Management's discussion and analysis

February 13, 2019

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, 2018.

This MD&A should be read with our accompanying December 31, 2018 audited Consolidated financial statements and notes for the same period, which have been prepared in accordance with U.S. 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 110. All information is as of February 13, 2019 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:

- our financial and operational performance, including the performance of our subsidiaries
- expectations about strategies and goals for growth and expansion
- expected cash flows and future financing options available, including portfolio management
- expected dividend growth
- expected future credit ratings
- expected costs and schedules for planned projects, including projects under construction and in development
- expected capital expenditures and contractual obligations
- expected regulatory processes and outcomes, including the impact of the 2018 FERC Actions
- expected outcomes with respect to legal proceedings, including arbitration and insurance claims
- 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

- regulatory decisions and outcomes, including final outcomes of the 2018 FERC Actions
- planned and unplanned outages and the use of our pipeline and energy assets
- integrity and reliability of our assets
- anticipated construction costs, schedules and completion dates
- access to capital markets, including portfolio management
- expected industry, market and economic conditions
- inflation rates and commodity prices
- interest, tax and foreign exchange rates
- nature and scope of hedging.

Risks and uncertainties

- our ability to successfully implement our strategic priorities and whether they will yield the expected benefits
- our ability to implement a capital allocation strategy aligned with maximizing shareholder value
- the operating performance of our pipeline and energy assets
- amount of capacity sold and rates achieved in our pipeline businesses
- the amount of capacity payments and revenues from our energy business due to plant availability
- production levels within supply basins
- construction and completion of capital projects
- costs for labour, equipment and materials
- the availability and market prices of commodities
- access to capital markets on competitive terms
- interest, tax and foreign exchange rates
- performance and credit risk of our counterparties
- regulatory decisions and outcomes of legal proceedings, including arbitration and insurance claims
- changes in environmental and other laws and regulations
- competition in the pipeline and energy sectors
- unexpected or unusual weather
- acts of civil disobedience
- cyber security and technological developments
- economic conditions in North America as well as globally
- our ability to effectively anticipate and assess changes to government policies and regulations.

You can read more about these factors in this MD&A and in other 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

You can also find more information about TransCanada in our Annual Information Form (AIF) 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 EBITDA
- comparable EBIT
- comparable earnings
- comparable earnings per common share
- 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 GAAP and therefore may not be comparable to similar measures presented by other entities.

Comparable measures

We calculate comparable measures by adjusting certain GAAP measures for specific items we believe are significant but not reflective of our underlying operations in the period. Except as otherwise described herein, 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 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 and integration 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.

The following table identifies our non-GAAP measures and their most directly comparable GAAP measures.

Non-GAAP measure	GAAP measure
comparable EBITDA	segmented earnings
comparable EBIT	segmented earnings
comparable earnings	net income attributable to common shares
comparable earnings per common share	net income per common share
comparable funds generated from operations	net cash provided by operations
comparable distributable cash flow	net cash provided by operations

Comparable EBITDA and comparable EBIT

Comparable EBITDA represents segmented earnings adjusted for certain specific items, excluding non-cash charges for depreciation and amortization. We use comparable EBITDA as a measure of our earnings from ongoing operations as it is a useful indicator of our performance and is also presented on a consolidated basis. Comparable EBIT represents segmented earnings adjusted for specific items. Comparable EBIT is an effective tool for evaluating trends in each segment. Refer to the Other information section for a reconciliation to segmented earnings.

Comparable earnings and comparable earnings per common share

Comparable earnings represents earnings or losses 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, non-controlling interests and preferred share dividends adjusted for specific items. Refer to the Financial highlights section for a reconciliation to net income attributable to common shares and net income per common share.

Funds generated from operations and comparable funds generated from operations

Funds generated from operations reflects 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. Comparable funds generated from operations is adjusted for the cash impact of specific items noted above. Refer to the Financial condition section for a reconciliation to net cash provided by operations.

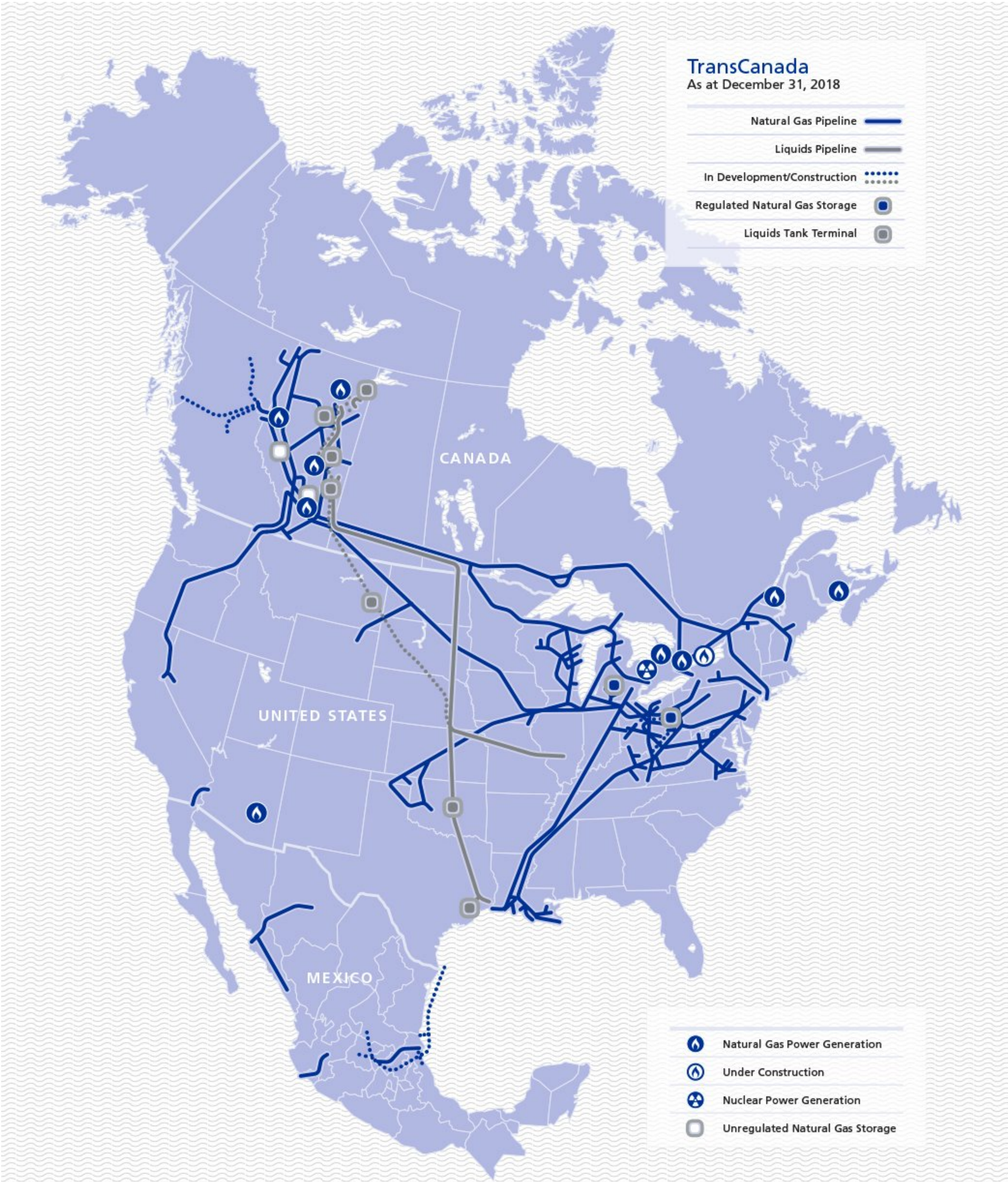
Comparable distributable cash flow and comparable distributable cash flow per common share

We believe comparable distributable cash flow is a useful supplemental measure of performance that defines cash available to common shareholders before capital allocation. Comparable distributable cash flow is defined as comparable funds generated from operations less preferred share dividends, distributions to non-controlling interests and non-recoverable maintenance capital expenditures. Refer to the Financial condition section for a reconciliation to net cash provided by operations.

Maintenance capital expenditures are expenditures incurred to maintain our operating capacity, asset integrity and reliability, and include amounts attributable to our proportionate share of maintenance capital expenditures on our equity investments. We have the opportunity to recover effectively all of our pipeline maintenance capital expenditures in Canadian Natural Gas Pipelines, U.S. Natural Gas Pipelines and Liquids Pipelines through tolls. Canadian natural gas pipelines maintenance capital expenditures are included in rate bases, on which we earn a regulated return and subsequently recover in tolls. Our U.S. natural gas pipelines can recover maintenance capital expenditures through tolls under current rate settlements, or have the ability to recover such expenditures through tolls established in future rate cases or settlements. Tolling arrangements in our liquids pipelines provide for the recovery of maintenance capital expenditures. As such, in 2018 our presentation of comparable distributable cash flow and comparable distributable cash flow per common share only includes a reduction for non-recoverable maintenance capital expenditures in their respective calculations. We have adjusted our comparable distributable cash flow and comparable distributable cash flow per common share for 2017 and 2016 to reflect the amended presentation format which we believe provides better information for readers.

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. In order to provide information that is aligned with how management decisions about our businesses are made and how performance of our businesses are assessed, our results are reflected in five operating segments: Canadian Natural Gas Pipelines, U.S. Natural Gas Pipelines, Mexico Natural Gas Pipelines, Liquids Pipelines and Energy. We also have a Corporate segment, consisting of corporate and administrative functions that provide governance, financing and other support to the Company's business segments.

Year at a glance

at December 31 (millions of $)	2018	2017
Total assets by segment		
Canadian Natural Gas Pipelines	**18,407**	16,904
U.S. Natural Gas Pipelines	**44,115**	35,898
Mexico Natural Gas Pipelines	**7,058**	5,716
Liquids Pipelines	**17,352**	15,438
Energy	**8,475**	8,503
Corporate	**3,513**	3,642
	98,920	86,101

year ended December 31 (millions of $)	2018	2017
Total revenues by segment		
Canadian Natural Gas Pipelines	**4,038**	3,693
U.S. Natural Gas Pipelines	**4,314**	3,584
Mexico Natural Gas Pipelines	**619**	570
Liquids Pipelines	**2,584**	2,009
Energy[1]	**2,124**	3,593
	13,679	13,449

1 Includes Cartier Wind assets until sold in 2018 and U.S. Northeast power generation assets and Ontario solar assets until sold in 2017.

year ended December 31 (millions of $)	2018	2017
Comparable EBITDA by segment		
Canadian Natural Gas Pipelines	**2,379**	2,144
U.S. Natural Gas Pipelines	**3,035**	2,357
Mexico Natural Gas Pipelines	**607**	519
Liquids Pipelines	**1,849**	1,348
Energy[1]	**752**	1,030
Corporate	**(59)**	(21)
	8,563	7,377

1 Includes Cartier Wind assets until sold in 2018 and U.S. Northeast power generation assets and Ontario solar assets until sold in 2017.

Company Name Change

In January 2019, we announced our intention to change our name to TC Energy to better reflect the scope of our operations as a leading North American energy infrastructure company. Subject to shareholder and regulatory approval, the name change will be effective immediately following the Annual and Special Meeting of Shareholders on May 3, 2019.

OUR STRATEGY

Our energy infrastructure business is made up of pipeline, storage 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 low cost supply basins with stable and growing markets, generating predictable and sustainable cash flow and earnings
- In Energy, long-term power sale agreements 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 $57 billion capital program, comprised of $36.6 billion in secured projects and $20.7 billion in largely commercially-supported projects under development. These investments will contribute incremental earnings and cash flows as they 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 permit, fund, build and integrate new pipeline and other energy facilities
- We are able to balance safety, profitability and social and environmental responsibility in our investing activities.

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

- We assess opportunities to develop and acquire energy infrastructure that complements our existing portfolio and diversifies access to attractive supply and market regions
- We focus on pipeline 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
- We monitor trends in energy supply and demand, and maintain resilience through diversification, high quality cash flows and contractually underpinned assets.

4 Maximize our competitive strengths

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

Our Competitive Advantage

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

- strong leadership: operating capabilities and strategy development; expertise in regulatory, legal, commercial and financing support
- a high quality portfolio: scale, presence and 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 with a focus on operational excellence and a commitment to health, safety, sustainability and the environment which are paramount parts of our core values
- financial positioning: consistently strong financial performance; long-term financial stability and profitability; disciplined approach to capital investment; ability to access sizable amounts of competitively priced capital to support our growth; simplicity and understandability of our business and corporate structure; ability to balance an increasing common share dividend while preserving financial flexibility to fund our capital program in all market conditions
- long-term relationships: long-term, transparent relationships with key customers and stakeholders; clear communication of our prospects to equity and fixed income investors – both the upside and the risks – to build trust and support.

Our Risk Preferences

The following is a discussion of our risk philosophy:

Live within our means
• Rely on internally-generated cash flows, existing debt capacity and portfolio management to finance new initiatives. Consider issuing new discrete common equity only for transformational opportunities, while the Corporate ATM program and DRP will be used as deemed appropriate.
Project risks known and acceptable
• Select investments with known, acceptable and manageable project execution risk, including stakeholder considerations.
Business underpinned by strong fundamentals
• Invest in assets that are investment-grade on a stand-alone basis, with stable cash flows, supported by strong underlying macroeconomic fundamentals, conducive regulations and/or long-term contracts with creditworthy counterparties.
Value 'A' grade credit ratings
• 'A' grade ratings are an important competitive advantage and TransCanada will seek to retain existing ratings while balancing the interests of equity and fixed income investors.
Prudent management of counterparty exposure
• Limit counterparty concentration and sovereign risk; seek diversification and solid commercial arrangements underpinned by strong fundamentals.

2018 FERC ACTIONS

Background

In December 2016, FERC issued a Notice of Inquiry (NOI) seeking comment on how to address the issue of whether its existing policies resulted in a 'double recovery' of income taxes in a pass-through entity such as an MLP. This NOI was in response to a decision by the U.S. Court of Appeals for the District of Columbia Circuit in July 2016 in United Airlines, Inc., et al. v. FERC (the United case), directing FERC to address the issue.

On December 22, 2017, H.R.1, the Tax Cuts and Jobs Act (U.S. Tax Reform), was signed resulting in significant changes to U.S. tax law including a decrease in the U.S. federal corporate income tax rate from 35 per cent to 21 per cent effective January 1, 2018. As a result, accumulated deferred income tax (ADIT) assets and liabilities related to our U.S. businesses, including amounts related to our proportionate share of assets held in TC PipeLines, LP, were remeasured as at December 31, 2017 to reflect the new lower U.S. federal corporate income tax rate. With respect to our U.S. rate-regulated natural gas pipelines and storage entities, the impact of this remeasurement was recorded as a net regulatory liability.

On March 15, 2018, FERC issued (1) a Revised Policy Statement to address the treatment of income taxes for rate-making purposes for MLPs; (2) a Notice of Proposed Rulemaking (NOPR) proposing natural gas pipeline and storage entities file a one-time report to quantify the impact of the federal income tax rate reduction and the impact of the Revised Policy Statement on each entity's ROE assuming a single-issue adjustment to an entity's rates; and (3) a NOI seeking comment on how FERC should address changes related to ADIT and bonus depreciation. On July 18, 2018, FERC issued (1) an Order on Rehearing of the Revised Policy Statement dismissing rehearing requests; and (2) a Final Rule adopting and revising procedures from, and clarifying aspects of, the NOPR (Final Rule), (collectively, the 2018 FERC Actions). The impacts of the Final Rule, which became effective September 13, 2018, relate to both FERC-regulated natural gas pipeline and gas storage assets. Discussion within this 2018 FERC Actions section primarily describes the impact to our natural gas pipelines, but also applies to our FERC-regulated natural gas storage assets.

FERC Revised Policy Statement on Treatment of Income Taxes for MLPs

The Revised Policy Statement changes FERC's long-standing policy allowing income tax amounts to be included in rates subject to cost-of-service rate regulation for pipelines owned by an MLP. The Revised Policy Statement creates a presumption that entities whose earnings are not taxed through a corporation should not be permitted to recover an income tax allowance in their regulated cost-of-service rates.

In the July 18, 2018 Order, FERC noted that an MLP is not automatically precluded in a future proceeding from arguing and providing evidentiary support that it is entitled to an income tax allowance in its cost-of-service rates. Additionally, FERC provided guidance with regards to ADIT for MLP pipelines and other pass-through entities. FERC found that, to the extent an entity's income tax allowance should be eliminated from rates, it must also eliminate its existing ADIT balance from its rate base. As a result, the Revised Policy Statement also precludes the recognition and subsequent amortization of any related regulatory assets or liabilities that might have otherwise impacted rates charged to customers as a refund or collection of excess or deficient deferred income tax assets or liabilities.

Final Rule on Tax Law Changes for Interstate Natural Gas Pipelines and Storage Entities

The Final Rule established a schedule by which interstate pipelines must either (i) file a new uncontested rate settlement or (ii) file a one-time report, called FERC Form 501-G (Form 501-G), that quantifies the isolated rate impact of U.S. Tax Reform on FERC-regulated pipelines and the impact of the Revised Policy Statement on pipelines held by MLPs. A pipeline filing a Form 501-G had to do so by established dates in fourth quarter 2018 and had four options:

1. Make a limited Natural Gas Act (NGA) Section 4 filing to reduce rates by the reduction in its cost-of-service shown in its Form 501-G. For any pipeline electing this option, FERC guarantees a three-year moratorium on NGA Section 5 rate investigations if the pipeline's Form 501-G shows the pipeline's estimated ROE as being 12 per cent or less. Under the Final Rule, and notwithstanding the Revised Policy Statement discussed above, a pipeline organized as an MLP is not required to eliminate its income tax allowance, but instead can reduce its rates to reflect the reduction in the federal corporate income tax rate. Alternatively, the MLP pipeline can eliminate its tax allowance along with its ADIT used for rate-making purposes. In situations where the ADIT balance is a liability, this elimination would have the effect of increasing the pipeline's rate base for rate-making purposes;
2. Commit to file either a pre-packaged uncontested rate settlement or a general Section 4 rate case if it believes that using the limited Section 4 option will not result in just and reasonable rates. For pipelines that committed to file either by December 31, 2018, FERC would not initiate a Section 5 investigation of its rates prior to that date;
3. File a statement explaining its rationale for why it does not believe the pipeline's rates must change; or
4. Take no other action. FERC will consider whether to initiate a Section 5 investigation of any pipeline that has not submitted a limited Section 4 rate filing or committed to file a general Section 4 rate case.

Impact of 2018 FERC Actions on TransCanada

In accordance with the Form 501-G filings for our directly-held U.S. natural gas pipelines, including ANR, Columbia Gas and Columbia Gulf, earnings and cash flows will not be materially impacted by the Revised Policy Statement as a significant proportion of their overall revenues are earned under non-recourse rates. Columbia Gas is required, under existing settlements, to adjust certain of its recourse rates for the decrease in the U.S. federal corporate income tax rate enacted December 22, 2017, with the changes implemented January 1, 2018. As ANR, Columbia Gas, Columbia Gulf and other wholly-owned regulated assets undergo future rate proceedings, future rates may be impacted prospectively as a result of U.S. Tax Reform, but the impact is expected to be largely mitigated by lower corporate income tax rates. The Revised Policy Statement also prohibits an income tax allowance for liquids pipelines held in MLP structures. We do not expect an impact on our U.S. liquids pipelines as they are not held in MLP form.

The following is an update on our filings in response to the Final Rule for our significant assets held outside of TC PipeLines, LP:

	Form 501-G Filing Option	Impact on Maximum Rates	Moratoriums and Mandatory Filing Requirements
Columbia Gas	Option 3	No rate change proposed	Moratorium in effect through January 31, 2022. Comeback provision with new rates effective by February 1, 2022
Columbia Gulf	Option 3	No rate change proposed	Moratorium in effect through June 30, 2019. Comeback provision with new rates effective by August 1, 2020
ANR	Option 3	No rate change proposed	Moratorium in effect through July 31, 2019. Comeback provision with new rates effective by August 1, 2022
ANR Storage	Option 3	No rate change proposed	No moratorium. Comeback provision with new rates effective by July 1, 2021
Millennium	Option 1 - filing accepted by FERC	10.3% reduction	No moratorium or comeback provisions
Crossroads	Option 3	No rate change proposed	No moratorium or comeback provisions

Impact of 2018 FERC Actions on TC PipeLines, LP

The following is an update on filings in response to the Final Rule for assets held by TC PipeLines, LP:

	Form 501-G Filing Option	Impact on Maximum Rates	Moratoriums and Mandatory Filing Requirements
Great Lakes	Option 1 - filing accepted by FERC	2.0% rate reduction effective February 1, 2019	No moratorium in effect. Comeback provision with new rates effective by October 1, 2022
GTN	Settlement approved by FERC on November 30, 2018 eliminating the requirement to file Form 501-G	A refund of US$10 million to its firm customers in 2018; a 10.0% reduction effective January 1, 2019; additional rate reduction of 6.6% effective January 1, 2020 through December 31, 2021	Moratorium on rate changes until December 31, 2021. Comeback provision with new rates effective by January 1, 2022
Northern Border	Option 1 - filing accepted by FERC	2.0% rate reduction effective February 1, 2019; additional 2.0% rate reduction effective January 1, 2020	No moratorium in effect. Comeback provision with new rates effective by July 1, 2024
Tuscarora	Option 1 - subsequently reached a settlement with customers and a notice of settlement-in-principle was filed with FERC on January 29, 2019	Expected to be finalized with the settlement	Expected to be finalized with the settlement
Bison	Option 3	No rate change proposed	No moratorium or comeback provisions
Iroquois	Option 3 - subsequently reached a settlement with customers and a notice of settlement-in-principle was filed with FERC on January 9, 2019	Expected to reduce rates by the impact of the lower U.S. federal tax rate as shown on Form 501-G	Likely to be reaffirmed with the settlement
Portland	Option 3	No rate change proposed	No moratorium or comeback provisions
North Baja	Option 1 - filing accepted by FERC	10.8% reduction effective December 1, 2018	No moratorium or comeback provisions

As a result of the 2018 FERC Actions initially proposed in March 2018, and in order to retain cash in anticipation of a possible reduction of revenues, TC PipeLines, LP reduced its quarterly distribution to common unitholders by 35 per cent to US$0.65 per unit beginning with its first quarter 2018 distribution.

Following the settlements and limited Section 4 filings for certain natural gas pipelines as noted above, TC PipeLines, LP's earnings, cash flows and financial position are less adversely impacted by the 2018 FERC Actions than initially expected. Furthermore, as our ownership in TC PipeLines, LP is approximately 25 per cent, the impact of the 2018 FERC Actions related to TC PipeLines, LP is not material to TransCanada's consolidated earnings or cash flows.

Financing

As a result of the initially proposed 2018 FERC Actions, we determined that further drop downs of assets into TC PipeLines, LP are not considered to be a viable funding lever. In addition, TC PipeLines, LP ceased to utilize its ATM program. It is yet to be determined whether these might be restored as competitive financing options. Regardless, we believe we have the financial capacity to fund our existing capital program through predictable and growing cash flow generated from operations, access to capital markets including through our DRP, portfolio management, cash on hand and substantial committed credit facilities.

Impairment Considerations

We review plant, property and equipment and equity investments for impairment whenever events or changes in circumstances indicate the carrying value of the asset may not be recoverable. Goodwill is tested for impairment on an annual basis, or more frequently if events or changes in circumstances indicate that it might be impaired. The filings noted above in response to the 2018 FERC Actions have been factored into the assumptions used in our annual goodwill impairment tests as well as our assessment of the recoverability of our long-lived asset balances. Refer to the Critical accounting estimates section for details on asset and goodwill impairments recorded in 2018.

IMPACT OF U.S. TAX REFORM

Pursuant to the enactment of U.S. Tax Reform, we adjusted our U.S. net ADIT liability balance at December 31, 2017 to reflect a decrease in the U.S. federal income tax rate from 35 per cent to 21 per cent. Amounts recorded to adjust income taxes remained provisional as our interpretation, assessment and presentation of the impact of U.S. Tax Reform was clarified during the one-year measurement period permitted by the SEC with additional guidance from tax authorities. In 2018, upon finalizing the 2017 annual tax returns for our U.S. businesses and clarifying the impact of U.S. Tax Reform on our deferred income tax liability at December 31, 2017, it was determined that an adjustment was required to the original estimate. Accordingly, a deferred income tax recovery of $52 million was recognized in fourth quarter 2018 to adjust our net regulatory liability and ADIT balances.

In addition to the adjustment noted above, the Final Rule resulting from the 2018 FERC Actions established that, to the extent an entity's income tax allowance should be eliminated from rates, it must also eliminate its existing ADIT balance from its rate base. In accordance with the Form 501-G and uncontested rate settlement filings summarized above, the ADIT balances for all pipelines held wholly or in part by TC PipeLines, LP were eliminated from their respective rate bases. As a result, net regulatory liabilities recorded for these assets pursuant to U.S. Tax Reform were written off, resulting in a further deferred income tax recovery of $115 million in fourth quarter 2018.

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 flows.

Our $57 billion capital program consists of approximately $36.6 billion of secured projects and approximately $20.7 billion of projects under development. Our secured projects include commercially supported, committed projects that are either under construction or are in or preparing to commence the permitting stage, but are not yet fully approved. Our projects under development are commercially supported except where noted, but have greater uncertainty with respect to timing and estimated project costs and are subject to certain approvals.

Three years of maintenance capital expenditures for our businesses are included in the secured projects table. Maintenance capital expenditures on our regulated Canadian and U.S. natural gas pipeline businesses are added to rate base on which we have the opportunity to earn a return and recover these expenditures through current or future tolls, which is similar to our capacity capital projects on these pipelines. Tolling arrangements in our liquids pipelines business provide for the recovery of maintenance capital expenditures.

All projects are subject to cost adjustments due to weather, market conditions, route refinement, permitting conditions, scheduling and timing of regulatory permits, among other factors. Amounts presented in the following tables exclude capitalized interest and AFUDC.

Secured projects

(billions of $)	Expected in-service date	Estimated project cost[1]	Carrying value at December 31, 2018
Canadian Natural Gas Pipelines			
Canadian Mainline	2019-2021	0.3	—
NGTL System	2019	2.8	1.4
	2020	1.7	0.2
	2021	2.8	—
	2022	1.3	—
Coastal GasLink[2,3]	2023	6.2	0.1
Regulated maintenance capital expenditures	2019-2021	1.8	—
U.S. Natural Gas Pipelines			
Columbia Gas			
Mountaineer XPress	2019	US 3.2	US 2.9
Modernization II	2019-2020	US 1.1	US 0.5
Columbia Gulf			
Gulf XPress	2019	US 0.6	US 0.5
Other capacity capital	2019-2022	US 0.9	US 0.1
Regulated maintenance capital expenditures	2019-2021	US 2.0	—
Mexico Natural Gas Pipelines			
Sur de Texas[4]	2019	US 1.5	US 1.4
Villa de Reyes[4]	2019	US 0.8	US 0.6
Tula[4]	2020	US 0.7	US 0.6
Liquids Pipelines			
White Spruce	2019	0.2	0.1
Other capacity capital	2020	0.1	—
Recoverable maintenance capital expenditures	2019-2021	0.1	—
Energy			
Napanee	2019	1.7	1.6
Bruce Power – life extension[5]	2019-2023	2.2	0.6
Other			
Non-recoverable maintenance capital expenditures[6]	2019-2021	0.7	0.2
		32.7	**10.8**
Foreign exchange impact on secured projects[7]		**3.9**	**2.4**
Total secured projects (Cdn$)		**36.6**	**13.2**

1 Amounts reflect our proportionate share of joint venture costs where applicable and 100 per cent of costs related to wholly-owned assets and assets held through TC PipeLines, LP.
2 Represents 100 per cent of required capital prior to potential joint venture partners or project financing.
3 Carrying value is net of fourth quarter 2018 receipts from the LNG Canada participants for the reimbursement of approximately $0.5 billion of pre-FID costs pursuant to project agreements. Refer to the Significant Events section in Canadian Natural Gas Pipelines for additional details.
4 The CFE has recognized force majeure events for these pipelines and approved the payment of fixed capacity charges in accordance with their respective TSAs. Payments will be recognized as revenue when the pipelines are placed in service.
5 Reflects our proportionate share of the Unit 6 Major Component Replacement program costs, expected to be in service in 2023, and amounts to be invested under the Asset Management program through 2023.
6 Includes non-recoverable maintenance capital expenditures from all segments and is primarily comprised of our proportionate share of maintenance capital expenditures for Bruce Power and other Energy assets.
7 Reflects U.S./Canada foreign exchange rate of 1.36 at December 31, 2018.

