**3,419**	1,867	203	1,664
Under construction	**1,108**	**—**	**1,108**	1,959	—	1,959
	4,766	**239**	**4,527**	3,826	203	3,623
Liquids Pipelines						
Keystone Pipeline System						
Pipeline	**10,572**	**901**	**9,671**	9,288	718	8,570
Pumping equipment	**928**	**121**	**807**	1,092	108	984
Tanks and other	**2,521**	**286**	**2,235**	3,034	228	2,806
	14,021	**1,308**	**12,713**	13,414	1,054	12,360
Under construction	**1,434**	**—**	**1,434**	1,826	—	1,826
	15,455	**1,308**	**14,147**	15,240	1,054	14,186
Energy[5]						
Natural Gas – Ravenswood	**—**	**—**	**—**	2,607	654	1,953
Natural Gas – Other[6,7]	**2,696**	**696**	**2,000**	3,361	1,164	2,197
Hydro, Wind and Solar	**1,180**	**245**	**935**	2,417	476	1,941
Natural Gas Storage and Other	**731**	**146**	**585**	740	132	608
	4,607	**1,087**	**3,520**	9,125	2,426	6,699
Under construction	**729**	**—**	**729**	430	—	430
	5,336	**1,087**	**4,249**	9,555	2,426	7,129
Corporate	**410**	**130**	**280**	267	82	185
	76,738	**22,263**	**54,475**	67,116	22,299	44,817

1 Includes Foothills and Venture LP.
2 Acquired as part of Columbia on July 1, 2016. Refer to Note 5, Acquisition of Columbia for further information.
3 Includes Midstream and mineral rights at December 31, 2016.
4 Includes Bison, Portland Natural Gas Transmission System, North Baja, Tuscarora, and Crossroads.
5 U.S. Northeast power assets except TCPM are excluded from the Energy net book value at December 31, 2016 as they have been classified as Assets held for sale. Refer to Note 6, Assets held for sale for further information.
6 Includes facilities with long-term PPAs that are accounted for as operating leases. The cost and accumulated depreciation of these facilities was $1,319 million and $335 million, respectively, at December 31, 2016 (2015 – $1,341 million and $302 million, respectively). Revenues of $212 million were recognized in 2016 (2015 – $235 million; 2014 – $223 million) through the sale of electricity under the related PPAs.
7 Includes Halton Hills, Coolidge, Bécancour, Mackay River and other natural gas-fired facilities.

Keystone XL

At December 31, 2016, the Company reviewed its remaining investment in Keystone XL and related projects with a carrying value of $526 million (2015 – $621 million) and found no events or changes in circumstance indicating that the carrying value may not be recoverable.

At December 31, 2015, the Company evaluated its investment in Keystone XL and related projects, including the Keystone Hardisty Terminal (KHT), for impairment in connection with the November 6, 2015 denial of the U.S. Presidential permit. As a result of the analysis, the Company recognized a non-cash impairment charge in its Liquids Pipelines segment of $3,686 million ($2,891 million after tax) based on the excess of the carrying value over the estimated fair value of $621 million of these assets. The impairment charge included $77 million ($56 million after tax) for certain cancellation fees that will be incurred in the future if the project is ultimately abandoned.

At December 31, 2015, included in the estimated fair value of $621 million was $463 million related to plant and equipment. The fair value of these assets was based on the price that would be received on sale of the plant and equipment in its condition at December 31, 2015. Key assumptions used in the determination of selling price included an estimated two year disposal period and the then current weak energy market conditions. The valuation considered a variety of potential selling prices that were based on the various markets that could be used in order to dispose of these assets.

At December 31, 2015, $158 million related to terminal assets, including KHT, was included in the fair value of $621 million. The fair value was determined using a discounted cash flow approach. The expected cash flows were discounted using a risk-adjusted discount rate to determine the fair value.

The valuation techniques above required the use of unobservable inputs. As a result, the fair value was classified within Level III of the fair value hierarchy at December 31, 2015 . Refer to Note 24, Risk management and financial instruments for further information on the fair value hierarchy.

Energy Turbine Impairment

Following the evaluation of specific capital project opportunities in 2015, it was determined that the carrying value of certain Energy turbine equipment was not fully recoverable. These turbines had been previously purchased for a power development project that did not proceed. As a result, at December 31, 2015, the Company recognized a non-cash impairment charge of $59 million ($43 million after tax) in the Energy segment. This impairment charge was based on the excess of the carrying value over the estimated fair value of the turbines, which was determined based on a comparison to similar assets available for sale in the market.

9. EQUITY INVESTMENTS

(millions of Canadian $)	Ownership Interest at December 31, 2016	Income/(Loss) from Equity Investments year ended December 31 2016	2015	2014	Equity Investments at December 31 2016	2015
Canadian Natural Gas Pipelines						
TQM	50.0%	**12**	12	12	**71**	72
U.S. Natural Gas Pipelines						
Northern Border[1]	50.0%	**92**	85	76	**597**	664
Iroquois[2]	50.0%	**54**	51	43	**309**	238
Millennium[3]	47.5%	**33**	—	—	**295**	—
Pennant Midstream[3]	47.0%	**6**	—	—	**246**	—
Other	Various	**29**	26	24	**93**	31
Mexico Natural Gas Pipelines						
Sur de Texas[4]	60.0%	**(3)**	—	—	**255**	—
Other[5]	Various	**—**	5	8	**28**	42
Liquids Pipelines						
Grand Rapids	50.0%	**(1)**	—	—	**876**	542
Other	Various	**—**	—	—	**39**	16
Energy						
Bruce Power[6,7]	48.5%	**293**	249	314	**3,356**	4,200
Portlands Energy	50.0%	**33**	30	36	**313**	321
ASTC Power Partnership	50.0%	**(37)**	(23)	8	**—**	21
Other	Various	**3**	5	1	**66**	67
		514	440	522	**6,544**	6,214

1 At December 31, 2016, the difference between the carrying value of the investment and the underlying equity in the net assets of Northern Border Pipeline Company is US$116 million (2015 – US$117 million) due to the fair value assessment of assets at the time of acquisition.

2 After the acquisition of an additional 4.87 per cent interest on March 31, 2016 and 0.65 per cent interest on May 1, 2016, TransCanada has an ownership interest of 50.0 per cent in Iroquois. Prior to these acquisitions, TransCanada had an ownership interest of 44.5 per cent. Refer to Note 26, Other acquisitions and dispositions for further information.

3 Acquired as part of Columbia. Reflects equity earnings from the date of acquisition to December 31, 2016.

4 TransCanada has an ownership interest of 60.0 per cent in Sur de Texas, which is a jointly controlled entity resulting in equity accounting.

5 Includes TransCanada's share of equity income from TransGas pipeline and Gas Pacifico/INNERGY. In November 2014, the Company sold its interest in Gas Pacifico/INNERGY.

6 As a result of TransCanada's increased ownership in Bruce Power L.P. (Bruce B) and the merger of Bruce Power A L.P. (Bruce A) and Bruce B to form Bruce Power in December 2015, TransCanada has an ownership interest in Bruce Power of 48.5 per cent. Prior to the acquisition and merger, TransCanada applied equity accounting to its 48.9 per cent ownership interest in Bruce A and 31.6 per cent ownership interest in Bruce B. TransCanada continues to apply equity accounting to Bruce Power. Refer to Note 26, Other acquisitions and dispositions for further information.

7 At December 31, 2016, the difference between the carrying value of the investment and the underlying equity in the net assets of Bruce Power is $942 million (2015 – $973 million) due to the fair value assessment of assets at the time of acquisitions.

On March 7, 2016, TransCanada issued notice to the Balancing Pool of the decision to terminate its Sundance B PPA held through ASTC Power Partnership. In accordance with a provision in the PPA, 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 changes in law surrounding the Alberta Specified Gas Emitters Regulation, the Company expected increasing costs related to carbon emissions to continue throughout the remaining term of the PPA resulting in increasing unprofitability. As a result, at March 31, 2016, the company recognized a non-cash impairment charge of $29 million ($21 million after tax) in its Energy segment income from equity investments which represented the carrying value of the equity investment in ASTC Partnership. The PPA termination was settled in December 2016.

Distributions received from equity investments for the year ended December 31, 2016 were $1,571 million (2015 – $802 million; 2014 – $738 million) of which $727 million (2015 – $9 million; 2014 – $12 million) were returns of capital and are included in Investing activities in the Consolidated statement of cash flows. The returns of capital were mainly for distributions received from Bruce Power in 2016 from its financing program. Undistributed earnings from equity investments were $198 million and $551 million at December 31, 2015 and December 31, 2014 respectively.

Contributions made to equity investments for the year ended December 31, 2016 were $765 million (2015 – $493 million; 2014 – $256 million) and are included in Investing activities in the Consolidated statement of cash flows.

Summarized Financial Information of Equity Investments

year ended December 31 (millions of Canadian $)	**2016**	**2015**	**2014**
Income			
Revenues	**4,336**	4,337	4,814
Operating and other expenses	**(3,143)**	(3,254)	(3,489)
Net income	**1,080**	1,046	1,264
Net income attributable to TransCanada	**514**	440	522

at December 31 (millions of Canadian $)	**2016**	**2015**
Balance Sheet		
Current assets	**1,669**	1,530
Non-current assets	**15,853**	13,190
Current liabilities	**(1,120)**	(1,370)
Non-current liabilities	**(5,867)**	(3,116)

10. RATE-REGULATED BUSINESSES

TransCanada's businesses that apply RRA currently include Canadian, U.S. and Mexican natural gas pipelines, regulated U.S. natural gas storage and certain Canadian liquids pipelines. Rate-regulated businesses account for and report assets and liabilities consistent with the economic impact of the way in which regulators establish rates, provided the rates established are designed to recover the costs of providing the regulated service and the competitive environment makes it probable that such rates can be charged and collected. Certain expenses and credits subject to utility regulation or rate determination normally reflected in the income statement are deferred on the balance sheet and are recognized in the income statement as the related amounts are included in service rates and recovered from or refunded to customers.

Canadian Regulated Operations

TransCanada's Canadian natural gas pipelines are regulated by the NEB under the *National Energy Board Act*. The NEB regulates the construction and operation of facilities, and the terms and conditions of services, including rates, for the Company's Canadian regulated natural gas transmission systems.

TransCanada's Canadian natural gas transmission services are supplied under natural gas transportation tariffs that provide for cost recovery, including return of and return on capital as approved by the NEB. Rates charged for these services are typically set through a process that involves filing an application with the regulator wherein forecasted operating costs, including a return of and on capital, determine the revenue requirement for the upcoming year or multiple years. To the extent that actual costs and revenues are more or less than the forecasted costs and revenues, the regulators generally allow the difference to be deferred to a future period and recovered or refunded in rates at that time. Differences between actual and forecasted costs that the regulator does not allow to be deferred are included in the determination of net income in the year they occur. The Company's significant Canadian natural gas pipelines are described below.

NGTL System
In April 2016, the NEB approved the NGTL System's 2016-2017 Revenue Requirement Settlement. The terms of the two-year settlement include an ROE of 10.1 per cent on 40 per cent deemed equity, a continuation of the 2015 depreciation rates, a mechanism for sharing variances above and below a fixed annual operating, maintenance and administration (OM&A) cost amount and flow-through treatment of all other costs.

The NGTL System's 2015 results reflect the terms of the 2015 Revenue Requirement Settlement. This one year settlement included a 10.1 per cent ROE on deemed common equity of 40 per cent, a continuation of the 2014 depreciation rates, a mechanism for sharing variances above and below a fixed annual OM&A cost amount that was based on an escalation of 2014 actual costs and flow-through treatment of all other costs.

The NGTL System's 2014 results reflect the terms of the 2013-2014 Revenue Requirement Settlement Application. This settlement included fixed annual OM&A costs and a 10.1 per cent ROE on a deemed common equity of 40 per cent and a continuation of 2013 depreciation rates. Any variance between fixed OM&A costs in the settlement and actual costs accrued to TransCanada.

Canadian Mainline
The Canadian Mainline currently operates under the terms of the 2015-2030 Tolls Application approved in 2014 (the NEB 2014 Decision). The terms of the settlement include an ROE of 10.1 per cent on deemed common equity of 40 per cent, an incentive mechanism that has both upside and downside risk and a $20 million after-tax annual TransCanada contribution to reduce the revenue requirement. Toll stabilization is achieved through the continued use of deferral accounts, namely the long-term adjustment account (LTAA) and the bridging amortization account, to capture the surplus or the shortfall between the Company's revenues and cost of service for each year over the six-year fixed toll term of the NEB 2014 Decision. A toll review filing will be required for the 2018 to 2020 period.

The Canadian Mainline's 2014 results reflect the terms of the NEB 2013 Decision. The decision established an ROE of 11.5 per cent on deemed common equity of 40 per cent and included mechanisms to achieve fixed tolls through use of the LTAA as well as establishment of a Tolls Stabilization Account (TSA) to capture the surplus or the shortfall between revenues and cost of service for each year over the five-year term of the decision. In addition, the NEB 2013 Decision provided an opportunity to generate incentive earnings by increasing revenues and reducing costs.

U.S. Regulated Operations
TransCanada's U.S. natural gas pipelines operate under the provisions of the Natural Gas Act of 1938, the Natural Gas Policy Act of 1978 (NGA) and the Energy Policy Act of 2005, and are subject to the jurisdiction of the FERC. The NGA grants the FERC authority over the construction and operation of pipelines and related facilities, including the regulation of tariffs which incorporates maximum and minimum rates for services and allows U.S. natural gas pipelines to discount or negotiate rates on a non-discriminatory basis. The Company's significant regulated U.S. natural gas pipelines, based on effective ownership and total operated pipe length, are described below.

Columbia Gas
Columbia Gas' natural gas transportation and storage services are provided under a tariff at rates subject to FERC approval. In 2013, the FERC approved a modernization settlement which provides for cost recovery and return on investment of up to US$1.5 billion over a five-year period to modernize the Columbia Gas system to improve system integrity and enhance service reliability and flexibility. In March 2016, an extension of this settlement was approved by the FERC, which will allow for the cost recovery and return on additional expanded scope investment of US$1.1 billion over a three-year period through 2020.

Columbia Gulf
Columbia Gulf's natural gas transportation services are provided under a tariff at rates subject to FERC approval. In September 2016, the FERC issued an order approving an uncontested settlement following a FERC-initiated rate proceeding pursuant to section 5 of the NGA, which required a reduction in Columbia Gulf's daily maximum recourse rate and addressed treatment of post-retirement benefits other than pensions, pension expense, and regulatory expenses. The FERC order also requires Columbia Gulf to file a general rate case under section 4 of the NGA by January 31, 2020, for rates to take effect by August 1, 2020.

ANR Pipeline Company

ANR Pipeline Company previously operated under rates established pursuant to a settlement approved by the FERC that was effective for all periods presented, beginning in 1997 through July 31, 2016. Effective August 1, 2016, ANR Pipeline Company began operating under new rates pursuant to a FERC-approved rate settlement in September 2016. Under terms of the September 2016 settlement, neither ANR Pipeline Company nor the settling parties can file to change or modify the new settlement rates to become effective earlier than August 1, 2019. However, ANR Pipeline Company is required to file for new rates to be effective no later than August 1, 2022.

Great Lakes

Great Lakes operates under rates established pursuant to a settlement approved by the FERC in November 2013. Under the settlement, Great Lakes is required to file for new rates to be effective no later than January 1, 2018.

Mexico Regulated Operations

TransCanada's Mexican operations are regulated by the CRE and operate in accordance with CRE-approved tariffs. The rates in effect on TransCanada's Mexican gas pipelines were established based on CRE-approved contracts that provide for the recovery of costs of providing services.

