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.

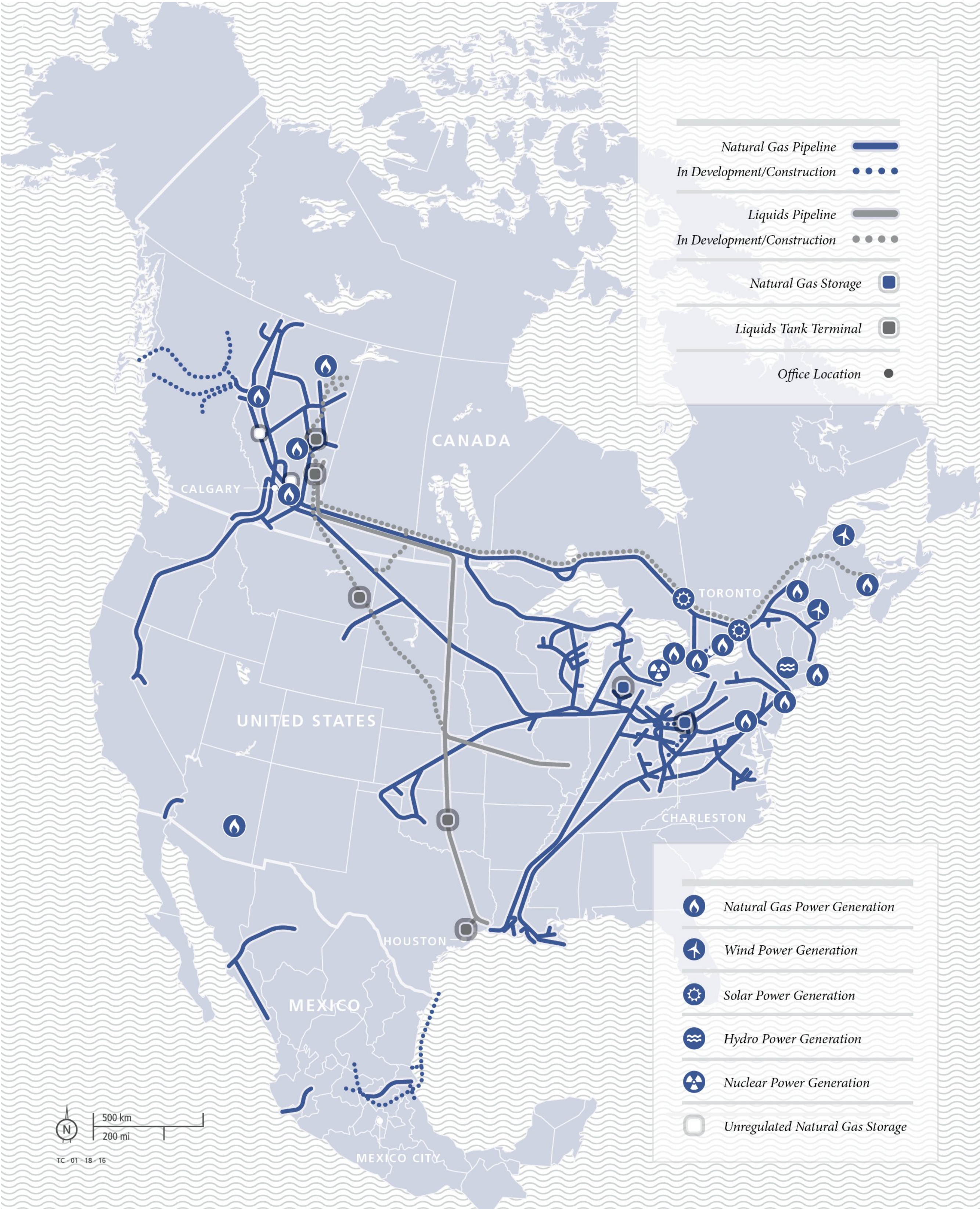
We believe comparable distributable cash flow is a useful supplemental measure of performance that defines cash available to common shareholders before capital allocation. See the Financial condition section for a reconciliation to net cash provided by operations.

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.