Projects under development

The costs provided in the table below reflect the most recent estimates for each project as filed with the various regulatory authorities or as otherwise determined by management.

(billions of $)	Estimated project cost[1]	Carrying value at December 31, 2018
Canadian Natural Gas Pipelines		
NGTL System – Merrick	1.9	—
Liquids Pipelines		
Keystone XL[2]	US 8.0	US 0.6
Heartland and TC Terminals[3]	0.9	0.1
Grand Rapids Phase II[3]	0.7	—
Keystone Hardisty Terminal[3]	0.3	0.1
Energy		
Bruce Power – life extension[4]	6.0	—
	17.8	**0.8**
Foreign exchange impact on projects under development[5]	**2.9**	**0.2**
Total projects under development (Cdn$)	**20.7**	**1.0**

1 Amounts reflect our proportionate share of joint venture costs where applicable.
2 Carrying value reflects amount remaining after impairment charge recorded in 2015, along with additional amounts capitalized from January 1, 2018.
3 Regulatory approvals have been obtained and additional commercial support is being pursued.
4 Reflects our proportionate share of Major Component Replacement program costs for Units 3, 4, 5, 7 and 8, and the remaining Asset Management program costs beyond 2023.
5 Reflects U.S./Canada foreign exchange rate of 1.36 at December 31, 2018.

2018 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 comparable to similar 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 24, 75 and 102 for reconciliations to the most directly comparable GAAP measures.

year ended December 31 (millions of $, except per share amounts)	**2018**	**2017**	**2016**
Income			
Revenues	**13,679**	13,449	12,547
Net income attributable to common shares	**3,539**	2,997	124
per common share – basic	**$3.92**	$3.44	$0.16
– diluted	**$3.92**	$3.43	$0.16
Comparable EBITDA	**8,563**	7,377	6,647
Comparable earnings	**3,480**	2,690	2,108
per common share	**$3.86**	$3.09	$2.78
Cash flows			
Net cash provided by operations	**6,555**	5,230	5,069
Comparable funds generated from operations	**6,522**	5,641	5,171
Comparable distributable cash flow	**5,885**	4,963	4,482
Comparable distributable cash flow per common share	**$6.52**	$5.69	$5.91
Capital spending[1]	**10,929**	9,210	6,067
Acquisitions, net of cash acquired	**—**	—	13,608
Proceeds from sales of assets, net of transaction costs	**614**	4,683	6
Reimbursement of costs related to capital projects in development	**470**	634	—
Balance sheet			
Total assets	**98,920**	86,101	88,051
Long-term debt	**39,971**	34,741	40,150
Junior subordinated notes	**7,508**	7,007	3,931
Preferred shares	**3,980**	3,980	3,980
Non-controlling interests	**1,655**	1,852	1,726
Common shareholders' equity	**25,358**	21,059	20,277
Dividends declared[2]			
per common share	**$2.76**	$2.50	$2.26
Basic common shares (millions)			
– weighted average for the year	**902**	872	759
– issued and outstanding at end of year	**918**	881	864

1 Capital spending Includes capacity capital expenditures, maintenance capital expenditures, capital projects in development and contributions to equity investments.

2 Refer to the Financial condition section on page 74 for details on common and preferred share dividends.

Consolidated results

year ended December 31 (millions of $, except per share amounts)	**2018**	**2017**	**2016**
Segmented earnings/(losses)			
Canadian Natural Gas Pipelines	**1,250**	1,236	1,307
U.S. Natural Gas Pipelines	**1,700**	1,760	1,190
Mexico Natural Gas Pipelines	**510**	426	287
Liquids Pipelines	**1,579**	(251)	806
Energy	**779**	1,552	(1,157)
Corporate	**(54)**	(39)	(120)
Total segmented earnings	**5,764**	4,684	2,313
Interest expense	**(2,265)**	(2,069)	(1,998)
Allowance for funds used during construction	**526**	507	419
Interest income and other	**(76)**	184	103
Income before income taxes	**3,949**	3,306	837
Income tax (expense)/recovery	**(432)**	89	(352)
Net income	**3,517**	3,395	485
Net loss/(income) attributable to non-controlling interests	**185**	(238)	(252)
Net income attributable to controlling interests	**3,702**	3,157	233
Preferred share dividends	**(163)**	(160)	(109)
Net income attributable to common shares	**3,539**	2,997	124
Net income per common share			
–basic	**$3.92**	$3.44	$0.16
–diluted	**$3.92**	$3.43	$0.16

Net income attributable to common shares in 2018 was $3,539 million or $3.92 per share (2017 – $2,997 million or $3.44 per share; 2016 – $124 million or $0.16 per share). Net income per common share increased by $0.48 per share in 2018 compared to 2017 due to the changes in net income described below, as well as the dilutive impact of common shares issued in 2017 and 2018 under our DRP and Corporate ATM program.

The following specific items were recognized in net income attributable to common shares and were excluded from comparable earnings in the relevant periods:

2018

- a $143 million after-tax gain related to the sale of our interests in the Cartier Wind power facilities
- a $115 million deferred income tax recovery from an MLP regulatory liability write-off resulting from the 2018 FERC Actions
- a $52 million recovery of deferred income taxes as a result of finalizing the impact of U.S. Tax Reform
- a $27 million income tax recovery related to the sale of our U.S. Northeast power generation assets
- $25 million of after-tax income recognized on the Bison contract terminations
- a $140 million after-tax impairment charge on Bison
- a $15 million after-tax goodwill impairment charge on Tuscarora
- an after-tax net loss of $4 million related to our U.S. Northeast power marketing contracts. These were excluded from Energy's comparable earnings beginning in 2018 as the wind-down of these contracts is not considered part of our underlying operations.

2017

- an $804 million recovery of deferred income taxes as a result of U.S. Tax Reform
- a $307 million after-tax net gain on the monetization of our U.S. Northeast power generation assets
- a $136 million after-tax gain on the sale of our Ontario solar assets
- a $7 million income tax recovery related to the realized loss on a third party sale of Keystone XL project assets
- a $954 million after-tax impairment charge for the Energy East pipeline and related projects following our decision not to proceed with the project applications
- a $69 million after-tax charge for integration-related costs associated with the acquisition of Columbia
- a $28 million after-tax charge related to the maintenance and liquidation of Keystone XL assets.

2016

- an $873 million after-tax loss on U.S. Northeast power generation assets held for sale
- $28 million of income tax recoveries related to the realized loss on a third party sale of Keystone XL project assets
- $273 million of after-tax costs associated with the acquisition of Columbia
- an after-tax charge of $42 million for Keystone XL costs related to the maintenance and liquidation of project assets
- a $656 million after-tax impairment of Ravenswood goodwill
- a $244 million after-tax impairment charge on the carrying value and settlement of our Alberta PPAs
- an after-tax charge of $16 million for restructuring mainly related to expected future losses under lease commitments
- an additional $3 million after-tax loss on the sale of TC Offshore which closed in early 2016.

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

Net income in all periods included unrealized gains and losses from changes in risk management activities which we exclude, along with the above noted items, to arrive at comparable earnings. A reconciliation of net income attributable to common shares to comparable earnings is shown in the following table.

Reconciliation of net income to comparable earnings

year ended December 31 (millions of $, except per share amounts)	**2018**	2017	2016
Net income attributable to common shares	**3,539**	2,997	124
Specific items (net of tax):			
Gain on sale of Cartier Wind power facilities	**(143)**	—	—
MLP regulatory liability write-off	**(115)**	—	—
U.S. Tax Reform	**(52)**	(804)	—
Net (gain)/loss on sales of U.S. Northeast power generation assets	**(27)**	(307)	873
Bison contract terminations	**(25)**	—	—
Bison asset impairment	**140**	—	—
Tuscarora goodwill impairment	**15**	—	—
U.S. Northeast power marketing contracts	**4**	—	—
Gain on sale of Ontario solar assets	**—**	(136)	—
Keystone XL income tax recoveries	**—**	(7)	(28)
Energy East impairment charge	**—**	954	—
Integration and acquisition related costs – Columbia	**—**	69	273
Keystone XL asset costs	**—**	28	42
Ravenswood goodwill impairment	**—**	—	656
Alberta PPA terminations and settlement	**—**	—	244
Restructuring costs	**—**	—	16
TC Offshore loss on sale	**—**	—	3
Risk management activities[1]	**144**	(104)	(95)
Comparable earnings	**3,480**	2,690	2,108
Net income per common share	**$3.92**	$3.44	$0.16
Specific items (net of tax):			
Gain on sale of Cartier Wind power facilities	**(0.16)**	—	—
MLP regulatory liability write-off	**(0.13)**	—	—
U.S. Tax Reform	**(0.06)**	(0.92)	—
Net (gain)/loss on sales of U.S. Northeast power generation assets	**(0.03)**	(0.34)	1.15
Bison contract terminations	**(0.03)**	—	—
Bison asset impairment	**0.16**	—	—
Tuscarora goodwill impairment	**0.02**	—	—
U.S. Northeast power marketing contracts	**0.01**	—	—
Gain on sale of Ontario solar assets	**—**	(0.16)	—
Keystone XL income tax recoveries	**—**	(0.01)	(0.04)
Energy East impairment charge	**—**	1.09	—
Integration and acquisition related costs – Columbia	**—**	0.08	0.37
Keystone XL asset costs	**—**	0.03	0.06
Ravenswood goodwill impairment	**—**	—	0.86
Alberta PPA terminations and settlement	**—**	—	0.32
Restructuring costs	**—**	—	0.02
TC Offshore loss on sale	**—**	—	—
Risk management activities[1]	**0.16**	(0.12)	(0.12)
Comparable earnings per common share	**$3.86**	$3.09	$2.78

1

year ended December 31 (millions of $)	2018	2017	2016
Liquids marketing	**71**	—	(2)
Canadian Power	**3**	11	4
U.S. Power	**(11)**	39	113
Natural Gas Storage	**(11)**	12	8
Interest rate	**—**	(1)	—
Foreign exchange	**(248)**	88	26
Income taxes attributable to risk management activities	**52**	(45)	(54)
Total unrealized (losses)/gains from risk management activities	**(144)**	104	95

Comparable EBITDA to comparable earnings

Comparable EBITDA represents segmented earnings adjusted for certain aspects of the specific items described above and excludes non-cash charges for depreciation and amortization.

year ended December 31 (millions of $)	2018	2017	2016
Comparable EBITDA	**8,563**	7,377	6,647
Adjustments:			
Depreciation and amortization	**(2,350)**	(2,048)	(1,939)
Interest expense included in comparable earnings	**(2,265)**	(2,068)	(1,883)
Allowance for funds used during construction	**526**	507	419
Interest income and other included in comparable earnings	**177**	159	71
Income tax expense included in comparable earnings	**(693)**	(839)	(841)
Net income attributable to non-controlling interests included in comparable earnings	**(315)**	(238)	(257)
Preferred share dividends	**(163)**	(160)	(109)
Comparable earnings	**3,480**	2,690	2,108

Comparable EBITDA and comparable earnings – 2018 versus 2017

Comparable EBITDA in 2018 increased by $1.2 billion compared to 2017 primarily due to the net result of the following:

- higher contribution from U.S. Natural Gas Pipelines mainly due to increased earnings from Columbia Gas and Columbia Gulf growth projects placed in service, additional contract sales on ANR and Great Lakes, and amortization of net regulatory liabilities recognized as a result of U.S. Tax Reform
- higher contribution from Liquids Pipelines primarily due to higher volumes on the Keystone Pipeline System, increased earnings from liquids marketing activities and earnings from intra-Alberta pipelines placed in service in the second half of 2017
- higher contribution from Canadian Natural Gas Pipelines primarily due to the recovery of increased depreciation as a result of higher rates approved in both the Mainline NEB 2018 Decision and the NGTL 2018-2019 Settlement, as well as higher overall pre-tax rate base earnings, partially offset by lower incentive earnings and flow-through income taxes
- lower earnings from U.S. Power mainly due to the sales of our U.S. Northeast power generation assets in second quarter 2017
- lower earnings from Bruce Power primarily due to lower volumes resulting from higher outage days and lower results from contracting activities.

Comparable earnings in 2018 were $790 million or $0.77 per common share higher than in 2017, and were primarily the net result of:

- changes in comparable EBITDA described above
- higher depreciation primarily in Canadian Natural Gas Pipelines due to increased depreciation rates approved in the Mainline NEB 2018 Decision and the NGTL 2018-2019 Settlement (these amounts are fully recovered as reflected in the increase in comparable EBITDA described above, having no net impact on comparable earnings) as well as higher depreciation related to new projects placed in service in 2017 and 2018
- higher interest expense primarily as a result of additional long-term debt issuances in 2018 and the full year impact of long-term debt and junior subordinated notes issuances in 2017, net of maturities, as well as lower capitalized interest, partially offset by the repayment of the Columbia acquisition bridge facilities in June 2017

- lower income tax expense primarily due to reduced income tax rates resulting from U.S. Tax Reform and lower flow-through income taxes in Canadian rate-regulated pipelines.

Comparable EBITDA and comparable earnings – 2017 versus 2016

Comparable EBITDA in 2017 increased by $730 million compared to 2016 primarily due to the net result of the following:

- higher contribution 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 a FERC-approved rate settlement effective August 1, 2016
- lower contribution from U.S. Power due to the monetization of our U.S. Northeast power generation assets in second quarter 2017 and the wind-down of our U.S. power marketing contracts
- increased earnings from Liquids Pipelines primarily due to higher uncontracted volumes on the Keystone Pipeline System, liquids marketing activities and the commencement of operations on Grand Rapids and Northern Courier
- higher earnings from Bruce Power mainly due to higher volumes resulting from fewer outage days
- higher contribution from Mexico Natural Gas Pipelines due to earnings from Topolobampo beginning in July 2016 and Mazatlán beginning in December 2016.

Comparable earnings in 2017 were $582 million or $0.31 per common share higher than in 2016, and were primarily the net result of:

- changes in comparable EBITDA described above
- higher interest expense as a result of debt assumed in the acquisition of Columbia on July 1, 2016 and long-term debt and junior subordinated notes issuances in 2017, net of maturities
- higher depreciation primarily from the Columbia acquisition in 2016 and projects placed in service
- higher AFUDC on our rate-regulated U.S. natural gas pipelines as well as on the NGTL System, Tula and Villa de Reyes, partially offset by the commercial in-service of Topolobampo and completion of Mazatlán construction
- higher interest income and other due to income related to the recovery of certain Coastal GasLink project costs and the termination of the Prince Rupert Gas Transmission (PRGT) project.

Comparable earnings per share in 2018 and 2017 were impacted by the dilutive impact of common shares issued under our DRP and Corporate ATM program, as well as the full-year impact in 2017 of the 2016 DRP and discrete equity issuances. Refer to the Financial condition section of this MD&A for further information on common share issuances.

Cash flows

Net cash provided by operations of $6.6 billion and comparable funds generated from operations of $6.5 billion were 25 per cent and 16 per cent higher, respectively, in 2018 compared to 2017, primarily due to higher comparable earnings, as described above. In addition, net cash provided by operations was affected by the amount and timing of working capital changes.

Comparable distributable cash flow, reflecting all non-recoverable maintenance capital expenditures, was $5.9 billion in 2018 compared to $5.0 billion in 2017, primarily due to higher comparable funds generated from operations. Comparable distributable cash flow per common share was also impacted by common share issuances in 2017 and 2018. Refer to 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 $)	2018	2017	2016
Canadian Natural Gas Pipelines	**2,478**	2,181	1,525
U.S. Natural Gas Pipelines	**5,771**	3,830	1,522
Mexico Natural Gas Pipelines	**797**	1,954	1,142
Liquids Pipelines	**581**	529	1,137
Energy	**1,257**	675	708
Corporate	**45**	41	33
	10,929	9,210	6,067

1 Capital spending includes capacity capital expenditures, maintenance capital expenditures, capital projects in development and contributions to equity investments.

We invested $10.9 billion in capital projects in 2018 to optimize the value of our existing assets and to develop new, complementary assets in high demand areas. Our total capital spending in 2018 included contributions of $1.0 billion to our equity investments primarily related to Sur de Texas and Bruce Power. This amount was partially offset by $470 million of Coastal GasLink pre-FID costs that were reimbursed by LNG Canada joint venture participants in 2018.

In 2017, we invested $9.2 billion in capital projects to optimize the value of our existing assets and to develop new, complementary assets in high demand areas. Our total capital spending in 2017 included contributions of $1.7 billion to our equity investments primarily related to Sur de Texas, Bruce Power, Grand Rapids and Northern Border. This amount was partially offset by the reimbursement of $0.6 billion in project costs received on the termination of PRGT.

Proceeds from sales of assets

In 2018, we completed the sale of our interests in the Cartier Wind power facilities in Québec for net proceeds of $630 million, before post-closing adjustments.

In 2017, we completed the sales of TC Hydro, Ravenswood, Ironwood, Kibby Wind and Ocean State Power for net proceeds of US$3.1 billion, before post-closing adjustments. We also closed the sale of our Ontario solar assets for $541 million, before post-closing adjustments.

Balance sheet

We continue to maintain a solid financial position while growing our total assets by $12.8 billion in 2018. At December 31, 2018, common shareholders' equity represented 34 per cent (2017 – 33 per cent) of our capital structure, while other subordinated capital, in the form of junior subordinated notes and preferred shares, represented an additional 14 per cent (2017 – 16 per cent). Refer to the Financial condition section for more information about our capital structure.

Dividends

We increased the quarterly dividend on our outstanding common shares by 8.7 per cent to $0.75 per common share for the quarter ending March 31, 2019 which equates to an annual dividend of $3.00 per common share. This was the 19th consecutive year we have increased the dividend on our common shares and reflects our commitment to growing our common dividend at an average annual rate of eight to ten per cent through 2021.

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. Under this program, common shares are issued from treasury at a discount of two per cent to market prices over a specified period rather than purchased on the open markets to satisfy participation in the DRP.

Cash dividends paid

year ended December 31 (millions of $)	**2018**	**2017**	**2016**
Common shares	**1,571**	1,339	1,436
Preferred shares	**158**	155	100

OUTLOOK

Earnings

Our 2019 earnings, on a per common share basis, after excluding specific items, are expected to be higher than 2018 primarily due to the anticipated impact of the following:

- contributions from Columbia Gas and Columbia Gulf projects coming in service
- higher equity income from Bruce Power due to increased contract pricing
- growth in the average investment base for the NGTL System
- completion of the Napanee generating station
- commencement of operations on the Sur de Texas Pipeline.

Partially offset by:

- the dilutive impact of common shares issued in 2018 under our DRP and Corporate ATM Program and expected to be issued in 2019 under our DRP
- higher interest expense as a result of long-term debt issuances, net of maturities, and lower capitalized interest after placing assets in service
- the sale of our interests in the Cartier Wind power facilities
- the expected sale of our Coolidge generating station
- the uncertain impact of recent U.S. Tax Reform legislation and proposed regulations on the cost of financing certain of our U.S. operations.

Consolidated capital spending and equity investments

We expect to spend approximately $8 billion in 2019 on growth projects, maintenance capital expenditures and contributions to equity investments. The majority of the 2019 capital program is attributable to spending on NGTL System projects, Coastal GasLink, Columbia Gas Modernization II, Keystone XL development costs, the Bruce Power life extension program along with normal course maintenance capital expenditures. The above capital spend includes 100 per cent of the expected Coastal GasLink construction costs in 2019 which could be partially funded by the introduction of joint venture partners and project financing.

Refer to the relevant business segment outlook sections for additional details on earnings and capital spending for 2019.

NATURAL GAS PIPELINES BUSINESS

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

- wholly-owned natural gas pipelines – 81,500 km (50,500 miles); and
- partially-owned natural gas pipelines – 11,100 km (7,000 miles).

In addition to our natural gas pipelines, we 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 midstream assets that provide 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 and electric power generation markets and LDCs
- expanding our systems in key locations and building development projects to provide connectivity to LNG export terminals on the west coast of Canada and the Gulf of Mexico
- connections to growing Canadian and U.S. shale gas and other supplies
- additional new pipeline developments within Mexico.

Each of these areas plays a critical role in meeting the transportation requirements for supply of and demand for natural gas in North America.

Highlights

Canadian Natural Gas Pipelines

- placed approximately $0.6 billion of projects in service
- announced four new expansion programs on our NGTL System totaling $4.1 billion with in-service dates between 2019 and 2022
- received an amending order and Certificate of Public Convenience and Necessity (CPCN) from the NEB approving construction of the North Montney Mainline facilities and guidance on related tolling matters
- received NEB approval on the NGTL 2018-2019 Revenue Requirement Settlement (2018-2019 Settlement), as filed
- received the NEB Decision on the Canadian Mainline 2018-2020 Tolls Application (NEB 2018 Decision) approving all elements of the filing except for the amortization period of the LTAA
- secured 670 TJ/d (625 MMcf/d) of new natural gas transportation contracts on the Canadian Mainline for North Bay Junction Long Term Fixed Price (NBJ LTFP) service from the WCSB to markets in Ontario, Québec, New Brunswick, Nova Scotia and the Northeastern U.S.
- proceeding with the estimated $6.2 billion Coastal GasLink pipeline project.

U.S. Natural Gas Pipelines

- placed in service in 2018 and early 2019 approximately US$5.8 billion of projects including Leach XPress, WB XPress, Cameron Access and partial in-service of Mountaineer XPress
- originated an additional US$0.5 billion of growth projects
- filed Form 501-Gs and uncontested rate settlements in response to the 2018 FERC Actions, which impacted rates for our U.S. natural gas pipelines and storage assets to varying degrees. Refer to the 2018 FERC Actions section for more detail.

Mexico Natural Gas Pipelines

- placed Topolobampo in operational service
- continued construction on our Sur de Texas, Villa de Reyes and Tula pipeline projects.

UNDERSTANDING OUR 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 pipelines 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 underground pipelines that 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 33 shows our extensive pipeline network in North America that connects major supply sources and markets. The highlights shown on the map include:

Canadian Natural Gas Pipelines

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. Our large capital program for new pipeline facilities is driven by these two supply areas, along with growing demand for intra-Alberta firm transportation for electric power generation conversion from coal, oil sands development and petro-chemical feedstock as well as to our major export points at the Empress and Alberta/B.C. delivery locations. The NGTL System is also well positioned to connect WCSB supply to LNG export facilities on the Canadian west coast, through future extensions of the system or future connections to other pipelines serving that area.

Canadian Mainline: This pipeline now provides supply to markets in Ontario, Québec, the Maritimes as well as the mid-west and northeast U.S. from the WCSB and, through interconnects, from the Appalachian Basin.

U.S. Natural Gas Pipelines

Columbia Gas: This is our natural gas transportation system for the Appalachian Basin, which contains the Marcellus and Utica shale plays, two of the fastest growing natural gas shale plays in North America. Similar to our footprint in the WCSB, our Columbia Gas assets are very well positioned to connect growing supply to markets 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: This pipeline system 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. In addition, ANR has bi-directional capability on its Southeast Mainline and delivers gas produced from the Appalachian basin to customers throughout the Gulf Coast region.

Columbia Gulf: This pipeline system was originally designed as a long-haul delivery system transporting supply from the Gulf of Mexico to major demand markets in the U.S. Northeast. The pipeline has largely transitioned to a north-to-south flow and is expanding to accommodate new supply in the Appalachian Basin and from its interconnections with Columbia Gas and other pipelines to deliver gas to various Gulf Coast markets.

TC PipeLines, LP: We own a 25.5 per cent interest in TC PipeLines, LP, which has ownership interests in eight wholly-owned or partially-owned natural gas pipelines serving major markets in the U.S.

Mexico Natural Gas Pipelines

Mexico Pipeline Network: We have a growing network of natural gas pipelines coupled with a large portfolio of pipeline projects under construction in Mexico, including Tula and Villa de Reyes as well as Sur de Texas, of which we own 60 per cent.

Regulation of tolls and cost recovery

Our natural gas pipelines are generally regulated by the NEB in Canada, by 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 recovery of the rate base over time through depreciation. Other costs recovered include OM&A, 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 a reasonable opportunity to recover those costs.

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 from LNG export 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 most prolific supply regions of North America, 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 demand within growing domestic markets, particularly in the electric generation and industrial sectors which benefit from a relatively low natural gas price. In addition, North American supply is expected to benefit from access to international markets via LNG exports. We expect North American natural gas demand, including LNG exports, of approximately 110 Bcf/d by 2020, reflecting an increase of approximately 10 Bcf/d from 2018 levels.

This expected increased demand for natural gas, coupled with the annual decline rate of 20 per cent to 25 per cent for natural gas production, implies over 35 Bcf/d of new supply connections being needed in the next two years, providing investment opportunities for pipeline infrastructure companies to build new facilities 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 electric-power generation
- petrochemical and industrial facilities
- Alberta oil sands
- exports to Mexico to fuel power generation facilities.

Natural gas producers have begun and continue to progress additional opportunities to sell natural gas to global markets which involves connecting natural gas supplies to LNG export terminals, both operating and proposed, along the U.S. Gulf Coast and the west coast of both the U.S. and Canada. 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 natural gas pipelines business is not directly tied to commodity prices given we are a transporter of the commodity and the fixed 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 development of gas reserves or, similarly on the demand side, projects requiring natural gas may be accelerated or delayed depending on market or price conditions. For example, lower natural gas prices have allowed this commodity to gain market share versus coal in serving power generation markets and to compete globally through LNG exports.

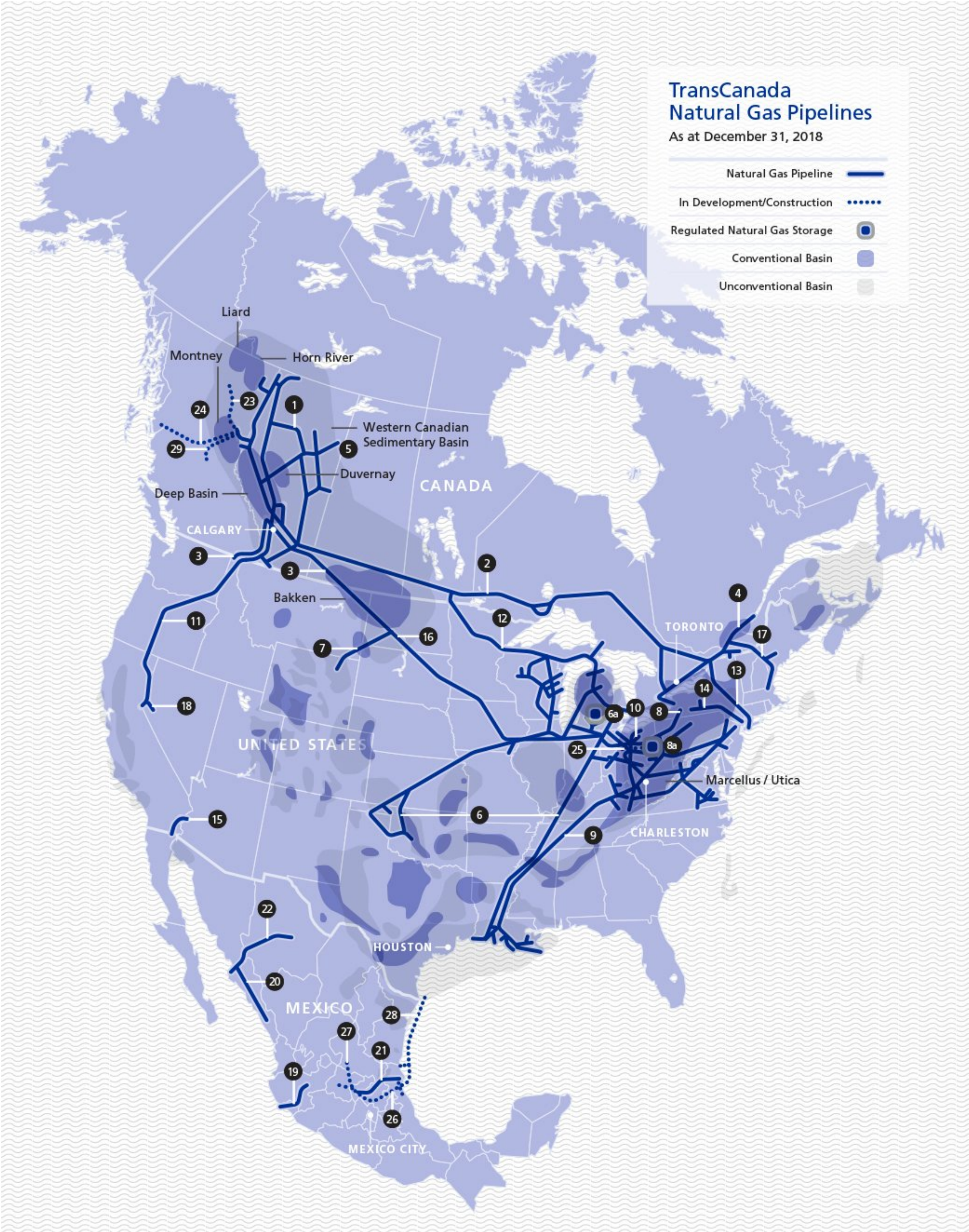
More competition

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. Incumbent pipelines in an area benefit from owning existing right-of-way and infrastructure given the increasing challenges of siting and permitting for new pipeline construction and expansions. We have, and will 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

Our pipelines deliver the natural gas that millions of individuals and businesses across North America rely on for their energy needs. 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 natural gas flow dynamics.