Regulatory Assets and Liabilities

at December 31 (millions of Canadian $)	2016	2015	Remaining Recovery/ Settlement Period (years)
Regulatory Assets			
Deferred income taxes[1]	**861**	894	n/a
Operating and debt-service regulatory assets[2]	**1**	47	1
Pensions and other post retirement benefits[3]	**382**	210	n/a
Foreign exchange on long-term debt[1,4]	**37**	54	1-13
Other	**74**	64	n/a
	1,355	1,269	
Less: Current portion included in Other current assets (Note 7)	**33**	85	
	1,322	1,184	
Regulatory Liabilities			
Operating and debt-service regulatory liabilities[2]	**47**	32	1
Pensions and other post retirement benefits[3]	**180**	—	n/a
ANR related post-employment and retirement benefits other than pension[5]	**141**	147	n/a
Long term adjustment account[6]	**659**	231	45
Pipeline abandonment costs	**541**	285	n/a
Bridging amortization account[6]	**451**	456	14
Cost of removal[7]	**226**	36	n/a
Other	**54**	16	n/a
	2,299	1,203	
Less: Current portion included in Accounts payable and other (Note 14)	**178**	44	
	2,121	1,159	

1 These regulatory assets are underpinned by non-cash transactions or are recovered without an allowance for return as approved by the regulator. Accordingly, these regulatory assets are not included in rate base and do not yield a return on investment during the recovery period.

2 Operating and debt-service regulatory assets and liabilities represent the accumulation of cost and revenue variances approved by the regulatory authority for inclusion in determining tolls for the following calendar year.

3 These balances represent the regulatory offset to pension plan and other post-retirement obligations to the extent the amounts are expected to be collected from customers in future rates. The balances are excluded from the rate base and do not earn a return on investment.

4 Foreign exchange on long-term debt of the NGTL System represents the variance resulting from revaluing foreign currency-denominated debt instruments to the current foreign exchange rate from the historical foreign exchange rate at the time of issue. Foreign exchange gains and losses realized when foreign debt matures or is redeemed early are expected to be recovered or refunded through the determination of future tolls.

5 This balance represents what ANR estimated that it would be required to refund to its customers for post-retirement and post-employment benefit amounts collected through its FERC-approved rates that have not been used to pay benefits to its employees since a 1997 rate settlement. Pursuant to a FERC-approved September 2016 rate settlement, $106 million of the regulatory liability balance that accumulated between January 2007 and July 2016 will be resolved through a refund of $53 million to its customers and ANR amortizing $53 million over a three year period that began August 1, 2016. A remaining $41 million balance accumulated prior to 2007 is subject to resolution through future regulatory proceedings, and accordingly a settlement period cannot be determined at this time.

6 These regulatory accounts are used to capture Canadian Mainline revenue and cost variances and stabilize tolls during the 2015-2030 settlement term.

7 This balance represents anticipated costs of removal that have been, and continue to be, included in depreciation rates and collected in the service rates of certain rate-regulated subsidiaries for future costs to be incurred.

11. GOODWILL

The Company has recorded the following Goodwill on its acquisitions in the U.S.:

(millions of Canadian $)	U.S. Natural Gas Pipelines	Energy	Total
Balance at January 1, 2015	3,074	960	4,034
Foreign exchange rate changes	593	185	778
Balance at December 31, 2015	3,667	1,145	4,812
Acquisition of Columbia (Note 5)	**10,078**	**—**	**10,078**
Impairment charge	**—**	**(1,085)**	**(1,085)**
Foreign exchange rate changes	**213**	**(60)**	**153**
Balance at December 31, 2016	**13,958**	**—**	**13,958**

As a result of information received during the process to monetize the Company's U.S. Northeast power business in the third quarter 2016, it was determined that the fair value of Ravenswood did not exceed its carrying value, including goodwill. The fair value of the reporting unit was determined using a combination of methods including a discounted cash flow approach and a range of expected consideration from a potential sale. The expected cash flows were discounted using a risk-adjusted discount rate to determine the fair value. As a result, the Company recorded a goodwill impairment charge on the full carrying value of Ravenswood goodwill of $1,085 million ($656 million after tax) within the Energy segment. The impairment charge was recorded prior to reclassification to Assets held for sale. Refer to Note 6, Assets held for sale for further detail.

At December 31, 2016, TransCanada's Goodwill included US$573 million (2015 – US$573 million) related to the Great Lakes natural gas transportation business. During 2015, TransCanada's share of this goodwill (net of non-controlling interests) increased by US$143 million, to US$386 million, as a result of a 2015 impairment charge of US$199 million recorded by TC PipeLines, LP on its equity method goodwill related to Great Lakes. On a consolidated basis, TransCanada's carrying value of its investment in Great Lakes was proportionately lower compared to the 46.45 per cent owned through TC PipeLines, LP. As a result, the estimated fair value of Great Lakes exceeded TransCanada's consolidated carrying value of the investment and no impairment was recorded in 2015.

At December 31, 2016, the estimated fair value of Great Lakes exceeded its carrying value by less than 10 per cent. The fair value of this reporting unit was measured using a discounted cash flow analysis in its most recent valuation. Assumptions used in the analysis regarding Great Lakes' ability to realize long-term value in the North American energy market included the impact of changing natural gas flows in its market region as well as a change in the Company's view of other strategic alternatives to increase utilization of Great Lakes. Although evolving market conditions and other factors relevant to Great Lakes' long term financial performance have remained relatively stable, there is a risk that reductions in future cash flow forecasts or adverse changes in other key assumptions could result in a future impairment of a portion of the goodwill balance relating to Great Lakes.

At December 31, 2016, the estimated fair value of ANR exceeded its carrying value by less than 10 per cent. The fair value of this reporting unit was measured using a discounted cash flow analysis. Assumptions regarding ANR's ability to realize long-term value depend upon trends in value for its storage services, continued growth in its asset base and favourable outcomes of future rate proceedings. The Company reduced long-term forecast cash flows from the reporting unit as compared to those utilized in previous impairment tests thereby reflecting the continued changes in the business environment. There is a risk that continued reductions in future cash flow forecasts and adverse changes in other key assumptions could result in a future impairment of a portion of the goodwill balance relating to ANR. The goodwill balance related to ANR at December 31, 2016 was US$1.9 billion (2015 – US$1.9 billion).

12. INTANGIBLE AND OTHER ASSETS

at December 31 (millions of Canadian $)	2016	2015
Capital projects in development	**2,094**	1,814
Deferred income tax assets (Note 16)	**392**	15
Employee post-retirement benefits (Note 23)	**189**	18
Fair value of derivative contracts (Note 24)	**133**	168
PPAs	**—**	220
Prepaid rent[1]	**—**	230
Loans and advances[1]	**—**	159
Other	**218**	478
	3,026	3,102

1 TransCanada held a note receivable from the seller of Ravenswood of $165 million (US$123 million) and $214 million (US$154 million) as at December 31, 2016 and at December 31, 2015, respectively,which bears interest at 6.75 per cent and matures in 2040. As of November 1, 2016, all Ravenswood assets including prepaid rent and the note receivable have been reclassified to Assets held for sale (Note 6). The current portion included in Other current assets was $55 million (US$40 million) at December 31, 2015.

The following amounts related to PPAs are included in Intangible and other assets:

at December 31 (millions of Canadian $)	2016			2015		
	Cost	Accumulated Amortization	Net Book Value	Cost	Accumulated Amortization	Net Book Value
Sheerness	—	—	—	585	390	195
Sundance A	—	—	—	225	200	25
	—	—	—	810	590	220

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 expected increasing costs related to carbon emissions to continue throughout the remaining terms of the PPAs resulting in increasing unprofitability. As such, in 2016, the Company recognized a non-cash impairment charge of $211 million ($155 million after tax) in its Energy segment, which represented the carrying value of the PPAs. Upon final settlement of the PPA terminations in December 2016, TransCanada transferred to the Balancing Pool a package of environmental credits that were being held to offset the PPA emissions costs and recorded a non-cash charge of $92 million ($68 million after tax) related to the carrying value of these environmental credits.

Amortization expense of $9 million was recognized in the Consolidated statement of income for the year ended December 31, 2016 (2015 and 2014 – $52 million), prior to the termination of the arrangements.

13. NOTES PAYABLE

(millions of Canadian $, unless otherwise noted)	2016 Outstanding at December 31	2016 Weighted Average Interest Rate per Annum at December 31	2015 Outstanding at December 31	2015 Weighted Average Interest Rate per Annum at December 31
Canadian	**509**	**0.9%**	697	0.8%
U.S. (2016 – US$197; 2015 – US$376)	**265**	**0.5%**	521	1.1%
	774		1,218	

At December 31, 2016, Notes payable consists of commercial paper issued by TransCanada PipeLines Limited (TCPL), TransCanada American Investments Ltd. (TAIL) and TransCanada PipeLines USA Limited (TCPL USA).

In December 2016, Columbia entered into a new US$1.0 billion credit facility. At December 31, 2016, total committed revolving and demand credit facilities were $11.1 billion (2015 – $8.9 billion). When drawn, interest on these lines of credit is charged at prime rates of Canadian and U.S. banks, and at other negotiated financial bases. These unsecured credit facilities included the following:

at December 31, 2016					year ended December 31 (millions of Canadian $)		
					2016	**2015**	**2014**
Amount	**Unused Capacity**	**Borrower**	**Description**	**Matures**	**Cost to maintain**		
$3 billion	$3 billion	TCPL	Committed, syndicated, revolving, extendible credit facility that supports TCPL's Canadian commercial paper program and general corporate purposes	December 2021	**6**	6	6
US$2 billion	US$2 billion	TCPL	Committed, syndicated, revolving, extendible credit facility that supports TCPL's U.S. commercial paper program	December 2017	**1**	—	—
US$1 billion	US$0.9 billion	TCPL USA	Committed, syndicated, revolving, extendible credit facility that is used for TCPL USA general corporate purposes, guaranteed by TCPL	December 2017	**1**	3	2
US$1 billion	US$1 billion	Columbia	Committed, syndicated, revolving, extendible credit facility that is issued for Columbia's general corporate purposes and provides additional liquidity, guaranteed by TCPL	December 2017	**—**	—	—
US$0.5 billion	US$0.5 billion	TAIL	Committed, syndicated, revolving, extendible credit facility that supports TAIL's commercial paper program, guaranteed by TCPL	December 2017	**2**	2	1
$2.1 billion	$0.7 billion	TCPL/TCPL USA	Supports the issuance of letters of credit and provides additional liquidity	Demand	**—**	—	—

At December 31, 2016, the Company's operated affiliates had an additional $0.6 billion (2015 – $0.6 billion) of undrawn capacity on committed credit facilities.

14. ACCOUNTS PAYABLE AND OTHER

at December 31 (millions of Canadian $)	2016	2015
Trade payables	**2,443**	1,506
Fair value of derivative contracts (Note 24)	**607**	926
Unredeemed shares of Columbia	**317**	—
Regulatory liabilities (Note 10)	**178**	44
Other	**316**	177
	3,861	2,653

15. OTHER LONG-TERM LIABILITIES

at December 31 (millions of Canadian $)	2016	2015
Fair value of derivative contracts (Note 24)	**330**	625
Employee post-retirement benefits (Note 23)	**448**	380
Asset retirement obligations	**108**	109
Guarantees (Note 27)	**82**	26
Other	**215**	120
	1,183	1,260

16. INCOME TAXES

Provision for Income Taxes

year ended December 31 (millions of Canadian $)	2016	2015	2014
Current			
Canada	**116**	44	103
Foreign	**40**	92	42
	156	136	145
Deferred			
Canada	**101**	33	309
Foreign	**95**	(135)	377
	196	(102)	686
Income Tax Expense	**352**	34	831

Geographic Components of Income

year ended December 31 (millions of Canadian $)	2016	2015	2014
Canada	**219**	(624)	1,146
Foreign	**618**	(482)	1,678
Income/(Loss) before Income Taxes	**837**	(1,106)	2,824

Reconciliation of Income Tax Expense

year ended December 31 (millions of Canadian $)	2016	2015	2014
Income/(Loss) before income taxes	**837**	(1,106)	2,824
Federal and provincial statutory tax rate	**27%**	26%	25%
Expected income tax expense/(recovery)	**226**	(288)	706
Income tax differential related to regulated operations	**81**	159	129
Foreign tax rate differentials	**(196)**	14	25
Income from equity investments and non-controlling interests	**(68)**	(56)	(38)
Asset impairment charges[1]	**242**	170	—
Non-deductible amounts	**46**	—	—
Tax rate and legislative changes	**—**	34	—
Other	**21**	1	9
Actual Income Tax Expense	**352**	34	831

1 Net of $112 million (2015 - $311 million) attributed to higher foreign tax rates.

Deferred Income Tax Assets and Liabilities

at December 31 (millions of Canadian $)	2016	2015
Deferred Income Tax Assets		
Tax loss and credit carryforwards	**2,063**	1,327
Difference in accounting and tax bases of impaired assets and assets held for sale	**1,168**	916
Regulatory and other deferred amounts	**277**	231
Unrealized foreign exchange losses on long-term debt	**446**	589
Financial instruments	**34**	111
Other	**352**	136
	4,340	3,310
Less: valuation allowance[1]	**1,336**	1,060
	3,004	2,250
Deferred Income Tax Liabilities		
Difference in accounting and tax bases of plant, property and equipment and PPAs	**9,015**	6,441
Equity investments	**905**	656
Taxes on future revenue requirement	**198**	227
Other	**156**	55
	10,274	7,379
Net Deferred Income Tax Liabilities	**7,270**	5,129

1 In 2016, an increase to the valuation allowance of $276 million was recorded as the Company believes that it is more likely than not that the tax benefits related to the unrealized foreign exchange losses on long-term debt, unrealized losses on certain impaired assets, certain operating losses and capital losses will not be realized in the future.

The above deferred tax amounts have been classified in the Consolidated balance sheet as follows:

at December 31 (millions of Canadian $)	2016	2015
Deferred Income Tax Assets		
Intangible and other assets (Note 12)	**392**	15
Deferred Income Tax Liabilities		
Deferred income tax liabilities	**7,662**	5,144
Net Deferred Income Tax Liabilities	**7,270**	5,129

At December 31, 2016, the Company has recognized the benefit of unused non-capital loss carryforwards of $1,786 million (2015 – $1,283 million) for federal and provincial purposes in Canada, which expire from 2029 to 2036. In addition, the Company has not recognized the benefit of capital loss carry forwards of $654 million (2015 – $75 million) for federal and provincial purposes in Canada. The Company also has Ontario minimum tax credits of $68 million (2015 – $57 million), which expire from 2027 to 2036.

At December 31, 2016, the Company has recognized the benefit of unused net operating loss carryforwards of US$2,545 million (2015 – US$1,617 million) for federal purposes in the U.S., which expire from 2028 to 2036. The Company has not recognized the benefit of unused net operating loss carryforwards of US$58 million (2015 – nil) for federal purposes in the U.S. The Company also has alternative minimum tax credits of US$37 million (2015 – US$41 million).

At December 31, 2016, the Company has recognized the benefit of unused net operating loss carryforwards of US$54 million (2015 – US$70 million) in Mexico, which expire from 2024 to 2025.

Unremitted Earnings of Foreign Investments

Income taxes have not been provided on the unremitted earnings of foreign investments that the Company does not intend to repatriate in the foreseeable future. Deferred income tax liabilities would have increased at December 31, 2016 by approximately $481 million (2015 – $308 million) if there had been a provision for these taxes.

Income Tax Payments

Income tax payments of $105 million, net of refunds, were made in 2016 (2015 – payments, net of refunds, of $162 million; 2014 – payments, net of refunds, of $109 million).