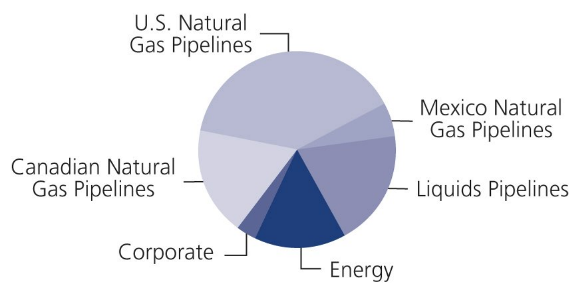
Our $88 billion portfolio of energy infrastructure assets meets the needs of people who rely on us to deliver their energy safely and reliably every day. We operate in seven Canadian provinces, 38 U.S. states and Mexico.

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.

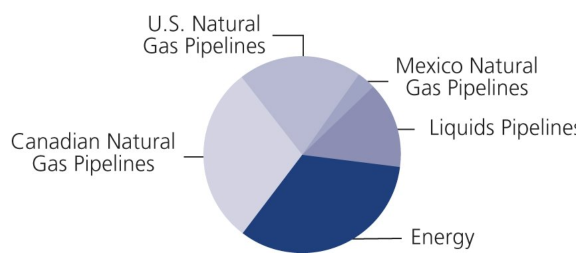
2016 Total assets



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.

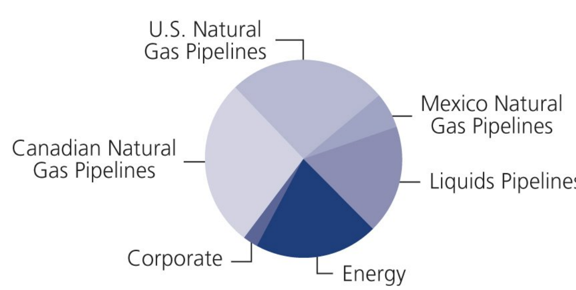
2016 Total revenues



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

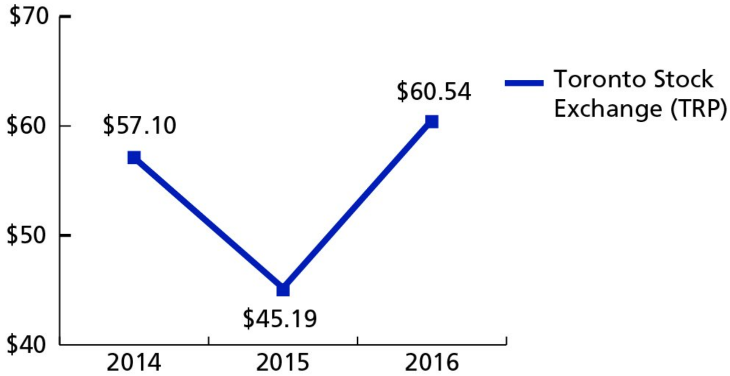
1 Includes Columbia effective July 1, 2016.

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.

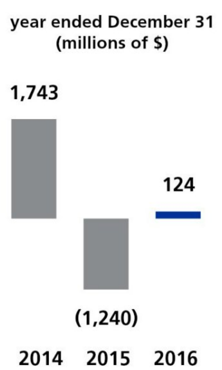
year ended December 31 (millions of $, except per share amounts)	2016	2015	2014
Income			
Revenues	**12,505**	11,300	10,185
Net income/(loss) attributable to common shares	**124**	(1,240)	1,743
per common share – basic & diluted	**$0.16**	($1.75)	$2.46
Comparable EBITDA	**6,647**	5,908	5,521
Comparable 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.

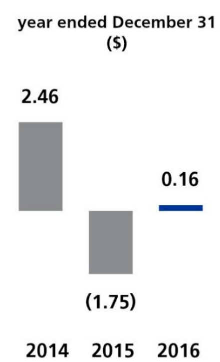
Consolidated results

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.

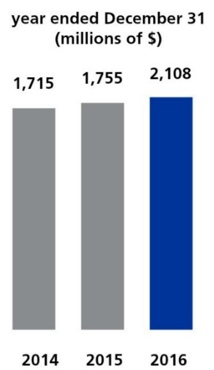
Refer to the Results section in each business segment and the Financial condition section of this MD&A for further discussion of these highlights.