In 2019, some of our key focus areas will be the continued execution of our existing capital program that includes further expansion of the NGTL System, commencement of construction of Coastal GasLink, as well as the completion of several pipeline projects in the U.S. and in Mexico. Our goal is to place all of our projects in service on time and on budget while ensuring the safety of our staff, contractors and all stakeholders impacted by the construction and operation of these facilities.



TransCanada
Natural Gas Pipelines
As at December 31, 2018
Natural Gas Pipeline
In Development/Construction
Regulated Natural Gas Storage
Conventional Basin
Unconventional Basin
Liard
Montney
Horn River
Western Canadian Sedimentary Basin
Duvernay
Deep Basin
CALGARY
CANADA
Bakken
TORONTO
UNITED STATES
Marcellus / Utica
CHARLESTON
HOUSTON
MEXICO
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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	24,568 km (15,266 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	14,082 km (8,750 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)	574 km (357 miles)	Connects with the 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.	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%
*	Great Lakes Canada	60 km (37 miles)	Transports natural gas from the Great Lakes system in the U.S. to a point near Dawn, Ontario through a connection at the U.S. border underneath the St. Clair River.	100%
	U.S. pipelines and gas storage assets			
6	ANR	15,075 km (9,367 miles)	Transports natural gas from various supply basins to markets throughout the U.S. Midwest and Gulf Coast.	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 25.5 per cent of the system through our interest in TC PipeLines, LP.	25.5%
8	Columbia Gas	18,525 km (11,511 miles)	Transports natural gas from supply primarily in the Appalachian Basin to markets and pipeline interconnects throughout the U.S. Northeast.	100%
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%
*	Midstream	295 km (183 miles)	Provides infrastructure between the producer upstream well-head and the downstream (interstate pipeline and distribution) sector and includes a 47.5 per cent interest in Pennant Midstream.	100%
9	Columbia Gulf	5,419 km (3,367 miles)	Transports natural gas to various markets and pipeline interconnects in the southern U.S. and Gulf Coast.	100%
10	Crossroads	325 km (202 miles)	Interstate natural gas pipeline operating in Indiana and Ohio with multiple interconnects to other pipelines.	100%
11	Gas Transmission Northwest (GTN)	2,216 km (1,377 miles)	Transports WCSB and Rockies natural gas to Washington, Oregon and California. Connects with Tuscarora and Foothills. We effectively own 25.5 per cent of the system through our interest in TC PipeLines, LP.	25.5%
12	Great Lakes	3,404 km (2,115 miles)	Connects with the Canadian Mainline near Emerson, Manitoba and to Great Lakes Canada near 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 65.4 per cent of the system through the combination of our 53.6 per cent direct ownership interest and our 25.5 per cent interest in TC PipeLines, LP.	65.4%

		Length	Description	Effective ownership
13	Iroquois	669 km (416 miles)	Connects with the Canadian Mainline and serves markets in New York. We effectively own 13.2 per cent of the system through a 0.7 per cent direct ownership and our 25.5 per cent interest in TC PipeLines, LP.	13.2%
14	Millennium	407 km (253 miles)	Transports natural gas primarily sourced from the Marcellus shale play to markets across southern New York and the lower Hudson Valley, as well as to New York City through its pipeline interconnections.	47.5%
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 25.5 per cent of the system through our interest in TC PipeLines, LP.	25.5%
16	Northern Border	2,272 km (1,412 miles)	Transports WCSB, Bakken and Rockies natural gas from connections with Foothills and Bison to U.S. Midwest markets. We effectively own 12.7 per cent of the system through our 25.5 per cent interest in TC PipeLines, LP.	12.7%
17	Portland	475 km (295 miles)	Connects with TQM near East Hereford, Québec to deliver natural gas to customers in the U.S. Northeast and Canadian Maritimes. We effectively own 15.7 per cent of the system through our 25.5 per cent interest in TC PipeLines, LP.	15.7%
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 25.5 per cent of the system through our interest in TC PipeLines, LP.	25.5%
	Mexico pipelines			
19	Guadalajara	310 km (193 miles)	Transports natural gas from Manzanillo, Colima to Guadalajara, Jalisco.	100%
20	Mazatlán	430 km (267 miles)	Transports natural gas from El Oro to Mazatlán, in the State of Sinaloa. Connects to the Topolobampo Pipeline at El Oro.	100%
21	Tamazunchale	370 km (230 miles)	Transports natural gas from Naranjos, Veracruz to Tamazunchale and on to El Sauz, Querétaro in central Mexico.	100%
22	Topolobampo	560 km (348 miles)	Transports natural gas to El Oro and Topolobampo, Sinaloa, from interconnects with third-party pipelines in El Encino, Chihuahua, and El Oro, Sinaloa.	100%
	Under construction			
	Canadian pipelines			
23	North Montney	206 km** (128 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.	100%
*	NGTL 2019 Facilities	160 km** (99 miles)	An expansion program on the NGTL System including multiple pipeline projects and compression additions with expected in-service dates by November 2019.	100%
24	Coastal GasLink	670 km** (416 miles)	A greenfield project to deliver natural gas from the Montney gas producing region to LNG Canada's liquefaction facility under construction near Kitimat, B.C.	100%
	U.S. pipelines			
25	Mountaineer XPress - 45 per cent in-service in January 2019 (192 km or 119 miles)	275 km** (171 miles)	A Columbia Gas project designed to transport supply from the Marcellus and Utica shale plays to points along the system and to the Leach interconnect with Columbia Gulf.	100%

	Under construction (continued)	Length	Description	Effective ownership
	Mexico pipelines			
26	Tula	324 km** (201 miles)	The pipeline will originate in Tuxpan in the state of Veracruz, where it will receive natural gas from Sur de Texas and interconnect with Villa de Reyes at Tula to supply natural gas to CFE combined-cycle power generating facilities in central Mexico.	100%
27	Villa de Reyes	420 km** (261 miles)	This bi-directional pipeline will transport natural gas from Tula, Hidalgo to Villa de Reyes, San Luis Potosi, connecting to the Tamazunchale and Tula pipelines including a lateral to the Salamanca industrial complex in Guanajuato.	100%
28	Sur de Texas	775 km** (482 miles)	The pipeline will begin offshore in the Gulf of Mexico at the border near Brownsville, Texas with landfalls at Altamira, Tamaulipas and Tuxpan, Veracruz, connecting with the Tamazunchale and Tula pipelines and other third-party facilities.	60%
	Permitting and pre-construction phase			
	Canadian pipelines			
*	NGTL 2020 Facilities	120 km** (75 miles)	An expansion program on the NGTL System including multiple pipeline projects and compression additions with expected in-service dates by November 2020.	100%
*	NGTL 2021 Facilities	375 km** (233 miles)	An expansion program on the NGTL System including multiple pipeline projects and compression additions with expected in-service dates by November 2021.	100%
*	NGTL 2022 Facilities	197 km** (122 miles)	An expansion program on the NGTL System including multiple pipeline projects and compression additions with expected in-service dates by April 2022.	100%
	U.S. pipelines			
*	Buckeye XPress	103 km** (64 miles)	A Columbia Gas project designed to upgrade and replace existing pipeline and compression facilities in Ohio to transport incremental supply from the Marcellus and Utica shale plays to points along the system.	100%
	In development			
	Canadian pipelines			
29	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%

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

Canadian Natural Gas Pipelines

UNDERSTANDING OUR CANADIAN NATURAL GAS PIPELINES SEGMENT

The Canadian natural gas pipeline business is subject to regulation by various federal and provincial governmental agencies. The NEB has jurisdiction over our regulated Canadian natural gas interprovincial pipeline systems, while the provinces have jurisdiction over pipeline systems operating entirely within a single province. For the interprovincial pipelines it regulates, the NEB approves tolls and services that are in the public interest and provide 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. Equity is generally 40 per cent of the deemed capital structure with the remaining 60 per cent from debt. 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 operating under a two-year settlement arrangement for 2018-2019 with an incentive agreement with shippers providing a 50/50 sharing mechanism for any variance between fixed and actual OM&A costs. The Canadian Mainline is entering the fifth year of a six-year fixed toll settlement that includes an incentive arrangement where it has discretion to price certain of its short-term services, such as interruptible transportation, 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

Coastal GasLink Pipeline Project

In October 2018, we announced that we are proceeding with construction of the Coastal GasLink pipeline project following the LNG Canada joint venture participants' announcement that they had reached a positive FID to build the LNG Canada natural gas liquefaction facility in Kitimat, B.C. Coastal GasLink will provide the natural gas supply to the LNG Canada facility and is underpinned by 25-year TSAs (with additional renewal provisions) with each of the five LNG Canada participants. Coastal GasLink will be a 670 km (416 miles) pipeline with an initial capacity of approximately 2.2 PJ/d (2.1 Bcf/d) with potential expansion capacity up to 5.4 PJ/d (5.0 Bcf/d). All necessary regulatory permits have been received to allow us to proceed with construction activities which began in December 2018, with a planned in-service date in 2023. Coastal GasLink has signed project and community agreements with all 20 elected Indigenous bands along the pipeline route, confirming strong support from Indigenous communities across the province of B.C.

In July 2018, an individual asked the NEB to consider whether the Coastal GasLink pipeline should be federally regulated by the NEB. In October 2018, the NEB advised that it would consider the question of jurisdiction, granted Coastal GasLink standing in the matter, and reserved the right to decide on the participation of all other potentially interested parties, including the individual who raised the question. In December 2018, the NEB issued a process letter addressing participation and set the schedule which is expected to conclude in the second half of 2019, with a decision to follow.

In December 2018, the B.C. Supreme Court issued an interim injunction ordering opponents of the Coastal GasLink project to allow pipeline construction workers access to a blockaded area of the Coastal GasLink right of way, south of Houston, B.C. In January 2019, the RCMP moved to enforce the injunction. Following negotiations, the blockaders agreed to abide by the terms of the injunction and allow access to the area.

The Coastal GasLink capital cost estimate is $6.2 billion with the majority of the construction spend occurring in 2020 and 2021. Subject to terms and conditions, differences between the estimated capital cost and final cost of the project will be recovered in future pipeline tolls. As part of the Coastal GasLink funding plan, we are exploring joint venture partners and project financing.

The total capital cost includes pre-FID costs incurred of $470 million. In accordance with provisions in the agreements with the LNG Canada joint venture participants, all five parties elected to reimburse us for their share of pre-FID costs, totaling $470 million, in November 2018. In addition, in January 2019, all five partners elected to make cash payments throughout the construction period with respect to carrying charges on costs incurred.

NGTL System

2022 NGTL System Expansion Program

In October 2018, we announced the NGTL System 2022 Expansion Program to meet capacity requirements for incremental firm receipt and intra-basin delivery services to commence in November 2021 and April 2022. This $1.5 billion expansion of the NGTL System consists of approximately 197 km (122 miles) of new pipeline, three compressor units, meter stations and associated facilities. Applications for approvals to construct and operate the facilities are expected to be filed with the NEB in second quarter 2019 and, pending receipt of regulatory approvals, construction would start as early as third quarter 2020.

2021 NGTL System Expansion Program

In February 2018, we announced the NGTL System 2021 Expansion Program with an estimated capital cost of $2.3 billion and an anticipated in-service date in the first half of 2021. The program consists of approximately 375 km (233 miles) of new pipeline, three compressor units, a control valve and associated facilities. The expansion is required to connect incremental supply and expand basin export capacity by 1.1 PJ/d (1.0 Bcf/d) to the Empress export delivery point at the interconnection of the NGTL System and the Canadian Mainline. An application to construct and operate the NGTL System 2021 Expansion Program was filed with the NEB in June 2018 and will proceed through a public hearing in third quarter 2019.

North Montney Project Approval

In July 2018, the NEB issued an amending order and amended CPCN, following Federal government approval of our application, to the existing North Montney project approvals to remove the condition requiring a positive FID for the Pacific Northwest LNG project prior to commencement of construction.

The North Montney project consists of approximately 206 km (128 miles) of new pipeline, three compressor units and 14 meter stations. The current estimated project cost increased from original estimates by $0.2 billion to $1.6 billion mainly due to construction schedule delays and an increase in market-dependent construction costs.

The NEB directed NGTL to seek approval for a revised tolling methodology for the project following a provisional period defined as one year after the receipt of the Federal government decision, otherwise stand-alone tolling will be imposed as a default. NGTL is working with its shippers to address this requirement and is confident an acceptable tolling mechanism, other than stand-alone tolling, will be established.

Construction on the North Montney project was initiated in August 2018. The first phase of the project is anticipated to be in service by fourth quarter 2019 and the second phase by second quarter 2020.

Other Projects

In February 2019, we announced the Riverbend Extension project. This $85 million pipeline will connect the NGTL System to a proposed major industrial facility in the Grande Prairie, Alberta area. The project consists of approximately 28 km (17 miles) of NPS 24-inch pipeline and a delivery meter station, is underpinned by contracts for 330 TJ/d (308 MMcf/d) of incremental firm delivery service, and has an anticipated in-service date of third quarter 2021.

In April 2018, the Sundre Crossover project was placed in service. This $100 million pipeline project increases NGTL System capacity to our Alberta / B.C. export delivery point by approximately 245 TJ/d (228 MMcf/d), enhancing connectivity to key downstream markets in the Pacific Northwest and California.

In April 2018, the Northwest Mainline Loop-Boundary Lake project was placed in service. The $160 million project added approximately 230 km (143 miles) of new pipeline along with compression facilities and increased the NGTL System capacity by approximately 535 TJ/d (500 MMcf/d).

In March 2018, we announced the successful completion of an open season for additional expansion capacity at the Empress / McNeill Export Delivery Point for service expected to commence in November 2021. The offering of 300 TJ/d (280 MMcf/d) was oversubscribed, with an average awarded contract term of approximately 22 years. The facilities and capital requirements for the expansion are estimated to be approximately $140 million.

NGTL 2018-2019 Revenue Requirement Settlement Approval

In June 2018, the NEB approved the 2018-2019 Settlement as filed and the resulting final 2018 tolls. The 2018-2019 Settlement, which is effective from January 1, 2018 to December 31, 2019, fixes ROE at 10.1 per cent on 40 per cent deemed common equity and increases the composite depreciation rate from 3.18 per cent to 3.45 per cent. OM&A costs are fixed at $225 million for 2018 and $230 million for 2019 with a 50/50 sharing mechanism for any variances between the fixed amounts and actual OM&A costs. All other costs, including pipeline integrity expenses and emissions costs, are treated as flow-through expenses.

Canadian Mainline

North Bay Junction Long Term Fixed Price

In December 2018, we announced 670 TJ/d (625 MMcf/d) of new natural gas transportation contracts from the WCSB on the Canadian Mainline. Upon NEB approval of the NBJ LTFP service, incremental volumes under these long-term, fixed-priced contracts will reach markets in Ontario, Québec, New Brunswick, Nova Scotia and the Northeastern U.S. using existing capacity on the Canadian Mainline as well as new compression facilities. Customers have executed 15-year precedent agreements to proceed with the project with an estimated capital cost of $96 million. We filed an application for approval of the NBJ LTFP with the NEB in January 2019 and expect a decision in third quarter 2019.

Canadian Mainline 2018-2020 Toll Review

In October 2018, we concluded the written hearing process for the Canadian Mainline 2018-2020 toll review with the filing of our reply evidence to the NEB. In December 2018, the NEB 2018 Decision was issued approving all elements of the application, including our cost and volume forecasts, higher depreciation rates and continuation of pricing discretion, with the exception of the amortization period for the LTAA, which is now to be amortized over 2018 to 2020. The impact of the decision was reflected in lower tolls effective February 1, 2019. As directed by the NEB, we filed a compliance filing in January 2019, the outcome of which is expected in first quarter 2019.

Maple Compressor Expansion Project

In April 2018, we received NEB approval to proceed with construction of this approximate $110 million new compressor unit. Work continues as planned to meet a November 1, 2019 in-service date.

FINANCIAL RESULTS

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented earnings (the most directly comparable GAAP measure). See page 8 for more information on non-GAAP measures we use.

year ended December 31 (millions of $)	**2018**	**2017**	**2016**
NGTL System	**1,197**	996	968
Canadian Mainline	**1,073**	1,043	1,105
Other Canadian pipelines[1]	**109**	105	109
Comparable EBITDA	**2,379**	2,144	2,182
Depreciation and amortization	**(1,129)**	(908)	(875)
Comparable EBIT and segmented earnings	**1,250**	1,236	1,307

1 Includes results from Foothills, Ventures LP, Great Lakes Canada, and our share of equity income from our investment in TQM, as well as general and administrative and business development costs related to our Canadian Natural Gas Pipelines.

Canadian Natural Gas Pipelines comparable EBIT and segmented earnings increased by $14 million in 2018 compared to 2017 and decreased by $71 million in 2017 compared to 2016.

Net income and comparable EBITDA for our rate-regulated Canadian natural gas 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.

Net Income and Average Investment Base

year ended December 31 (millions of $)	2018	2017	2016
Net income			
NGTL System	**398**	352	318
Canadian Mainline	**182**	199	208
Average investment base			
NGTL System	**9,669**	8,385	7,451
Canadian Mainline	**3,828**	4,184	4,441

Net income for the NGTL System was $46 million higher in 2018 compared to 2017 mainly due to a higher average investment base as a result of continued system expansions. NGTL System net income in 2017 was $34 million higher than 2016 due to a higher average investment base, partially offset by higher carrying charges on regulatory deferrals. The two-year 2016-2017 Revenue Requirement Settlement included an ROE of 10.1 per cent on 40 per cent deemed common equity and a mechanism for sharing variances above and below a fixed annual OM&A amount.

Canadian Mainline's net income in 2018 decreased by $17 million compared to 2017 mainly due to a lower average investment base and lower incentive earnings, partially offset by lower carrying charges to shippers on the 2018 net revenue surplus. Net income in 2017 was $9 million lower than 2016 mainly due to a lower average investment base and higher carrying charges to shippers on the 2017 net revenue surplus, partially offset by higher incentive earnings in 2017. The lower average investment base in 2018 and 2017 was mainly due to depreciation and the inclusion of the 2017 and 2016 net revenue surplus deferrals in investment base.

The Canadian Mainline operated under the 2015-2030 Tolls Application approved in 2014 (NEB 2014 Decision) throughout 2015 to 2018. 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 from 2015 to 2020.

The NEB 2014 Decision also directed us to file an application to review tolls for the 2018-2020 period. In December 2018, the NEB 2018 Decision was received which included an accelerated amortization of the December 31, 2017 LTAA balance and an increase to the composite depreciation rate from 3.2 per cent to 3.9 per cent. See the Significant events section for additional details on the NEB 2018 Decision.

Comparable EBITDA

Comparable EBITDA for Canadian Natural Gas Pipelines was $235 million higher in 2018 compared to 2017 primarily due to the recovery of increased depreciation as a result of higher rates approved in both the Canadian Mainline NEB 2018 Decision and the NGTL 2018-2019 Settlement, as well as higher overall pre-tax rate base earnings, partially offset by lower incentive earnings and flow-through income taxes. Comparable EBITDA for Canadian Natural Gas Pipelines in 2017 was consistent with 2016.

Depreciation and amortization

Depreciation and amortization was $221 million higher in 2018 compared to 2017 due to the increase in depreciation rates approved in the Mainline NEB 2018 Decision and the NGTL 2018-2019 Settlement, as well as NGTL System facilities that were placed in service in 2018. Depreciation and amortization was $33 million higher in 2017 compared to 2016 primarily due to NGTL System facilities that were placed in service in both 2017 and 2016.

OUTLOOK

Earnings

Net income for Canadian rate-regulated pipelines is affected by changes in investment base, ROE and regulated capital structure, as well as by the terms of toll settlements approved by the NEB.

Canadian Natural Gas Pipelines earnings in 2019 are expected to be higher than 2018 mainly due to continued growth in the NGTL System. We expect the NGTL System investment base to continue to increase as we extend and expand the northwest supply facilities, northeast and intra-Alberta delivery facilities and incremental service at our major border delivery locations in response to requests for firm service on the system.

We expect earnings from the Canadian Mainline to be slightly lower in 2019 due to lower incentive earnings. We were directed by the NEB 2018 Decision to accelerate the amortization of the LTAA over the 2018 to 2020 period, which effectively reduces the tolls and revenues in those years, but has no significant impact on net income.

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 systems 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 $2.5 billion in 2018 on our Canadian natural gas pipelines and expect to spend approximately $3.1 billion in 2019, primarily on the NGTL System expansion projects, Canadian Mainline capacity projects and maintenance capital, all of which are immediately reflected in investment base. In addition, we spent $0.1 billion on advancing the Coastal GasLink project and we expect to spend an additional $1.0 billion in 2019, prior to any contributions from potential third party investors.

U.S. Natural Gas Pipelines

UNDERSTANDING OUR 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. FERC, however, has comprehensive jurisdiction over our U.S. natural gas business. 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.

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 revenues 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 FERC for a new determination of rates, subject to any moratorium in effect. Similarly, FERC or our shippers 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 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 rate proceeding for all parties and can provide an incentive for pipelines to lower costs.

Additionally, we operate a non-regulated Midstream business that provides midstream services including gathering, treating, conditioning, processing, compression and liquids handling in the Appalachian Basin. The Midstream footprint consists of over 295 km (183 miles) of pipeline ranging in size from 16 to 36 inches. Midstream also manages our mineral rights positions in the Marcellus and Utica shale areas.

TC PipeLines, LP

We own a 25.5 per cent interest in, and are the general partner of, TC PipeLines, LP, an MLP which trades on the NYSE under the symbol TCP. TC PipeLines, LP has ownership interests in the GTN, Northern Border, Bison, Great Lakes, North Baja, Tuscarora, Iroquois, and Portland pipeline systems. Our overall effective ownership for each of these assets considering the ownership through the MLP is provided in the asset listing of our major pipelines starting on page 34.

SIGNIFICANT EVENTS

Mountaineer XPress and Gulf XPress

Mountaineer XPress (MXP), a Columbia Gas project, is designed to transport supply from the Marcellus and Utica shale plays to points along the system and to the Leach interconnect with Columbia Gulf. Approximately 45 per cent of this project was placed in service on January 18, 2019, with the remainder to be placed in service in February and March 2019, along with Gulf XPress, a Columbia Gulf project. Total estimated MXP project costs have been revised upwards to US$3.2 billion reflecting the impact of delays of various regulatory approvals from FERC and other agencies, increased contractor construction costs due to unusually high demand for construction resources in the region, unusually high instances of inclement weather throughout construction, and modifications to contractor work plans to mitigate construction delays associated with these impacts.

Louisiana Xpress

In November 2018, we sanctioned the Louisiana XPress project which will connect supply directly to Gulf Coast LNG export markets with the addition of three greenfield mid-point compressor stations along Columbia Gulf. The anticipated in-service date is in 2022 and estimated project costs are US$0.4 billion.

Cameron Access

The Cameron Access project, a Columbia Gulf project designed to transport approximately 0.9 PJ/d (0.8 Bcf/d) of gas supply to the Cameron LNG export terminal in Louisiana, was placed in service in March 2018.

WB XPress

The WB XPress project, a Columbia Gas project designed to transport approximately 1.4 PJ/d (1.3 Bcf/d) of Marcellus gas supply westbound to the Gulf Coast and eastbound to Mid-Atlantic Markets, was placed in service in October 2018 and November 2018 for the Western Build and Eastern Build, respectively.

Nixon Ridge

On June 7, 2018, a natural gas pipeline rupture on Columbia Gas occurred on Nixon Ridge in Marshall County, West Virginia. Emergency response procedures were enacted and the segment of impacted pipeline was isolated shortly thereafter. There were no injuries involved with this incident and no material damage to surrounding structures. The pipeline was placed back in service on July 15, 2018. The preliminary investigation, as noted in the PHMSA Proposed Safety Order, suggests that the rupture was a result of land subsidence. The investigation remains ongoing and we are fully cooperating with PHMSA to determine the root cause of the incident. This event did not have a significant impact on our 2018 financial results.

U.S. Natural Gas Pipelines rate settlements

Since September 30, 2018, a number of rate settlements have been reached with customers in response to the 2018 FERC Actions. As of the end of January 2019, rate settlements for certain of our FERC-regulated natural gas pipelines and gas storage assets have been approved or accepted by FERC. Refer to the 2018 FERC Actions section for further information.

Bison contract terminations and asset impairment

In the second half of 2018, two customers on Bison elected to pay out the remainder of their future contracted revenues and terminate their associated TSAs. The termination of these agreements was agreed to following the receipt of US$97 million in 2018, which was recorded in Revenues, as the terminations released us from providing any future services. This development, coupled with the persistence of unfavourable market conditions which have inhibited system flows on the pipeline, led us to determine that the asset's remaining carrying value was no longer recoverable and a non-cash impairment charge of US$537 million was recorded in our U.S. Natural Gas Pipelines segment. As Bison is a TC PipeLines, LP asset, in which we have a 25.5 per cent interest, this impairment charge impacts our net income by $140 million after tax and non-controlling interests, but is excluded from comparable earnings. We continue to explore alternative transportation-related options for Bison. Refer to the Critical accounting estimates section for further details.

Tuscarora goodwill impairment

In fourth quarter 2018, Tuscarora finalized its regulatory approach in response to the 2018 FERC Actions, resulting in a reduction in its recourse rates. In connection with its annual goodwill impairment analysis, we evaluated Tuscarora's future revenues as well as changes to other assumptions responsive to Tuscarora's commercial environment. In doing so, we incorporated the outcome of a settlement-in-principle reached with its customers in January 2019. As a result of these developments, we determined that the fair value of Tuscarora did not exceed its carrying value, including goodwill, and recorded a goodwill impairment charge of US$59 million within the U.S. Natural Gas Pipelines segment. The remaining goodwill balance related to Tuscarora at December 31, 2018 was US$23 million (2017 – US$82 million). As Tuscarora is a TC PipeLines, LP asset, in which we have a 25.5 per cent interest, this impairment charge impacts our net income by $15 million after tax and non-controlling interests, but is excluded from comparable earnings. Refer to the Critical accounting estimates section for further details.

FINANCIAL RESULTS

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented earnings (the most directly comparable GAAP measure). See page 8 for more information on non-GAAP measures we use.

year ended December 31 (millions of US$, unless otherwise noted)	**2018**	**2017**	**2016**
Columbia Gas[1]	**873**	623	269
ANR	**508**	400	321
TC PipeLines, LP[2,3]	**138**	118	118
Midstream[1]	**122**	93	40
Columbia Gulf[1]	**120**	76	25
Great Lakes[3,4]	**97**	64	60
Other U.S. pipelines[2,3,5]	**68**	80	71
Non-controlling interests[6]	**415**	359	365
Comparable EBITDA	**2,341**	1,813	1,269
Depreciation and amortization	**(511)**	(453)	(322)
Comparable EBIT	**1,830**	1,360	947
Foreign exchange impact	**541**	410	310
Comparable EBIT (Cdn$)	**2,371**	1,770	1,257
Specific items:			
Bison asset impairment[7]	**(722)**	—	—
Tuscarora goodwill impairment[7]	**(79)**	—	—
Bison contract terminations[7]	**130**	—	—
Integration and acquisition related costs – Columbia	**—**	(10)	(63)
TC Offshore loss on sale	**—**	—	(4)
Segmented earnings (Cdn$)	**1,700**	1,760	1,190

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

2 Results reflect our earnings from TC PipeLines, LP's ownership interests in GTN, Great Lakes, Iroquois, Northern Border, Bison, Portland, North Baja and Tuscarora, as well as general and administrative costs related to TC PipeLines, LP. Results from Northern Border and Iroquois reflect our share of equity income from these investments. We acquired additional interests in Iroquois of 4.87 per cent on March 31, 2016 and 0.65 per cent on May 1, 2016. TC PipeLines, LP acquired 49.34 per cent of our 50 per cent interest in Iroquois on June 1, 2017. On January 1, 2016, we sold a 49.9 per cent direct interest in Portland to TC PipeLines, LP and the remaining 11.81 per cent to TC PipeLines, LP on June 1, 2017.