Reconciliation of Unrecognized Tax Benefit

Below is the reconciliation of the annual changes in the total unrecognized tax benefit:

at December 31 (millions of Canadian $)	**2016**	**2015**	**2014**
Unrecognized tax benefit at beginning of year	**17**	18	23
Gross increases – tax positions in prior years	**3**	2	3
Gross decreases – tax positions in prior years	**—**	(2)	(8)
Gross increases – tax positions in current year	**2**	1	1
Settlement	**(1)**	—	—
Lapse of statutes of limitations	**(3)**	(2)	(1)
Unrecognized Tax Benefit at End of Year	**18**	17	18

Subject to the results of audit examinations by taxing authorities and other legislative amendments, TransCanada does not anticipate further adjustments to the unrecognized tax benefits during the next 12 months that would have a material impact on its financial statements.

TransCanada and its subsidiaries are subject to either Canadian federal and provincial income tax, U.S. federal, state and local income tax or the relevant income tax in other international jurisdictions. The Company has substantially concluded all Canadian federal and provincial income tax matters for the years through 2008. Substantially all material U.S. federal, state and local income tax matters have been concluded for years through 2011.

TransCanada's practice is to recognize interest and penalties related to income tax uncertainties in income tax expense. Income tax expense for the year ended December 31, 2016 reflects nil of interest expense and nil for penalties (2015 – $1 million reversal of interest expense and nil for penalties; 2014 – $1 million of interest expense and nil for penalties). At December 31, 2016, the Company had $4 million accrued for interest expense and nil accrued for penalties (December 31, 2015 – $4 million accrued for interest expense and nil accrued for penalties).

17. LONG-TERM DEBT

Outstanding amounts (millions of Canadian $, unless otherwise noted)	Maturity Dates	2016 Outstanding at December 31	2016 Interest Rate[1]	2015 Outstanding at December 31	2015 Interest Rate[1]
TRANSCANADA PIPELINES LIMITED					
Debentures					
Canadian	2017 to 2020	**599**	**10.7%**	599	10.7%
U.S. (2016 and 2015 – US$400)	2021	**536**	**9.9%**	553	9.9%
Medium Term Notes					
Canadian	2017 to 2046	**5,787**	**4.6%**	5,175	5.3%
Senior Unsecured Notes					
U.S. (2016 – US$14,517; 2015 – US$14,641)	2017 to 2045	**19,521**	**5.1%**	20,245	4.8%
Acquisition Bridge Facility (2016 – US$2,006)[2]	2018	**2,693**	**1.9%**	—	—
		29,136		26,572	
NOVA GAS TRANSMISSION LTD.					
Debentures and Notes					
Canadian	2024	**100**	**9.9%**	324	11.5%
U.S. (2016 and 2015 – US$200)	2023	**268**	**7.9%**	276	7.9%
Medium Term Notes					
Canadian	2025 to 2030	**503**	**7.4%**	503	7.4%
U.S. (2016 and 2015 – US$33)	2026	**43**	**7.5%**	44	7.5%
		914		1,147	
TRANSCANADA PIPELINE USA LTD.					
Acquisition Bridge Facility (2016 – US$1,695)[2]	2018	**2,276**	**1.9%**	—	—
COLUMBIA PIPELINE GROUP, INC.					
Senior Unsecured Notes					
U.S. (2016 – US$2,968)[3]	2018 to 2045	**3,985**	**3.7%**	—	—
TC PIPELINES, LP					
Unsecured Loan Facility					
U.S. (2016 – US$158; 2015 – US$200)	2021	**213**	**1.9%**	277	1.6%
Unsecured Term Loan					
U.S. (2016 and 2015 – US$670)	2018	**899**	**1.9%**	927	1.6%
Senior Unsecured Notes					
U.S. (2016 and 2015 – US$694)	2021 to 2025	**932**	**4.7%**	957	4.7%
		2,044		2,161	
ANR PIPELINE COMPANY					
Senior Unsecured Notes					
U.S. (2016 – US$671; 2015 – US$432)	2021 to 2026	**901**	**7.2%**	597	8.9%
GAS TRANSMISSION NORTHWEST LLC					
Unsecured Term Loan					
U.S. (2016 – US$65; 2015 – US$75)	2019	**87**	**1.6%**	104	1.4%
Senior Unsecured Notes					
U.S. (2016 and 2015 – US$250)	2020 to 2035	**335**	**5.6%**	346	5.6%
		422		450	
GREAT LAKES GAS TRANSMISSION LIMITED PARTNERSHIP					
Senior Unsecured Notes					
U.S. (2016 – US$278; 2015 – US$297)	2018 to 2030	**373**	**7.7%**	411	7.8%

Outstanding amounts (millions of Canadian $, unless otherwise noted)	Maturity Dates	2016 Outstanding at December 31	2016 Interest Rate[1]	2015 Outstanding at December 31	2015 Interest Rate[1]
PORTLAND NATURAL GAS TRANSMISSION SYSTEM					
Senior Secured Notes[4]					
U.S. (2016 – US$52; 2015 – US$69)	2018	**70**	**6.0%**	96	6.1%
TUSCARORA GAS TRANSMISSION COMPANY					
Unsecured Term Loan					
U.S. (2016 – US$10)	2019	**13**	**1.9%**	—	—
Senior Secured Notes					
U.S. (2016 – US$12; 2015 – US$16)	2017	**16**	**4.0%**	22	4.0%
		29		22	
		40,150		31,456	
Less: Current portion of Long-term debt		**1,838**		2,547	
		38,312		28,909	

1 Interest rates are the effective interest rates except for those pertaining to long-term debt issued for the Company's Canadian regulated natural gas operations, in which case the weighted average interest rate is presented as approved by the regulators. Weighted average and effective interest rates are stated as at the respective outstanding dates.

2 These facilities were put in place to finance a portion of the Columbia acquisition and bear interest at London Interbank Offered Rate (LIBOR) plus an applicable margin. Proceeds from the U.S. Northeast power business monetization will be used to repay the majority of these facilities.

3 Certain subsidiaries of Columbia have guaranteed the principal payments of Columbia's senior unsecured notes. Each guarantor of Columbia's obligations is required to comply with covenants under the debt indenture and in the event of default, the guarantors would be obligated to pay the principal and related interest.

4 Secured by shipper transportation contracts, existing and new guarantees, letters of credit and collateral requirements.

Principal Repayments

At December 31, 2016, principal repayments on the Long-term debt of the Company for the next five years are approximately as follows:

(millions of Canadian $)	2017	2018	2019	2020	2021
Principal repayments on Long-term debt	1,838	8,941	1,742	2,762	2,165

Long-Term Debt Issued

The Company issued Long-term debt over the three years ended December 31, 2016 as follows:

(millions of Canadian $, unless otherwise noted) 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	3.69% [2]
	June 2016	Medium Term Notes	June 2046	700	4.35%
	January 2016	Senior Unsecured Notes	January 2026	US 850	4.875%
	January 2016	Senior Unsecured Notes	January 2019	US 400	3.125%
	November 2015	Senior Unsecured Notes	November 2017	US 1,000	1.625%
	October 2015	Medium Term Notes	November 2041	400	4.55%
	July 2015	Medium Term Notes	July 2025	750	3.30%
	March 2015	Senior Unsecured Notes	March 2045	US 750	4.60%
	January 2015	Senior Unsecured Notes	January 2018	US 500	1.875%
	January 2015	Senior Unsecured Notes	January 2018	US 250	Floating
	February 2014	Senior Unsecured Notes	March 2034	US 1,250	4.63%
TRANSCANADA PIPELINE USA LTD.					
	June 2016	Acquisition Bridge Facility[1]	June 2018	US 1,700	Floating
ANR PIPELINE COMPANY					
	June 2016	Senior Unsecured Notes	June 2026	US 240	4.14%
TUSCARORA GAS TRANSMISSION COMPANY					
	April 2016	Term Loan	April 2019	US 10	Floating
TC PIPELINES, LP					
	September 2015	Unsecured Term Loan	October 2018	US 170	Floating
	March 2015	Senior Unsecured Notes	March 2025	US 350	4.375%
GAS TRANSMISSION NORTHWEST LLC					
	June 2015	Unsecured Term Loan	June 2019	US 75	Floating

1 These facilities were put in place to finance a portion of the Columbia acquisition and bear interest at LIBOR plus an applicable margin. Proceeds from the monetization of the U.S. Northeast power business will be used to repay these facilities.

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

Long-Term Debt Retired/Repaid

The Company retired/repaid Long-term debt over the three years ended December 31, 2016 as follows:

(millions of Canadian $, unless otherwise noted)				
Company	**Retirement/ Repayment Date**	**Type**	**Amount**	**Interest Rate**
TRANSCANADA PIPELINES LIMITED				
	November 2016	Acquisition Bridge Facility[1]	US 3,200	Floating
	October 2016	Medium Term Notes	400	4.65%
	June 2016	Senior Unsecured Notes	US 84	7.69%
	June 2016	Senior Unsecured Notes	US 500	Floating
	January 2016	Senior Unsecured Notes	US 750	0.75%
	August 2015	Debentures	150	11.90%
	June 2015	Senior Unsecured Notes	US 500	3.40%
	March 2015	Senior Unsecured Notes	US 500	0.875%
	January 2015	Senior Unsecured Notes	US 300	4.875%
	June 2014	Debentures	125	11.10%
	February 2014	Medium Term Notes	300	5.05%
	January 2014	Medium Term Notes	450	5.65%
NOVA GAS TRANSMISSION LTD.				
	February 2016	Debentures	225	12.20%
	June 2014	Debentures	53	11.20%
GAS TRANSMISSION NORTHWEST LLC				
	June 2015	Senior Unsecured Notes	US 75	5.09%

1 Proceeds from the November 2016 common equity offering were used to partially repay the Acquisition Bridge Facility.

Interest Expense

Interest expense over the three years ended December 31 was as follows:

year ended December 31 (millions of Canadian $)	**2016**	**2015**	**2014**
Interest on Long-term debt	**1,765**	1,487	1,317
Interest on Junior subordinated notes (Note 18)	**180**	116	70
Interest on short-term debt	**18**	16	15
Capitalized interest	**(176)**	(280)	(259)
Amortization and other financial charges[1]	**211**	31	55
	1,998	1,370	1,198

1 Amortization and other financial charges includes amortization of transaction costs and debt discounts calculated using the effective interest method and changes in the fair value of derivatives used to manage the Company's exposure to changes in interest rates. In 2016, this amount includes dividend equivalent payments of $109 million on the subscription receipts issued to partially fund the Columbia acquisition. Refer to Note 20, Common shares for further information.

The Company made interest payments of $1,721 million in 2016 (2015 – $1,266 million; 2014 – $1,123 million) on long-term debt, junior subordinated notes and notes payable, net of interest capitalized.

18. JUNIOR SUBORDINATED NOTES

Outstanding loan amount (millions of Canadian $, unless otherwise noted)	Maturity Date	2016 Outstanding at December 31	2016 Effective Interest Rate	2015 Outstanding at December 31	2015 Effective Interest Rate
TRANSCANADA PIPELINES LIMITED					
U.S. (2016 and 2015 – US$1,000)[1]	2067	**1,342**	**6.4%**	1,382	6.4%
U.S. (2016 and 2015 – US$742)[1, 2]	2075	**996**	**5.5%**	1,027	5.3%
U.S. (2016 – US$1,186)[1, 2]	2076	**1,593**	**6.2%**	—	—
		3,931		2,409	

1 The Junior subordinated notes are subordinated in right of payment to existing and future senior indebtedness or other obligations of TCPL.

2 The Junior subordinated notes were issued to TransCanada Trust (the Trust), a financing trust subsidiary wholly-owned by TCPL. While the obligations of the Trust are fully and unconditionally guaranteed by TCPL on a subordinated basis, the Trust is not consolidated in TransCanada's financial statements because TCPL does not have a variable interest in the Trust and the only substantive assets of the Trust are junior subordinated notes of TCPL.

In August 2016, TransCanada Trust (the Trust) issued US$1.2 billion of Trust Notes – Series 2016-A (Trust Notes) to third party investors at a fixed interest rate of 5.875 per cent for the first ten years, converting to a floating rate thereafter. All of the issuance proceeds of the Trust were loaned to TCPL for US$1.2 billion of junior subordinated notes of TCPL at an initial fixed rate of 6.125 per cent, including a 0.25 per cent administration charge. The rate will reset commencing August 2026 until August 2046 to the three month LIBOR plus 4.89 per cent per annum; from August 2046 to August 2076 the interest rate will reset to the three month LIBOR plus 5.64 per cent per annum. The junior subordinated notes are callable at TCPL's option at any time on or after August 15, 2026 at 100 per cent of the principal amount plus accrued and unpaid interest to the date of redemption.

In May 2015, the Trust issued US$750 million Trust Notes – Series 2015-A (Trust Notes) to third party investors at a fixed interest rate of 5.625 per cent for the first ten years, converting to a floating rate thereafter. All of the issuance proceeds of the Trust were loaned to TCPL for US$750 million of junior subordinated notes of TCPL at an initial fixed rate of 5.875 per cent, including a 0.25 per cent administration charge. The rate will reset commencing May 2025 until May 2045 to the three month LIBOR plus 3.778 per cent per annum; from May 2045 to May 2075 the interest rate will reset to the three month LIBOR plus 4.528 per cent per annum. The junior subordinated notes of TCPL are callable at TCPL's option at any time on or after May 20, 2025 at 100 per cent of the principal amount plus accrued and unpaid interest to the date of redemption.

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

Junior subordinated notes of US$1.0 billion mature in May 2067 and bear interest at a fixed rate of 6.35 per cent per annum until May 15, 2017, when interest will convert to a floating rate that is reset quarterly to the three month LIBOR plus 2.21 per cent. TCPL has the option to defer payment of interest for periods of up to ten years without giving rise to a default or permitting acceleration of payment under the terms of the junior subordinated notes, however, both TransCanada and TCPL would be prohibited from paying dividends during any such deferral period. The junior subordinated notes are callable at TCPL's option at any time on or after May 15, 2017 at 100 per cent of the principal amount plus accrued and unpaid interest to the date of redemption. The junior subordinated notes are callable earlier, in whole or in part, upon the occurrence of certain events and at the Company's option at an amount equal to the greater of 100 per cent of the principal amount plus accrued and unpaid interest to the date of redemption and an amount determined by a specified formula in accordance with their terms.

19. NON-CONTROLLING INTERESTS

The Company's Non-controlling interests included in the Consolidated balance sheet are as follows:

at December 31 (millions of Canadian $)	2016	2015
Non-controlling interest in TC PipeLines, LP	**1,596**	1,590
Non-controlling interest in Portland Natural Gas Transmission System	**130**	127
	1,726	1,717

The Company's Non-controlling interests included in the Consolidated statement of income are as follows:

year ended December 31 (millions of Canadian $)	2016	2015	2014
Non-controlling interest in TC PipeLines, LP	**215**	(13)	136
Non-controlling interest in Portland Natural Gas Transmission System	**20**	19	15
Non-controlling interest in Columbia Pipeline Partners LP	**17**	—	—
Preferred shares of TCPL	**—**	—	2
	252	6	153

During 2016, the non-controlling interest in TC PipeLines, LP increased from 72.0 per cent to 73.2 per cent due to periodic issuances of common units in TC PipeLines, LP to third parties under an at-the-market issuance program (ATM program). In 2015, the non-controlling interest in TC PipeLines, LP ranged between 71.7 per cent and 72.0 per cent and, in 2014, between 71.1 per cent and 71.7 per cent.

On July 1, 2016, TransCanada acquired Columbia, which included a 53.5 per cent non-controlling interest in CPPL. On November 1, 2016, TransCanada announced that it had entered into an agreement to acquire, for cash, all outstanding publicly held common units of CPPL. The transaction is expected to close in the first quarter of 2017 subject to receipt of CPPL unitholder approval and customary closing conditions.