Reconciliation of net income/(loss) to comparable earnings

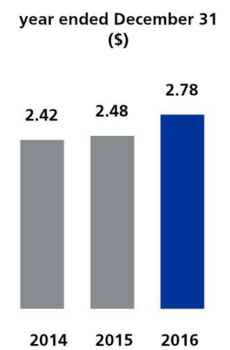
year ended December 31 (millions of $, except per share amounts)	2016	2015	2014
Net income/(loss) attributable to common shares	**124**	(1,240)	1,743
Specific items (net of tax):			
Ravenswood goodwill impairment	**656**	—	—
Loss on U.S. Northeast power assets held for sale	**873**	—	—
Alberta PPA terminations 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.

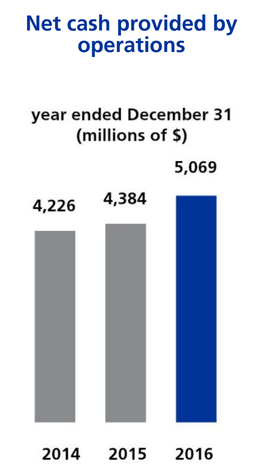
Comparable earnings in 2015 were $40 million higher than 2014, an increase of $0.06 per common share.

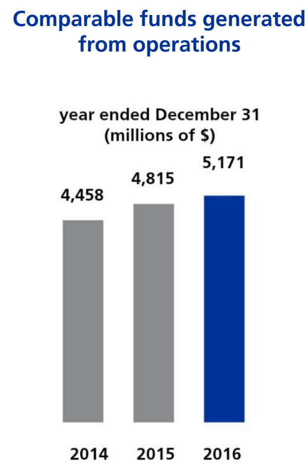
The 2015 increase in comparable earnings was primarily the net result of:

- 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

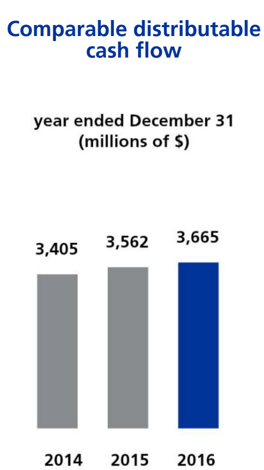
- higher earnings from U.S. Power due to increased margins and sales volumes to wholesale, commercial and industrial customers, partially offset by lower capacity revenue in New York and lower realized prices at our northeastern U.S. Power facilities
- higher earnings from U.S. Natural Gas Pipelines 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.

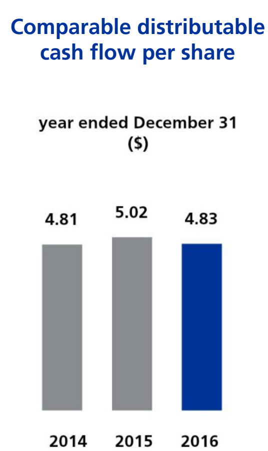
Cash flows





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.

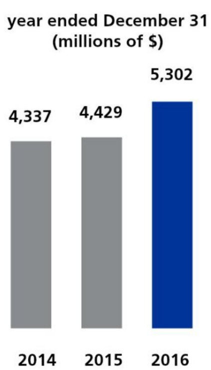
Funds used in investing activities

***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.

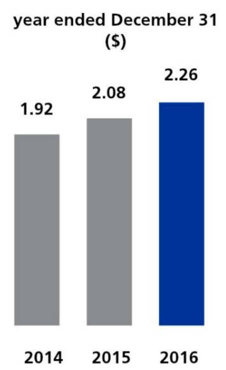
Common shares repurchased

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.