3 TC PipeLines, LP periodically conducted ATM issuances which decreased our ownership in TC PipeLines, LP. Effective March 2018, this program ceased to be utilized. Our ownership interest in TC PipeLines, LP was 25.5 per cent as at December 31, 2018 compared to 25.7 per cent and 26.8 per cent at December 31, 2017 and December 31, 2016, respectively.

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 Results reflect earnings from our direct ownership interests in Crossroads, as well as Iroquois and Portland until June 1, 2017, our effective ownership in Millennium and Hardy Storage, and general and administrative and business development costs related to U.S. natural gas pipelines.

6 Results reflect earnings attributable to portions of TC PipeLines, LP, Portland (until June 1, 2017) and Columbia Pipeline Partners LP (CPPL) (until February 17, 2017) that we do not own.

7 These amounts were recorded in TC PipeLines, LP. The pre-tax impact to us is 25.5 per cent of these amounts net of non-controlling interests.

U.S. Natural Gas Pipelines segmented earnings in 2018 decreased by $60 million compared to 2017 and increased by $570 million in 2017 compared to 2016. Segmented earnings in 2018 include the following specific items which have been excluded from our calculation of comparable EBIT and comparable earnings:

- a $722 million non-cash asset impairment charge related to Bison
- a $79 million non-cash goodwill impairment charge related to Tuscarora
- $130 million of termination payments received on two of Bison's transportation contracts, which was recorded in Revenues.

Each of the specific items noted above are pre-tax and before reduction for the 74.5 per cent non-controlling interests in TC Pipelines, LP.

Segmented earnings in 2017 included pre-tax costs of $10 million mainly related to retention and severance expenses resulting from the Columbia acquisition. Segmented earnings in 2016 also included a pre-tax loss of $4 million 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 their 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 U.S. Natural Gas Pipelines was US$528 million higher in 2018 than 2017 primarily due to the net effect of:

- increased earnings from Columbia Gas and Columbia Gulf growth projects placed in service, additional contract sales on ANR and Great Lakes, and improved commodity prices and throughput volumes in Midstream
- increased earnings due to the amortization of the net regulatory liabilities that were recorded at the end of 2017, partially offset by a reduction in certain rates on Columbia Gas as a result of U.S. Tax Reform
- a US$10 million refund from GTN to its recourse rate customers as per the 2018 GTN Settlement. Refer to the 2018 FERC Actions section for additional details.

Comparable EBITDA for U.S. Natural Gas Pipelines was US$544 million higher in 2017 than 2016 primarily due to the net effect of:

- a full year contribution from the Columbia assets acquired in 2016
- higher ANR transportation revenue resulting from a FERC-approved rate settlement, effective August 1, 2016.

Depreciation and amortization

Depreciation and amortization was US$58 million higher in 2018 compared to 2017 mainly due to new projects placed in service and US$131 million higher in 2017 compared to 2016 primarily due to our acquisition of Columbia 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, as well as broader conditions that impact demand from certain customers or market segments. Earnings are also affected by the level of operational and other costs, which can be impacted by safety, environmental and other regulators' decisions.

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

U.S. Natural Gas Pipelines earnings are expected to be higher in 2019 than in 2018 due to, among other factors, increased revenues following the completion of expansion projects on the Columbia Gas and Columbia Gulf systems in 2018 and 2019. These projects will provide our customers with increased access to new sources of supply while extending their market reach. Further, we continue to pursue expansions across our existing geographical footprint that are expected to allow for the transport of additional natural gas production in the constrained Marcellus and Utica producing regions to areas of demand.

We continue to seek opportunities to expand on these developments, along with continued growth in end-use markets for natural gas, as we examine commercial, regulatory and operational changes to optimize our pipelines' positions in response to positive developments in supply fundamentals.

ANR is positioned to continue to benefit from its combination of long-term contracts originating in the Utica and Marcellus shale plays, a broad reach of storage and transmission services to customers in the Midwest, and its connectivity to Gulf Coast area production and end-use markets including LNG exporters. We expect ANR to provide stable earnings for 2019 consistent with 2018.

As a result of the 2018 FERC Actions, we do not anticipate that the earnings and cash flows from our directly-held U.S. natural gas pipelines, including ANR, Columbia Gas and Columbia Gulf, will be materially impacted as a significant proportion of their overall revenues are earned under non-recourse rates. As our ownership interest in TC PipeLines, LP is 25.5 per cent, the limited impact of the 2018 FERC Actions related to our investment in TC PipeLines, LP is not expected to be significant to our consolidated earnings or cash flows. For more information on the impact of the 2018 FERC Actions and filings in response to the Final Rule, refer to the 2018 FERC Actions section.

Capital spending

We spent a total of US$4.4 billion in 2018 on our U.S. natural gas pipelines and expect to spend approximately US$1.5 billion in 2019 primarily on completion costs for the Columbia Gas and Columbia Gulf expansion projects, ANR and Columbia Gas maintenance capital, which is generally expected to be recovered in future tolls, and our Columbia Gas Modernization program.

Mexico Natural Gas Pipelines

UNDERSTANDING OUR MEXICO NATURAL GAS PIPELINES SEGMENT

For over a decade, Mexico has been undergoing a significant transition from using fuel oil and diesel to using natural gas as its primary energy source for electric generation. As a result, new 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 state-owned electric utility. As pipeline operator, we are at risk for the construction and ongoing operating costs and subject to penalties, excluding force majeure events.

Our Mexico pipelines have approved tariffs, services and related rates for other potential users of the pipeline. All of the contracts that underpin the construction and operation of the pipelines in Mexico are long-term, fixed-rate contracts designed to recover the cost of our service and earn a return on and of invested capital.

SIGNIFICANT EVENTS

Topolobampo

In June 2018, the Topolobampo pipeline was placed in service. The 560 km (348 miles) pipeline provides capacity of 720 TJ/d (670 MMcf/d), receiving natural gas from upstream pipelines near El Encino, in the state of Chihuahua, and delivering to points along the pipeline route including our Mazatlán pipeline at El Oro, in the state of Sinaloa. Under the force majeure terms of the TSA, we began collecting and recognizing revenue from the original TSA service commencement date of July 2016.

Sur de Texas

Offshore construction was completed in May 2018 and the project continues to progress toward an anticipated in-service date in early second quarter 2019. An amending agreement was signed with the CFE that recognizes force majeure events and the commencement of payments of fixed capacity charges began on October 31, 2018.

Tula and Villa de Reyes

The CFE has approved the recognition of force majeure events for both of these pipelines, including the continuation of the payment of fixed capacity charges to us that began in first quarter 2018. Construction for the Villa de Reyes project is ongoing and is anticipated to be in service in the second half of 2019. Commencement of construction of the central segment of the Tula project has been delayed due to a lack of progress by the Secretary of Energy, the governmental department responsible for Indigenous consultations. Project completion has been revised to the end of 2020. We have negotiated separate CFE contracts that would allow certain segments of Tula and Villa de Reyes to be placed in service when gas is available.

FINANCIAL RESULTS

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented earnings (the most directly comparable GAAP measure). See page 8 for more information on non-GAAP measures we use.

year ended December 31 (millions of US$, unless otherwise noted)	**2018**	**2017**	**2016**
Topolobampo	**172**	157	81
Tamazunchale	**127**	112	105
Mazatlán	**78**	65	5
Guadalajara	**71**	68	67
Sur de Texas[1]	**16**	8	—
Other	**4**	(11)	(8)
Comparable EBITDA	**468**	399	250
Depreciation and amortization	**(75)**	(72)	(35)
Comparable EBIT	**393**	327	215
Foreign exchange impact	**117**	99	72
Comparable EBIT and segmented earnings (Cdn$)	**510**	426	287

1 Represents our 60 per cent equity interest in a joint venture with IEnova to build, own and operate the Sur de Texas pipeline.

Mexico Natural Gas Pipelines segmented earnings in 2018 increased by $84 million compared to 2017 and increased by $139 million in 2017 compared to 2016.

Comparable EBITDA for Mexico Natural Gas Pipelines was US$69 million higher in 2018 than 2017 mainly due to the net effect of:

- higher revenues from operations as a result of changes in timing of revenue recognition
- incremental earnings from a CRE tariff increase
- the $12 million impairment of our equity investment in TransGas in 2017, recorded in Other above
- equity earnings from our investment in the Sur de Texas pipeline which records AFUDC during construction, net of interest expense on an inter-affiliate loan from TransCanada. The interest expense on this inter-affiliate loan is fully offset in Interest income and other in the Corporate segment.

Comparable EBITDA for Mexico Natural Gas Pipelines was US$149 million higher in 2017 than 2016 mainly due to the net effect of:

- incremental earnings from Topolobampo beginning July 2016 and Mazatlán beginning December 2016
- equity earnings from our investment in the Sur de Texas pipeline which records AFUDC during construction, net of interest expense on an inter-affiliate loan from TransCanada which is fully offset in Interest income and other in the Corporate segment.

Depreciation and amortization

Depreciation and amortization in 2018 remained consistent with 2017. Depreciation and amortization increased by US$37 million in 2017 compared to 2016 primarily due to the commencement of depreciation on Topolobampo and Mazatlán.

OUTLOOK

Earnings

Mexico Natural Gas Pipelines earnings reflect long-term, stable, principally U.S. dollar-denominated 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.

Due to the long-term nature of the underlying revenue contracts, earnings are generally consistent year-over-year. Earnings for 2019 are expected to be higher than in 2018 primarily due to the incremental contribution from the Sur de Texas pipeline, which is expected to be in service in early second quarter 2019.

Capital spending

We spent a total of US$0.6 billion in 2018 on our Mexico natural gas pipelines and expect to spend approximately US$0.3 billion in 2019, primarily on completion of the Sur de Texas and Villa de Reyes pipelines.

NATURAL GAS PIPELINES – BUSINESS RISKS

The following are risks specific to our natural gas pipelines business. See page 85 for information about general risks that affect the company as a whole, including other operational and financial risks.

Production levels within supply basins

Our pipelines downstream of the NGTL System depend largely on supply from the WCSB. Our Columbia System and its connecting pipes largely depend on Appalachian supply. We continue to monitor any changes in our customers' natural gas production plans and how these may impact our existing assets and new project schedules. There is competition amongst pipelines to connect to major basins. An overall decrease in production and/or increased competition for supply could reduce throughput on our connected pipelines that, in turn, could negatively impact overall revenues generated. The WCSB and Appalachian basins are two of the most prolific basins in North America and have considerable natural gas reserves. However, 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 global 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 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 and is impacted 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 decrease in the level of demand for our pipeline transportation services could adversely 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 natural gas pipeline infrastructure. As well, sustained low natural gas prices could impact our shippers' financial condition and their ability to meet their transportation service cost obligations.

Regulatory risk

Decisions by regulators and other government authorities, including changes in regulation, 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 adversely impact construction costs, in-service dates, anticipated 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 lead to an unfavourable decision due to 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 adverse impact to income if these costs are not fully recoverable.

We continuously monitor regulatory developments and decisions to determine the possible impact on our natural 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 meters regularly to ensure accuracy, and continuously maintain compression equipment to ensure safe and reliable operation.

Liquids Pipelines

Our existing liquids pipelines infrastructure connects Alberta crude oil supplies to U.S. refining markets in Illinois, Oklahoma and the U.S. Gulf Coast, as well as U.S. crude oil supplies from the key market hub at Cushing, Oklahoma to the U.S. Gulf Coast.

Strategy at a glance

- focus on accessing and delivering growing North American liquids supply to key markets by expanding our crude oil pipelines infrastructure to deliver directly from supply regions seamlessly along a contiguous path to market
- maximizing the value from our current operating assets and securing organic growth around these assets
- positioning our business development activities to identify and capture attractive organic growth and acquisition opportunities
- expand transportation service offerings to other areas of the liquids value chain including ancillary services such as short- and long-term storage of liquids, which complement our pipeline transportation infrastructure.

Highlights

- commenced construction on the White Spruce pipeline
- obtained shipper commitments on all available Keystone XL project capacity
- completed construction of an additional one million barrels of crude oil storage at our Cushing Terminal in Oklahoma.

TransCanada
Liquids Pipelines
As at December 31, 2018
Liquids Pipeline
In Development/Construction
Liquids Tank Terminal
Production Basin
Western Canadian
Sedimentary Basin
Oil Sands
Duvernay
CANADA
CALGARY
Williston
TORONTO
Denver-Julesburg
UNITED STATES
Anadarko
CHARLESTON
Permian
HOUSTON
Eagle Ford
MEXICO
MEXICO CITY
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2
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11

We are the operator and developer of the following:

		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 the U.S. Gulf Coast.	100%
2	Marketlink		Transports crude oil from Cushing, Oklahoma to the U.S. Gulf Coast on facilities that form part of the Keystone Pipeline System.	100%
3	Grand Rapids	460 km (287 miles)	Transports crude oil from the producing area northwest of Fort McMurray, Alberta to the Edmonton/Heartland, Alberta market region.	50%
4	Northern Courier	90 km (56 miles)	Transports bitumen and diluent between the Fort Hills mine site and Suncor Energy's terminal located north of Fort McMurray, Alberta.	100%
	Under construction			
5	White Spruce	72 km (45 miles)	To transport crude oil from the Canadian Natural Resources Limited's Horizon facility in northeast Alberta into the Grand Rapids pipeline.	100%
	In development			
6	Keystone XL	1,947 km (1,210 miles)	To transport crude oil from Hardisty, Alberta to Steele City, Nebraska to expand capacity of the Keystone Pipeline System.	100%
7	Keystone Hardisty Terminal		Crude oil terminal located at Hardisty, Alberta.	100%
8	Bakken Marketlink		To transport crude oil from the Williston Basin producing region in North Dakota and Montana to Cushing, Oklahoma and the U.S. Gulf Coast on facilities that form part of the Keystone Pipeline System.	100%
9 10	Heartland and TC Terminals	200 km (125 miles)	Terminal and pipeline facilities to transport crude oil from the Edmonton/Heartland, Alberta region to Hardisty, Alberta.	100%
11	Grand Rapids Phase II	460 km (286 miles)	Expansion of Grand Rapids to transport additional crude oil from the producing area northwest of Fort McMurray, Alberta to the Edmonton/Heartland, Alberta market region.	50%

UNDERSTANDING OUR LIQUIDS PIPELINES BUSINESS

Our liquids pipelines business consists of crude oil and products pipelines. We efficiently transport crude oil from major supply sources to markets where crude oil can be refined into various petroleum products, transport diluent and diesel products within northern Alberta, and offer ancillary services such as short- and long-term storage of liquids at key terminal locations to optimize the value of our pipeline assets.

We provide pipeline transportation capacity to shippers predominantly 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. The terms of service and fixed monthly payments are determined by contracts negotiated with shippers which provide for the recovery of costs we incur to construct, operate and maintain the system. Uncontracted pipeline capacity is offered to the market to secure additional contracts on a monthly spot basis which provides opportunities to generate incremental earnings. Term storage of liquids at terminals 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 Keystone Pipeline System, our largest liquids pipeline asset, transports 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 provides significant capacity between Cushing, Oklahoma and the U.S. Gulf Coast market to primarily transport U.S. crude oil. The Grand Rapids and Northern Courier pipelines, two intra-Alberta liquids pipelines, provide crude oil, diluent and diesel transportation for producers in northern Alberta.

Our liquids marketing business provides customers with a variety of crude oil marketing services including transportation, storage, and crude oil management, primarily through the purchase and sale of physical crude oil. TransCanada Liquids Marketing holds contractual rights on TransCanada pipelines and will seek to contract capacity as required on third-party owned pipelines and tank terminals.

Business environment

Global crude oil demand continues to grow despite a shift towards fuel efficiency and cleaner energy technologies, driven mainly by increasing demand in Asia and global population growth which is expected to increase by more than 11 per cent by 2030. Global crude oil demand growth is projected to increase from 82 million Bbl/d in 2017 to 91 million Bbl/d in 2030, driven primarily by the transportation and industrial sectors. In addition to meeting this anticipated crude oil demand growth of approximately 9.0 million Bbl/d, a significant amount of crude oil production capacity is required to meet global annual conventional decline rates of approximately 27 million Bbl/d of crude oil by 2030.

To meet this combined 36 million Bbl/d demand requirement to 2030, a strong crude oil price environment will be needed to support continuing investment. Global supply of crude oil necessary to meet this demand is largely supported by countries with significant crude oil reserves, mainly in North America and the Middle East. Crude oil prices have strengthened since experiencing a global oversupply in 2014, as crude oil supply management efforts, primarily by OPEC, and global demand growth have combined to stabilize and provide sufficient support for ongoing infrastructure investments.

Supply and demand outlook

Canada

Canada has the world's third largest crude oil reserves with approximately 164 billion barrels of economically and technically recoverable conventional and oil sands reserves in Alberta as of 2017. Total 2018 WCSB crude oil production was approximately 4.5 million Bbl/d and is expected to increase to 5.7 million Bbl/d by 2030, subject to the resolution of current ex-Alberta pipeline capacity constraints. Oil sands production comprises the majority of western Canadian crude oil supply at approximately 3.3 million Bbl/d and is a favourable supply source given its long reserve life and steady production.

Canada's proximity to the U.S., which is the world's largest consumer of crude oil at 18 million Bbl/d, and Canada's significant heavy crude oil production is of strategic importance to the U.S. refining industry. The U.S. Midwest and U.S. Gulf Coast refining markets have a strong reliance on heavy crude oil imports of approximately 5.0 million Bbl/d. Canada is currently the largest exporter of crude oil to the U.S. at approximately 3.4 million Bbl/d. Demand for heavy crude oil in the U.S. has been resilient and is expected to remain as such for the foreseeable future. While Canada, Venezuela and Mexico are the top suppliers of heavy crude oil to the U.S., the latter two countries are experiencing declining production.

The U.S. Midwest refiners have total refining capacity of approximately 3.8 million Bbl/d, which requires approximately 1.8 million Bbl/d of heavy crude oil. The U.S. Gulf Coast is the largest regional refining center in the world with a total capacity of 9.7 million Bbl/d, which is more than half of the total U.S. refining capacity. The U.S. Gulf Coast imported 3.1 million Bbl/d of crude oil in 2018 to meet demand, of which 2.1 million Bbl/d was heavy crude oil. Many refiners in the U.S. Midwest and U.S. Gulf Coast process a wide variety of crudes, including significant amounts of heavy crude oil. This flexibility, access to an abundance of low-cost natural gas, proximity of light and heavy crude oil supply and ready access to markets, has positioned these refineries to be the most profitable in the world.

U.S.

The U.S. has become one of the world's largest crude oil producers, exceeding 11 million Bbl/d in the fourth quarter of 2018, which is attributable to significant light tight oil production growth. The majority of continental U.S. crude oil production is from the Williston, Eagle Ford, Niobrara and Permian basins. The Permian basin is the dominant region accounting for approximately 40 per cent of total U.S. crude oil production and is expected to grow by 3.0 million Bbl/d by 2030.

Due to the current light oil processing capacity being fully utilized in the U.S., the U.S. exports the majority of light tight oil, which is currently over 2.0 million Bbl/d. By 2030, the U.S. is expected to export approximately 3.0 million Bbl/d of crude oil.

Strategic priorities

Our strategic focus is to provide transportation solutions which link growing supply basins in North America to key market hubs and demand centers. Our intra-Alberta and Keystone pipeline systems will form a contiguous path from Alberta through the U.S. Midwest to the U.S. Gulf Coast, which strategically positions TransCanada to provide competitive transportation solutions for growing supplies of Alberta heavy crude oil and U.S. light tight oil.

We remain committed to:

- expanding and leveraging our existing infrastructure
- protecting and optimizing the value of our existing assets
- expanding the transportation services that we offer and extend into adjacent jurisdictions
- extending into emerging growth opportunities.

We continue to work with existing and new customers to provide pipeline transportation and terminal services. The combination of the scale and location of our assets assists us in attracting new volumes and growing our business.

In 2019 one of our key focus areas will be to progress Keystone XL into construction, more than doubling the capacity of the Keystone Pipeline System with enhanced access to over 4.3 million Bbl/d of refinery capacity in Houston and Port Arthur, Texas. Expanding the pipeline capacity to these key markets is expected to enhance both short and long-haul volumes.

Within Alberta, we continue to develop and grow our intra-Alberta liquids pipelines business. The White Spruce pipeline, once completed, will transport crude oil from Canadian Natural Resources Limited's Horizon facility into Grand Rapids and will further expand our regional footprint. With additional commercial support, the Heartland pipeline, Heartland Terminal and Hardisty Terminal projects, all of which have received regulatory approval, will allow shippers to seamlessly connect from the Fort McMurray production region directly to market.

With the fast-paced growth of U.S. light tight oil production and fully satisfied demand for light oil in North America, we will examine opportunities to expand our transportation services and extend our pipeline platform to include terminals with storage and marine export capabilities. We will also focus on leveraging our existing assets and development of projects to reach emerging growth regions such as the Williston, Niobrara and Permian basins.

We believe our liquids pipelines business is well positioned to endure the impact of short-term commodity price fluctuations and supply demand responses. 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 which are not affected by commodity prices or throughput. The cyclical nature of commodity prices may influence the pace at which our shippers expand their operations. This can impact the rate of project growth in our industry, the value of our services as contracts expire, and the timing for the demand of transportation services and/or new liquids infrastructure.

We 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 opportunities.

SIGNIFICANT EVENTS

Keystone Pipeline System

In 2018, we concluded successful open seasons for Marketlink securing incremental contractual support.

We continue to expand our terminal facilities which are integral to our operations, with the completion of an additional one million barrels of storage at Cushing, Oklahoma in 2018.

Keystone XL

We have secured commercial support for all available Keystone XL project capacity and commenced certain pre-construction activities.

In November 2017, the Nebraska PSC approved a route for the Keystone XL project through the state. The Nebraska Supreme Court agreed to hear an appeal of the Nebraska PSC route approval, in which oral arguments were heard in November 2018. We expect the Nebraska Supreme Court, as the final arbiter, could reach a decision in first quarter 2019.

The Keystone XL Presidential Permit (Presidential Permit), issued in 2017, was challenged in two separate lawsuits commenced in Montana. Together with the DOJ, we are actively participating in these lawsuits to defend both the issuance of the permit and the exhaustive environmental assessments that support the U.S. President's actions. Legal arguments addressing the merits of these lawsuits were heard in second quarter 2018.

In third quarter 2018, the U.S. District Court in Montana issued a Partial Order requiring the DOJ and the DOS (collectively, the Federal Defendants) to prepare a supplemental environmental impact statement (SEIS) to the 2014 Final SEIS.

In fourth quarter 2018, the U.S. District Court Judge in Montana invalidated the Presidential Permit and granted a partial injunction on the Keystone XL project. We applied to the U.S. District Court for a stay of its various decisions affecting the issuance of the Presidential Permit and the extensive environmental assessments that have been done in support of its issuance. That stay application was heard on January 14, 2019 and we are awaiting a decision. We intend to further pursue a stay of these decisions with the Ninth Circuit Court of Appeals. Our plans to commence construction of the Keystone XL project in 2019 will be impacted by the timing and outcome of our appeal and stay proceedings.

In September 2018, two U.S. Native American communities filed a lawsuit in Montana challenging the Presidential Permit. We have been granted intervenor status in the lawsuits. Initial briefing dates have been established, but no further action has occurred.

The South Dakota Public Utilities Commission permit for the Keystone XL project was issued in June 2010 and certified in January 2016. An appeal of that certification was denied in June 2017 and that decision was further appealed to the South Dakota Supreme Court. In June 2018, the Supreme Court dismissed the appeal against the certification of the Keystone XL project finding that the lower court lacked jurisdiction to hear the case. This decision is final as there can be no further appeals from this decision by the Supreme Court.

White Spruce

In February 2018, the AER issued a permit for the construction of the $200 million White Spruce pipeline, which will transport crude oil from Canadian Natural Resources Limited's Horizon facility in northeast Alberta to the Grand Rapids pipeline. Construction has commenced with an anticipated in-service date in second quarter 2019.

FINANCIAL RESULTS

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented earnings (the most directly comparable GAAP measure). See page 8 for more information on non-GAAP measures we use.

year ended December 31 (millions of $)	2018	2017	2016
Keystone Pipeline System	**1,443**	1,283	1,155
Intra-Alberta pipelines	**160**	33	—
Liquids marketing and other	**246**	32	(3)
Comparable EBITDA	**1,849**	1,348	1,152
Depreciation and amortization	**(341)**	(309)	(292)
Comparable EBIT	**1,508**	1,039	860
Specific items:			
Energy East impairment charge	**—**	(1,256)	—
Keystone XL asset costs	**—**	(34)	(52)
Risk management activities	**71**	—	(2)
Segmented earnings/(losses)	**1,579**	(251)	806
Comparable EBIT denominated as follows:			
Canadian dollars	**370**	255	223
U.S. dollars	**876**	604	482
Foreign exchange impact	**262**	180	155
Comparable EBIT	**1,508**	1,039	860

Liquids Pipelines segmented earnings increased by $1,830 million in 2018 compared to 2017 and decreased by $1,057 million in 2017 compared to 2016. Segmented losses in 2017 include the following specific items which have been excluded from our calculation of comparable EBIT and comparable earnings:

- a $1,256 million pre-tax impairment charge for the Energy East pipeline and related projects
- $34 million (2016 – $52 million) of pre-tax costs related to Keystone XL for the maintenance and liquidation of project assets which were expensed pending further advancement of the project.

Segmented earnings/(losses) includes unrealized gains and losses from changes in the fair value of derivatives related to our liquids marketing business. These amounts have been excluded from our calculation of comparable EBIT. The remainder of the Liquids Pipelines segmented earnings, with the exception of the specific items described above, are equivalent to comparable EBIT.

Comparable EBITDA for Liquids Pipelines was $501 million higher in 2018 compared to 2017 primarily due to the effect of:

- higher contracted and uncontracted volumes on the Keystone Pipeline System
- higher contribution from liquids marketing activities from improved margins and volumes
- incremental contributions from intra-Alberta pipelines, Grand Rapids and Northern Courier, which began operations in the second half of 2017
- lower business development costs as a result of capitalizing Keystone XL expenditures in 2018.

Comparable EBITDA for Liquids Pipelines was $196 million higher in 2017 compared to 2016 primarily due to the net effect of:

- higher uncontracted volumes on the Keystone Pipeline System
- a higher contribution from liquids marketing activities from improved margins and volumes
- contributions from intra-Alberta pipelines, Grand Rapids and Northern Courier, which began operations in the second half of 2017
- higher business development activities, including advancement of Keystone XL for which costs were expensed
- a weaker U.S. dollar which had a negative impact on the Canadian dollar equivalent comparable earnings from our U.S. operations.

Depreciation and amortization

Depreciation and amortization was $32 million higher in 2018 than in 2017 primarily as a result of new facilities being placed in-service. Depreciation and amortization was $17 million higher in 2017 than in 2016 as a result of new facilities being placed in-service, partially offset by the effect of a weaker U.S. dollar.

OUTLOOK

Earnings

Our 2019 earnings are expected to be similar to 2018, primarily as a result of significant take-or-pay contracts and continued high demand for capacity on our assets. Our liquids marketing business will hold capacity on TransCanada assets in 2019 at levels similar to 2018 and is expected to generate a similar amount of earnings in 2019.

Capital spending

We spent a total of $0.6 billion in 2018 on our liquids pipelines and expect to spend approximately $0.6 billion in 2019, primarily on advancing Keystone XL and constructing the White Spruce pipeline. A portion of the 2019 expenditures for advancing Keystone XL is recoverable from shippers under certain circumstances.

BUSINESS RISKS

The following are risks specific to our liquids pipelines business. See page 85 for information about general risks that affect TransCanada as a whole, including other operational and financial risks.

Construction and operations

Constructing and operating our liquids pipelines to ensure transportation services are provided safely and reliably as well as optimizing and maintaining their availability are essential to the success of our business. Interruptions in our pipeline operations impact our throughput capacity and may result in reduced fixed payment revenue 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 liquids pipelines are passed through to our shippers, a portion of our volume is transported under an all-in fixed toll structure where we are exposed to changing costs which may adversely impact our earnings.

Regulatory and government

Decisions by Canadian and U.S. regulators can have a significant impact on the approval, construction, operation, commercial and financial performance of our liquids pipelines. Public opinion about crude oil development and production, particularly in light of climate change concerns, 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 the current regulatory process may adversely impact the timing or ability 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 our assets.