At December 31, 2016, the entire $1,073 million (US$799 million) of TransCanada's non-controlling interest in CPPL was recorded as Common units subject to rescission or redemption on the Consolidated balance sheet. The Company classified this non-controlling interest outside of equity because the potential rights of the units are not within the control of the Company.

The non-controlling interest in Portland Natural Gas Transmission System (PNGTS) as at December 31, 2016 represented the 38.3 per cent interest held by third parties (2015 and 2014 – 38.3 per cent). On January 1, 2016, TransCanada sold 49.9 per cent of PNGTS to TC PipeLines, LP. Refer to Note 26, Other acquisitions and disposition for further information.

In 2016, TransCanada received fees of $4.5 million from TC PipeLines, LP (2015 – $4 million and 2014 – $3 million) and $8 million from PNGTS (2015 – $11 million; 2014 – $8 million) for services provided.

At December 31, 2015, TC PipeLines, LP recorded an impairment charge of US$199 million related to its equity investment in Great Lakes. The non-controlling interest's share of this charge was US$143 million and was included in the Net income attributable to non-controlling interests in the Consolidated statement of income.

On March 5, 2014, TCPL redeemed all of its four million outstanding 5.60 per cent cumulative redeemable first preferred shares Series Y at a price of $50 per share plus $0.2455 representing accrued and unpaid dividends to the redemption date.

Common Units of TC PipeLines, LP Subject to Rescission

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

At December 31, 2016, $106 million (US$82 million) was recorded as Common units subject to rescission or redemption on the 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.

20. COMMON SHARES

	Number of Shares (thousands)	Amount (millions of Canadian $)
Outstanding at January 1, 2014	707,441	12,149
Exercise of options	1,221	53
Outstanding at December 31, 2014	708,662	12,202
Exercise of options	737	30
Repurchase of shares	(6,785)	(130)
Outstanding at December 31, 2015	702,614	12,102
Issued under public offerings[1]	**156,825**	**7,752**
Dividend reinvestment and share purchase plan	**2,942**	**177**
Exercise of options	**1,683**	**74**
Repurchase of shares	**(305)**	**(6)**
Outstanding at December 31, 2016	**863,759**	**20,099**

1 Net of underwriting commissions and deferred income taxes.

Common Shares Issued and Outstanding

The Company is authorized to issue an unlimited number of common shares without par value.

Common Share Public Offering and Subscription Receipts

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 gross proceeds of approximately $4.4 billion. Holders of subscription receipts received one common share in exchange for each subscription receipt on July 1, 2016 upon closing of the Columbia acquisition. Holders of record at close of business on April 15, 2016 and June 30, 2016 received a cash payment per subscription receipt that was equal in amount to dividends declared on each common share. For the year ended December 31, 2016, $109 million of dividend equivalent payments on these subscription receipts was recorded as Interest expense.

On November 16, 2016, the Company issued 60.2 million common shares at a price of $58.50 each for gross proceeds of approximately $3.5 billion. Proceeds from the offering were used to repay a portion of the US$6.9 billion acquisition bridge facilities which were used to partially fund the closing of the Columbia acquisition.

Dividend Reinvestment and Share Purchase Plan

Effective July 1, 2016, the Company re-initiated the issuance of common shares from treasury under its Dividend Reinvestment and Share Purchase Plan (DRP). Under this 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.

Common Shares Repurchased

On November 19, 2015, the Company received approval from the Toronto Stock Exchange (TSX) for a normal course issuer bid (NCIB) allowing it to repurchase, for cancellation, up to 21 million of its common shares representing three per cent of its then issued and outstanding common shares. Under the NCIB, which expired on November 22, 2016, the Company purchased these common shares through the facilities of the TSX, the New York Stock Exchange and other designated exchanges and published markets in both Canada and the U.S., or through off-exchange block purchases by way of private agreement.

In January 2016, the Company repurchased 305,407 of its common shares at an average price of $44.90 for a total of $14 million and these shares had a 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.

In December 2015, the Company repurchased 6,784,738 of its common shares at an average price of $43.29 for a total of $294 million and these shares had a weighted average cost of $130 million. The difference of $164 million between the total price paid and the weighted average cost was recorded in Additional paid-in capital.

Basic and Diluted Net Income/(Loss) per Common Share

Net income/(loss) per common share is calculated by dividing Net income/(loss) attributable to common shares by the weighted average number of common shares outstanding. The higher weighted average number of shares for the diluted earnings per share calculation is due to options exercisable under TransCanada's Stock Option Plan.

Weighted Average Common Shares Outstanding (millions)	**2016**	**2015**	**2014**
Basic	**759**	709	708
Diluted	**760**	709	710

Stock Options

	Number of Options (thousands)	**Weighted Average Exercise Prices**	**Weighted Average Remaining Contractual Life** (years)
Options outstanding at January 1, 2016	9,834	$46.63	
Options granted	**2,479**	**$48.44**	
Options exercised	**(1,683)**	**$38.92**	
Options Outstanding at December 31, 2016	**10,630**	**$48.28**	**4.2**
Options Exercisable at December 31, 2016	**5,957**	**$46.09**	**3.1**

At December 31, 2016, an additional 13,630,114 common shares were reserved for future issuance under TransCanada's Stock Option Plan. The contractual life of options granted is seven years. Options may be exercised at a price determined at the time the option is awarded and vest 33.3 per cent on the anniversary date in each of the three years following the award. Forfeiture of stock options results from their expiration and, if not previously vested, upon resignation or termination of the option holder's employment.

The Company used a binomial model for determining the fair value of options granted applying the following weighted average assumptions:

year ended December 31	2016	2015	2014
Weighted average fair value	**$5.67**	$6.45	$5.54
Expected life (years)	**5.8**	5.8	6.0
Interest rate	**0.7%**	1.1%	1.8%
Volatility[1]	**21%**	18%	17%
Dividend yield	**4.9%**	3.7%	3.8%
Forfeiture rate	**5%**	5%	5%

1 Volatility is derived based on the average of both the historical and implied volatility of the Company's common shares.

The amount expensed for stock options, with a corresponding increase in Additional paid-in capital, was $15 million in 2016 (2015 – $13 million; 2014 – $7 million).

The following table summarizes additional stock option information:

year ended December 31 (millions of Canadian $, unless otherwise noted)	2016	2015	2014
Total intrinsic value of options exercised	**31**	10	21
Fair value of options that have vested	**126**	91	95
Total options vested	**2.1 million**	2.0 million	1.7 million

As at December 31, 2016, the aggregate intrinsic value of the total options exercisable was $86 million and the total intrinsic value of options outstanding was $130 million.

Shareholder Rights Plan

TransCanada's Shareholder Rights Plan is designed to provide the Board of Directors with sufficient time to explore and develop alternatives for maximizing shareholder value in the event of a takeover offer for the Company and to encourage the fair treatment of shareholders in connection with any such offer. Attached to each common share is one right that, under certain circumstances, entitles certain holders to purchase two common shares of the Company for the then current market price of one.

21. PREFERRED SHARES

at December 31	Number of Shares 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[3,4,5]	2016 (millions of Canadian $)[6]	2015 (millions of Canadian $)[6]
Cumulative First Preferred Shares								
Series 1	9,498	3.266%	$0.8165	$25.00	December 31, 2019	Series 2	**233**	233
Series 2	12,502	Floating [7]	Floating	$25.00	December 31, 2019	Series 1	**306**	306
Series 3	8,533	2.152%	$0.538	$25.00	June 30, 2020	Series 4	**209**	209
Series 4	5,467	Floating [7]	Floating	$25.00	June 30, 2020	Series 3	**134**	134
Series 5	12,714	2.263%	$0.56575	$25.00	January 30, 2021	Series 6	**310**	342
Series 6	1,286	Floating [8]	Floating	$25.00	January 30, 2021	Series 5	**32**	—
Series 7	24,000	4.00%	$1.00	$25.00	April 30, 2019	Series 8	**589**	589
Series 9	18,000	4.25%	$1.0625	$25.00	October 30, 2019	Series 10	**442**	442
Series 11	10,000	3.80%	$0.95	$25.00	November 30, 2020	Series 12	**244**	244
Series 13	20,000	5.50%	$1.375	$25.00	May 31, 2021	Series 14	**493**	—
Series 15	40,000	4.90%	$1.3292	$25.00	May 31, 2022	Series 16	**988**	—
							3,980	2,499

1 The holder is entitled to receive a fixed cumulative quarterly preferential dividend as and when declared by the Board with the exception of Series 2, Series 4 and Series 6 preferred shares. The holders of Series 2, Series 4 and Series 6 preferred shares are entitled to receive quarterly floating rate cumulative preferential dividends 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 thereafter. In addition, Series 2, Series 4 and Series 6 preferred shares are redeemable by TransCanada at any time other than on a designated 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 Each of the even numbered series of preferred shares, if in existence, will be entitled to receive floating rate cumulative quarterly preferential dividends per share at an annualized rate equal to the 90-day Government of Canada Treasury bill rate (T-bill rate) plus 1.92 per cent (Series 2), 1.28 per cent (Series 4), 1.54 per cent (Series 6), 2.38 per cent (Series 8), 2.35 per cent (Series 10), 2.96 per cent (Series 12), 4.69 per cent (Series 14) and 3.85 per cent (Series 16). These rates reset quarterly with the then current T-Bill rate.

5 The odd numbered series of preferred shares, if in existence, will be entitled to receive fixed rate cumulative quarterly preferential dividends which will reset on the redemption and conversion option date and every fifth year thereafter, equal to an annualized rate equal to the then five-year Government of Canada bond yield plus 1.92 per cent (Series 1), 1.28 per cent (Series 3), 1.54 per cent (Series 5), 2.38 per cent (Series 7), 2.35 per cent (Series 9), 2.96 per cent (Series 11), 4.69 per cent, subject to a minimum of 5.50 per cent (Series 13) and 3.85 per cent, subject to a minimum of 4.90 per cent per cent (Series 15).

6 Net of underwriting commissions and deferred income taxes.

7 The floating quarterly dividend rate for the Series 2 preferred shares is 2.429 per cent and for the Series 4 preferred shares is 1.789 per cent for the period starting December 30, 2016 to, but excluding, March 31, 2017. These rates will reset each quarter going forward.

8 The floating quarterly dividend rate for the Series 6 preferred shares is 2.073 per cent for the period starting October 30, 2016 to, but excluding, January 31, 2017. These rates will reset each quarter going forward.

In February 2016, holders of 1,285,739 Series 5 cumulative redeemable first preferred shares exercised their option to convert to Series 6 cumulative redeemable first preferred shares.

In April 2016, the Company completed a public offering of 20 million Series 13 cumulative redeemable minimum rate reset first preferred shares at $25 per share resulting in gross proceeds of $500 million.

In November 2016, the Company completed a public offering of 40 million Series 15 cumulative redeemable minimum rate reset first preferred shares at $25 per share resulting in gross proceeds of $1.0 billion.

In March 2015, TransCanada completed a public offering of 10 million Series 11 cumulative redeemable first preferred shares at $25.00 per share, resulting in gross proceeds of $250 million.

In June 2015, holders of 5,466,595 Series 3 cumulative redeemable first preferred shares exercised their option to convert to Series 4 cumulative redeemable first preferred shares.

22. OTHER COMPREHENSIVE (LOSS)/INCOME AND ACCUMULATED OTHER COMPREHENSIVE LOSS

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

year ended December 31, 2016 (millions of Canadian $)	Before Tax Amount	Income Tax Recovery/ (Expense)	Net of Tax Amount
Foreign currency translation gains on net investment in foreign operations	**3**	**—**	**3**
Change in fair value of net investment hedges	**(14)**	**4**	**(10)**
Change in fair value of cash flow hedges	**44**	**(14)**	**30**
Reclassification to net income of gains and losses on cash flow hedges	**71**	**(29)**	**42**
Unrealized actuarial gains and losses on pension and other post-retirement benefit plans	**(38)**	**12**	**(26)**
Reclassification to net income of actuarial loss on pension and other post-retirement benefit plans	**22**	**(6)**	**16**
Other comprehensive loss on equity investments	**(117)**	**30**	**(87)**
Other Comprehensive Loss	**(29)**	**(3)**	**(32)**

year ended December 31, 2015 (millions of Canadian $)	Before Tax Amount	Income Tax Recovery/ (Expense)	Net of Tax Amount
Foreign currency translation gains on net investment in foreign operations	798	15	813
Change in fair value of net investment hedges	(505)	133	(372)
Change in fair value of cash flow hedges	(92)	35	(57)
Reclassification to net income of gains and losses on cash flow hedges	144	(56)	88
Unrealized actuarial gains and losses on pension and other post-retirement benefit plans	74	(23)	51
Reclassification to net income of actuarial loss and prior service costs on pension and other post-retirement benefit plans	41	(9)	32
Other comprehensive income on equity investments	62	(15)	47
Other Comprehensive Income	522	80	602

year ended December 31, 2014 (millions of Canadian $)	Before Tax Amount	Income Tax Recovery/ (Expense)	Net of Tax Amount
Foreign currency translation gains on net investment in foreign operations	462	55	517
Change in fair value of net investment hedges	(373)	97	(276)
Change in fair value of cash flow hedges	(118)	49	(69)
Reclassification to net income of gains and losses on cash flow hedges	(95)	40	(55)
Unrealized actuarial gains and losses on pension and other post-retirement benefit plans	(146)	44	(102)
Reclassification to net income of actuarial loss and prior service costs on pension and other post-retirement benefit plans	25	(7)	18
Other comprehensive loss on equity investments	(272)	68	(204)
Other Comprehensive Loss	(517)	346	(171)

The changes in AOCI by component are as follows:

	Currency Translation Adjustments	Cash Flow Hedges	Pension and Other Post-Retirement Benefit Plan Adjustments	Equity Investments	Total[1]
AOCI balance at January 1, 2014	(629)	(4)	(197)	(104)	(934)
Other comprehensive income/(loss) before reclassifications[2]	111	(69)	(102)	(206)	(266)
Amounts reclassified from accumulated other comprehensive loss	—	(55)	18	2	(35)
Net current period other comprehensive income/(loss)	111	(124)	(84)	(204)	(301)
AOCI balance at December 31, 2014	(518)	(128)	(281)	(308)	(1,235)
Other comprehensive income/(loss) before reclassifications[2]	135	(57)	51	33	162
Amounts reclassified from accumulated other comprehensive loss	—	88	32	14	134
Net current period other comprehensive income	135	31	83	47	296
AOCI balance at December 31, 2015	(383)	(97)	(198)	(261)	(939)
Other comprehensive income/(loss) before reclassifications[2]	**7**	**27**	**(26)**	**(101)**	**(93)**
Amounts reclassified from accumulated other comprehensive loss[3]	**—**	**42**	**16**	**14**	**72**
Net current period other comprehensive income/(loss)	**7**	**69**	**(10)**	**(87)**	**(21)**
AOCI balance at December 31, 2016	**(376)**	**(28)**	**(208)**	**(348)**	**(960)**

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 $14 million (2015 – $306 million gains; 2014 – $130 million gains) and gains of $3 million (2015 and 2014 - nil), respectively in 2016.

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 $5 million ($3 million, net of tax) at December 31, 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:

year ended December 31	Amounts Reclassified From Accumulated Other Comprehensive Loss[1]			Affected Line Item in the Consolidated Statement of Income
(millions of Canadian $)	2016	2015	2014	
Cash flow hedges				
Commodities	**(57)**	(128)	111	Revenues (Energy)
Interest	**(14)**	(16)	(16)	Interest expense
	(71)	(144)	95	Total before tax
	29	56	(40)	Income tax expense/(recovery)
	(42)	(88)	55	Net of tax
Pension and other post-retirement benefit plan adjustments				
Amortization of actuarial loss and past service cost	**(22)**	(41)	(25)	Plant operating costs and other[2]
	6	9	7	Income tax expense
	(16)	(32)	(18)	Net of tax
Equity investments				
Equity income	**(19)**	(19)	(2)	Income from equity investments
	5	5	—	Income tax expense
	(14)	(14)	(2)	Net of tax

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

2 These AOCI components are included in the computation of net benefit cost. Refer to Note 23, Employee post-retirement benefits for further information.