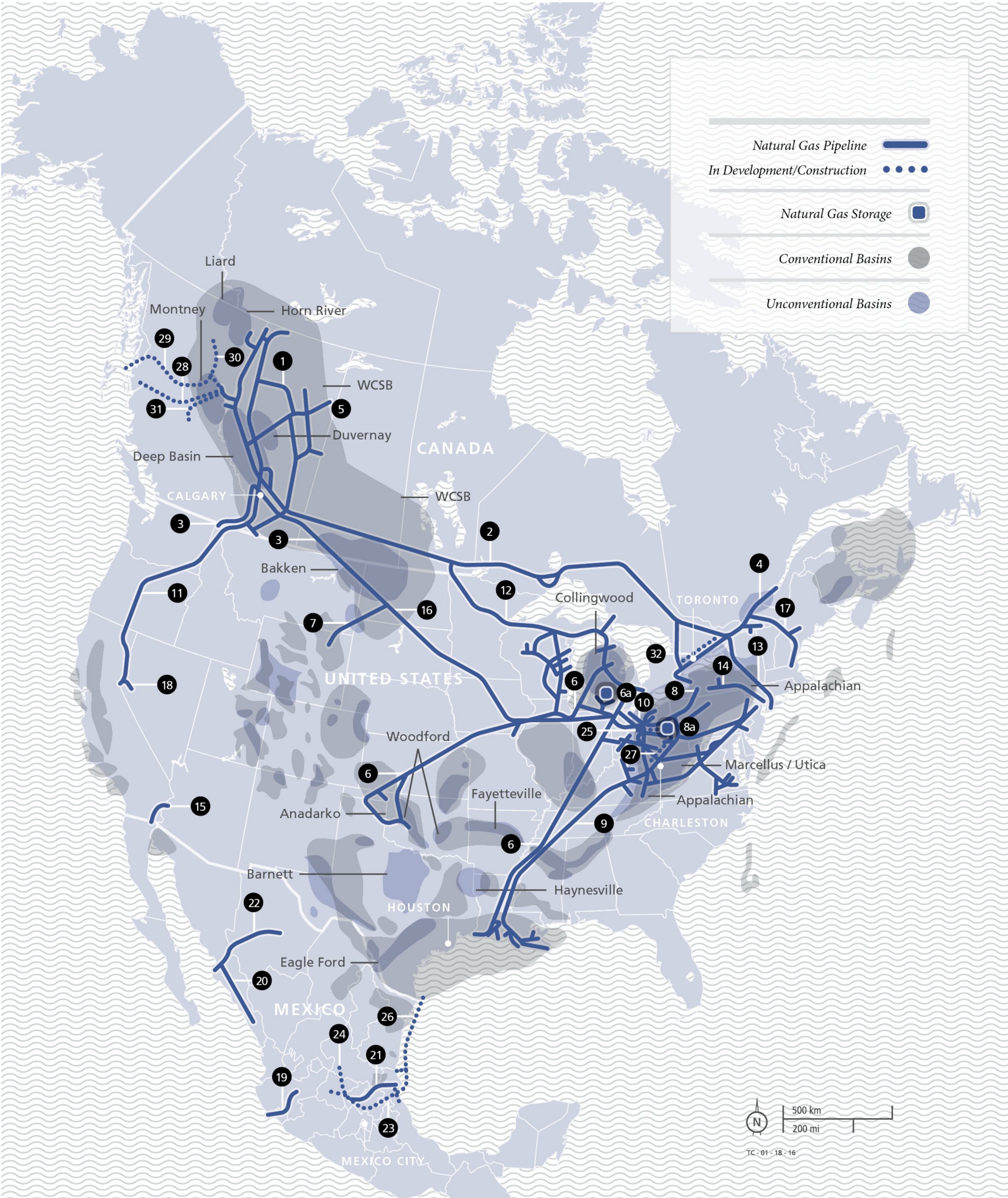
More competition

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

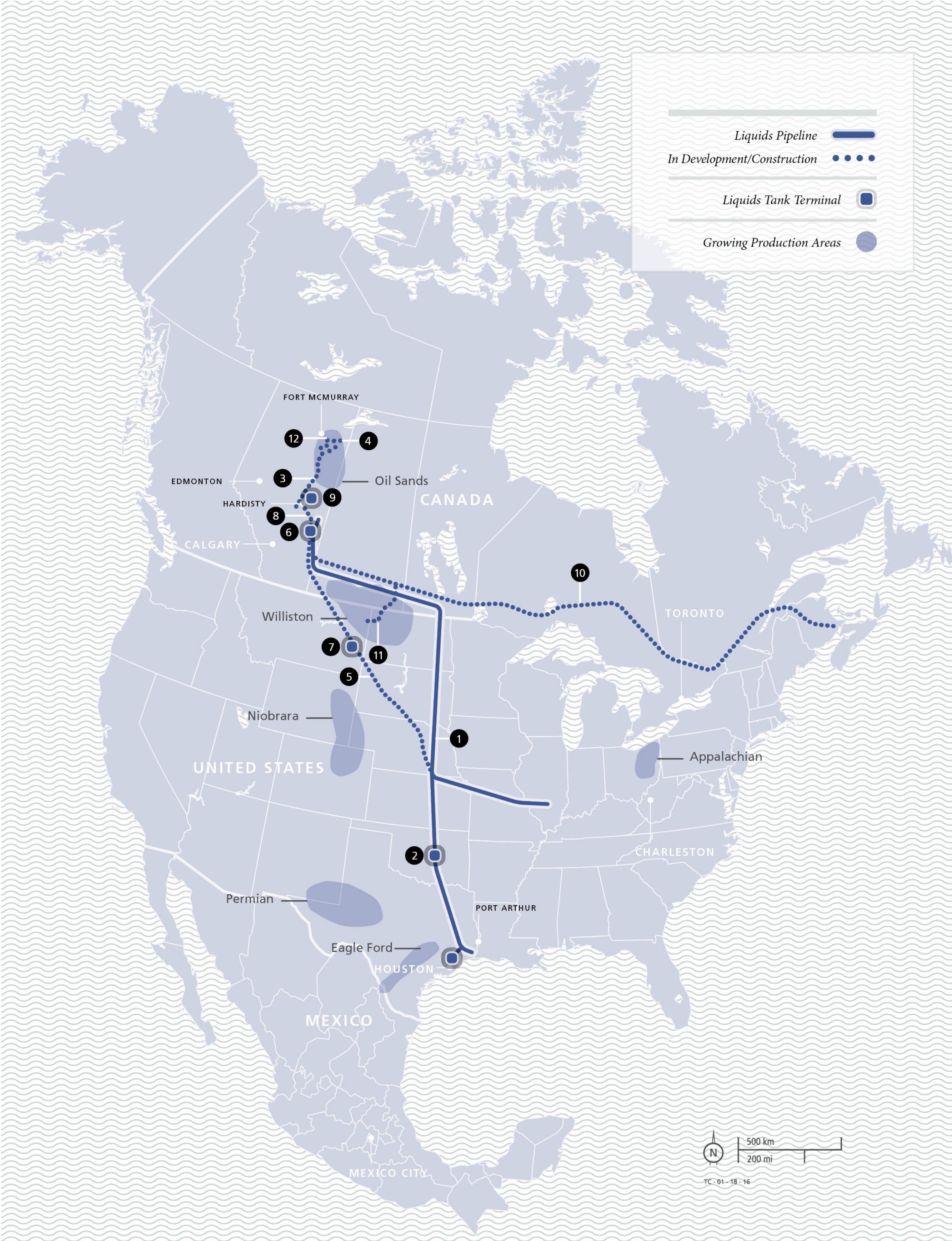
Our existing liquids pipeline infrastructure connects Alberta crude oil supplies to U.S. refining markets in Illinois, Oklahoma and Texas, as well as connecting U.S. crude oil supplies from the Cushing, Oklahoma hub to refining markets in the U.S Gulf Coast. Our proposed future pipeline infrastructure 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
TORONTO
Appalachian
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.