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. Long-term 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 further develop our competitive position in the North American liquids transportation market to connect growing crude oil and diluent 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 diluent 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 provides customers with a variety of crude oil marketing services including transportation, storage, and crude oil management, primarily through the purchase and sale of physical crude oil. Changing market conditions could adversely impact the value of the underlying 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 the Other information – Enterprise risk management section.

Energy

Our Energy business consists of power generation and unregulated natural gas storage assets.

The power business includes approximately 6,600 MW of generation capacity that we currently either own or are developing. Our power generation assets are located in Alberta, Ontario, Québec, New Brunswick and Arizona, and are powered by natural gas and nuclear fuel sources. The majority of these assets are supported by long-term contracts.

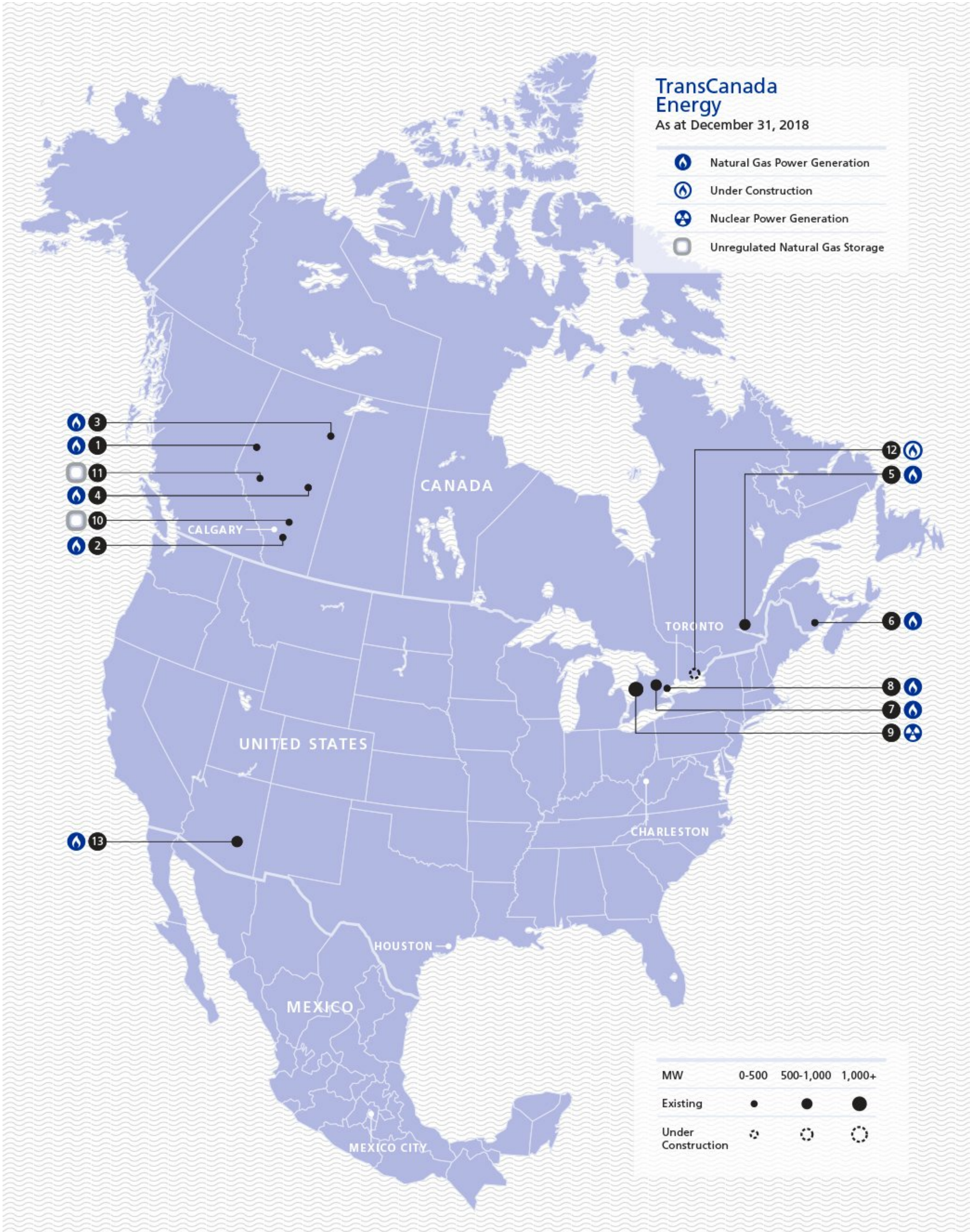
We own and operate approximately 118 Bcf of unregulated natural gas storage capacity in Alberta and hold a contract with a third party for additional storage, in total accounting for approximately one-third of all storage capacity in the province.

Strategy at a glance

- maximize the value of our portfolio of Energy assets through safe and optimized operations
- disciplined execution of capital programs
- pursue growth in contracted power infrastructure with a focus on our core markets of Alberta and Ontario.

Highlights

- advanced the life extension program at Bruce Power with the final Unit 6 Major Component Replacement (MCR) cost and schedule duration estimate verified by the IESO. The Unit 6 MCR outage is scheduled to begin in early 2020
- completed the sale of our interests in the Cartier Wind power facilities
- entered into an agreement to sell our Coolidge power generation station for approximately US$465 million
- completed monetization of the U.S. Northeast power retail contracts as part of the continued wind-down of our U.S. Northeast power marketing business
- construction is substantially complete on the Napanee natural gas-fired power plant with expected in-service in second quarter 2019.


TransCanada Energy
As at December 31, 2018
Natural Gas Power Generation
Under Construction
Nuclear Power Generation
Unregulated Natural Gas Storage
3
1
11
4
10
2
12
5
6
8
7
9
13
CANADA
CALGARY
TORONTO
UNITED STATES
CHARLESTON
HOUSTON
MEXICO
MEXICO CITY
MW
0-500
500-1,000
1,000+
Existing
Under Construction

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

		Generating capacity (MW)	Type of fuel	Description	Ownership
	Power 6,615 MW of power generation capacity (including facilities under construction and held for sale)				
	Western Power 1,023 MW of power generation capacity in Alberta and Arizona (including asset held for sale)				
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	Mackay River	207	natural gas	Cogeneration plant in Fort McMurray, Alberta.	100%
4	Redwater	46	natural gas	Cogeneration plant in Redwater, Alberta.	100%
	Eastern Power 2,498 MW of power generation capacity (including facility under construction)				
5	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%
6	Grandview	90	natural gas	Cogeneration plant in Saint John, New Brunswick. Power sold under a 20-year tolling agreement for 100 per cent of heat and electricity output with Irving Oil which expires in 2024.	100%
7	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%
8	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%
	Bruce Power 3,094 MW of power generation capacity				
9	Bruce Power	3,094[1]	nuclear	Eight operating reactors in Tiverton, Ontario. Bruce Power leases the eight nuclear facilities from OPG.	48.3%
	Unregulated natural gas storage 118 Bcf of non-regulated natural gas storage capacity				
10	Crossfield	68 Bcf		Underground facility connected to the NGTL System near Crossfield, Alberta.	100%
11	Edson	50 Bcf		Underground facility connected to the NGTL System near Edson, Alberta.	100%
	Under construction				
12	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 second quarter 2019.	100%
	Asset held for sale				
13	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%

1 Our share of power generation capacity.

UNDERSTANDING OUR ENERGY BUSINESS

Our Energy business is made up of two groups:

- Power
- Natural Gas Storage (Canadian, non-regulated).

Power

Western Power

We own approximately 1,000 MW of power supply through four natural gas-fired cogeneration facilities in Alberta and the Coolidge natural gas peaking facility in Arizona. Although we have reached an agreement to sell our Coolidge power generating station, results from Coolidge will continue to be included in comparable EBITDA until the sale is complete.

A disciplined operating strategy is integral to maximizing revenue at our cogeneration facilities in Western Canada. Optimized plant operations are also critical to maximizing earnings at Coolidge, where revenue is based on plant availability and performance.

Our marketing group sells uncommitted power from the Alberta cogeneration plants, and buys and sells power and natural gas to maximize earnings from these assets. To reduce exposure associated with uncontracted power, 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 short-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.

The Government of Alberta has implemented a process to procure additional renewable energy in the coming years along with adding a capacity market in 2021 to the current energy-only market design of the Alberta power market. We 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 constructing approximately 2,500 MW of power generation capacity in Eastern Canada, excluding Bruce Power. All the power produced by our Eastern Power assets is sold under long-term contracts.

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

The IESO is in the process of reforming the wholesale energy market in Ontario to improve efficiency and introduce an incremental capacity market with an initial commitment year of 2024. The incremental capacity market is expected to incent existing power generating resources approaching contract expiry to remain in the market as well as procure incremental power generation supplies to meet adequacy requirements. We continue to monitor and participate in the industry engagement processes on the Ontario market reforms to identify impacts to our existing Ontario assets and opportunities for potential growth.

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 facilities from OPG and will return the facilities to OPG for decommissioning at the end of the lease. We hold a 48.3 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. Bruce Power also markets and trades power in Ontario and neighbouring jurisdictions under strict risk controls.

Through a long-term agreement with the IESO, Bruce Power has begun to progress a series of incremental life extension investments to extend the operating life of the facility to 2064. This agreement represents an extension and material amendment to the earlier agreement that led to the refurbishment of Units 1 and 2 at the site. Under the amended agreement, which took economic effect in January 2016, Bruce Power began investing in life extension activities for Units 3 through 8 to support the long-term refurbishment programs. Investment in the Asset Management (AM) program is designed to result in near-term life extensions up to the planned major refurbishment outages and beyond. The MCR program includes work undertaken to replace key, life-limiting reactor components. The AM program includes the one-time refurbishment or replacement of systems, structures or components that are not within the scope of the MCR program.

The Unit 6 MCR program has been verified by the IESO and the outage is scheduled to proceed in early 2020 with expected completion in late 2023. Investments in the remaining five-unit MCR program are expected to continue through 2033. Future MCR investments will be subject to discrete decisions for each unit with specified off-ramps available for Bruce Power and the IESO.

As part of the life extension and refurbishment agreement, Bruce Power receives a uniform contract price for all units which includes certain flow-through items such as fuel and lease expense recovery. The contract also provides for payment if the IESO requests a reduction in Bruce Power's generation to balance the supply of, and demand for, electricity and/or manage other operating conditions of the Ontario power grid. The amount of the reduction is considered deemed generation, for which Bruce Power is paid the contract price.

The contract price is subject to adjustments for the return of and on capital invested at Bruce Power under the AM and MCR capital programs, along with various other pricing adjustments that allow for a better matching of revenues and costs over the long term. As part of the amended agreement, Bruce Power is also required to share operating cost efficiencies with the IESO for better than planned performance. These efficiencies are reviewed every three years and paid out on a monthly basis over the subsequent three-year period. For the 2016 to 2018 period, the total to be paid to the IESO is approximately $200 million. Our 48.3 per cent share would be approximately $100 million.

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 and 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 changes 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. In addition, the business may be affected by pipeline restrictions in Alberta which limit the ability to capture price differentials.

Our natural gas storage business contracts with third parties, typically participants in the Alberta and interconnected gas markets, for a fixed fee to provide natural 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 natural gas prices.

SIGNIFICANT EVENTS

Power

Cartier Wind

In October 2018, we completed the sale of our interests in the Cartier Wind power facilities in Québec to Innergex Renewable Energy Inc. for gross proceeds of approximately $630 million before closing adjustments, resulting in a gain of $170 million ($143 million after tax).

Coolidge Generating Station

On December 14, 2018, we entered into an agreement to sell our Coolidge generating station in Arizona to SWG Coolidge Holdings, LLC, for approximately US$465 million, subject to timing of the close and related adjustments. Salt River Project Agriculture Improvement and Power District, the PPA counterparty, exercised its contractual right of first refusal on a sale to a third party in January 2019. The sale will result in an estimated gain of approximately $65 million ($50 million after tax) to be recognized upon closing of the sale transaction, which is expected to occur mid-2019.

Bruce Power – Life Extension

In September 2018, Bruce Power submitted its final cost and schedule duration estimate (basis of estimate) for the Unit 6 MCR program to the IESO. The IESO has verified the basis of estimate and the Unit 6 MCR program is scheduled to begin in early 2020 with an expected completion in late 2023.

Our project cost estimates in our Capital Program tables reflect our expected investment of approximately $2.2 billion (in nominal dollars) in Bruce Power's Unit 6 MCR program and its ongoing AM program through 2023 as well as approximately $6.0 billion (in 2018 dollars) for the remaining five-unit MCR program and the remainder of the AM program beyond 2023. Future MCR investments will be subject to discrete decisions for each unit with specified off-ramps available for Bruce Power and the IESO.

Bruce Power's current contract price of approximately $68 per MWh is expected to increase to approximately $75 per MWh on April 1, 2019 to reflect capital to be invested under the Unit 6 MCR program and the AM program as well as normal annual inflation adjustments.

Ontario Greenhouse Gas Regulations

The Government of Ontario canceled the provincial cap-and-trade program effective July 3, 2018. The regulation originally came into effect July 1, 2016 setting a limit on annual province-wide greenhouse gas emissions beginning January 1, 2017 and introduced a market to administer the purchase and trading of emission allowances. The cancellation of this regulation did not have a significant impact to our Energy business.

In June 2018, the Government of Canada passed into law the Greenhouse Gas Pollution Pricing Act which exposes natural gas-fired generators in Ontario to certain emission charges subject to the quantity of annual emissions produced. For facilities with annual emissions greater than 50,000 tonnes of CO_2 equivalent, an OBPS will be in effect as of January 1, 2019. Our natural gas power facilities in Ontario are subject to this OBPS program. At this time, we do not anticipate any material impact to the financial performance of our Ontario natural gas power facilities as a result of this program.

Napanee

Construction is substantially complete and commissioning activities are continuing at our 900 MW natural gas-fired power plant at OPG's Lennox site in eastern Ontario in the town of Greater Napanee. We expect our total investment in the Napanee facility will be approximately $1.7 billion with commercial operations expected to begin in second quarter 2019.

Monetization of U.S. Northeast power marketing business

In March 2018, as part of the continued wind-down of our U.S. Northeast power marketing contracts, we closed the sale of our U.S. power retail contracts for proceeds of approximately US$23 million and recognized income of US$10 million (US$7 million after tax).

FINANCIAL RESULTS

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented earnings (the most directly comparable GAAP measure). Refer to page 8 for more information on non-GAAP measures we use.

year ended December 31 (millions of Canadian $, unless otherwise noted)	**2018**	**2017**	**2016**
Western and Eastern Power[1,2]	**428**	444	423
Bruce Power[2]	**311**	434	293
U.S. Power (US$)[3]	**—**	100	394
Foreign exchange impact on U.S. Power	**—**	30	128
Natural Gas Storage and other	**27**	55	58
Business Development[4]	**(14)**	(33)	(15)
Comparable EBITDA	**752**	1,030	1,281
Depreciation and amortization	**(119)**	(151)	(302)
Comparable EBIT	**633**	879	979
Specific items:			
Gain on sale of Cartier Wind power facilities	**170**	—	—
U.S. Northeast power marketing contracts	**(5)**	—	—
Net gain/(loss) on sales of U.S. Northeast power generation assets	**—**	484	(844)
Gain on sale of Ontario solar assets	**—**	127	—
Ravenswood goodwill impairment	**—**	—	(1,085)
Alberta PPA terminations and settlement	**—**	—	(332)
Risk management activities	**(19)**	62	125
Segmented earnings/(losses)	**779**	1,552	(1,157)

1 Includes losses from the Alberta PPAs up to March 2016 when the PPAs were terminated.
2 Includes our share of equity income from our investments in Portlands Energy and Bruce Power.
3 In second quarter 2017, we completed the sales of our U.S. Northeast power generation assets.
4 Includes a $21 million impairment charge in 2017 related to obsolete equipment.

Energy segmented earnings decreased $773 million in 2018 compared to 2017 and increased $2,709 million in 2017 compared to 2016 and included the following specific items:

- a pre-tax gain in 2018 of $170 million related to the sale of our interests in the Cartier Wind power facilities. Refer to the Significant events section for more details
- a pre-tax net loss of $5 million in 2018 related to our U.S. Northeast power marketing contracts, including a gain in first quarter 2018 on the sale of our retail contracts. These results have been excluded from Energy's comparable earnings in 2018 as we do not consider the wind-down of the remaining contracts part of our underlying operations. The contract portfolio is scheduled to run-off through to mid-2020. Refer to the Significant events section for more details on the sale of our retail contracts
- a pre-tax net gain in 2017 of $484 million (2016 – loss of $844 million) related to the monetization of our U.S. Northeast power generation assets which included a $715 million gain on the sale of TC Hydro, a loss of $211 million (2016 – $829 million) on the sale of the thermal and wind package and $20 million (2016 – $15 million) of pre-tax disposition costs
- a pre-tax gain in 2017 of $127 million related to the sale of our Ontario solar assets
- a $1,085 million pre-tax 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 exceeded its carrying value
- 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
- unrealized gains and losses from changes in the fair value of certain derivatives used to reduce our exposure to certain commodity price risks, as noted in the table below:

Risk management activities (millions of $, pre-tax)	**2018**	**2017**	**2016**
Canadian Power	**3**	11	4
U.S. Power	**(11)**	39	113
Natural Gas Storage	**(11)**	12	8
Total unrealized (losses)/gains from risk management activities	**(19)**	62	125

Comparable EBITDA for Energy decreased $278 million in 2018 compared to 2017 primarily due to the net effect of:

- lower earnings from U.S. Power mainly due to the sales of the U.S. Northeast power generation assets in second quarter 2017
- decreased earnings from Bruce Power primarily due to lower volumes resulting from higher outage days and lower results from contracting activities. Additional financial and operating information on Bruce Power is provided below
- decreased Natural Gas Storage results due to pipeline constraints in the Alberta natural gas market which limited our ability to access our storage facilities and resulted in lower realized natural gas storage price spreads
- lower earnings from Western and Eastern Power due to the sales of our Ontario solar assets in December 2017 and our interest in the Cartier Wind power facilities in October 2018, partially offset by higher Western Power realized margins on higher generation volumes.

Comparable EBITDA for Energy decreased $251 million in 2017 compared to 2016 primarily due to the net effect of:

- lower earnings from U.S. Power mainly due to the sales of the U.S. Northeast power generation assets in second quarter 2017 and the wind-down of our U.S. power marketing contracts
- increased earnings from Bruce Power mainly due to higher volumes resulting from fewer outage days
- higher earnings from Western and Eastern Power primarily due to the termination of the Alberta PPAs.

Depreciation and amortization

Depreciation and amortization decreased by $32 million in 2018 compared to 2017 primarily due to the sale of our Ontario Solar assets in December 2017 as well as the cessation of depreciation on our Cartier Wind power facilities upon classification as held for sale at June 30, 2018. Depreciation was $151 million lower in 2017 compared to 2016 as depreciation on our U.S. Northeast power generation assets ceased effective November 2016 when they were classified as assets held for sale and following the termination of the Alberta PPAs in March 2016.

Bruce Power results

Bruce Power results reflect our proportionate share. Comparable EBITDA and comparable EBIT are non-GAAP measures. Refer to 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 otherwise noted)	2018	2017	2016
Equity income included in comparable EBITDA and EBIT comprised of:			
Revenues[1]	**1,526**	1,626	1,491
Operating expenses	**(852)**	(846)	(870)
Depreciation and other	**(363)**	(346)	(328)
Comparable EBITDA and EBIT[2]	**311**	434	293
Bruce Power – other information			
Plant availability[3]	**87%**	90%	83%
Planned outage days	**280**	221	415
Unplanned outage days	**92**	49	76
Sales volumes (GWh)[2]	**23,486**	24,368	22,178
Realized sales price per MWh[4]	**$67**	$67	$68

1 Net of amounts recorded to reflect operating cost efficiencies shared with the IESO.
2 Represents our 48.3 per cent (2017 – 48.4 per cent; 2016 – 48.5 per cent) ownership interest in Bruce Power. Sales volumes include deemed generation.
3 The percentage of time the plant was available to generate power, regardless of whether it was running.
4 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. Excludes unrealized gains and losses on contracting activities and non-electricity revenues.

Plant availability in 2018 was 87 per cent as planned maintenance was completed on Bruce Units 1, 4 and 8 and began on Unit 3 in fourth quarter 2018, which is scheduled to be completed in first quarter 2019.

Plant availability in 2017 was 90 per cent as planned maintenance was completed on Bruce Units 3, 5 and 6. Plant availability in 2016 was 83 per cent as planned maintenance was completed on six of the eight units.

OUTLOOK

Earnings

Our 2019 comparable earnings for the Energy segment are expected to be higher than 2018 primarily due to a higher contribution from Bruce Power and incremental earnings from the completion of the Napanee power plant in Ontario, partially offset by the sale of our interests in the Cartier Wind power facilities in 2018 and the expected sale of our Coolidge generating station in 2019. Results from our natural gas storage business are expected to be lower primarily due to pipeline constraints in the Alberta market limiting access to our facilities.

Bruce Power equity income in 2019 is expected to be higher primarily due to an increased contract price to reflect the capital to be invested under the Unit 6 MCR and AM programs, as well as normal annual inflation adjustments. Planned maintenance is expected to occur on Bruce Units 2, 3 and 7 in the first half of 2019 and Unit 5 in the second half of 2019. The average plant availability percentage in 2019 is expected to be in the high 80 per cent range, comparable to 2018.

Capital spending

We spent a total of $0.7 billion in 2018 on our Energy assets, primarily on continuing construction of Napanee, and expect to spend approximately $0.1 billion in 2019.

We invested $0.5 billion in 2018 for our share of Bruce Power's life extension and maintenance capital projects and expect to invest approximately $0.5 billion in 2019.

BUSINESS RISKS

The following are risks specific to our Energy business. See page 85 for information about general risks that affect the Company as a whole, including other operational and financial risks.

Fluctuating power and natural gas market prices

Our portfolio of assets in Eastern Canada and our Coolidge generating station in Arizona are fully contracted, and are therefore not materially impacted by fluctuating spot power and natural gas prices. As these contracts expire in the long term, it is uncertain if we will be able to re-contract on similar terms and may face future commodity exposure.

Much of the physical power generation and fuel used in our Western Power operations in Alberta is currently exposed to commodity price volatility. These exposures are partially mitigated through long-term contracts and hedging activities including selling and purchasing power and natural gas in forward markets. As contracts expire, new 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. In addition, the business may be affected by pipeline restrictions in Alberta which limit the ability to capture price differentials.

Construction and plant availability

Constructing and operating our plants to ensure services are provided safely and reliably as well as optimizing and maintaining their availability are 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.

Regulatory

We operate in both regulated and deregulated power markets in Canada and a regulated market in Arizona. 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 or market design 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. 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.

Compliance
Market rules, regulations and operating standards apply to our power business based on the jurisdictions in which they operate. Our trading and marketing activities may be subject to fair competition and market conduct requirements, as well as specific rules that apply to physical and financial transactions in deregulated markets. Similarly, our generators may be subject to specific operating and technical standards relating to maintenance activities, generator availability and delivery of energy and energy-related products. While significant efforts are made to ensure we comply with all applicable statutory requirements, situations including unforeseen operational challenges, lack of rule clarity, and the ambiguous and unpredictable application of requirements by regulators and market monitors occasionally arise and create compliance risk. Deemed contravention of these requirements may result in mandatory mitigation activities, monetary penalties, imposition of operational limitations, or even prosecution.

Weather
Significant changes in temperature and weather 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 and production of our natural gas-fired power plants.

Competition
We face various competitive forces that impact our existing assets and prospects for growth. For instance, our existing power plants 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 Alberta and Ontario as well as in the development of greenfield power plants. To remain competitive it is also important for us to be on time and on budget with our major capital projects.

Corporate

The following is a reconciliation of comparable EBITDA and comparable EBIT (our non-GAAP measures) to segmented losses (the most directly comparable GAAP measure). See page 8 for more information on non-GAAP measures we use.

year ended December 31 (millions of $)	**2018**	**2017**	**2016**
Comparable EBITDA and EBIT	**(59)**	(21)	18
Specific items:			
Foreign exchange gain – inter-affiliate loan[1]	**5**	63	—
Integration and acquisition related costs – Columbia	**—**	(81)	(116)
Restructuring costs	**—**	—	(22)
Segmented losses	**(54)**	(39)	(120)

1 Reported in Income from equity investments on the Consolidated statement of income.

Corporate segmented losses increased by $15 million in 2018 compared to 2017 and decreased by $81 million in 2017 compared to 2016.

Segmented losses in 2018 and 2017 included foreign exchange gains of $5 million and $63 million, respectively, on a peso-denominated inter-affiliate loan to the Sur de Texas project for our proportionate share of the project's financing. There is a corresponding foreign exchange loss included in Interest income and other on the inter-affiliate loan receivable which fully offsets this gain.

Segmented losses in 2017 and 2016 included integration and acquisition costs of $81 million and $116 million, respectively, associated with the acquisition of Columbia. Segmented losses in 2016 also included restructuring costs of $22 million. These amounts have been excluded from our calculation of comparable EBITDA and EBIT.

Comparable EBITDA decreased by $38 million in 2018 compared to 2017 and by $39 million in 2017 compared to 2016, primarily due to increased general and administrative costs.

Corporate restructuring and business transformation

In mid-2015, we commenced a business restructuring and transformation initiative to reduce overall costs and maximize the effectiveness and efficiency of our existing operations. As a result, we incurred corporate restructuring costs and recorded a provision to allow for planned severance costs in future years, as well as expected future losses under lease commitments.

Cumulatively to December 31, 2018, we have incurred costs of $86 million for employee severance and $60 million for lease commitments, net of $157 million related to costs that were recoverable through regulatory and tolling structures. We recorded additional provisions in 2018 to reflect the changes in expected future losses under lease commitments. The remaining lease commitments provision at December 31, 2018 is expected to be fully realized by 2027.

Changes in the restructuring liability were as follows:

(millions of $)	Employee Severance	Lease Commitments	Total
Restructuring liability as at December 31, 2016	36	63	99
Restructuring charges[1]	—	6	6
Accretion expense	—	1	1
Cash payments	(27)	(17)	(44)
Restructuring liability as at December 31, 2017	9	53	62
Restructuring charges[1]	—	42	42
Accretion expense	—	1	1
Cash payments	(9)	(15)	(24)
Restructuring Liability as at December 31, 2018	**—**	**81**	**81**

1 At December 31, 2018, we recorded an additional $21 million in Plant operating costs and other in the Consolidated statement of income and $21 million as a regulatory asset on the Consolidated balance sheet related to costs that are expected to be recovered through regulatory and tolling structures in future periods (2017 – $3 million and $3 million, respectively).

OTHER INCOME STATEMENT ITEMS

Interest Expense

year ended December 31 (millions of $)	**2018**	**2017**	**2016**
Interest on long-term debt and junior subordinated notes			
Canadian dollar-denominated	**(549)**	(494)	(452)
U.S. dollar-denominated	**(1,325)**	(1,269)	(1,127)
Foreign exchange impact	**(394)**	(379)	(366)
	(2,268)	(2,142)	(1,945)
Other interest and amortization expense	**(121)**	(99)	(114)
Capitalized interest	**124**	173	176
Interest expense included in comparable earnings	**(2,265)**	(2,068)	(1,883)
Specific items:			
Integration and acquisition related costs – Columbia	**—**	—	(115)
Risk management activities	**—**	(1)	—
Interest expense	**(2,265)**	(2,069)	(1,998)

Interest expense in 2018 increased by $196 million compared to 2017 primarily due to the net effect of:
- long-term debt and junior subordinated note issuances in 2018 and 2017, net of maturities. See the Financial condition section for further details on long-term debt
- lower capitalized interest primarily due to the completion of Grand Rapids and Northern Courier in the second half of 2017, partially offset by ongoing construction at Napanee and the recommencement of capitalization of Keystone XL costs in 2018
- higher levels of short-term borrowing
- final repayment of the Columbia acquisition bridge facilities in June 2017 resulting in lower interest and debt amortization expense.

Interest expense in 2017 increased by $71 million compared to 2016 mainly due to the net effect of:
- long-term debt and junior subordinated notes issuances in 2017 and 2016, net of maturities. Refer to the Financial condition section for further details on long-term debt
- debt assumed in the acquisition of Columbia on July 1, 2016
- lower amortization expense on debt issuance costs related to the Columbia acquisition bridge facilities, which were fully repaid in June 2017
- higher foreign exchange on interest expense related to higher levels of U.S. dollar-denominated debt
- the specific item of $115 million in 2016 included the dividend equivalent payments of $109 million on the subscription receipts issued to partially fund the Columbia acquisition and $6 million of other acquisition related costs.