23. EMPLOYEE POST-RETIREMENT BENEFITS

The Company sponsors DB Plans for its employees. Pension benefits provided under the DB Plans are based on years of service and highest average earnings over three consecutive years of employment. Upon commencement of retirement, pension benefits in the Canadian DB Plan increase annually by a portion of the increase in the Consumer Price Index. Net actuarial gains or losses are amortized out of AOCI over the expected average remaining service life of employees, which is approximately nine years at December 31, 2016 (2015 and 2014 – nine years).

The Company also provides its employees with a savings plan in Canada, DC Plans consisting of 401(k) Plans in the U.S., and post-employment benefits other than pensions, including termination benefits and life insurance and medical benefits beyond those provided by government-sponsored plans. Net actuarial gains or losses are amortized out of AOCI over the expected average remaining life expectancy of former employees, which was approximately 12 years at December 31, 2016 (2015 – 12 years; 2014 – 12 years). In 2016, the Company expensed $52 million (2015 – $41 million; 2014 – $37 million) for the savings and DC Plans.

Total cash contributions by the Company for employee post-retirement benefits were as follows:

year ended December 31 (millions of Canadian $)	**2016**	**2015**	**2014**
DB Plans	**111**	96	73
Other post-retirement benefit plans	**8**	6	6
Savings and DC Plans	**52**	41	37
	171	143	116

Current Canadian pension legislation allows for partial funding of solvency requirements over a number of years through letters of credit in lieu of cash contributions, up to certain limits. As such, in addition to the cash contributions noted above, the Company provided a $20 million letter of credit to the Canadian DB Plan in 2016 (2015 – $33 million; 2014 – $47 million), resulting in a total of $233 million provided to the Canadian DB Plan under letters of credit at December 31, 2016.

The most recent actuarial valuation of the pension plans for funding purposes was as at January 1, 2016 and the next required valuation will be as at January 1, 2017.

The Company's funded status at December 31 is comprised of the following:

at December 31	Pension Benefit Plans		Other Post-Retirement Benefit Plans	
(millions of Canadian $)	**2016**	**2015**	**2016**	**2015**
Change in Benefit Obligation[1]				
Benefit obligation – beginning of year	**2,780**	2,658	**225**	216
Service cost	**107**	108	**3**	3
Interest cost	**127**	115	**13**	10
Employee contributions	**4**	4	**2**	—
Benefits paid	**(204)**	(129)	**(16)**	(7)
Actuarial loss/(gain)	**111**	(57)	**(8)**	(11)
Acquisition of Columbia	**527**	—	**151**	—
Settlement loss	**2**	—	**—**	—
Foreign exchange rate changes	**2**	81	**2**	14
Benefit obligation – end of year	**3,456**	2,780	**372**	225
Change in Plan Assets				
Plan assets at fair value – beginning of year	**2,591**	2,398	**45**	39
Actual return on plan assets	**227**	160	**14**	(1)
Employer contributions[2]	**111**	96	**8**	6
Employee contributions	**4**	4	**2**	—
Benefits paid	**(204)**	(129)	**(16)**	(7)
Acquisition of Columbia	**475**	—	**294**	—
Foreign exchange rate changes	**4**	62	**7**	8
Plan assets at fair value – end of year	**3,208**	2,591	**354**	45
Funded Status – Plan Deficit	**(248)**	(189)	**(18)**	(180)

1 The benefit obligation for the Company's pension benefit plans represents the projected benefit obligation. The benefit obligation for the Company's other post-retirement benefit plans represents the accumulated post-retirement benefit obligation.

2 Excludes $233 million in letters of credit provided to the Canadian DB Plans for funding purposes (2015 – $214 million).

The amounts recognized in the Company's Consolidated balance sheet for its DB Plans and other post-retirement benefits plans are as follows:

at December 31	Pension Benefit Plans		Other Post-Retirement Benefit Plans	
(millions of Canadian $)	**2016**	**2015**	**2016**	**2015**
Intangible and other assets (Note 12)	**—**	—	**189**	18
Accounts payable and other	**—**	—	**(7)**	(7)
Other long-term liabilities (Note 15)	**(248)**	(189)	**(200)**	(191)
	(248)	(189)	**(18)**	(180)

Included in the above benefit obligation and fair value of plan assets were the following amounts for plans that are not fully funded:

at December 31	Pension Benefit Plans		Other Post-Retirement Benefit Plans	
(millions of Canadian $)	**2016**	**2015**	**2016**	**2015**
Projected benefit obligation[1]	**(3,456)**	(2,780)	**(207)**	(198)
Plan assets at fair value	**3,208**	2,591	**—**	—
Funded Status – Plan Deficit	**(248)**	(189)	**(207)**	(198)

1 The projected benefit obligation for the pension benefit plan differs from the accumulated benefit obligation in that it includes an assumption with respect to future compensation levels.

The funded status based on the accumulated benefit obligation for all DB Plans is as follows:

at December 31		
(millions of Canadian $)	**2016**	**2015**
Accumulated benefit obligation	**(3,202)**	(2,600)
Plan assets at fair value	**3,208**	2,591
Funded Status – Plan Surplus/(Deficit)	**6**	(9)

Included in the above accumulated benefit obligation and fair value of plan assets are the following amounts in respect of plans that are not fully funded.

at December 31		
(millions of Canadian $)	**2016**	**2015**
Accumulated benefit obligation	**(990)**	(807)
Plan assets at fair value	**868**	680
Funded Status – Plan Deficit	**(122)**	(127)

The Company pension plans' weighted average asset allocations and target allocations by asset category were as follows:

	Percentage of Plan Assets		Target Allocations
at December 31	**2016**	**2015**	**2016**
Debt securities	**31%**	34%	**25% to 40%**
Equity securities	**63%**	66%	**45% to 75%**
Alternatives	**6%**	—	**5% to 15%**
	100%	100%	

Debt and equity securities include the Company's debt and common shares as follows:

at December 31			Percentage of Plan Assets	
(millions of Canadian $)	**2016**	**2015**	**2016**	**2015**
Debt securities	**9**	2	**0.2%**	0.1%
Equity securities	**4**	4	**0.1%**	0.1%

Pension plan assets are managed on a going concern basis, subject to legislative restrictions, and are diversified across asset classes to maximize returns at an acceptable level of risk. Asset mix strategies consider plan demographics and may include traditional equity and debt securities, as well as alternative assets such as infrastructure, private equity, real estate and derivatives to diversify risk. Derivatives are not used for speculative purposes and the use of leveraged derivatives is prohibited.

All investments are measured at fair value using market prices. Where the fair value cannot be readily determined by reference to generally available price quotations, the fair value is determined by considering the discounted cash flows on a risk-adjusted basis and by comparison to similar assets which are publicly traded. In Level I, the fair value of assets is determined by reference to quoted prices in active markets for identical assets that the Company has the ability to access at the measurement date. In Level II, the fair value of assets is determined using valuation techniques, such as option pricing models and extrapolation using significant inputs, which are observable directly or indirectly. In Level III, the fair value of assets is determined using a market approach based on inputs that are unobservable and significant to the overall fair value measurement.

The following table presents plan assets for DB Plans and other post-retirement benefits measured at fair value, which have been categorized into the three categories based on a fair value hierarchy. For further information on the fair value hierarchy, refer to Note 24, Risk management and financial instruments.

at December 31	Quoted Prices in Active Markets (Level I)		Significant Other Observable Inputs (Level II)		Significant Unobservable Inputs (Level III)		Total		Percentage of Total Portfolio	
(millions of Canadian $)	**2016**	2015	**2016**	2015	**2016**	2015	**2016**	2015	**2016**	2015
Asset Category										
Cash and Cash Equivalents	**22**	44	**12**	2	**—**	—	**34**	46	**1**	2
Equity Securities:										
Canadian	**388**	317	**143**	147	**—**	—	**531**	464	**15**	17
U.S.	**504**	589	**476**	40	**—**	—	**980**	629	**27**	24
International	**39**	38	**327**	300	**—**	—	**366**	338	**10**	13
Global	**—**	—	**235**	154	**—**	—	**235**	154	**7**	6
Emerging	**7**	7	**137**	143	**—**	—	**144**	150	**4**	6
Fixed Income Securities:										
Canadian Bonds:										
Federal	**—**	—	**192**	206	**—**	—	**192**	206	**5**	8
Provincial	**—**	—	**179**	202	**—**	—	**179**	202	**5**	8
Municipal	**—**	—	**8**	7	**—**	—	**8**	7	**—**	—
Corporate	**—**	—	**126**	113	**—**	—	**126**	113	**4**	4
U.S. Bonds:										
Federal	**—**	—	**82**	—	**—**	—	**82**	—	**2**	—
State	**—**	—	**41**	50	**—**	—	**41**	50	**1**	2
Municipal	**—**	—	**39**	—	**—**	—	**39**	—	**1**	—
Corporate	**—**	—	**188**	57	**—**	—	**188**	57	**5**	2
International:										
Government	**—**	—	**6**	—	**—**	—	**6**	—	**—**	—
Corporate	**—**	—	**21**	25	**—**	—	**21**	25	**1**	1
Mortgage backed	**—**	—	**62**	58	**—**	—	**62**	58	**2**	2
Other Investments:										
Real Estate	**—**	—	**—**	—	**133**	—	**133**	—	**4**	—
Infrastructure	**—**	—	**—**	—	**58**	—	**58**	—	**2**	—
Private equity funds	**—**	—	**—**	—	**8**	14	**8**	14	**—**	—
Funds held on deposit	**129**	123	**—**	—	**—**	—	**129**	123	**4**	5
	1,089	1,118	**2,274**	1,504	**199**	14	**3,562**	2,636	**100**	100

The following table presents the net change in the Level III fair value category:

(millions of Canadian $, pre-tax)	Private Equity Funds
Balance at December 31, 2014	13
Purchases and sales	(1)
Realized and unrealized gains	2
Balance at December 31, 2015	14
Purchases and sales	**183**
Realized and unrealized gains	**2**
Balance at December 31, 2016	**199**

The Company's expected funding contributions in 2017 are approximately $100 million for the DB Plans, approximately $7 million for the other post-retirement benefit plans and approximately $51 million for the savings plan and DC Plans. The Company expects to provide an additional estimated $20 million letter of credit to the Canadian DB Plan for the funding of solvency requirements.

The following are estimated future benefit payments, which reflect expected future service:

(millions of Canadian $)	Pension Benefits	Other Post-Retirement Benefits
2017	178	19
2018	183	19
2019	189	20
2020	196	20
2021	200	20
2022 to 2026	1,067	97

The rate used to discount pension and other post-retirement benefit plan obligations was developed based on a yield curve of corporate AA bond yields at December 31, 2016. This yield curve is used to develop spot rates that vary based on the duration of the obligations. The estimated future cash flows for the pension and other post-retirement obligations were matched to the corresponding rates on the spot rate curve to derive a weighted average discount rate.

The significant weighted average actuarial assumptions adopted in measuring the Company's benefit obligations were as follows:

	Pension Benefit Plans		Other Post-Retirement Benefit Plans	
at December 31	**2016**	**2015**	**2016**	**2015**
Discount rate	**4.00%**	4.20%	**4.15%**	4.40%
Rate of compensation increase	**1.20%**	0.50%	—	—

The significant weighted average actuarial assumptions adopted in measuring the Company's net benefit plan costs were as follows:

year ended December 31	Pension Benefit Plans 2016	2015	2014	Other Post-Retirement Benefit Plans 2016	2015	2014
Discount rate	**4.20%**	4.15%	4.95%	**4.30%**	4.20%	5.00%
Expected long-term rate of return on plan assets	**6.70%**	6.95%	6.90%	**5.95%**	4.60%	4.60%
Rate of compensation increase	**0.80%**	3.15%	3.15%	—	—	—

The overall expected long-term rate of return on plan assets is based on historical and projected rates of return for the portfolio in aggregate and for each asset class in the portfolio. Assumed projected rates of return are selected after analyzing historical experience and estimating future levels and volatility of returns. Asset class benchmark returns, asset mix and anticipated benefit payments from plan assets are also considered in determining the overall expected rate of return. The discount rate is based on market interest rates of high-quality bonds that match the timing and benefits expected to be paid under each plan.

An eight per cent weighted average annual rate of increase in the per capita cost of covered health care benefits was assumed for 2017 measurement purposes. The rate was assumed to decrease gradually to five per cent by 2024 and remain at this level thereafter. A one per cent change in assumed health care cost trend rates would have the following effects:

(millions of Canadian $)	Increase	Decrease
Effect on total of service and interest cost components	1	(1)
Effect on post-retirement benefit obligation	15	(13)

The Company's net benefit cost recognized is as follows:

at December 31 (millions of Canadian $)	Pension Benefit Plans 2016	2015	2014	Other Post-Retirement Benefit Plans 2016	2015	2014
Service cost	**107**	108	85	**3**	3	2
Interest cost	**127**	115	113	**13**	10	10
Expected return on plan assets	**(175)**	(155)	(139)	**(11)**	(2)	(2)
Amortization of actuarial loss	**20**	35	21	**2**	3	2
Amortization of past service cost	**—**	2	2	**—**	1	—
Amortization of regulatory asset	**27**	23	18	**1**	1	1
Amortization of transitional obligation related to regulated business	**—**	—	—	**2**	2	2
Net Benefit Cost Recognized	**106**	128	100	**10**	18	15

Pre-tax amounts recognized in AOCI were as follows:

at December 31 (millions of Canadian $)	2016		2015		2014	
	Pension Benefits	Other Post-Retirement Benefits	Pension Benefits	Other Post-Retirement Benefits	Pension Benefits	Other Post-Retirement Benefits
Net loss	**268**	**23**	247	28	348	39
Prior service cost	**—**	**—**	—	—	2	1
	268	**23**	247	28	350	40

The estimated net loss for the DB Plans and for the other post-retirement benefit plans that will be amortized from AOCI into net periodic benefit cost in 2017 is $20 million and $2 million, respectively.

Pre-tax amounts recognized in OCI were as follows:

at December 31 (millions of Canadian $)	2016		2015		2014	
	Pension Benefits	Other Post-Retirement Benefits	Pension Benefits	Other Post-Retirement Benefits	Pension Benefits	Other Post-Retirement Benefits
Amortization of net loss from AOCI to OCI	**(20)**	**(2)**	(34)	(4)	(21)	(2)
Amortization of prior service costs from AOCI to OCI	**—**	**—**	(2)	(1)	(2)	—
Funded status adjustment	**43**	**(5)**	(67)	(7)	137	9
	23	**(7)**	(103)	(12)	114	7

24. 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.

Risk management strategies, policies and limits are designed to ensure TransCanada's risks and related exposures are in line with the Company's business objectives and risk tolerance. Market risk and counterparty credit risk are managed within limits ultimately established by the Company's Board of Directors, implemented by senior management and monitored by the Company's risk management and internal audit groups. The Board of Directors' Audit Committee oversees how management monitors compliance with market risk and counterparty credit risk management policies and procedures, and oversees management's review of the adequacy of the risk management framework.

Market Risk

The Company constructs and invests in energy infrastructure projects, purchases and sells commodities, issues short-term and long-term debt, including amounts in foreign currencies, and invests in foreign operations. Certain of these activities expose the Company to market risk from changes in commodity prices, foreign exchange rates and interest rates, which may affect the Company's earnings and the value of the financial instruments it holds. The Company assesses contracts used to manage market risk to determine whether all, or a portion, meets the definition of a derivative.