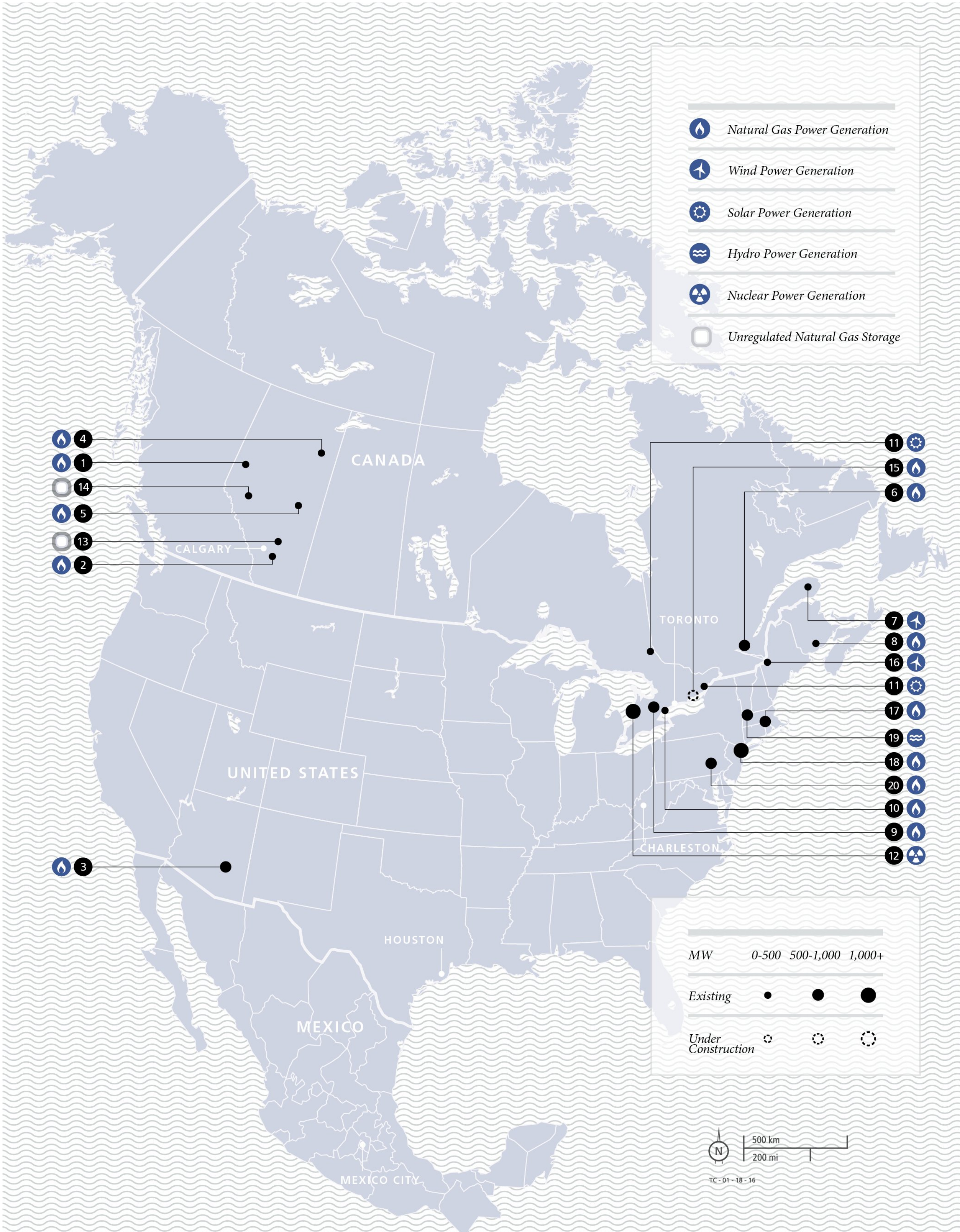
We own and operate approximately 118 Bcf of unregulated natural gas storage capacity in Alberta and hold a contract with a third party for additional storage, in total accounting for approximately one-third of all storage capacity in the province.

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.