Allowance for funds used during construction

year ended December 31 (millions of $)	2018	2017	2016
Allowance for funds used during construction			
Canadian dollar-denominated	**103**	174	181
U.S. dollar-denominated	**326**	259	181
Foreign exchange impact	**97**	74	57
Allowance for funds used during construction	**526**	507	419

AFUDC increased by $19 million in 2018 compared to 2017 mainly due to continued investment in Mexico projects and additional investment in and higher rates on Columbia Gas growth projects, partially offset by our decision in the second half of 2017 not to proceed with the Energy East Pipeline and lower capital expenditures in Canadian Mainline.

AFUDC increased by $88 million in 2017 compared to 2016 mainly due to continued investment in and higher rates on projects acquired as part of the 2016 Columbia acquisition, as well as continued investment in Mexico projects and the NGTL System, partially offset by the commercial in-service of Topolobampo, the completion of Mazatlán construction and our decision not to proceed with the Energy East Pipeline.

Interest income and other

year ended December 31 (millions of $)	2018	2017	2016
Interest income and other included in comparable earnings	**177**	159	71
Specific items:			
Foreign exchange loss – inter-affiliate loan	**(5)**	(63)	—
Integration and acquisition related costs – Columbia	**—**	—	6
Risk management activities	**(248)**	88	26
Interest income and other	**(76)**	184	103

In 2018, Interest income and other decreased by $260 million compared to 2017 due to the net effect of:

- unrealized losses on risk management activities in 2018 compared to unrealized gains in 2017, reflecting the strengthening of the U.S. dollar at the end of 2018. These amounts have been excluded from comparable earnings
- higher interest income combined with a lower foreign exchange loss related to an inter-affiliate loan receivable from the Sur de Texas joint venture. The corresponding interest expense and foreign exchange gain are reflected in Income from equity investments in the Mexico Natural Gas Pipelines and Corporate segments, respectively, resulting in no impact on net income. The offsetting currency-related gain and loss amounts are excluded from comparable earnings
- realized losses in 2018 compared to realized gains in 2017 on derivatives used to manage our net exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income
- lower recovery in 2018 related to carrying charges on Coastal GasLink project costs incurred
- $10 million recognized on the termination of the PRGT project in 2017.

In 2017, Interest income and other increased by $81 million compared to 2016 due to the net effect of:

- higher unrealized gains on risk management activities in 2017. These amounts have been excluded from comparable earnings
- recovery of $32 million related to carrying charges on Coastal GasLink project costs incurred, and amounts recognized on the termination of the PRGT project in 2017
- foreign exchange impact on the translation of foreign currency denominated working capital balances
- lower realized gains in 2017 compared to 2016 on derivatives used to manage our net exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income
- higher interest income along with a $63 million foreign exchange loss in 2017 related to an inter-affiliate loan receivable from the Sur de Texas joint venture. The corresponding interest expense and foreign exchange gain are reflected in Income from equity investments in the Mexico Natural Gas Pipelines and Corporate segments, respectively, resulting in no impact on net income. The offsetting currency-related gain and loss amounts are excluded from comparable earnings.

Income tax (expense)/recovery

year ended December 31 (millions of $)	2018	2017	2016
Income tax expense included in comparable earnings	**(693)**	(839)	(841)
Specific items:			
MLP regulatory liability write-off	**115**	—	—
U.S. Tax Reform	**52**	804	—
Bison asset impairment	**44**	—	—
Sales of U.S. Northeast power generation assets	**27**	(177)	(29)
Tuscarora goodwill impairment	**5**	—	—
U.S. Northeast power marketing contracts	**1**	—	—
Gain on sale of Cartier Wind power facilities	**(27)**	—	—
Bison contract terminations	**(8)**	—	—
Energy East impairment charge	**—**	302	—
Integration and acquisition related costs – Columbia	**—**	22	10
Gain on sale of Ontario solar assets	**—**	9	—
Keystone XL income tax recoveries	**—**	7	28
Keystone XL asset costs	**—**	6	10
Ravenswood goodwill impairment	**—**	—	429
Alberta PPA terminations and settlement	**—**	—	88
Restructuring costs	**—**	—	6
TC Offshore loss on sale	**—**	—	1
Risk management activities	**52**	(45)	(54)
Income tax (expense)/recovery	**(432)**	89	(352)

Income tax expense included in comparable earnings in 2018 decreased by $146 million in 2018 compared to 2017 primarily due to lower income tax rates as a result of U.S. Tax Reform and lower flow-through income taxes in Canadian rate-regulated pipelines, partially offset by income taxes recorded on higher pre-tax earnings.

Income tax expense included in comparable earnings in 2017 remained consistent with 2016 and reflects the net impact of higher comparable earnings, changes in the proportion of income earned between Canadian and foreign jurisdictions and changes in flow-through taxes in regulatory operations.

Net loss/(income) attributable to non-controlling interests

year ended December 31 (millions of $)	2018	2017	2016
Net income attributable to non-controlling interests included in comparable earnings	**(315)**	(238)	(257)
Specific items:			
Bison impairment	**538**	—	—
Tuscarora goodwill impairment	**59**	—	—
Bison contract terminations	**(97)**	—	—
Integration and acquisition related costs – Columbia	**—**	—	5
Net loss/(income) attributable to non-controlling interests	**185**	(238)	(252)

Net loss/(income) attributable to non-controlling interests decreased by $423 million in 2018 compared to 2017 due to the net effect of:

- a $538 million charge related to the non-controlling interests portion of a $722 million Bison asset impairment charge recorded by TC PipeLines, LP
- a $59 million charge related to the non-controlling interests portion of a $79 million Tuscarora goodwill impairment charge recorded by TC PipeLines, LP
- $97 million in income related to the non-controlling interests portion of Bison contract termination payments of $130 million received from certain customers and recorded by TC PipeLines, LP.

On consolidation, we recorded the non-controlling interests' 74.5 per cent of these transactions. These items have been excluded in the calculation of comparable earnings. Refer to the Critical accounting estimates section for more information on our goodwill and asset impairment testing.

In 2018, net income attributable to non-controlling interests included in comparable earnings increased by $77 million compared to 2017 primarily due to higher earnings in TC PipeLines, LP, partially offset by our acquisition of the remaining outstanding publicly held common units of CPPL in February 2017.

Net income attributable to non-controlling interests and net income attributable to non-controlling interests included in comparable earnings decreased by $14 million and $19 million, respectively, in 2017 compared to 2016 primarily due to our acquisition of the remaining outstanding publicly held common units of CPPL in February 2017.

Preferred share dividends

year ended December 31 (millions of $)	**2018**	**2017**	**2016**
Preferred share dividends	**(163)**	(160)	(109)

Preferred share dividends of $163 million in 2018 were consistent with 2017. Preferred share dividends in 2017 increased by $51 million compared to 2016 due to the issuance of Series 13 and Series 15 preferred shares in April 2016 and November 2016, respectively. Refer to the Financial condition section 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. More information on how our credit ratings can impact our financing costs, liquidity and operations is available in our AIF available on SEDAR (www.sedar.com).

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, portfolio management, cash on hand, substantial committed credit facilities and, if deemed appropriate, our Corporate ATM program and DRP. Annually, in fourth quarter, we renew and extend our credit facilities as required.

In light of the 2018 FERC Actions, further drop downs of assets into TC PipeLines, LP are currently considered to not be a viable funding lever. In addition, the TC PipeLines, LP ATM program ceased to be utilized effective March 2018. It is yet to be determined if and when in the future these might be restored as competitive financing options. Refer to the 2018 FERC Actions section for further information.

Balance sheet analysis

Our total assets at December 31, 2018 were $98.9 billion compared to $86.1 billion at December 31, 2017 primarily reflecting our 2018 capital spending program.

At December 31, 2018, our total liabilities were $67.9 billion compared to $59.2 billion at December 31, 2017 mainly reflecting a net increase in long-term debt, primarily as a result of issuances of senior and medium-term notes, net of maturities, and higher notes payable.

Total assets and total liabilities both increased due to a stronger U.S. dollar at December 31, 2018 compared to December 31, 2017.

Our equity at December 31, 2018 was $31.0 billion compared to $26.9 billion at December 31, 2017. The increase is primarily due to common shares issued under our DRP and Corporate ATM program, as well as annual net income and OCI attributable to controlling interests.

Consolidated capital structure

The following table summarizes the components of our capital structure.

at December 31 (millions of $, unless otherwise noted)	**2018**	**Per cent of total**	**2017**	**Per cent of total**
Notes payable	**2,762**	**3**	1,763	3
Long-term debt, including current portion	**39,971**	**50**	34,741	50
Cash and cash equivalents	**(446)**	**(1)**	(1,089)	(2)
Debt	**42,287**	**52**	35,415	51
Junior subordinated notes	**7,508**	**9**	7,007	10
Preferred shares	**3,980**	**5**	3,980	6
Common shareholders' equity[1]	**27,013**	**34**	22,911	33
	80,788	**100**	69,313	100

1 Includes non-controlling interests.

At February 11, 2019 we had unused capacity of $2.7 billion, $1.0 billion, and US$2.1 billion under our various equity, Canadian debt and U.S. debt shelf prospectuses, respectively, to facilitate future access to capital markets.

Provisions of various trust indentures and credit arrangements with certain of our subsidiaries can restrict those subsidiaries' and, in certain cases, our ability to declare and pay dividends or make distributions under certain circumstances. In the opinion of management, these provisions do not currently restrict 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. We were in compliance with all of our financial covenants at December 31, 2018.

Cash flow

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

year ended December 31 (millions of $)	2018	2017	2016
Net cash provided by operations	**6,555**	5,230	5,069
Net cash used in investing activities	**(10,019)**	(3,699)	(18,783)
	(3,464)	1,531	(13,714)
Net cash provided by/(used in) financing activities	**2,748**	(1,419)	14,007
	(716)	112	293
Effect of foreign exchange rate changes on cash and cash equivalents	**73**	(39)	(127)
(Decrease)/increase in cash and cash equivalents	**(643)**	73	166

At December 31, 2018, our current assets totaled $5.1 billion (2017 – $4.7 billion) and current liabilities amounted to $12.9 billion (2017 – $9.9 billion), leaving us with a working capital deficit of $7.8 billion compared to a deficit of $5.2 billion at December 31, 2017. Our working capital deficiency is considered to be in the normal course of business and is managed through:

- our ability to generate predictable and growing cash flow from operations
- approximately $11.8 billion of unutilized, unsecured credit facilities
- our access to capital markets, including through our DRP and Corporate ATM programs, if deemed appropriate.

Cash provided by operating activities

year ended December 31 (millions of $)	2018	2017	2016
Net cash provided by operations	**6,555**	5,230	5,069
Increase/(decrease) in operating working capital	**102**	273	(248)
Funds generated from operations	**6,657**	5,503	4,821
Specific items:			
Bison contract terminations	**(122)**	—	—
U.S. Northeast power marketing contracts	**1**	—	—
Integration and acquisition related costs – Columbia	**—**	84	283
Keystone XL asset costs	**—**	34	52
Net (gain)/loss on sales of U.S. Northeast power generation assets	**(14)**	20	15
Comparable funds generated from operations	**6,522**	5,641	5,171
Dividends on preferred shares	**(158)**	(155)	(100)
Distributions to non-controlling interests	**(225)**	(283)	(279)
Non-recoverable maintenance capital expenditures	**(254)**	(240)	(310)
Comparable distributable cash flow	**5,885**	4,963	4,482
Comparable distributable cash flow per common share	**$6.52**	$5.69	$5.91

Net cash provided by operations

The year-over-year increases in net cash provided by operations are primarily due to the net effect of higher earnings (as discussed in Financial highlights on page 21), the recovery of higher depreciation as approved by the NEB in the Mainline NEB 2018 Decision and NGTL's 2018-2019 Settlement as well as the amount and 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 by excluding the timing effects of working capital changes as well as the cash impact of our specific items. See page 8 for more information about non-GAAP measures.

Comparable funds generated from operations increased by $881 million in 2018 compared to 2017, primarily due to higher comparable earnings adjusted for non-cash items and the cash impact of specific items as well as the recovery of higher depreciation for both the Canadian Mainline and the NGTL System as described above.

Comparable funds generated from operations increased by $470 million in 2017 compared to 2016 mainly due to higher comparable EBITDA (excluding income from equity investments) and higher distributions from our equity investments, partially offset by higher interest expense and increased funding of our employee post-retirement benefit plans.

Comparable distributable cash flow

Comparable distributable cash flow, a non-GAAP measure, helps us assess the cash available to common shareholders before capital allocation. Refer to page 8 for more information on non-GAAP measures we use.

The year-over-year increases in comparable distributable cash flow primarily reflect higher comparable funds generated from operations, as described above as well as the impact of the reduction to TC PipeLines, LP's quarterly distribution to common unitholders beginning in first quarter 2018. Comparable distributable cash flow per common share for the year ended December 31, 2018 also includes the dilutive effect of common shares issued in 2017 and 2018.

In 2018, our determination of comparable distributable cash flow has been revised to exclude the deduction of maintenance capital expenditures for assets for which we have the ability to recover these costs in pipeline tolls. Comparative periods presented in the table above have been adjusted accordingly. We believe that including only non-recoverable maintenance capital expenditures in the calculation of distributable cash flow best depicts the cash available for reinvestment or distribution to shareholders. For our rate-regulated Canadian and U.S. natural gas pipelines, we have the opportunity to recover and earn a return on maintenance capital expenditures through current and future tolls. Tolling arrangements in our liquids pipelines provide for the recovery of maintenance capital expenditures. Therefore, we have not deducted the recoverable maintenance capital expenditures for these businesses in the calculation of comparable distributable cash flow.

Cash used in investing activities

year ended December 31 (millions of $)	**2018**	**2017**	**2016**
Capital spending			
Capital expenditures	**(9,418)**	(7,383)	(5,007)
Capital projects in development	**(496)**	(146)	(295)
Contributions to equity investments	**(1,015)**	(1,681)	(765)
	(10,929)	(9,210)	(6,067)
Acquisitions, net of cash acquired	**—**	—	(13,608)
Proceeds from sale of assets, net of transaction costs	**614**	4,683	6
Reimbursement of costs related to capital projects in development	**470**	634	—
Other distributions from equity investments	**121**	362	727
Deferred amounts and other	**(295)**	(168)	159
Net cash used in investing activities	**(10,019)**	(3,699)	(18,783)

Net cash used in investing activities increased from $3.7 billion in 2017 to $10.0 billion in 2018 primarily as a result of proceeds received on the sales of our U.S. Northeast power generation assets and solar assets in 2017, along with higher capital expenditures and spending on capital projects in development in 2018. This was partially offset by the proceeds from the sale of our interests in the Cartier Wind power facilities.

Net cash used in investing activities decreased from $18.8 billion in 2016 to $3.7 billion in 2017 mainly due to the net effect of:
- the 2016 acquisitions of Columbia and Ironwood
- higher capital spending in 2017
- proceeds from the sales of our U.S. Northeast power generation assets and solar assets in 2017
- recovery of PRGT project costs.

Capital spending[1]

The following table summarizes capital spending by segment.

year ended December 31 (millions of $)	2018	2017	2016
Canadian Natural Gas Pipelines	**2,478**	2,181	1,525
U.S. Natural Gas Pipelines	**5,771**	3,830	1,522
Mexico Natural Gas Pipelines	**797**	1,954	1,142
Liquids Pipelines	**581**	529	1,137
Energy	**1,257**	675	708
Corporate	**45**	41	33
	10,929	9,210	6,067

1 Capital spending includes capacity capital expenditures, maintenance capital expenditures, capital projects in development and contributions to equity investments.

Capital expenditures

Our 2018 and 2017 capital expenditures were incurred primarily for the expansion of the Columbia Gas, Columbia Gulf, NGTL System and Canadian Mainline natural gas pipelines as well as the construction of the Napanee power generating facility and Mexico natural gas pipelines.

Our 2016 capital expenditures were incurred mainly for expanding the Columbia Gas and Columbia Gulf pipelines from their acquisition date along with the NGTL System, Canadian Mainline and ANR, plus construction of our Mexico natural gas pipelines, Northern Courier pipeline and the Napanee power generating facility.

Capital projects in development

Costs incurred during 2018 on capital projects in development were predominantly attributable to spending on Keystone XL and Coastal GasLink. Spending in 2017 and 2016 primarily related to the Energy East and LNG-related pipeline projects.

Contributions to equity investments

Contributions to equity investments decreased in 2018 compared to 2017 mainly due to lower annual investment in Sur de Texas, Northern Border and the completion of Grand Rapids in 2017, partially offset by higher investment in Millennium and Bruce Power.

Contributions to equity investments increased in 2017 compared to 2016 primarily due to our investments in Sur de Texas, Bruce Power and Northern Border, partially offset by decreased contributions to Grand Rapids which went in service in August 2017.

2018 and 2017 contributions to equity investments include our proportionate share of Sur de Texas debt financing.

Sales of assets

In October 2018, we completed the sale of our interests in the Cartier Wind power facilities in Québec for proceeds of approximately $630 million, before post-closing adjustments.

In 2017, we completed the following transactions:
- sold Ravenswood, Ironwood, Kibby Wind and Ocean State Power for proceeds of approximately US$2.029 billion, before post-closing adjustments
- sold TC Hydro for proceeds of approximately US$1.07 billion, before post-closing adjustments
- sold our Ontario solar assets for proceeds of approximately $541 million, before post-closing adjustments.

Reimbursement of costs related to capital projects in development

In November 2018, we received $0.5 billion in accordance with provisions in the agreements with the LNG Canada joint venture participants allowing them to reimburse us for their share of pre-FID costs.

In July 2017, we were notified that PNW LNG would not be proceeding with their LNG project. As a result, in October 2017, we received a payment of $0.6 billion from Progress Energy for full recovery of our PRGT project costs plus carrying charges.

Other distributions from equity investments

Other distributions from equity investments primarily reflects our proportionate share of Bruce Power financings undertaken to fund its capital program and make distributions to its partners. In 2018, Bruce Power issued senior notes in the capital markets which resulted in such distributions totaling $121 million being received by us. In 2017, Bruce Power issued senior notes in the capital markets which resulted in $362 million being received by us.

Cash provided by/(used in) financing activities

year ended December 31 (millions of $)	2018	2017	2016
Notes payable issued/(repaid), net	**817**	1,038	(329)
Long-term debt issued, net of issue costs	**6,238**	3,643	12,333
Long-term debt repaid	**(3,550)**	(7,085)	(7,153)
Junior subordinated notes issued, net of issue costs	**—**	3,468	1,549
Dividends and distributions paid	**(1,954)**	(1,777)	(1,815)
Common shares issued, net of issue costs	**1,148**	274	7,747
Common shares repurchased	**—**	—	(14)
Preferred shares issued, net of issue costs	**—**	—	1,474
Partnership units of TC PipeLines, LP issued, net of issue costs	**49**	225	215
Common units of Columbia Pipelines Partners LP acquired	**—**	(1,205)	—
Net cash provided by/(used in) financing activities	**2,748**	(1,419)	14,007

Net cash provided by financing activities increased by $4.2 billion in 2018 compared to 2017 primarily due to issuances of long-term debt (net of long-term debt repaid) and common shares and the acquisition of CPPL in 2017, partially offset by junior subordinated notes issued in 2017.

Net cash provided by financing activities decreased by $15.4 billion in 2017 compared to 2016 primarily due to significant financing activity, including common share issuances, associated with funding the US$10.3 billion cash acquisition of Columbia in 2016 and the US$921 million acquisition of the outstanding publicly held common units of CPPL in 2017.

The principal transactions reflected in our financing activities are discussed in further detail below.

Long-term debt issued

The following table outlines significant debt issuances in 2018:

(millions of Canadian $, unless otherwise noted) Company	Issue date	Type	Maturity Date	Amount	Interest rate
TRANSCANADA PIPELINES LIMITED					
	October 2018	Senior Unsecured Notes	March 2049	US 1,000	5.10%
	October 2018	Senior Unsecured Notes	May 2028	US 400	4.25%
	July 2018	Medium Term Notes	July 2048	800	4.18%
	July 2018	Medium Term Notes	March 2028	200	3.39%
	May 2018	Senior Unsecured Notes	May 2048	US 1,000	4.875%
	May 2018	Senior Unsecured Notes	May 2038	US 500	4.75%
	May 2018	Senior Unsecured Notes	May 2028	US 1,000	4.25%
NORTH BAJA PIPELINE, LLC					
	December 2018	Unsecured Term Loan	December 2021	US 50	Floating

The net proceeds of the above debt issuances were used for general corporate purposes, to fund our capital program and to prefund 2019 senior note maturities.

Long-term debt repaid

The following table outlines significant debt repaid in 2018 and early 2019:

(millions of Canadian $, unless otherwise noted) Company	Retirement date	Type	Amount	Interest rate
TRANSCANADA PIPELINES LIMITED				
	January 2019	Senior Unsecured Notes	US 750	7.125%
	January 2019	Senior Unsecured Notes	US 400	3.125%
	August 2018	Senior Unsecured Notes	US 850	6.50%
	March 2018	Debentures	150	9.45%
	January 2018	Senior Unsecured Notes	US 500	1.875%
	January 2018	Senior Unsecured Notes	US 250	Floating
TC PIPELINES, LP				
	December 2018	Unsecured Term Loan	US 170	Floating
COLUMBIA PIPELINE GROUP, INC.				
	June 2018	Senior Unsecured Notes	US 500	2.45%

For more information about long-term debt and junior subordinated notes issued and long-term debt repaid in 2018, 2017 and 2016, refer to our 2018 annual Consolidated financial statements.

Dividend reinvestment plan

On July 1, 2016, we re-initiated the issuance of common shares from treasury under our DRP. Under this plan, eligible holders of common and preferred shares of TransCanada can reinvest their dividends and make optional cash payments to obtain additional TransCanada common shares. Common shares are issued from treasury at a discount of two per cent to market prices over a specified period. On dividends declared in 2018, the participation rate by common shareholders was approximately 35 per cent (2017 – 36 per cent), resulting in $870 million (2017 – $787 million) reinvested in common equity under the program.

TransCanada's Corporate ATM Program

In June 2017, we established an ATM program that allows us to issue common shares from treasury from time to time, at the prevailing market price, when sold through the TSX, the NYSE, or any other existing trading market for TransCanada common shares in Canada or the United States. The ATM program, which is effective for a 25-month period, was initially established with an aggregate gross sales limit of $1.0 billion or the U.S. dollar equivalent. In June 2018, we replenished the capacity available under our existing ATM program to allow for the issuance of additional common shares from treasury having an aggregate gross sales price of up to $1.0 billion. The Corporate ATM program, as amended, is effective to July 23, 2019, and may be utilized at our discretion, if and as required, based on the spend profile of our capital program and relative cost of other funding options.

In 2018, 20 million common shares (2017 – 3.5 million common shares) were issued under the Corporate ATM program at an average price of $56.13 per share (2017 – $63.03 per share) for proceeds of $1.1 billion (2017 – $216 million), net of approximately $10 million (2017 – $2 million) of related commissions and fees. Subsequent to the issuances in 2017 and 2018 under the Corporate ATM program, an aggregate gross sales limit of $656 million or its U.S. dollar equivalent remains available for issuance.

Common units of Columbia Pipeline Partners LP

On February 17, 2017, we acquired all outstanding publicly held common units of CPPL at a price of US$17.00 and a stub period distribution payment of US$0.10 per common unit for an aggregate transaction value of US$921 million. As this was a transaction between entities under common control, it was recognized in equity.

TC PipeLines, LP

ATM equity issuance program

Under the TC PipeLines, LP ATM program, TC PipeLines, LP is authorized, from time to time, to offer and sell common units through ordinary brokers' transactions on the NYSE at market prices, in block transactions or as otherwise agreed upon by TC PipeLines, LP and by one or more of its agents. Our ownership interest in TC PipeLines, LP decreases as a result of equity issuances under the TC PipeLines, LP ATM program.

During 2018, 0.7 million (2017 – 3.1 million) common units were issued under the TC PipeLines, LP ATM program generating net proceeds of approximately US$39 million (2017 – US$173 million). At December 31, 2018, our ownership interest in TC PipeLines, LP was 25.5 per cent (2017 – 25.7 per cent) after issuances under the TC PipeLines, LP ATM program and resulting dilution.

In March 2018, as a result of the initially proposed 2018 FERC Actions, the TC PipeLines, LP ATM program ceased to be utilized. Following the 2018 FERC Actions that became effective September 13, 2018, it is yet to be determined if and when it might be restored as a competitive financing option.

Asset drop downs

On June 1, 2017, we closed the sale of 49.34 per cent of our 50 per cent interest in Iroquois, along with an option to sell the remaining 0.66 per cent at a later date, to TC PipeLines, LP. At the same time, we closed the sale of our remaining 11.81 per cent interest in Portland to TC PipeLines, LP. Proceeds from these transactions were US$765 million before post-closing adjustments and were comprised of US$597 million in cash and US$168 million representing a proportionate share of Iroquois and Portland debt.

Refer to the 2018 FERC Actions section for more information.

Share information

as at February 11, 2019		
Common Shares	**issued and outstanding**	
	922 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**
	12 million	8 million

For more information on preferred shares refer to the notes to our Consolidated financial statements.

Dividends

year ended December 31	2018	2017	2016
Dividends declared			
per common share	**$2.76**	$2.50	$2.26
per Series 1 preferred share	**$0.8165**	$0.8165	$0.8165
per Series 2 preferred share	**$0.78835**	$0.62138	$0.60648
per Series 3 preferred share	**$0.538**	$0.538	$0.538
per Series 4 preferred share	**$0.62748**	$0.46138	$0.44648
per Series 5 preferred share	**$0.56575**	$0.56575	$0.56575
per Series 6 preferred share	**$0.69341**	$0.55275	$0.50648
per Series 7 preferred share	**$1.00**	$1.00	$1.00
per Series 9 preferred share	**$1.0625**	$1.0625	$1.0625
per Series 11 preferred share	**$0.95**	$0.95	$1.1875
per Series 13 preferred share	**$1.375**	$1.375	$1.18525
per Series 15 preferred share	**$1.225**	$1.225	$0.3323

Credit facilities

We have several committed credit facilities that support our commercial paper programs and provide short-term liquidity for general corporate purposes. 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 February 11, 2019, we had a total of $12.8 billion of committed revolving and demand credit facilities, including:

Amount	Unused capacity	Borrower	Description	Matures
Committed, syndicated, revolving, extendible, senior unsecured credit facilities:				
$3.0 billion	$3.0 billion	TCPL	Supports TCPL's Canadian dollar commercial paper program and is used for general corporate purposes	December 2023
US$4.5 billion	US$4.5 billion	TCPL/TCPL USA/ Columbia/TAIL	Supports TCPL and TCPL USA's U.S. dollar commercial paper programs, and is used for general corporate purposes of the borrowers, guaranteed by TCPL	December 2019
US$1.0 billion	US$1.0 billion	TCPL/TCPL USA/ Columbia/TAIL	Used for general corporate purposes of the borrowers, guaranteed by TCPL	December 2021
Demand senior unsecured revolving credit facilities:				
$2.1 billion	$1.0 billion	TCPL/TCPL USA	Supports the issuance of letters of credit and provides additional liquidity; TCPL USA facility guaranteed by TCPL	Demand
MXN$5.0 billion	MXN$5.0 billion	Mexican subsidiary	Used for Mexico general corporate purposes, guaranteed by TCPL	Demand

At February 11, 2019, our operated affiliates had an additional $0.8 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 pension and post-retirement benefit plans.

Payments due (by period)

at December 31, 2018 (millions of $)	**Total**	**< 1 year**	**1 - 3 years**	**4 - 5 years**	**> 5 years**
Notes payable	2,762	2,762	—	—	—
Long-term debt and junior subordinated notes	47,479	3,465	4,932	4,031	35,051
Operating leases[1]	729	74	143	130	382
Purchase obligations	8,187	2,985	3,640	372	1,190
	59,157	9,286	8,715	4,533	36,623

1 Future payments for various premises, services and equipment, less sub-lease receipts.

Notes payable

Total notes payable were $2.8 billion at the end of 2018 compared to $1.8 billion at the end of 2017.

Long-term debt and junior subordinated notes

At the end of 2018, we had $40.0 billion of long-term debt and $7.5 billion of junior subordinated notes outstanding, compared to $34.7 billion of long-term debt and $7.0 billion of junior subordinated notes at December 31, 2017.