Derivative contracts the Company uses to assist in managing the exposure to market risk may consist of the following:

- Forwards and futures contracts – contractual agreements to purchase or sell a specific financial instrument or commodity at a specified price and date in the future. TransCanada enters into foreign exchange and commodity forwards and futures to manage the impact of changes in interest rates, foreign exchange rates and commodity prices
- Swaps – contractual agreements between two parties to exchange streams of payments over time according to specified terms. The Company enters into interest rate, cross-currency and commodity swaps to manage the impact of changes in interest rates, foreign exchange rates and commodity prices
- Options – contractual agreements that convey the right, but not the obligation of the purchaser to buy or sell a specific amount of a financial instrument or commodity at a fixed price, either at a fixed date or at any time within a specified period. The Company enters into option agreements to manage the impact of changes in interest rates, foreign exchange rates and commodity prices.

Commodity price risk

The Company is exposed to commodity price movements as part of its normal business operations. A number of strategies are used to manage these exposures, including the following:

- Subject to its overall risk management strategy, the Company commits a portion of its expected power supply to fixed-price medium-term or long-term sales contracts, while reserving an amount of unsold supply to manage operational and price risks in its asset portfolio
- The Company purchases a portion of the natural gas required for its power plants or enters into contracts that base the sale price of electricity on the cost of natural gas, effectively locking in a margin
- The Company's power sales commitments are fulfilled through power generation or through purchased contracts, thereby reducing the Company's exposure to fluctuating commodity prices
- The Company enters into offsetting or back-to-back positions using derivative instruments to manage price risk exposure in power and natural gas commodities created by certain fixed and variable pricing arrangements for different pricing indices and delivery points.

Natural gas storage commodity price risk

TransCanada manages its exposure to seasonal natural gas price spreads in its non-regulated Natural Gas Storage business by economically hedging storage capacity with a portfolio of third-party storage capacity contracts and proprietary natural gas purchases and sales. TransCanada simultaneously enters into a forward purchase of natural gas for injection into storage and an offsetting forward sale of natural gas for withdrawal at a later period, thereby locking in future positive margins and effectively eliminating exposure to natural gas price movements. Unrealized gains and losses on fair value adjustments recorded each period on these forward contracts are not necessarily representative of the amounts that will be realized on settlement.

Liquids marketing commodity price risk

The liquids marketing business began operations in 2016. TransCanada 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.

Foreign exchange and interest rate risk

Foreign exchange and interest rate risk is created by fluctuations in the fair value or cash flow of financial instruments due to changes in foreign exchange rates and interest rates. TransCanada generates revenues and incurs expenses that are denominated in currencies other than Canadian dollars. As a result, our earnings and cash flows are expected to fluctuate.

A portion of TransCanada’s earnings from its U.S. Natural Gas Pipelines, Mexico Natural Gas Pipelines, Liquids Pipelines and Energy segments are generated in U.S. dollars and, therefore, fluctuations in the value of the Canadian dollar relative to the U.S. dollar can affect TransCanada’s net income. As the Company’s U.S. dollar-denominated operations continue to grow, exposure to changes in currency rates increases. This foreign exchange impact is partially offset by interest expense on U.S. dollar-denominated debt and by using foreign exchange derivatives.

The Company uses foreign currency and interest rate derivatives to manage the foreign exchange and interest rate risks related to other U.S. dollar-denominated transactions including those that may arise on some of the Company's regulated assets. The realized gains and losses on these derivatives are deferred as regulatory assets and liabilities until they are recovered from or paid to the shippers.

TransCanada has floating interest rate debt which subjects it to interest rate cash flow risk. The Company uses a combination of interest rate swaps and options to manage its exposure to this risk.

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 and foreign exchange options.

U.S. Dollar-Denominated Debt Designated as a Net Investment Hedge

The notional amounts and fair value of U.S. dollar-denominated debt designated as a net investment hedge were as follows:

at December 31 (millions of Canadian $, unless otherwise noted)	2016	2015
Notional amount	**26,600 (US 19,800)**	23,100 (US 16,700)
Fair value	**29,400 (US 21,900)**	23,800 (US 17,200)

Derivatives Designated as a Net Investment Hedge

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

	2016		2015	
at December 31 (millions of Canadian $, unless otherwise noted)	Fair Value[1]	Notional or Principal Amount	Fair Value[1]	Notional or Principal Amount
U.S. dollar cross-currency interest rate swaps (maturing 2017 to 2019)[2]	**(425)**	**US 2,350**	(730)	US 3,150
U.S. dollar foreign exchange forward contracts (maturing 2017)	**(7)**	**US 150**	50	US 1,800
	(432)	**US 2,500**	(680)	US 4,950

1 Fair values equal carrying values.

2 In 2016, net realized gains of $6 million (2015 – gains of $8 million) related to the interest component of cross-currency swap settlements are included in Interest expense.

Counterparty Credit Risk

Counterparty credit risk represents the financial loss the Company would experience if a counterparty to a financial instrument failed to meet its obligations in accordance with the terms and conditions of the related contract or agreement with the Company.

The Company manages its exposure to this potential loss by using recognized credit management techniques, including:

- Dealing with creditworthy counterparties – a significant amount of the Company's credit exposure is with investment grade counterparties or, if not, is generally partially supported by financial assurances from investment grade parties
- Setting limits on the amount TransCanada can transact with any one counterparty – the Company monitors and manages the concentration of risk exposure with any one counterparty, and reduces the exposure when necessary and when it is allowed under the terms of the contracts
- Using contract netting arrangements and obtaining financial assurances such as guarantees, letters of credit or cash when deemed necessary.

There is no guarantee that these techniques will protect the Company from material losses.

TransCanada's maximum counterparty credit exposure with respect to financial instruments at December 31, 2016, without taking into account security held, consisted of cash and cash equivalents, accounts receivable, available for sale assets recorded at fair value, the fair value of derivative assets, notes, loans and advances receivable. The Company regularly reviews its accounts receivable and records an allowance for doubtful accounts as necessary using the specific identification method. At December 31, 2016, there were no significant amounts past due or impaired, and there were no significant credit losses during the year.

The Company had a credit risk concentration due from a counterparty of $200 million (US$149 million) and $248 million (US$179 million) at December 31, 2016 and 2015, respectively. This amount is expected to be fully collectible and is secured by a guarantee from the counterparty's investment grade parent company.

TransCanada has significant credit and performance exposures to financial institutions as they hold cash deposits and provide committed credit lines and letters of credit that help manage the Company's exposure to counterparties and provide liquidity in commodity, foreign exchange and interest rate derivative markets.

For TransCanada's Canadian regulated gas pipeline assets, counterparty credit risk is managed through application of tariff provisions as approved by the NEB.

Fair Value of Non-Derivative Financial Instruments

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

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

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

Balance Sheet Presentation of Non-Derivative Financial Instruments

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

at December 31 (millions of Canadian $)	**2016**		**2015**	
	Carrying Amount	**Fair Value**	**Carrying Amount**	**Fair Value**
Notes receivable[1]	**165**	**211**	214	265
Current and Long-term debt[2,3] (Note 17)	**(40,150)**	**(45,047)**	(31,456)	(34,309)
Junior subordinated notes (Note 18)	**(3,931)**	**(3,825)**	(2,409)	(2,011)
	(43,916)	**(48,661)**	(33,651)	(36,055)

1 Notes receivable are included in Assets held for sale on the Consolidated balance sheet at December 31, 2016 and in Other current assets and Intangible and other assets on the Consolidated balance sheet at December 31, 2015. The fair value is calculated based on the original contract terms.

2 Long-term debt is recorded at amortized cost, except for US$850 million (2015 – US$850 million) that is attributed to hedged risk and recorded at fair value.

3 Consolidated net income in 2016 included unrealized gains of $2 million (2015 – gains of $2 million) for fair value adjustments attributable to the hedged interest rate risk associated with interest rate swap fair value hedging relationships on US$850 million of Long-term debt at December 31, 2016 (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:

(millions of Canadian $)	2016		2015	
	LMCI Restricted Investments[2]	Other Restricted Investments[3]	LMCI Restricted Investments[2]	Other Restricted Investments[3]
Fair values[1]				
Fixed income securities (maturing within 1 year)	**—**	**19**	—	26
Fixed income securities (maturing within 1-5 years)	**—**	**117**	—	64
Fixed income securities (maturing within 5-10 years)	**9**	**—**	—	—
Fixed income securities (maturing after 10 years)	**513**	**—**	261	—
Total fair value at December 31	**522**	**136**	261	90
Net unrealized losses for the year ended December 31	**(28)**	**(1)**	—	—

1 Available for sale assets are recorded at fair value and included in Other current assets and Restricted investments on the Consolidated balance sheet.

2 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.

3 Other restricted investments have been set aside to fund insurance claim losses to be paid by the Company's wholly-owned captive insurance subsidiary. Unrealized gains and losses on other restricted investments are included in OCI.

Fair Value of Derivative Instruments

The fair value of foreign exchange and interest rate derivatives has been calculated using the income approach which uses year-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.

The recognition of gains and losses on derivatives for Canadian natural gas regulated pipeline exposures is determined through the regulatory process. Gains and losses arising from changes in the fair value of derivatives accounted for as part of RRA, including those that qualify for hedge accounting treatment, can be recovered or refunded through the tolls charged by the Company. As a result, these gains and losses are deferred as regulatory assets or regulatory liabilities and are refunded to or collected from the ratepayers in subsequent years when the derivative settles.

Balance Sheet Presentation of Derivative Instruments

The balance sheet classification of the fair value of the derivative instruments as at December 31, 2016 is as follows:

at December 31, 2016 (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 (Note 7)					
Commodities[2]	**6**	**—**	**—**	**351**	**357**
Foreign exchange	**—**	**—**	**6**	**10**	**16**
Interest rate	**1**	**1**	**—**	**1**	**3**
	7	**1**	**6**	**362**	**376**
Intangible and other assets (Note 12)					
Commodities[2]	**4**	**—**	**—**	**118**	**122**
Foreign exchange	**—**	**—**	**10**	**—**	**10**
Interest rate	**1**	**—**	**—**	**—**	**1**
	5	**—**	**10**	**118**	**133**
Total Derivative Assets	**12**	**1**	**16**	**480**	**509**
Accounts payable and other (Note 14)					
Commodities[2]	**—**	**—**	**—**	**(330)**	**(330)**
Foreign exchange	**—**	**—**	**(237)**	**(38)**	**(275)**
Interest rate	**(1)**	**(1)**	**—**	**—**	**(2)**
	(1)	**(1)**	**(237)**	**(368)**	**(607)**
Other long-term liabilities (Note 15)					
Commodities[2]	**—**	**—**	**—**	**(118)**	**(118)**
Foreign exchange	**—**	**—**	**(211)**	**—**	**(211)**
Interest rate	**—**	**(1)**	**—**	**—**	**(1)**
	—	**(1)**	**(211)**	**(118)**	**(330)**
Total Derivative Liabilities	**(1)**	**(2)**	**(448)**	**(486)**	**(937)**

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 (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 (Note 7)					
Commodities[2]	46	—	—	326	372
Foreign exchange	—	—	65	2	67
Interest rate	—	1	—	2	3
	46	1	65	330	442
Intangible and other assets (Note 12)					
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 (Note 14)					
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 (Note 15)					
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 maturity and notional principal or quantity outstanding related to the Company's derivative instruments excluding hedges of the net investment in foreign operations is as follows:

at December 31, 2016	**Power**	**Natural Gas**	**Liquids**	**Foreign Exchange**	**Interest**
Purchases[1]	**86,887**	**182**	**6**	**—**	**—**
Sales[1]	**58,561**	**147**	**6**	**—**	**—**
Millions of dollars	**—**	**—**	**—**	**US 2,394**	**US 1,550**
Maturity dates	**2017-2021**	**2017-2020**	**2017**	**2017**	**2017-2019**

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.

year ended December 31 (millions of Canadian $)	2016	2015
Derivative instruments held for trading[1]		
Amount of unrealized gains/(losses) in the year		
Commodities[2]	**123**	(37)
Foreign exchange	**25**	(21)
Amount of realized (losses)/gains in the year		
Commodities	**(204)**	(151)
Foreign exchange	**62**	(112)
Derivative instruments in hedging relationships		
Amount of realized (losses)/gains in the year		
Commodities	**(167)**	(179)
Foreign exchange	**(101)**	—
Interest rate	**4**	8

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

2 Following the March 17, 2016 announcement of the Company's intention to sell the U.S. Northeast power assets, losses of $49 million and gains of $7 million (2015 - nil) were recorded in net income in 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 22) related to derivatives in cash flow hedging relationships including the portion attributable to non-controlling interests are as follows:

year ended December 31 (millions of Canadian $, pre-tax)	2016	2015
Change in fair value of derivative instruments recognized in OCI (effective portion)[1]		
Commodities[2]	**39**	(92)
Interest rate[3]	**5**	—
	44	(92)
Reclassification of gains on derivative instruments from AOCI to Net income (effective portion)[1]		
Commodities[2]	**57**	128
Interest rate[3]	**14**	16
	71	144
Losses on derivative instruments recognized in Net income (ineffective portion)		
Commodities[2]	**—**	—

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 Consolidated statement of income.
3 Reported within Interest expense on the 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 Consolidated 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 December 31, 2016 (millions of Canadian $)	Gross Derivative Instruments Presented on the Balance Sheet	Amounts Available for Offset[1]	Net Amounts
Derivative – Asset			
Commodities	**479**	**(362)**	**117**
Foreign exchange	**26**	**(26)**	**—**
Interest rate	**4**	**(1)**	**3**
	509	**(389)**	**120**
Derivative – Liability			
Commodities	**(448)**	**362**	**(86)**
Foreign exchange	**(486)**	**26**	**(460)**
Interest rate	**(3)**	**1**	**(2)**
	(937)	**389**	**(548)**

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 (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
	610	(512)	98
Derivative – Liability			
Commodities	(717)	418	(299)
Foreign exchange	(828)	93	(735)
Interest rate	(6)	1	(5)
	(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 December 31, 2016, the Company had provided cash collateral of $305 million (2015 – $482 million) and letters of credit of $27 million (2015 – $41 million) to its counterparties. The Company held nil (2015 – nil) in cash collateral and $3 million (2015 – $2 million) in letters of credit from counterparties on asset exposures at December 31, 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 December 31, 2016, the aggregate fair value of all derivative instruments with credit-risk-related contingent features that were in a net liability position was $19 million (2015 – $32 million), for which the Company has provided collateral in the normal course of business of nil (2015 – nil). If the credit-risk-related contingent features in these agreements were triggered on December 31, 2016, the Company would have been required to provide additional collateral of $19 million (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 bank lines 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 assets and liabilities measured on a recurring basis, including both current and non-current portions for 2016, are categorized as follows:

at December 31, 2016 (millions of Canadian $)	**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	**134**	**326**	**19**	**479**
Foreign exchange	**—**	**26**	**—**	**26**
Interest rate	**—**	**4**	**—**	**4**
Derivative Instrument Liabilities:				
Commodities	**(102)**	**(343)**	**(3)**	**(448)**
Foreign exchange	**—**	**(486)**	**—**	**(486)**
Interest rate	**—**	**(3)**	**—**	**(3)**
	32	**(476)**	**16**	**(428)**

1 There were no transfers from Level I to Level II or from Level II to Level III for the year ended December 31, 2016.

The fair value of the Company's derivative 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 (millions of Canadian $)	**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:

(millions of Canadian $, pre-tax)	**2016**	**2015**
Balance at beginning of year	**9**	4
Total gains included in Net income	**13**	3
Sales	**(3)**	(2)
Settlements	**(2)**	(1)
Transfers out of Level III	**(1)**	5
Balance at end of year[1]	**16**	9

1 Revenues include unrealized gains attributed to derivatives in the Level III category that were still held at December 31, 2016 of $7 million (2015 – $7 million).