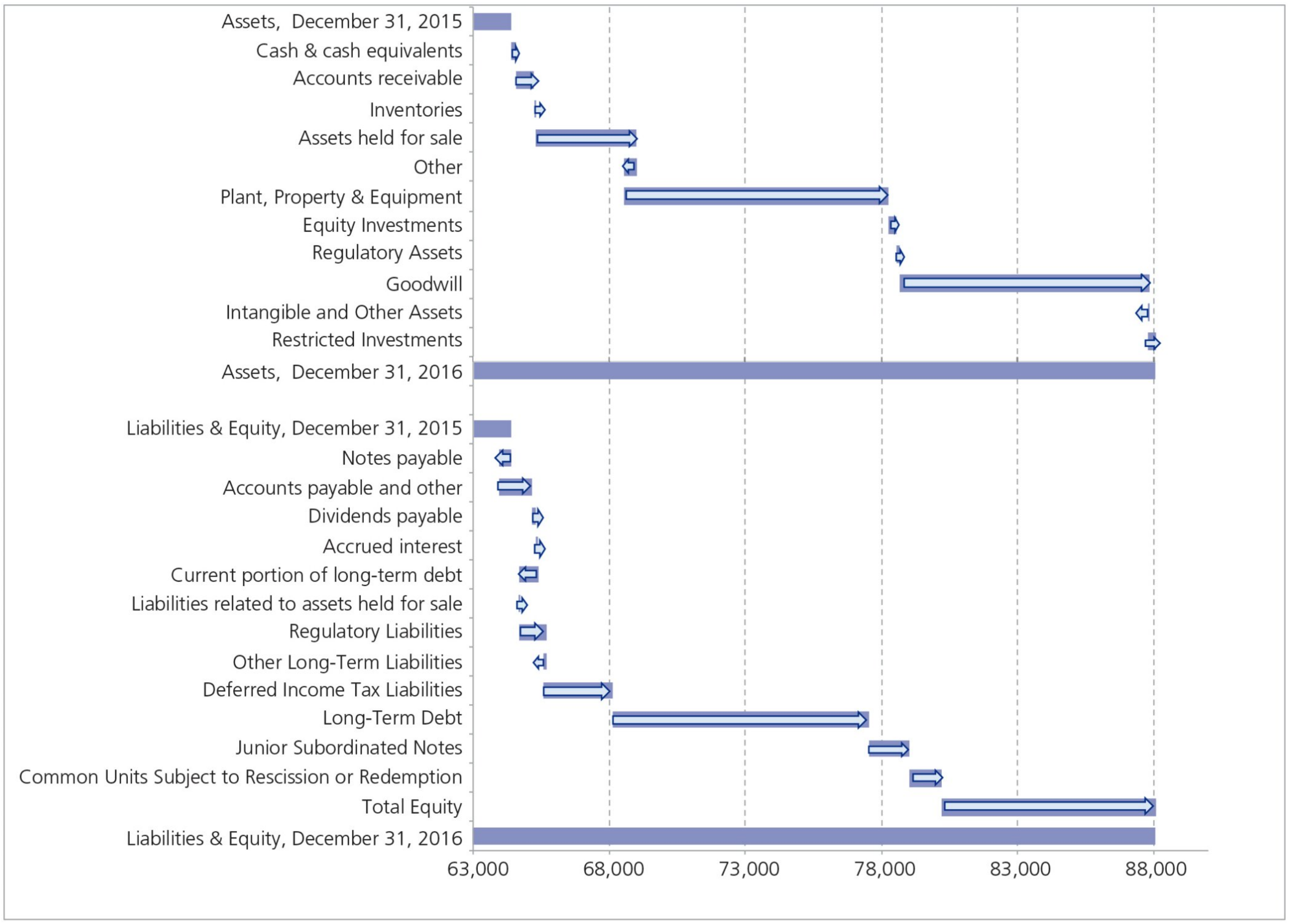
Financial condition

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.

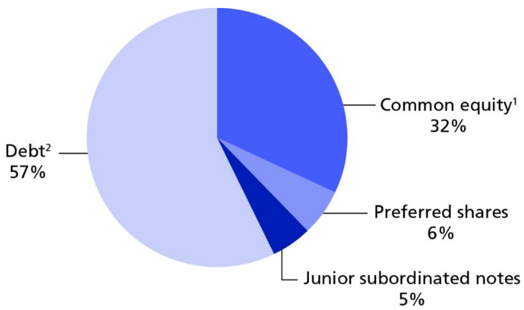


The acquisition of Columbia on July 1, 2016 and related financing activities resulted in significant increases to our assets, liabilities and equity. Also impacting the balance sheet in 2016 was the pending sales of our U.S. Northeast power assets as we have classified these as assets held for sale. 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 a 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**

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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