We attempt to smooth the maturity profile of our debt. The weighted-average maturity of our long-term debt and junior subordinated notes is 20 years, with the majority of final repayments occurring beyond five years.

Interest payments

At December 31, 2018, scheduled interest payments related to our long-term debt and junior subordinated notes were as follows:

at December 31, 2018 (millions of $)	**Total**	**< 1 year**	**1 - 3 years**	**4 - 5 years**	**> 5 years**
Long-term debt	27,447	1,941	3,593	3,163	18,750
Junior subordinated notes	28,039	416	833	834	25,956
	55,486	2,357	4,426	3,997	44,706

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.

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)

at December 31, 2018 (millions of $)	Total	< 1 year	1 - 3 years	4 - 5 years	> 5 years
Canadian Natural Gas Pipelines					
Transportation by others[1]	859	83	161	138	477
Capital spending[2]	4,647	1,700	2,947	—	—
U.S. Natural Gas Pipelines					
Transportation by others[1]	700	119	199	108	274
Capital spending[2]	50	50	—	—	—
Mexico Natural Gas Pipelines					
Capital spending[2]	342	287	55	—	—
Liquids Pipelines					
Capital spending[2]	406	406	—	—	—
Other	22	5	7	6	4
Energy					
Commodity purchases	91	63	28	—	—
Capital spending[2]	700	199	163	56	282
Other[3]	300	34	56	58	152
Corporate					
Capital spending[2]	70	39	24	6	1
	8,187	2,985	3,640	372	1,190

1 Demand rates are subject to change. The contractual obligations in the table are based on demand volumes only and exclude variable charges incurred when volumes flow.
2 Amounts are primarily for capital expenditures and contributions to equity investments for capital projects. Amounts are estimates and are subject to variability based on timing of construction and project requirements.
3 Includes estimates of certain amounts which are subject to change depending on plant-fired hours, the consumer price index, actual plant maintenance costs, plant salaries as well as changes in regulated rates for fuel transportation.

Outlook

We are developing quality projects under our $57 billion capital program. These long-life infrastructure assets are supported by long-term commercial arrangements or regulated cost of service business models and, once completed, are expected to generate significant growth in earnings and cash flow.

Our $57 billion capital program is comprised of $36.6 billion of secured projects and $20.7 billion of projects under development, 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 and a combination of other funding options including:

- senior debt
- hybrid securities
- preferred shares
- asset sales
- project financing
- potential involvement of strategic or financial partners.

In addition, we may access the funding options below, as deemed appropriate:

- common shares issued under our DRP
- common shares issued under our Corporate ATM program
- discrete common equity issuances.

GUARANTEES

Sur de Texas

We and our partner on the Sur de Texas pipeline, IEnova, have jointly guaranteed the financial performance of this entity. Such agreements include a guarantee and a letter of credit which are primarily related to construction services and the delivery of natural gas. The guarantees have terms ranging to 2020.

At December 31, 2018, our share of potential exposure under the Sur de Texas pipeline guarantees was estimated to be $183 million. The carrying amount of the guarantees was approximately $1 million.

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 2021.

At December 31, 2018, our share of the potential exposure under the Bruce Power guarantee was estimated to be $88 million. The carrying amount of the guarantee was nil.

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 2059.

Our share of the potential exposure under these assurances was estimated at December 31, 2018 to be $104 million. The carrying amount of these guarantees was approximately $11 million. 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 2019, we expect to make funding contributions of approximately $113 million for the defined benefit pension plans, approximately $7 million for other post-retirement benefit plans and approximately $61 million for the savings plan and defined contribution pension plans. In addition, we expect to provide a $17 million letter of credit to the Canadian defined benefit plan for solvency funding requirements.

In 2018, we made funding contributions of $103 million to our defined benefit pension plans, $23 million for the other post-retirement benefit plans and $59 million for the savings plan and defined contribution pension plans. We also provided a $17 million letter of credit to the Canadian defined benefit plan for solvency funding requirements.

Outlook

The next actuarial valuation for our pension and other post-retirement benefit plans will be carried out as at January 1, 2019. Based on current market conditions, we expect funding requirements for these plans to approximate 2018 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 $74 million in 2018 from $106 million in 2017 mainly due to higher expected returns on 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

ENTERPRISE RISK MANAGEMENT

Risk management is integral to the successful operation of our business. Our strategy is to ensure that our risks and related exposures are aligned with our business objectives and risk tolerance. We manage risk through a centralized enterprise risk management process that identifies risks that could materially impact the achievement of our strategic objectives.

Our Board of Directors' Governance Committee oversees our enterprise risk management activities, which includes ensuring appropriate management systems are in place to identify and manage our risks, including adequate Board oversight of our risk management policies, programs and practices. Other Board committees oversee specific types of risk:

- the Human Resources Committee oversees executive resourcing, organizational capabilities and compensation risk to ensure compensation practices align with our overall business strategy
- the HSSE Committee oversees operational, health, safety, sustainability and environmental risk
- the Audit Committee oversees management's role in managing financial risk.

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

The following is a summary of certain general risks that affect our company and are being continuously monitored. Risks specific to each operating business segment can be found in each business segment discussion.

Risk and Description	Impact	Monitoring and Mitigation
Business interruption		
Operational risks, including equipment malfunctions and breakdowns, labour disputes, or natural disasters and other catastrophic events, including those related to climate change, acts of terror and sabotage.	Decrease in revenues and increase in operating costs, legal proceedings or regulatory actions or other expenses all of which could reduce our earnings. Losses not recoverable through tolls or contracts or covered by insurance could have an adverse effect on operations, cash flow and financial position. Certain events could lead to risk of injury and environmental damage.	We have TOMS that includes our corporate health, safety, sustainability, environment and asset integrity programs to prevent incidents and protect people, the environment and our assets. TOMS includes incident, emergency and crisis management programs to ensure TransCanada can effectively respond to operational risk events, minimize loss or injury and enhance our ability to resume operations. This is supported by our business continuity program that identifies critical business processes and develops corresponding business resumption plans. We also have a comprehensive insurance program to mitigate a certain portion of these risks, but insurance does not cover all events in all circumstances.
Cyber security		
We rely on our information technology to process, transmit and store electronic information, including information we use to safely operate our assets. We continue to face cyber security risks, and could be subject to cyber-security events directed against our information technology. The methods used to obtain unauthorized access, disable or degrade service or sabotage systems are constantly evolving and may be difficult to anticipate or to detect for long periods of time.	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, and/or result in 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 is regularly reviewed and updated, and the status of our cyber security program is reported to the Audit Committee on a quarterly basis. The program 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 may cover losses from physical damage to our facilities as a result of a cyber security event, but insurance does not cover all events in all circumstances.

Risk and Description	Impact	Monitoring and Mitigation
Reputation and relationships		
Our operations and growth prospects require us to have strong relationships with key stakeholders including Indigenous communities, landowners, governments and government agencies, and environmental non-governmental organizations. Inadequately managing expectations and issues important to stakeholders, including those related to climate change, could affect our reputation and our ability to operate and grow, as well as our access to and cost of capital.	Our reputation with stakeholders, including Indigenous communities, can have a significant impact on our operations and projects, infrastructure development and overall reputation. Should investors develop negative perceptions regarding our energy infrastructure business, future access to investment capital could be negatively impacted.	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. We also have specific stakeholder programs and policies that set requirements, assess risks and facilitate compliance with legal and policy requirements.
Access to capital at a competitive cost		
We require substantial amounts of capital in the form of debt and equity to finance our portfolio of growth projects and maturing debt obligations at costs that are sufficiently lower than the returns on our investments.	Significant deterioration in market conditions for an extended period of time and changes in investor sentiment could affect our ability to access capital at a competitive cost, which could negatively impact our ability to deliver an attractive return on our investments.	We operate within our financial means and risk tolerances, maintain a diverse array of funding levers and also utilize portfolio management as an important component of our financing program. In addition, we have candid and proactive engagement with the investment community, including credit rating agencies, with the objective of keeping them apprised of developments in our business and factually communicating our prospects, risks and challenges.
Capital allocation strategy		
To be competitive, we must offer energy infrastructure services in supply and demand areas, and for forms of energy that are attractive to customers.	Should alternative lower-carbon forms of energy result in decreased demand for our current services, the value of our long-lived energy infrastructure assets could be negatively impacted.	We have a diverse portfolio of assets and we utilize portfolio management to divest of non-strategic assets. We conduct analyses to identify resilient supply basins as part of our energy fundamentals and strategic development reviews. We also monitor the development of innovative technologies to inform our capital allocation strategy.
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 determine the expected cost of our capital projects, under some commercial arrangements we bear capital cost overrun and schedule risk which may decrease our return on these projects.	Our Project Governance Program supports project execution and operational excellence. The program aligns with TOMS which provides the framework and standards to optimize project execution, ensuring timely and on budget execution. We prefer to contractually structure our projects to recover development costs if a project does not proceed along with mechanisms to minimize the impact should cost overruns occur. However, under some commercial arrangements, we share or bear the cost of execution risk.

Health, safety, sustainability and environment

The Board's HSSE Committee oversees operational risk, people and process safety, security of personnel, environmental and climate-change related risks, and monitors development and implementation of systems, programs and policies relating to HSSE matters through regular reporting from management. We use an integrated management system that establishes a framework for managing these risks and which is used to capture, organize, document, monitor and improve our related policies, programs and procedures.

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

- planning – risk and regulatory assessment, objective and target setting, defining roles and responsibilities
- implementing – development and implementation of programs, procedures and standards to manage operational risk
- reporting – incident reporting and investigation, and performance monitoring
- action – assurance activities and review of performance by management.

The HSSE Committee reviews HSSE performance and operational risk management. It receives detailed reports on:
- overall HSSE corporate governance
- operational performance and preventive maintenance metrics
- asset integrity programs
- emergency preparedness, incident response and evaluation
- people and process safety performance metrics
- our Environment Program
- developments in and compliance with applicable legislation and regulations, including those related to the environment
- prevention, mitigation and management of risks related to HSSE matters, including climate change related risks which may adversely impact TransCanada
- sustainability matters, including social, environmental and climate-change related matters
- management's approach to voluntary public disclosure on HSSE matters.

Health and safety

The safety of our employees, contractors and the public, as well as the integrity of our pipeline and energy infrastructure, is a top priority. All assets are designed, constructed and commissioned with full consideration given to safety and integrity, and are placed in service only after all necessary requirements have been satisfied.

In 2018, we spent $1.3 billion for pipeline integrity on the natural gas and liquids pipelines we operate, a $0.3 billion increase over 2017 in part due to increased capital spending in Canada, increased integrity activities on Columbia assets, and integrity work related to our Keystone U.S. pipeline. Pipeline integrity spending will fluctuate based on the results of annual risk assessments conducted on our pipeline systems and evaluations of information obtained from recent inspections, incidents 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 generally have no impact on our earnings. Similarly, under Keystone contracts, pipeline integrity expenditures are recovered through the tolling mechanism and, as a result, generally have no impact on our earnings. Non-capital pipeline integrity expenditures on our U.S. natural gas pipelines are primarily treated as operations and maintenance expenditures.

Spending associated with process safety and various integrity programs for the Energy assets we operate is used to minimize risk to employees, the public, equipment, and surrounding environment, and to prevent disruptions to serving the energy needs of our customers.

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 the potential for adverse effects on the environment.

Environmental risk, compliance and liabilities

We maintain an Environment Program to minimize potentially adverse environmental impacts. This program identifies our requirements to proactively and systematically manage environmental hazards and risks throughout the lifecycle of our assets.

Our primary sources of risk related to the environment include:
- changing regulations and costs associated with our emissions of air pollutants and GHG
- product releases, including crude oil, diluent and natural gas, that may cause harm to 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 as well as new regulations.

Our assets are subject to federal, state, provincial and local environmental statutes and regulations governing environmental protection, including air and GHG emissions, water quality, species at risk, wastewater discharges and waste management. Operating our assets requires obtaining and complying 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 the implementation of 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 uncertain or have the potential to affect our ability to effectively operate our business, we comment on proposals independently or through industry associations.

On November 28, 2017, in connection with the line break experienced on the Keystone Pipeline System near Amherst, South Dakota on November 16, 2017, PHMSA issued a Correction Action Order (the "Amherst CAO") directing us to, among other things, repair the pipeline in accordance with an approved repair plan, return the pipeline to service in accordance with an approved return to service plan, operate the affected section of the pipeline at a reduced operating pressure until further directed and facilitate an investigation into the cause of the incident. The pressure restriction imposed by PHMSA was subsequently lifted on May 1, 2018. We are fully cooperating with PHMSA on all matters relating to this incident as well as with the SDDENR on site remediation. We have completed remediation of all contaminated soil and groundwater and all soil confirmation and groundwater sample results meet required standards. SDDENR issued a closure letter on January 3, 2019. Surface reclamation and revegetation were completed in 2018, and this segment of the right-of-way has been returned to the Keystone Pipeline System right-of-way vegetation management program. On January 29, 2019, we received confirmation from PHMSA that we have complied with the terms of the Amherst CAO and the case is now closed.

On June 7, 2018, there was a natural gas pipeline rupture on a section of Columbia Gas located on Nixon Ridge in Marshall County, West Virginia. The pipeline was placed back in service on July 15, 2018. TransCanada received a Notice of Proposed Safety Order from PHMSA for this matter on July 9, 2018, and responded on August 7, 2018. We expect to receive a final order outlining the final remedial requirements in due course.

Other than the Amherst CAO and the pending Proposed Safety Order for the section of Columbia Gas located on Nixon Ridge, 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.

The timing and complete extent of future expenditures related to environmental matters is difficult to estimate accurately because:

- environmental laws and regulations and their interpretations and enforcement 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 investigations or agreements
- new contaminated sites may be found, 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, 2018, accruals related to these obligations totaled $32 million (2017 – $34 million), representing the estimated amount we will need to manage our currently known environmental liabilities. We believe we have considered all necessary contingencies and established appropriate reserves for environmental liabilities, however, a risk exists that unforeseen matters may arise requiring us to set aside additional amounts. We adjust reserves regularly to account for changes in liabilities.

Climate change and related regulation risk

We own assets and have business interests in a number of regions subject to GHG emissions regulations, including GHG emissions management and carbon pricing policies. In 2018, we incurred $62 million (2017 – $63 million) of expense under existing carbon pricing programs. Across North America, there are a variety of new and evolving initiatives in development at the federal, regional, state and provincial level aimed at reducing GHG emissions. We actively monitor and submit comments to regulators as these new and evolving initiatives are undertaken. We support transparent climate change policies that promote sustainable and economically responsible natural resource development. We expect that, over time, most of our assets will be subject to some form of regulation to manage GHG emissions. Changes in regulations may result in higher operating costs or other expenses, or higher capital expenditures to comply with possible new regulations.

Existing policies

Canadian Jurisdiction

- Environment and Climate Change Canada (ECCC) issued the final Methane Reduction Regulation on April 26, 2018. The regulations detail requirements to reduce methane emissions through operational and capital modifications. There are multiple timeframes for compliance depending on the provision, beginning in 2020. Alberta, British Columbia and Saskatchewan have drafted their own methane regulations which take the place of the federal regulation in those jurisdictions. However, for the federally regulated facilities in these jurisdictions, the federal methane regulation will be applicable. For most of TransCanada's Canadian pipeline assets, it is likely that the federal regulation will be applicable. Compliance will involve equipment retrofits, frequent leak detection and repair surveys and measurements to quantify emission reductions and associated annual reporting. Power facilities are not affected by this regulation
- B.C. has a tax on GHG emissions from fossil fuel combustion. We recover the compliance costs through the tolls our customers pay
- in Alberta, the CCIR replaced the SGER effective January 1, 2018. This regulation requires established industrial facilities with GHG emissions above a certain threshold to reduce their emissions below an intensity baseline. The CCIR covers our natural gas pipelines and Energy assets in Alberta. Canadian natural gas pipeline compliance costs are recovered through regulated tolls. A portion of the compliance costs for the Energy assets are recovered through market pricing and hedging activities
- Québec has a GHG cap-and-trade program under the Western Climate Initiative (WCI) GHG emissions market. In Québec, the Bécancour cogeneration plant is subject to this program. 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 are recovered through commercial contracts. The Canadian Mainline natural gas pipeline facilities in Québec are also subject to this program and compliance instruments have been purchased in order to comply with the requirements of this initiative
- Ontario repealed its cap-and-trade program in 2018. The compliance credits purchased under the previous cap-and-trade program have been retired by the new government. With the repeal of the cap-and-trade program, Ontario does not have carbon pricing regulation, therefore, TransCanada's electricity and pipeline facilities in this jurisdiction are subject to the Canadian Federal OBPS as of January 1, 2019. Federal OBPS applies to electric generation facilities with annual emissions greater than 50,000 tonnes of CO_2 equivalent. At this time we do not anticipate any material impact to the financial performance of our Ontario natural gas facilities as a result of this program.

U.S. Jurisdiction

- the U.S. Environmental Protection Agency (EPA) published regulations related to fugitive methane emissions for new and modified compressor stations in the natural gas transmission and storage sector in 2015. In 2017, the EPA indicated its intention to reconsider this regulation. In 2018, with direction from the Trump administration, the EPA is working on reducing the requirements of this regulation
- on March 23, 2017, the California Air Resources Board published regulations related to monitoring and repairing methane leaks. Tuscarora Gas Transmission facilities are required to comply with these regulations
- Washington State adopted emission standards to cap and reduce GHGs from certain stationary sources in September 2016. Some GTN compressor stations in Washington are potentially impacted by the standards beginning in 2020
- the Pennsylvania Department of Environmental Protection has adopted new operating permits for oil and gas facilities that include numerous requirements including methane leak detection and repair
- California has a GHG cap-and-trade program under the WCI GHG emissions market. In California, TransCanada has costs associated with the cap-and-trade program with respect to our electricity marketing activities.

Mexico Jurisdiction

- on November 6, 2018, the Government of Mexico published a new regulation that established guidelines for the prevention and control of methane emissions in the hydrocarbon sector, which will impact our Mexico natural gas pipelines. Companies will have one year to comply with the regulations which include equipment requirements such as installation of vapor recovery systems and detection and repair of leaks, as well as administrative requirements including the identification of methane emissions and implementation of a program for emissions reporting.

Anticipated policies

- the Government of Canada has finalized a Federal plan to have carbon pricing in place in all Canadian jurisdictions. ECCC is in the process of finalizing the Federal OBPS regulation to impose carbon pricing for larger industrial facilities and will set federal benchmarks for GHG emissions for various industry sectors. This new federal regulation will apply to the provinces of Ontario, Manitoba, Saskatchewan, and New Brunswick as those jurisdictions do not currently have a provincial plan in place for carbon pricing or meet the criteria of the Federal plan. This may result in increased costs for current pipeline and energy facilities in those jurisdictions
- the Government of Canada has proposed a Federal plan, the Clean Fuel Standard (CFS), to implement a single national standard encompassing all fuel types and applications. As part of the CFS, compressor station electrification is proposed by the Federal Government as a mechanism to reduce natural gas transmission GHG emissions. This could have negative impacts to our Canadian natural gas compression assets. Efforts to influence this policy are being managed through CEPA and CGA. Different components of the CFS regulations are expected to be released through 2019
- the Government of Saskatchewan has announced that certain large industrial emitters will be subject to a provincially proposed carbon pricing system based on an OBPS approach, which has potential to impact our Canadian natural gas pipelines in that province. This proposed system only partially meets the Federal plan and, therefore, the Federal OBPS will apply to emission sources not covered by the proposed system, including electricity generation and natural gas pipelines
- New York State announced its intent to adopt regulations to reduce methane from existing, new and modified facilities. New York has not yet proposed regulations, but the Governor announced the State's plan to achieve its clean energy goals by 2030, which includes a 40% reduction from 1990 emissions levels. Impacts to our facilities are dependent on the specifics of the regulations once they are proposed, but it is likely that our compression facilities in New York State would be affected
- Maryland announced its intent to establish fugitive methane regulations for compressor stations. Maryland has been working with operators, including TransCanada, to develop regulations to reduce greenhouse gases. TransCanada has only one compressor station in Maryland, and it is electric, therefore, no significant impact is expected.

Changes to Environmental Assessment Legislation

The majority of TransCanada's natural gas and liquids pipeline assets in Canada are federally regulated by the NEB under the National Energy Board Act while others are provincially regulated in Alberta and B.C. New projects that will be regulated by the NEB require an environmental assessment, overseen by the NEB and consistent with the Canadian Environmental Assessment Act. Our assets in operation do not fall under the Canadian Environmental Assessment Act. All assets may be subject to the Federal Navigation Protection Act and the Fisheries Act. In Canada, there are several evolving policy initiatives at the federal level related to environmental impact assessment. We actively monitor and submit comments to regulators as these new and evolving initiatives are undertaken.

In February 2018, the Government of Canada released Bill C-69, to enact the Impact Assessment Act and the Canadian Energy Regulator Act, to amend the Navigation Protection Act and to make consequential amendments to other acts. Under the bill, it appears that major projects will have a longer, more complex regulatory approval process, and introduces significant potential uncertainty for new projects in Canada.

In February 2018, the Government of Canada also released Bill C-68, an Act to amend the Fisheries Act and other acts in consequence. The bill leaves a number of details unaddressed, such as project permitting process, requirements, timelines and how Indigenous concerns will be managed, and could have cost and schedule impacts for projects.

Financial risks

We are exposed to market risk and counterparty credit risk and have strategies, policies and limits in place to manage the impact of these risks on our earnings, cash flow and, ultimately, shareholder value.

Risk management strategies, policies and limits are designed to ensure our risks and related exposures are in line with our business objectives and risk tolerance. Market risk and counterparty credit risk are managed within limits that are established by the Board of Directors, implemented by senior management and monitored by our risk management and internal audit groups. The Board of Directors' Audit Committee oversees how management monitors compliance with market risk and counterparty credit risk management policies and procedures, and oversees management's review of the adequacy of the risk management framework.

Market risk

We construct and invest in energy infrastructure projects, purchase and sell 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, foreign exchange rates 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, meet the definition of a derivative.

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

- forwards and futures contracts – agreements to purchase or sell a specific financial instrument or commodity at a specified price and date in the future
- swaps – agreements between two parties to exchange streams of payments over time according to specified terms
- options – agreements that convey the right, but not the obligation of the purchaser, to buy or sell a specific amount of a financial instrument or commodity at a fixed price, either at a fixed date or at any time within a specified period.

Commodity price risk

The following strategies may be used to manage exposure to commodity price risk in our non-regulated businesses:

- in our power generation business, we manage our exposure to fluctuating commodity prices through long-term contracts and hedging activities including selling and purchasing power and natural gas in forward markets
- in our non-regulated natural gas storage business, our exposure to seasonal natural gas price spreads is managed with a portfolio of third-party storage capacity contracts and through offsetting purchases and sales of natural gas in forward markets to lock in future positive margins
- in our liquids marketing business, we enter into pipeline and storage terminal capacity contracts. We fix a portion of our exposure on these contracts by entering into derivative instruments to manage our variable price fluctuations that arise from physical liquids transactions.

Our exposure to electricity price risk has been greatly reduced following the sales of our U.S. Northeast power generation assets in 2017 and our U.S. Northeast power retail contracts on March 1, 2018 as well as the continued wind-down of our remaining U.S. Power marketing contracts.

Interest rate risk

We utilize short-term and long-term debt to finance our operations which exposes us to interest rate risk. We typically pay fixed rates of interest on our long-term debt and floating rates on our commercial paper programs and amounts drawn on our credit facilities. A small portion of our long-term debt is at floating interest rates. In addition, we are exposed to interest rate risk on financial instruments and contractual obligations containing variable interest rate components. We manage our interest rate risk using a combination of interest rate swaps and option derivatives.

Foreign exchange 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 currency 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. A portion of this risk is offset by interest expense on U.S. dollar-denominated debt. The balance of the exposure is hedged on a rolling one-year basis using foreign exchange derivatives, but the exposure remains beyond that period.

Average exchange rate – U.S. to Canadian dollars

The average exchange rate for one U.S. dollar converted into Canadian dollars was as follows:

2018	**1.30**
2017	1.30
2016	1.33

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

Significant U.S. dollar-denominated amounts

year ended December 31 (millions of US$)	**2018**	**2017**	**2016**
U.S. Natural Gas Pipelines comparable EBIT	**1,830**	1,360	947
Mexico Natural Gas Pipelines comparable EBIT[1]	**486**	353	215
U.S. Liquids Pipelines comparable EBIT	**876**	604	482
U.S. Power comparable EBIT[2]	**—**	100	285
Interest on U.S. dollar-denominated long-term debt and junior subordinated notes	**(1,325)**	(1,269)	(1,127)
Capitalized interest on U.S. dollar-denominated capital expenditures	**15**	3	22
U.S. dollar-denominated allowance for funds used during construction	**326**	259	181
U.S. comparable non-controlling interests and other	**(264)**	(195)	(195)
	1,944	1,215	810

1 Excludes interest expense on our inter-affiliate loan with Sur de Texas which is offset in Interest income and other.
2 Effective January 1, 2018, U.S. Power is no longer included in comparable EBIT.

Net investment hedges

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

Counterparty credit risk

Our maximum counterparty credit exposure with respect to financial instruments at December 31, 2018, without taking into account security held, consisted of cash and cash equivalents, accounts receivable, available-for-sale assets, derivative assets and a loan receivable.

We have exposure to counterparty credit risk in the following areas:
- cash and cash equivalents
- accounts receivable
- available-for-sale assets
- the fair value of derivative assets
- a loan 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 by dealing with creditworthy counterparties, obtaining financial assurances such as guarantees, letters of credit or cash where considered necessary, and setting limits on the amount we can transact with any one counterparty. There is no guarantee that these techniques will protect us from material losses.

We monitor counterparties and review our accounts receivable regularly. We record allowances for doubtful accounts using the specific identification method. At December 31, 2018 and 2017, we had no significant credit losses, no significant credit risk concentration and no significant amounts past due or impaired.

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.

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 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. Refer to the Financial condition section 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 or potential legal proceeding or action to 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 year ended December 31, 2018, 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 accurately 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, 2018, 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, 2018, the internal control over financial reporting was effective.

Our internal control over financial reporting as of December 31, 2018 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 2018 reports filed with Canadian securities regulators and the SEC, and have filed certifications with them.

Changes in internal control over financial reporting

There were no changes during the year covered by this annual report that had or are reasonably likely to have a material impact on 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 amounts 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 significant assumptions based on factors that are either subjective or highly uncertain when preparing our financial statements and changes in these assumptions could have a material impact on the financial statements. Our accounting policies disclose the critical accounting estimates we make when preparing our financial statements.

Impairment of long-lived assets and goodwill

We review long-lived assets, such as plant, property and equipment, equity investments and capital projects in development, for impairment whenever events or changes in circumstances lead us to believe we might not be able to recover an asset's carrying value. Factors we consider in our assessment of the recoverability of long-lived assets include, but are not limited to, macroeconomic conditions, changes in the industries and markets in which we operate, our ability to renew contracts, and the financial performance and prospects of our assets. If the total of the undiscounted future cash flows that we estimate for an asset within Property, plant and equipment, or the estimated selling price of any long-lived asset is less than its carrying value, we consider its fair value to be less than its carrying value and record an impairment loss to recognize this. For goodwill, if the fair value of the reporting unit determined using discounted cash flows is less than its carrying value, we consider it to be impaired.

In 2018, the following impairments were recorded:

- a $722 million pre-tax impairment of the carrying value of our investment in Bison ($140 million after-tax and net of non-controlling interests)
- a $79 million pre-tax impairment of the carrying value of Tuscarora's goodwill ($15 million after-tax and net of non-controlling interests).

In 2017, the following impairments were recorded:

- a $954 million after-tax charge on the carrying value of our investment in Energy East and related projects
- a $16 million after-tax charge on the remaining carrying value of certain Energy turbine equipment
- a $12 million after-tax charge related to the remaining carrying value of our investment in TransGas.

Long-lived assets

Bison

At December 31, 2018, we evaluated our investment in the Bison natural gas pipeline for impairment in connection with the termination of certain customer transportation agreements. With the loss of these contracted future cash flows, and the persistence of unfavourable market conditions which have inhibited system flows on the pipeline, we determined that the asset’s remaining carrying value was no longer recoverable and recognized a non-cash impairment charge of $722 million in the U.S. Natural Gas Pipelines segment. Our share of the impairment charge, after-tax and net of non-controlling interests, was $140 million.