A 10 per cent increase or decrease in commodity prices, with all other variables held constant, would result in a $2 million decrease or increase, respectively, in the fair value of outstanding derivative instruments included in Level III as at December 31, 2016.

25. CHANGES IN OPERATING WORKING CAPITAL

year ended December 31 (millions of Canadian $)	**2016**	**2015**	**2014**
Increase in Accounts receivable	**(482)**	(65)	(189)
Increase in Inventories	**(87)**	(3)	(28)
Increase in Assets held for sale	**(13)**	—	—
Decrease/(increase) in Other current assets	**328**	(272)	(385)
Increase/(decrease) in Accounts payable and other	**424**	(97)	377
Increase in Accrued interest	**62**	91	36
Increase in Liabilities related to assets held for sale	**16**	—	—
Decrease/(increase) in Operating Working Capital	**248**	(346)	(189)

26. OTHER ACQUISITIONS AND DISPOSITIONS

U.S. Natural Gas Pipelines

Portland Natural Gas Transmission System

On January 1, 2016, TransCanada completed the sale of a 49.9 per cent interest in 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 of a proportional share of PNGTS debt.

TC Offshore LLC

On March 1, 2016, the Company closed the sale of TC Offshore LLC. This resulted in an additional loss on disposal of $4 million pre-tax which is included in (Loss)/gain on sale of assets held for sale/sold in the Consolidated statement of income.

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$54 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 million, further increasing TransCanada's interest in Iroquois to 50 per cent.

Gas Transmission Northwest LLC

In April 2015, TransCanada completed the sale of its remaining 30 per cent interest in GTN to TC PipeLines, LP for an aggregate purchase price of US$457 million. Proceeds were comprised of US$264 million in cash, the assumption of US$98 million of a proportional share of GTN debt and US$95 million of new Class B units of TC PipeLines, LP.

Bison Pipeline LLC

In October 2014, TransCanada completed the sale of its remaining 30 per cent interest in Bison to TC PipeLines, LP for an aggregate purchase price of US$215 million.

Mexico Natural Gas Pipelines

Gas Pacifico/INNERGY

In November 2014, TransCanada sold its 30 per cent equity investments in Gas Pacifico and INNERGY for aggregate gross proceeds of $9 million and recognized a gain of $9 million ($8 million after tax).

Energy

Ironwood

On February 1, 2016, TransCanada acquired the Ironwood natural gas fired, combined cycle power plant in Lebanon, Pennsylvania, with a capacity of 778 MW, for US$653 million in cash after post-acquisition adjustments. The Ironwood power plant delivers energy into the PJM power market. The evaluation of assigned fair value of acquired assets and liabilities did not result in the recognition of goodwill. The Company began consolidating Ironwood as of the date of acquisition which has not had a material impact on the Revenues and Net income of the Company. In addition, the pro forma incremental impact on the Company's Revenues and Net income for each of the periods presented is not material. At December 31, 2016, Ironwood is classified as an asset held for sale. Refer to Note 6, Assets held for sale for further information.

Bruce Power

In December 2015, TransCanada exercised its option to acquire an additional 14.89 per cent ownership interest in Bruce B from the Ontario Municipal Employees Retirement System for $236 million, increasing its ownership interest to 46.5 per cent. The difference between the purchase price and the underlying carrying value of Bruce B is primarily related to the estimated fair value of the amended agreement with Ontario's Independent Electricity System Operator to extend the operating life of the Bruce Power facility to 2064. In December 2015, Bruce B and Bruce A merged to form a single limited partnership, Bruce Power. This merger was accounted for as a transaction between entities under common control whereby the assets and liabilities of Bruce A and Bruce B were combined at their carrying values. Upon completion of the merger, TransCanada applied equity accounting to its resulting 48.5 per cent ownership interest in Bruce Power. Prior to the acquisition, TransCanada applied equity accounting to its 48.9 per cent ownership interest in Bruce A and 31.6 per cent ownership interest in Bruce B.

Ontario Solar

As part of a purchase agreement with Canadian Solar Solutions Inc. signed in 2011, TransCanada completed the acquisition of four Ontario solar facilities for $241 million in 2014. All power produced by the solar facilities is sold under 20-year PPAs with the Ontario Power Authority.

Cancarb

In April 2014, TransCanada sold Cancarb Limited and its related power generation for aggregate gross proceeds of $190 million and recognized a gain of $108 million ($99 million after-tax).

27. COMMITMENTS, CONTINGENCIES AND GUARANTEES

Commitments

Operating leases

Future annual payments under the Company's operating leases for various premises, services and equipment, net of sublease receipts, are approximately as follows:

year ended December 31 (millions of Canadian $)	**Minimum Lease Payments**	**Amounts Recoverable under Subleases**	**Net Payments**
2017	129	5	124
2018	122	4	118
2019	106	2	104
2020	69	2	67
2021	69	1	68
2022 and thereafter	621	3	618
	1,116	17	1,099

The operating lease agreements for premises, services and equipment expire at various dates through 2052, with an option to renew certain lease agreements for periods of one year to 25 years. Net rental expense on operating leases in 2016 was $145 million (2015 – $131 million; 2014 – $114 million).

TransCanada's commitments at December 31, 2016 include future payments related to our U.S. Northeast power business. At the close of the sale of Ravenswood, TransCanada's commitments are expected to decrease by $54 million in 2017 and 2018, $35 million in 2019 and $106 million in 2022 and beyond.

TransCanada and its affiliates have long-term natural gas transportation and natural gas purchase arrangements as well as other purchase obligations, all of which are transacted at market prices and in the normal course of business.

Other commitments

Capital expenditure commitments include obligations related to the construction of growth projects and are based on the projects proceeding as planned. Changes to these projects, including cancellation, would reduce or possibly eliminate these commitments as a result of cost mitigation efforts.

At December 31, 2016, TransCanada was committed to Canadian Natural Gas Pipelines capital expenditures totaling approximately $0.8 billion (2015 – $0.5 billion), primarily related to construction costs associated with the NGTL System natural gas pipeline projects.

At December 31, 2016, TransCanada was committed to U.S. Natural Gas Pipelines capital expenditures totaling approximately $0.1 billion (2015 – $0.2 billion), primarily related to construction costs associated with the ANR natural gas pipeline projects.

At December 31, 2016, TransCanada was committed to Mexico Natural Gas Pipelines capital expenditures totaling approximately $2.1 billion (2015 – $0.2 billion), primarily related to construction on the Sur de Texas, Tula and Villa de Reyes Mexico gas pipeline projects.

At December 31, 2016, the Company was committed to Liquids Pipelines capital expenditures totaling approximately $0.2 billion (2015 – $0.8 billion), primarily related to construction costs of Northern Courier.

At December 31, 2016, the Company was committed to Energy capital expenditures totaling approximately $0.5 billion (2015 – $0.6 billion), primarily related to construction costs of the Napanee Generating Station.

At December 31, 2016, the Company was committed to Corporate expenditures totally approximately $0.2 billion (2015 – $0.1 billion), primarily related to an information technology services agreement.

Contingencies

TransCanada is subject to laws and regulations governing environmental quality and pollution control. As at December 31, 2016, the Company had accrued approximately $39 million (2015 – $32 million; 2014 – $31 million) related to operating facilities, which represents the present value of the estimated future amount it expects to expend to remediate the sites. However, additional liabilities may be incurred as assessments occur and remediation efforts continue.

TransCanada and its subsidiaries are subject to various legal proceedings, arbitrations and actions arising in the normal course of business. The amounts involved in such proceedings are not reasonably estimable as the final outcome of such legal proceedings cannot be predicted with certainty. It is the opinion of management that the ultimate resolution of such proceedings and actions, other than the Keystone XL legal proceeding described below, will not have a material impact on the Company's consolidated financial position or results of operations.

In June 2016, TransCanada 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 Keystone XL. TransCanada has 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. This arbitration is in a preliminary stage and the likelihood of success and resulting impact on the Company's financial position or results of operations is unknown at this time.

Guarantees

TransCanada and its joint venture partner on Bruce Power, BPC Generation Infrastructure Trust, have each severally guaranteed a contingent financial obligation of Bruce Power related to a lease agreement. The Bruce Power guarantee has a term to 2018.

The Company and its partners in certain jointly owned entities, including Sur de Texas, 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:

		2016		2015	
year ended December 31 (millions of Canadian $)	**Term**	**Potential Exposure**[1]	**Carrying Value**	**Potential Exposure**[1]	**Carrying Value**
Sur de Texas	Ranging to 2040	**805**	**53**	—	—
Bruce Power	Ranging to 2018	**88**	**1**	88	2
Other jointly owned entities	Ranging to 2040	**87**	**28**	139	24
		980	**82**	227	26

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

28. CORPORATE RESTRUCTURING COSTS

In mid-2015, the Company commenced a business restructuring and transformation initiative to reduce overall costs and maximize the effectiveness and efficiency of our existing operations.

Restructuring costs consist primarily of severance and expected future losses under lease commitments. In 2015, the Company incurred $122 million before tax of restructuring costs and recorded a provision of $87 million before tax related to planned severance costs in 2016 and 2017 and expected future losses under lease commitments.

In 2016, an additional provision of $44 million before tax was recorded related to changes to the expected future losses under lease commitments. Approximately $157 million and $22 million was recorded in Plant operating costs and other in the Consolidated statement of income for the years ended December 31, 2015 and 2016, respectively. In 2015, $58 million was recorded in Revenues in the Consolidated statement of income related to costs that were recoverable through regulatory and tolling structures. In addition, $44 million and $22 million was recorded as a Regulatory asset on the Consolidated balance sheet at December 31, 2015 and 2016, respectively, as these amounts are expected to be recovered through regulatory and tolling structures in future periods, and $8 million was capitalized in 2015 to projects impacted by the corporate restructuring.

Changes in the restructuring liability were as follows:

(millions of Canadian $)	Employee Severance	Lease Commitments	Total
Restructuring liability as at December 31, 2015	60	27	87
Restructuring charges	—	44	44
Cash payments	(24)	(8)	(32)
Restructuring Liability as at December 31, 2016	**36**	**63**	**99**

29. 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 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 is the primary beneficiary. As the primary beneficiary, 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:

at December 31 (millions of Canadian $)	2016	2015
ASSETS		
Current Assets		
Cash and cash equivalents	**77**	54
Accounts receivable	**71**	55
Inventories	**25**	25
Other	**10**	6
	183	140
Plant, Property and Equipment	**3,685**	3,704
Equity Investments	**606**	664
Goodwill	**525**	541
Intangible and Other Assets	**1**	—
	5,000	5,049
LIABILITIES		
Current Liabilities		
Accounts payable and other	**80**	74
Accrued interest	**21**	21
Current portion of long-term debt	**76**	45
	177	140
Regulatory Liabilities	**34**	33
Other Long-Term Liabilities	**4**	4
Deferred Income Tax Liabilities	**7**	—
Long-Term Debt	**2,827**	2,998
	3,049	3,175

Non-Consolidated VIEs

The Company's non-consolidated VIEs consist of legal entities where the Company is not the primary beneficiary as it 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:

at December 31 (millions of Canadian $)	2016	2015
Balance sheet		
Equity investments	**4,964**	5,410
Off-balance sheet		
Potential exposure to guarantees	**163**	227
Maximum exposure to loss	**5,127**	5,637

Supplementary information

SELECTED QUARTERLY AND ANNUAL CONSOLIDATED FINANCIAL DATA

	First	Second	Third	Fourth	Annual
Toronto Stock Exchange (Stock trading symbol TRP)					
2016 (dollars)					
High	**51.55**	**58.83**	**63.41**	**63.00**	**63.41**
Low	**41.51**	**48.46**	**58.15**	**57.36**	**41.51**
Close	**51.06**	**58.46**	**62.31**	**60.54**	**60.54**
Volume (millions of shares)	**123.5**	**107.2**	**104.5**	**115.4**	**450.6**
2015 (dollars)					
High	59.50	58.12	52.16	48.44	59.50
Low	50.51	50.15	41.10	40.58	40.58
Close	54.16	50.76	42.20	45.19	45.19
Volume (millions of shares)	84.2	79.6	84.4	124.4	372.6
2014 (dollars)					
High	50.97	51.89	63.86	58.18	63.86
Low	47.14	49.34	50.38	49.30	47.14
Close	50.25	50.93	57.68	57.10	57.10
Volume (millions of shares)	58.6	58.9	104.7	115.0	337.2
2013 (dollars)					
High	50.08	51.21	48.48	48.93	51.21
Low	46.80	44.62	44.75	43.94	43.94
Close	48.50	45.28	45.25	48.54	48.54
Volume (millions of shares)	76.90	85.80	64.30	68.90	295.90
2012 (dollars)					
High	44.75	43.80	46.29	47.44	47.44
Low	40.34	41.47	42.73	43.16	40.34
Close	42.83	42.67	44.74	47.02	47.02
Volume (millions of shares)	95.4	79.3	78.5	66.0	319.2
New York Stock Exchange (Stock trading symbol TRP)					
2016 (U.S. dollars)					
High	**39.70**	**45.34**	**48.52**	**47.92**	**48.52**
Low	**28.40**	**36.76**	**44.77**	**42.69**	**28.40**
Close	**39.31**	**45.22**	**47.56**	**45.15**	**45.15**
Volume (millions of shares)	**86.4**	**67.9**	**61.3**	**61.4**	**277.0**
2015 (U.S. dollars)					
High	49.64	48.10	40.78	35.57	49.64
Low	41.51	40.33	30.60	29.89	29.89
Close	42.72	40.62	31.58	32.59	32.59
Volume (millions of shares)	69.9	57.9	66.4	78.1	272.3
2014 (U.S. dollars)					
High	45.81	48.13	58.40	51.84	58.40
Low	42.21	44.78	47.24	43.71	42.21
Close	45.52	47.72	51.53	49.10	49.10
Volume (millions of shares)	31.9	29.5	88.2	99.5	249.0
2013 (U.S. dollars)					
High	49.64	49.65	46.79	46.45	49.65
Low	45.80	42.39	42.59	42.41	42.39
Close	47.89	43.11	43.94	45.66	45.66
Volume (millions of shares)	33.3	38.2	30.3	27.9	129.7
2012 (U.S. dollars)					
High	45.07	44.50	47.02	47.78	47.78
Low	39.74	39.87	41.68	43.54	39.74
Close	43.00	41.90	45.50	47.32	47.32
Volume (millions of shares)	39.7	29.2	20.1	20.0	109.0

Five year financial highlights

(millions of Canadian $, unless otherwise noted)	2016	2015	2014	2013	2012
Income Statement					
Revenues	**12,505**	11,300	10,185	8,797	8,007
Segmented earnings					
Canadian Natural Gas Pipelines	**1,373**	1,413	1,454	1,347	1,168
U.S Natural Gas Pipelines	**1,219**	606	556	455	550
Mexico Natural Gas Pipelines	**290**	171	142	79	90
Liquids Pipelines	**827**	(2,643)	830	603	553
Energy	**(1,140)**	792	1,036	1,113	579
Corporate	**(256)**	(238)	(87)	(124)	(111)
	2,313	101	3,931	3,473	2,829
Interest expense and other	**(1,476)**	(1,207)	(1,107)	(951)	(891)
Income taxes	**(352)**	(34)	(831)	(611)	(466)
Net income/(loss)	**485**	(1,140)	1,993	1,911	1,472
Net income attributable to non-controlling interests	**(252)**	(6)	(153)	(125)	(118)
Net income/(loss) attributable to controlling interests	**233**	(1,146)	1,840	1,786	1,354
Preferred share dividends	**(109)**	(94)	(97)	(74)	(55)
Net income/(loss) attributable to common shares	**124**	(1,240)	1,743	1,712	1,299
Comparable earnings	**2,108**	1,755	1,715	1,584	1,330
Comparable EBITDA	**6,647**	5,908	5,521	4,859	4,245
Cash Flow Statement					
Funds generated from operations	**4,821**	4,730	4,415	4,120	3,344
Decrease/(Increase) in operating working capital	**248**	(346)	(189)	(326)	287
Net cash provided by operations	**5,069**	4,384	4,226	3,794	3,631
Comparable distributable cash flow	**3,665**	3,562	3,405	3,234	2,589
Capital spending – capital expenditures	**5,007**	3,918	3,489	4,264	2,595
Capital spending – projects in development	**295**	511	848	488	3
Acquisitions, net of cash acquired	**13,608**	236	241	216	214
Cash dividends paid on common and preferred shares	**1,536**	1,538	1,439	1,356	1,281
Balance Sheet					
Assets					
Plant, property and equipment	**54,475**	44,817	41,774	37,606	33,713
Total assets	**88,051**	64,398	58,407	53,778	48,287
Capitalization					
Long-term debt	**40,150**	31,456	24,639	22,745	18,804
Junior subordinated notes	**3,931**	2,409	1,160	1,063	994
Preferred shares	**3,980**	2,499	2,255	1,813	1,224
Common shareholders' equity	**20,277**	13,939	16,815	16,712	15,687

	2016	2015	2014	2013	2012
Per Common Share Data					
Net income – basic	**$0.16**	($1.75)	$2.46	$2.42	$1.84
– diluted	**$0.16**	($1.75)	$2.46	$2.42	$1.84
Comparable earnings per share	**$2.78**	$2.48	$2.42	$2.24	$1.89
Dividends declared	**$2.26**	$2.08	$1.92	$1.84	$1.76
Book Value[1,2]	**$23.47**	$19.84	$23.73	$23.62	$22.24
Market Price					
Toronto Stock Exchange (dollars)					
High	**63.41**	59.50	63.86	51.21	47.44
Low	**41.51**	40.58	47.14	43.94	40.34
Close	**60.54**	45.19	57.10	48.54	47.02
Volume (millions of shares)	**450.6**	372.6	337.2	295.9	319.2
New York Stock Exchange (U.S. dollars)					
High	**48.52**	49.64	58.40	49.65	47.78
Low	**28.40**	29.89	42.21	42.39	39.74
Close	**45.15**	32.59	49.10	45.66	47.32
Volume (millions of shares)	**277.0**	272.3	249.0	129.7	109.0
Common shares outstanding (millions)					
Average for the year	**759.0**	708.6	708.0	706.7	704.6
End of year	**863.8**	702.6	708.7	707.4	705.5
Registered common shareholders[1]	**28,475**	29,367	30,513	31,300	31,449
Per Preferred Share Data (dollars)					
Dividends declared:					
Series 1, 2, 3, 4, 5, 7, 9, 11, 13 and 15 cumulative first preferred shares[3]	$7.27	$6.31	$5.34	$4.16	$3.25
Financial Ratios					
Dividend yield[4,5]	**3.7%**	4.6%	3.4%	3.8%	3.7%
Price/earnings multiple[5,6]	**378.4**	(25.8)	23.2	20.1	25.5
Price/book multiple[2,5]	**2.6**	2.3	2.4	2.1	2.1
Debt to debt plus shareholders' equity[7]	**68%**	71%	61%	59%	56%
Total shareholder return[8]	**39.4%**	(17.7)%	22.0%	7.2%	9.9%
Earnings to fixed charges[9]	**1.3**	0.2	2.8	2.8	2.2

1 As at December 31.

2 The price/book multiple is determined by dividing price per common share by book value per common share as calculated by dividing common shareholders' equity by the number of common shares outstanding as at December 31.

3

Cumulative First Preferred Shares	Issue Date	Annual Dividend Per Share	First quarterly dividend paid
Series 1	September 2009	$0.82	December 2009
Series 2 - upon conversion of Series 1	December 2014	$0.61	March 2015
Series 3	March 2010	$0.54	June 2010
Series 4 - upon conversion of Series 3	June 2015	$0.45	September 2015
Series 5	June 2010	$0.57	November 2010
Series 6 - upon conversion of Series 5	February 2016	$0.51	May 2016
Series 7	March 2013	$1.00	April 2013
Series 9	January 2014	$1.06	January 2014
Series 11	March 2015	$1.19	May 2015
Series 13	April 2016	$0.19	May 2016
Series 15	November 2016	$0.33	January 2017

4 The dividend yield is determined by dividing dividends per common share declared during the year by price per common share as at December 31.

5 Price per common share refers to market price per share as reported on the Toronto Stock Exchange as at December 31.

6 The price/earnings multiple is determined by dividing price per common share by the basic net income per share.

7 Debt includes Junior Subordinated Notes, total long-term debt, including the current portion of long-term debt, plus preferred securities as at December 31 and excludes long-term debt of joint ventures. Shareholders' equity in this ratio is as at December 31.

8 Total shareholder return is the sum of the change in price per common share plus the dividends received plus the impact of dividend re-investment in a calendar year, expressed as a percentage of the value of shares at the end of the previous year.

9 The earnings to fixed charges ratio is determined by dividing earnings by fixed charges. Earnings is calculated as the sum of EBIT and interest income and other, less income attributable to non-controlling interests with interest expense and undistributed earnings of investments accounted for by the equity method. Fixed charges is calculated as the sum of interest expense, and capitalized interest.

Investor information

STOCK EXCHANGES, SECURITIES AND SYMBOLS

TransCanada Corporation

Common shares are listed on the Toronto and New York stock exchanges under the symbol: TRP

First Preferred Shares, Series 1 are listed on the Toronto Stock Exchange under the symbol: TRP.PR.A

First Preferred Shares, Series 2 are listed on the Toronto Stock Exchange under the symbol: TRP.PR.F

First Preferred Shares, Series 3 are listed on the Toronto Stock Exchange under the symbol: TRP.PR.B

First Preferred Shares, Series 4 are listed on the Toronto Stock Exchange under the symbol: TRP.PR.H

First Preferred Shares, Series 5 are listed on the Toronto Stock Exchange under the symbol: TRP.PR.C

First Preferred Shares, Series 6 are listed on the Toronto Stock Exchange under the symbol: TRP.PR.I

First Preferred Shares, Series 7 are listed on the Toronto Stock Exchange under the symbol: TRP.PR.D

First Preferred Shares, Series 9 are listed on the Toronto Stock Exchange under the symbol: TRP.PR.E

First Preferred Shares, Series 11 are listed on the Toronto Stock Exchange under the symbol: TRP.PR.G

First Preferred Shares, Series 13 are listed on the Toronto Stock Exchange under the symbol: TRP.PR.J

First Preferred Shares, Series 15 are listed on the Toronto Stock Exchange under the symbol: TRP.PR.K

Dividend Payment Dates Scheduled common share dividend payment dates in 2017 are January 31, April 28, July 31 and October 31.

For information on dividend payment dates for preferred shares visit our website at www.transcanada.com.

Dividend Reinvestment and Share Purchase Plan TransCanada's dividend reinvestment and share purchase plan (Plan) allows common and preferred shareholders of TransCanada to purchase common shares of TransCanada by reinvesting their cash dividends without incurring brokerage or administrative fees. Participants in the Plan may also buy additional common shares, up to Cdn$10,000 per quarter. For more information on the Plan please contact our Plan agent, Computershare Investor Services Inc. or visit our website at www.transcanada.com.

TRANSFER AGENTS, REGISTRARS AND TRUSTEES

TransCanada Corporation Common Shares Computershare Investor Services Inc. (Montréal, Toronto, Calgary and Vancouver) and Computershare Trust Company, N.A. (Golden)

TransCanada Corporation First Preferred Shares, Series 1, 2, 3, 4, 5, 6, 7, 9, 11, 13 and 15 Computershare Investor Services Inc. (Montréal, Toronto, Calgary and Vancouver)

TCPL Debentures

Canadian Series: BNY Trust Company of Canada (Halifax, Montréal, Toronto, Calgary and Vancouver)

10.5% series P	11.80% series U	9.80% series V	9.45% series W

U.S. Series: The Bank of New York (New York) 9.875%

TCPL Canadian Medium-Term Notes CIBC Mellon Trust Company (Montréal and Toronto)

TCPL U.S. Medium-Term Notes and Senior Notes The Bank of New York Mellon (New York)

TCPL U.S. Junior Subordinated Notes 2007 Computershare Trust Company, N.A. (Jersery City, NJ)

NOVA Gas Transmission Ltd. (NGTL) Debentures

Canadian Series: BNY Trust Company of Canada (Montreal and Toronto) 9.90% series 23

U.S. Series: U.S. Bank Trust National Association (New York) 7.875%

NGTL Canadian Medium-Term Notes BNY Trust Company of Canada (Montreal and Toronto)

NGTL U.S. Medium-Term Notes U.S. Bank Trust National Association (New York)

TransCanada Trust Subordinated Notes

2015 U.S. Junior Subordinated Notes: CST Trust Company

2016 U.S. Junior Subordinated Notes: CST Trust Company

REGULATORY FILINGS

Annual Information Form TransCanada's 2016 Annual information form, as filed with Canadian securities commissions and as filed under Form 40-F with the SEC, is available on our website at www.transcanada.com.

A printed copy may be obtained from:

Corporate Secretary, TransCanada Corporation, 450 1st Street SW, Calgary, Alberta, Canada T2P 5H1

Shareholder assistance

If you are a registered shareholder and have questions regarding your account, please contact our transfer agent in writing, by telephone or e-mail at:

Computershare Investor Services Inc., 100 University Avenue, 8th Floor, Toronto, Ontario, Canada M5J 2Y1

Toll-free: 1.800.340.5024
Telephone: 1.514.982.7959

E-mail: transcanada@computershare.com

www.computershare.com

If you hold your shares in a brokerage account (beneficial shareholder), questions should be directed to your broker on all administrative matters.

If you would like to receive quarterly reports, please contact Computershare or visit our website at www.transcanada.com.

Electronic Proxy Voting and Delivery of Documents TransCanada is using Notice & Access which allows an issuer to deliver the Management information circular to registered shareholders by posting it and other related materials on SEDAR at www.sedar.com and www.transcanada/notice-and-access.html. Registered shareholders who still wish to receive a paper copy of the Management information circular may request one free of charge by following the instructions set out in the notice that will be sent to all registered shareholders by mail. TransCanada is pleased to offer all shareholders the ability to receive their documents (annual report, management information circular, notice of meeting and view-only proxy form or voting instruction form) and vote online.

In 2017, registered shareholders who opt to receive their documents electronically will have a tree planted on their behalf through eTree. For more information and to sign up online, registered shareholders can visit www.investorcentre.com/transcanada.

Shareholders who do not have access to e-mail, or who still prefer to receive their proxy materials by mail also have the ability to choose whether to receive TransCanada's annual report by regular mail. Each year, shareholders are required to renew their option and will receive a notification for doing so. The annual report is available on the TransCanada website at www.transcanada.com at the same time that the report is mailed to shareholders.

Notice and Access, electronic delivery and the ability to opt out of receiving the annual report by mail, provides increased convenience to shareholders, benefits to the environment and reduced mailing and printing costs for the company.

TransCanada in the Community TransCanada's annual Corporate Responsibility Report is available at www.transcanada.com. If you would like to receive a copy of this report by mail, please contact:

Communications 450 1st Street SW, Calgary, Alberta T2P 5H1, 1.403.920.2000 or 1.800.661.3805 or Communications@transcanada.com

Visit our website at www.transcanada.com to access TransCanada's corporate and financial information, including quarterly reports, news releases, real-time conference call webcasts and investor presentations.

Si vous désirez vous procurer un exemplaire de ce rapport en français, veuillez consulter notre site web ou vous adresser par écrit à TransCanada Corporation, bureau du secrétaire.

Board of directors

(as at December 31, 2016)

S. Barry Jackson[1,2]
Chairman
TransCanada Corporation
Calgary, Alberta

Russell K. Girling
President and CEO
TransCanada Corporation
Calgary, Alberta

Kevin E. Benson[1,4]
Corporate Director
Calgary, Alberta

Derek H. Burney, O.C.[4,7]
Senior Strategic Advisor
Norton Rose Canada LLP
Ottawa, Ontario

John E. Lowe[4,5]
Chairman
Apache Corporation
Houston, Texas

Paula Rosput Reynolds[5,8]
President and CEO
PreferWest LLC
Seattle, Washington

John Richels[2,5]
Corporate Director
Toronto, Ontario

Mary Pat Salomone[4,5]
Corporate Director
Naples, FL

Indira V. Samarasekera[1,4]
Senior Advisor
Bennett Jones LLP
Vancouver, British Columbia

D. Michael G. Stewart[4,6]
Corporate Director
Calgary, Alberta

Siim A. Vanaselja[1,3]
Corporate Director
Westmount, Québec

Richard E. Waugh[1,2]
Corporate Director
Toronto, Ontario

1 Member, Governance Committee
2 Member, Human Resources Committee
3 Chair, Audit Committee
4 Member, Audit Committee
5 Member, Health, Safety & Environment Committee
6 Chair, Health, Safety & Environment Committee
7 Chair, Governance Committee
8 Chair, Human Resources Committee

Corporate governance

Please refer to TransCanada's Notice of 2017 annual meeting of shareholders and Management information circular for the company's statement of corporate governance.

TransCanada's Corporate Governance Guidelines, Board charter, Committee charters, Chair and Chief Executive Officer terms of reference and code of business ethics are available on our website at www.transcanada.com. Also available on our website is a summary of the significant ways in which TransCanada's corporate governance practices differ from those required to be followed by U.S. domestic companies under the New York Stock Exchange's listing standards.

Additional information relating to the company is filed with securities regulators in Canada on SEDAR (www.sedar.com) and in the United States on EDGAR (www.sec.gov). The documents referred to in this Annual Report may be obtained free of charge by contacting TransCanada's Corporate Secretary at 450 1st Street SW, Calgary, Alberta, Canada T2P 5H1, or by calling 1.800.661.3805.

Ethics Help-Line The Audit Committee of the Board of Directors has established an anonymous and confidential toll-free telephone number for employees, contractors and others to call with respect to accounting irregularities and ethical violations. The Ethics Help-Line number is 1.888.920.2042.

Shareholder Information

TransCanada welcomes questions from shareholders and investors. Please contact:

David Moneta, Vice President, Investor Relations
telephone: **403.920.7911**
toll free: **1.800.361.6522**

investor_relations@transcanada.com
www.transcanada.com

Listing Information

Common Shares (TSX, NYSE): TRP

Preferred Shares (TSX):

Series 1: TRP.PR.A
Series 2: TRP.PR.F
Series 3: TRP.PR.B
Series 4: TRP.PR.H
Series 5: TRP.PR.C
Series 6: TRP.PR.I
Series 7: TRP.PR.D
Series 9: TRP.PR.E
Series 11: TRP.PR.G
Series 13: TRP.PR.J
Series 15: TRP.PR.K

Transfer Agent

Computershare Investor Services
100 University Avenue, 8th Floor
Toronto, Ontario M5J 2Y1

telephone: **1.514.982.7959**
toll free: **1.800.340.5024**
fax: **1.888.453.0330**
email: **transcanada@computershare.com**

Corporate Social Responsibility Report

Building a successful future means doing the right thing today.
View our CSR report: **www.csrreport.transcanada.com**

Corporate Head Office

TransCanada Corporation
450 – 1 Street SW
Calgary, Alberta, Canada
T2P 5H1

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February 2017

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