Energy East and related projects

In September 2017, we requested the NEB suspend the review of the Energy East and Eastern Mainline project applications for 30 days to provide time for us to conduct a careful review of the NEB's changes, announced on August 23, 2017, regarding the list of issues and environmental assessment factors related to the projects and how these changes impact the projects' costs, schedules and viability.

In October 2017, after careful review of the changed circumstances, we informed the NEB that we would not be proceeding with the Energy East and Eastern Mainline project applications. We also notified Québec’s Ministère du Developpement durable, de l’Environnement, et de la Lutte contre les changements climatiques that we were withdrawing the Energy East project from the environmental review process. As the Energy East pipeline was also to provide transportation services for the Upland pipeline, the U.S. Department of State was notified in October 2017 that we would no longer be pursuing the U.S. Presidential Permit application for that project.

We reviewed the approximate $1.3 billion carrying value of the projects, including AFUDC capitalized since inception, and recorded a $954 million after-tax non-cash charge in fourth quarter 2017. We ceased capitalizing AFUDC on the projects effective August 23, 2017, being the date of the NEB's announced scope changes. With Energy East’s inability to reach a regulatory decision, no recoveries of costs from third parties are forthcoming.

Energy Turbine Equipment

At December 31, 2017, we recognized a non-cash impairment charge of $16 million after tax related to the carrying value of certain turbine equipment after determining that it was no longer recoverable. This turbine equipment was previously purchased for a power development project that did not proceed.

TransGas

In third quarter 2017, we recognized an impairment charge of $12 million after tax on our 46.5 per cent equity investment in TransGas.

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 can elect to 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 perform a quantitative goodwill impairment test. We can also elect to proceed directly to the quantitative goodwill impairment test for any reporting unit. When a quantitative goodwill impairment test is performed, we compare the fair value of the reporting unit to its carrying value, including its goodwill. If the carrying value of a reporting unit including its goodwill exceeds its fair value, goodwill impairment is measured at the amount by which the reporting unit’s carrying value exceeds its fair value.

We determine the fair value of a reporting unit based on our projections of future cash flows, which involves making estimates and assumptions about transportation rates, market supply and demand, growth opportunities, output levels, competition from other companies, operating costs, regulatory changes, discount rates and earnings and other multiples.

Tuscarora

In fourth quarter 2018, Tuscarora finalized its regulatory filing in response to the 2018 FERC Actions resulting in a reduction in its recourse rates and, in January 2019, reached a settlement-in-principle with its customers. As a result of these developments, as well as changes to other valuation assumptions responsive to Tuscarora's commercial environment, we determined that the fair value of Tuscarora did not exceed its carrying value, including goodwill, and recorded a goodwill impairment charge of $79 million within the U.S. Natural Gas Pipelines segment. Our share of the goodwill impairment charge, after-tax and net of non-controlling interests, was $15 million. Our share of the remaining goodwill balance related to Tuscarora, net of non-controlling interests, was US$6 million at December 31, 2018 (2017 – US$21 million).

Great Lakes

At December 31, 2018, 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 its Form 501-G election, revenue opportunities on the system as well as changes to other valuation assumptions responsive to Great Lakes’ commercial environment. Although evolving market conditions and other factors relevant to Great Lakes’ long term financial performance have been positive, 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$378 million at December 31, 2018 (2017 – US$379 million).

Ravenswood

As a result of information received during the process to monetize the Company's U.S. Northeast power business in third quarter 2016, it was determined that the fair value of Ravenswood did not exceed its carrying value, including goodwill. The fair value of the reporting unit was determined using a combination of methods including a discounted cash flow analysis 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, in 2016, 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.

FINANCIAL INSTRUMENTS

Non-derivative financial instruments

Fair value of non-derivative financial instruments

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, intangible and other assets, notes payable, accounts payable and other, accrued interest and other long-term liabilities have carrying amounts that approximate their fair value due to the nature of the item or the short time to maturity and would 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. Derivative instruments, including those that qualify and are designated for hedge accounting treatment, are recorded at fair value.

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 and are classified as 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 market rates and applies a discounted cash flow valuation model. The fair value of commodity derivatives has been calculated using a market approach which bases the fair value on a comparable transaction using quoted market prices, or in the absence of quoted market prices, third-party broker quotes or other valuation techniques. Credit risk has been taken into consideration when calculating the fair value of derivative instruments. Unrealized gains and losses on derivative instruments are not necessarily representative of the amounts that will be realized on settlement.

Balance sheet presentation of derivative instruments

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

at December 31 (millions of $)	**2018**	**2017**
Other current assets	**737**	332
Intangible and other assets	**61**	73
Accounts payable and other	**(922)**	(387)
Other long-term liabilities	**(42)**	(72)
	(166)	(54)

Anticipated timing of settlement of derivative instruments

The anticipated timing of settlement of 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, 2018 (millions of $)	Total fair value	< 1 year	1 - 3 years	4 - 5 years	> 5 years
Derivative instruments held for trading					
Assets	767	717	50	—	—
Liabilities	(838)	(810)	(23)	—	(5)
Derivative instruments in hedging relationships					
Assets	31	20	8	2	1
Liabilities	(126)	(112)	(4)	(2)	(8)
	(166)	(185)	31	—	(12)

Unrealized and realized gains/(losses) on derivative instruments

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

year ended December 31 (millions of $)	2018	2017	2016
Derivative instruments held for trading[1]			
Amount of unrealized gains/(losses) in the year			
Commodities[2]	**28**	62	123
Foreign exchange	**(248)**	88	25
Interest rate	**—**	(1)	—
Amount of realized gains/(losses) in the year			
Commodities	**351**	(107)	(204)
Foreign exchange	**(24)**	18	62
Interest rate	**—**	1	—
Derivative instruments in hedging relationships			
Amount of realized (losses)/gains in the year			
Commodities	**(1)**	23	(167)
Foreign exchange	**—**	5	(101)
Interest rate	**(1)**	1	4

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

2 In 2018 and 2017, there were no gains or losses included in net income relating to discontinued cash flow hedges where it was probable that the anticipated transaction would not occur (2016 – net loss of $42 million).

Effect of fair value and cash flow hedging relationships

The following table details amounts presented on the Consolidated statement of income in which the effects of fair value or cash flow hedging relationships are recorded.

year ended December 31	Revenues (Energy)			Interest Expense		
(millions of $)	**2018**	**2017**	**2016**	**2018**	**2017**	**2016**
Total Amount Presented in the Condensed Consolidated Statement of Income	**2,124**	3,593	4,206	**(2,265)**	(2,069)	(1,998)
Fair Value Hedges						
Interest rate contracts						
Hedged items	**—**	—	—	**(71)**	(74)	(74)
Derivatives designated as hedging instruments	**—**	—	—	**(4)**	1	8
Cash Flow Hedges						
Reclassification of gains/(losses) on derivative instruments from AOCI to net income[1]						
Interest rate contracts	**—**	—	—	**22**	17	14
Commodity contracts	**5**	(20)	57	**—**	—	—

1 There are no amounts recognized in earnings that were excluded from effectiveness testing. Refer to the notes to our Consolidated financial statements.

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, 2018, the aggregate fair value of all derivative contracts with credit-risk-related contingent features that were in a net liability position was $6 million (2017 – $2 million), with no collateral provided in the normal course of business at December 31, 2018 and 2017. If the credit-risk-related contingent features in these agreements were triggered on December 31, 2018, we would have been required to provide collateral of $6 million (2017 – $2 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 2018

Revenue from contracts with customers

In 2014, the FASB issued new guidance on revenue from contracts with customers. The new guidance requires that an entity recognize revenue from these contracts in accordance with a prescribed model. This model is used to depict the transfer of promised goods or services to customers in amounts that reflect the total consideration to which it expects to be entitled during the term of the contract in exchange for those promised goods or services. Goods or services that are promised to a customer are referred to as our "performance obligations". The total consideration to which we expect to be entitled can include fixed and variable amounts. We have variable revenue that is subject to factors outside of our influence, such as market prices, actions of third parties and weather conditions. We consider this variable revenue to be "constrained" as it cannot be reliably estimated, and therefore recognize variable revenue when the service is provided.

The new guidance also requires additional disclosures about the nature, amount, timing and uncertainty of revenue recognition and related cash flows.

Our accounting policies related to revenue recognition have not substantially changed as a result of adopting the new guidance on revenue from contracts with customers. Results reported for 2018 reflect the application of the new guidance, while the 2017 and 2016 comparative results were prepared and reported under previous revenue recognition guidance which is referred to herein as "legacy U.S. GAAP". Under legacy U.S. GAAP, revenues were recognized when the risk, rewards, and benefits were transferred to the customer by the Company providing the goods or services under the contract, in an amount the Company expected to collect from the customer.

Under the new guidance applied in 2018, revenues are recognized when we satisfy our performance obligations by transferring control of the promised goods or services to our customers, in an amount that reflects the consideration we expect to be entitled to in exchange for those goods or services. We have elected to utilize a practical expedient to recognize revenues from our U.S. and certain Mexico natural gas pipelines contracts as customers are invoiced. The new guidance was effective January 1, 2018, was applied using the modified retrospective transition method, and did not result in any material differences in the amount and timing of revenue recognition.

Financial instruments

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

Income taxes

In October 2016, the FASB issued new guidance on the 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 intra-entity asset transfers when the transfer occurs. The new guidance was effective January 1, 2018, was applied using a modified retrospective approach, and resulted in an adjustment to retained earnings of $95 million.

In February 2018, the FASB issued new guidance that allows a reclassification from AOCI to retained earnings for stranded tax effects resulting from U.S. Tax Reform. This guidance can be applied either in the period of adoption or retrospectively to each period (or periods) in which the effect of the change is recognized. This new guidance is effective January 1, 2019, however, early adoption is permitted. The Company elected to early adopt this guidance effective fourth quarter 2018 and used a portfolio approach for releasing the income tax effects from AOCI to retained earnings. The Company applied this guidance retrospectively, at the beginning of the period of adoption, resulting in an adjustment to retained earnings of $17 million.

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 balance, and amounts generally described as restricted cash or restricted cash equivalents. Restricted cash and cash equivalents will be included with cash and cash equivalents when reconciling the beginning of period and end of period total amounts on the statement of cash flows. This new guidance was effective January 1, 2018, was applied retrospectively, and did not have an impact on our consolidated financial statements.

Employee post-retirement benefits

In March 2017, the FASB issued new guidance that requires entities to disaggregate the current service cost component from the other components of net benefit cost and present it with other current compensation costs for related employees in the income statement. The new guidance also requires that the other components of net benefit cost be presented elsewhere in the income statement and excluded from income from operations if such a subtotal is presented. In addition, the new guidance makes changes to the components of net benefit cost that are eligible for capitalization. Entities must use a retrospective transition method to adopt the requirement for separate presentation in the income statement of the components of net benefit cost, and a prospective transition method to adopt the change to capitalization of benefit costs. This new guidance was effective January 1, 2018 and did not have a material impact on our consolidated financial statements.

Hedge accounting

In August 2017, the FASB issued new guidance making more financial and non-financial hedging strategies eligible for hedge accounting. The new guidance also amends the presentation requirements relating to the change in fair value of a derivative and requires additional disclosures including cumulative basis adjustments for fair value hedges and the effect of hedging on individual line items in the statement of income. This new guidance is effective January 1, 2019 with early adoption permitted. This new guidance, which we elected to adopt effective January 1, 2018, was applied prospectively and did not have a material impact on our consolidated financial statements.

Derecognition of Nonfinancial Assets

In February 2017, the FASB issued new guidance that clarifies the scope provisions of nonfinancial assets and how to allocate consideration to each distinct asset. The FASB also amended the guidance for derecognition of a distinct nonfinancial asset in partial sale transactions. This new guidance was effective January 1, 2018, was applied using the modified retrospective transition method and did not have a material impact on our consolidated financial statements.

Goodwill impairment

In January 2017, the FASB issued new guidance on simplifying the test for goodwill impairment by eliminating Step 2 of the impairment test, which is the requirement to calculate the implied fair value of goodwill to measure the impairment charge. Instead, entities will record an impairment charge based on the excess of a reporting unit’s carrying amount over its fair value. This new guidance is effective January 1, 2020 with early adoption permitted. We elected to adopt this guidance effective fourth quarter 2018 as it simplified goodwill impairment testing. The guidance was applied prospectively and used in the 2018 annual goodwill impairment test.

Future accounting changes

Leases

In February 2016, the FASB issued new guidance on the accounting for leases. The new guidance amends the definition of a lease such that, in order for an arrangement to qualify as a lease, the lessee is required to have both (1) the right to obtain substantially all of the economic benefits from the use of the asset and (2) the right to direct the use of the asset. The new guidance also establishes a right-of-use (ROU) model that requires a lessee to recognize a ROU asset and corresponding lease liability on the balance sheet for all leases with a term longer than 12 months. Lessees will classify leases as finance or operating, with classification affecting the pattern of expense recognition in the statement of income. The new guidance does not make extensive changes to lessor accounting. We currently expect that substantially all of our leases where we are the lessor will continue to be classified as operating leases under the new standard.

In January 2018, the FASB issued an optional practical expedient, to be applied upon transition, to omit the evaluation of land easements not previously accounted for as leases that existed or expired prior to the entity's adoption of the new lease guidance. An entity that elects this practical expedient is required to apply it consistently to all of its existing or expired land easements not previously accounted for as leases. We will apply this practical expedient upon transition to the new standard.

The new guidance is effective January 1, 2019, with early adoption permitted. We will adopt the new standard on its effective date. A modified retrospective transition approach is required, applying the new standard to all leases existing at the date of initial application being January 1, 2019. In July 2018, the FASB issued a transition option allowing entities to not apply the new guidance, including disclosure requirements, to the comparative periods they present in their financial statements in the year of adoption. We will apply this transition option and use the effective date as the date of initial application. Consequently, financial information will not be updated and disclosures required under the new standard will not be provided for dates and periods before January 1, 2019.

We will elect the package of practical expedients which permits entities not to reassess prior conclusions about lease identification, lease classification and initial direct costs under the rules of the new standard.

We believe that the most significant effects of adoption will relate to the recognition of new ROU assets and lease liabilities on our balance sheet for our operating leases and providing significant new disclosures about our leasing activities. The guidance will not impact our income statement. On adoption, we will recognize ROU assets of approximately $606 million and additional operating lease liabilities of approximately $600 million based on the present value of the remaining minimum lease payments for existing operating leases. The new standard also provides practical expedients for ongoing accounting. We will elect the short-term lease recognition exemption for all eligible leases. This means, for those leases that qualify, we will not recognize ROU assets or lease liabilities. We will also elect the practical expedient to not separate lease and non-lease components for all leases for which we are the lessee and for facility and liquids tank terminals for which we are the lessor.

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 financial 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 as 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.

Fair value measurement

In August 2018, the FASB issued new guidance that amends certain disclosure requirements for fair value measurements. This new guidance is effective January 1, 2020, however, early adoption of certain or all requirements is permitted. We are currently evaluating the timing and impact of adoption of this guidance and have not yet determined the effect on our consolidated financial statements.

Defined benefit plans

In August 2018, the FASB issued new guidance which amends and clarifies disclosure requirements related to DB pension and other post retirement benefit plans. This new guidance is effective January 1, 2021, and will be applied on a retrospective basis, however early adoption is permitted. We are currently evaluating the timing and impact of the adoption of this guidance and have not yet determined the effect on our consolidated financial statements.

Implementation costs of cloud computing arrangements

In August 2018, the FASB issued new guidance requiring an entity in a hosting arrangement that is a service contract to follow the guidance for internal-use software to determine which implementation costs should be capitalized as an asset and which costs should be expensed. The guidance also requires the entity to amortize the capitalized implementation costs of a hosting arrangement over the term of the arrangement. This guidance is effective January 1, 2020, however, early adoption is permitted. This guidance can be applied either retrospectively or prospectively to all implementation costs incurred after the date of adoption. We are currently evaluating the timing and impact of adoption of this guidance and have not yet determined the effect on our consolidated financial statements.

Consolidation

In October 2018, the FASB issued new guidance for determining whether fees paid to decision makers and service providers are variable interests for indirect interests held through related parties under common control. This new guidance is effective January 1, 2020, and will be applied on a retrospective basis, however early adoption is permitted. We are currently evaluating the timing and 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)	2018	2017	2016
Comparable EBITDA			
Canadian Natural Gas Pipelines	**2,379**	2,144	2,182
U.S. Natural Gas Pipelines	**3,035**	2,357	1,682
Mexico Natural Gas Pipelines	**607**	519	332
Liquids Pipelines	**1,849**	1,348	1,152
Energy	**752**	1,030	1,281
Corporate	**(59)**	(21)	18
Comparable EBITDA	**8,563**	7,377	6,647
Depreciation and amortization	**(2,350)**	(2,048)	(1,939)
Comparable EBIT	**6,213**	5,329	4,708
Specific items:			
Bison asset impairment	**(722)**	—	—
Tuscarora goodwill impairment	**(79)**	—	—
U.S. Northeast power marketing contracts	**(5)**	—	—
Gain on sale of Cartier Wind power facilities	**170**	—	—
Bison contract terminations	**130**	—	—
Foreign exchange gain – inter-affiliate loan	**5**	63	—
Energy East impairment charge	**—**	(1,256)	—
Integration and acquisition related costs – Columbia	**—**	(91)	(179)
Keystone XL asset costs	**—**	(34)	(52)
Net gain/(loss) on sales of U.S. Northeast power generation assets	**—**	484	(844)
Gain on sale of Ontario solar assets	**—**	127	—
Ravenswood goodwill impairment	**—**	—	(1,085)
Alberta PPA terminations and settlement	**—**	—	(332)
Restructuring costs	**—**	—	(22)
TC Offshore loss on sale	**—**	—	(4)
Risk management activities[1]	**52**	62	123
Segmented earnings	**5,764**	4,684	2,313

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year ended December 31 (millions of $)	2018	2017	2016
Canadian Power	**3**	11	4
U.S. Power	**(11)**	39	113
Liquids marketing	**71**	—	(2)
Natural Gas Storage	**(11)**	12	8
Total unrealized gains from risk management activities	**52**	62	123

QUARTERLY RESULTS

Selected quarterly consolidated financial data

(millions of $, except per share amounts)

2018	Fourth	Third	Second	First
Revenues	**3,904**	**3,156**	**3,195**	**3,424**
Net income attributable to common shares	**1,092**	**928**	**785**	**734**
Comparable earnings	**946**	**902**	**768**	**864**
Share statistics:				
Net income per common share – basic and diluted	**$1.19**	**$1.02**	**$0.88**	**$0.83**
Comparable earnings per common share	**$1.03**	**$1.00**	**$0.86**	**$0.98**
Dividends declared per common share	**$0.69**	**$0.69**	**$0.69**	**$0.69**

2017	Fourth	Third	Second	First
Revenues	3,617	3,195	3,230	3,407
Net income attributable to common shares	861	612	881	643
Comparable earnings	719	614	659	698
Share statistics:				
Net income per common share – basic and diluted	$0.98	$0.70	$1.01	$0.74
Comparable earnings per common share	$0.82	$0.70	$0.76	$0.81
Dividends declared per common share	$0.625	$0.625	$0.625	$0.625

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:

- regulatory decisions
- developments outside of the normal course of operations
- newly constructed assets being placed in service
- demand for uncontracted transportation services
- liquids marketing activities
- certain fair value adjustments.

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

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

Factors affecting financial information by quarter

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

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

In fourth quarter 2018, comparable earnings also excluded:

- a $143 million after-tax gain related to the sale of our interests in the Cartier Wind power facilities
- a $115 million deferred income tax recovery from an MLP regulatory liability write-off resulting from the 2018 FERC Actions
- a $52 million recovery of deferred income taxes as a result of finalizing the impact of U.S. Tax Reform
- a $27 million income tax recovery related to the sale of our U.S. Northeast power generation assets
- $25 million of after-tax income recognized on the Bison contract terminations
- a $140 million after-tax impairment charge on Bison
- a $15 million after-tax goodwill impairment charge on Tuscarora
- an after-tax net loss of $7 million related to our U.S. Northeast power marketing contracts.

In third quarter 2018, comparable earnings also excluded:

- after-tax income of $8 million related to our U.S. Northeast power marketing contracts.

In second quarter 2018, comparable earnings also excluded:

- an after-tax loss of $11 million related to our U.S. Northeast power marketing contracts.

In first quarter 2018, comparable earnings also excluded:

- an after-tax gain of $6 million related to our U.S. Northeast power marketing contracts, primarily due to income recognized on the sale of our retail contracts.

In fourth quarter 2017, comparable earnings excluded:

- an $804 million recovery of deferred income taxes as a result of U.S. Tax Reform
- a $136 million after-tax gain related to the sale of our Ontario solar assets
- a $64 million net after-tax gain related to the monetization of our U.S. Northeast power generation assets
- a $954 million after-tax impairment charge for the Energy East pipeline and related projects as a result of our decision not to proceed with the project applications
- a $9 million after-tax charge related to the maintenance and liquidation of Keystone XL assets.

In third quarter 2017, comparable earnings excluded:

- an incremental net loss of $12 million after tax related to the monetization of our U.S. Northeast power generation assets
- an after-tax charge of $30 million for integration-related costs associated with the acquisition of Columbia
- an after-tax charge of $8 million related to the maintenance of Keystone XL assets.

In second quarter 2017, comparable earnings excluded:

- a $265 million net after-tax gain related to the monetization of our U.S. Northeast power generation assets which included a $441 million after-tax gain on the sale of TC Hydro and a loss of $176 million after tax on the sale of the thermal and wind package
- an after-tax charge of $15 million for integration-related costs associated with the acquisition of Columbia
- an after-tax charge of $4 million related to the maintenance of Keystone XL assets.

In first quarter 2017, comparable earnings excluded:

- a charge of $24 million after tax for integration-related costs associated with the acquisition of Columbia
- a charge of $10 million after tax for costs related to the monetization of our U.S. Northeast power generation assets
- a charge of $7 million after tax related to the maintenance of Keystone XL assets
- a $7 million income tax recovery related to the realized loss on a third party sale of Keystone XL project assets.

FOURTH QUARTER 2018 HIGHLIGHTS

Consolidated results

three months ended December 31 (millions of $, except per share amounts)	2018	2017
Canadian Natural Gas Pipelines	**450**	333
U.S. Natural Gas Pipelines	**(34)**	461
Mexico Natural Gas Pipelines	**128**	93
Liquids Pipelines	**532**	(932)
Energy	**315**	472
Corporate	**23**	63
Total segmented earnings	**1,414**	490
Interest expense	**(603)**	(541)
Allowance for funds used during construction	**161**	140
Interest income and other	**(215)**	(9)
Income before income taxes	**757**	80
Income tax (expense)/recovery	**(38)**	870
Net income	**719**	950
Net loss/(income) attributable to non-controlling interests	**414**	(49)
Net income attributable to controlling interests	**1,133**	901
Preferred share dividends	**41**	40
Net income attributable to common shares	**1,092**	861
Net income per common share – basic and diluted	**$1.19**	$0.98

Net income attributable to common shares increased by $231 million or $0.21 per common share for the three months ended December 31, 2018 compared to the same period in 2017 primarily due to the changes in net income described below, as well as the dilutive impact of common shares issued in 2017 and 2018 under our DRP and Corporate ATM program.

Fourth quarter 2018 results included:
- a $143 million after-tax gain related to the sale of our interests in the Cartier Wind power facilities
- a $115 million deferred income tax recovery from an MLP regulatory liability write-off resulting from the 2018 FERC Actions
- a $52 million recovery of deferred income taxes as a result of finalizing the impact of U.S. Tax Reform
- a $27 million income tax recovery related to the sale of our U.S. Northeast power generation assets
- $25 million of after-tax income recognized on the Bison contract terminations
- a $140 million after-tax impairment charge on Bison
- a $15 million after-tax goodwill impairment charge on Tuscarora
- an after-tax net loss of $7 million related to our U.S. Northeast power marketing contracts.

Fourth quarter 2017 results included:
- an $804 million recovery of deferred income taxes as a result of U.S. Tax Reform
- a $136 million after-tax gain related to the sale of our Ontario solar assets
- a $64 million net after-tax gain related to the monetization of our U.S. Northeast power generation assets
- a $954 million after-tax impairment charge for the Energy East pipeline and related projects as a result of our decision not to proceed with the project applications
- a $9 million after-tax charge related to the maintenance and liquidation of Keystone XL assets.

Net income in both 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 income to comparable earnings

three months ended December 31 (millions of $, except per share amounts)	2018	2017
Net income attributable to common shares	**1,092**	861
Specific items (net of tax):		
Gain on sale of Cartier Wind power facilities	**(143)**	—
MLP regulatory liability write-off	**(115)**	—
U.S. Tax Reform	**(52)**	(804)
Net gain on sales of U.S. Northeast power generation assets	**(27)**	(64)
Bison contract terminations	**(25)**	—
Bison asset impairment	**140**	—
Tuscarora goodwill impairment	**15**	—
U.S. Northeast power marketing contracts	**7**	—
Gain on sale of Ontario solar assets	**—**	(136)
Energy East impairment charge	**—**	954
Keystone XL asset costs	**—**	9
Risk management activities[1]	**54**	(101)
Comparable earnings	**946**	719
Net income per common share	**$1.19**	$0.98
Specific items (net of tax):		
Gain on sale of Cartier Wind power facilities	**(0.16)**	—
MLP regulatory liability write-off	**(0.13)**	—
U.S. Tax Reform	**(0.06)**	(0.92)
Net gain on sales of U.S. Northeast power generation assets	**(0.03)**	(0.08)
Bison contract terminations	**(0.03)**	—
Bison asset impairment	**0.16**	—
Tuscarora goodwill impairment	**0.02**	—
U.S. Northeast power marketing contracts	**0.01**	—
Gain on sale of Ontario solar assets	**—**	(0.16)
Energy East impairment charge	**—**	1.09
Keystone XL asset costs	**—**	0.01
Risk management activities[1]	**0.06**	(0.10)
Comparable earnings per common share	**$1.03**	$0.82

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three months ended December 31 (millions of $)	2018	2017
Liquids marketing	**81**	15
Canadian Power	**—**	6
U.S. Power	**20**	136
Natural Gas Storage	**(5)**	7
Foreign exchange	**(169)**	(1)
Income tax attributable to risk management activities	**19**	(62)
Total unrealized (losses)/gains from risk management activities	**(54)**	101

Comparable EBITDA to comparable earnings

Comparable EBITDA represents segmented earnings adjusted for certain aspects of the specific items described above and excludes non-cash charges for depreciation and amortization.

(millions of $)	three months ended December 31	
	2018	**2017**
Comparable EBITDA	**2,453**	1,903
Adjustments:		
Depreciation and amortization	**(681)**	(516)
Interest expense included in comparable earnings	**(603)**	(541)
Allowance for funds used during construction	**161**	140
Interest income and other included in comparable earnings	**11**	56
Income tax expense included in comparable earnings	**(268)**	(234)
Net income attributable to non-controlling interests included in comparable earnings	**(86)**	(49)
Preferred share dividends	**(41)**	(40)
Comparable earnings	**946**	719

Comparable EBITDA and comparable earnings – 2018 versus 2017

Comparable EBITDA increased by $550 million for the three months ended December 31, 2018 compared to the same period in 2017 primarily due to the net effect of the following:

- higher contribution from Canadian Natural Gas Pipelines primarily due to the recovery of increased depreciation as a result of higher rates approved in both the Mainline NEB 2018 Decision and the NGTL 2018-2019 Settlement, as well as higher flow-through taxes and incentive earnings
- higher contribution from U.S. Natural Gas Pipelines mainly due to increased earnings from Columbia Gas and Columbia Gulf growth projects placed in service, additional contract sales on ANR and Great Lakes, and amortization of net regulatory liabilities recognized as a result of U.S. Tax Reform
- higher contribution from Liquids Pipelines primarily due to higher volumes on the Keystone Pipeline System, increased earnings from liquids marketing activities and earnings from intra-Alberta pipelines placed in service in the second half of 2017
- higher revenues from Mexico Natural Gas Pipelines as a result of changes in timing of revenue recognition
- lower earnings from Bruce Power primarily due to lower volumes resulting from higher outage days.

Comparable earnings increased by $227 million or $0.21 per common share for the three months ended December 31, 2018 compared to the same period in 2017 and was primarily the net effect of:

- changes in comparable EBITDA described above
- higher depreciation primarily in Canadian Natural Gas Pipelines due to increased depreciation rates approved in the Mainline NEB 2018 Decision and the NGTL 2018-2019 Settlement (these amounts are fully recovered as reflected in the increase in comparable EBITDA described above, having no net impact on comparable earnings) as well as higher depreciation related to new projects placed in service in 2017 and 2018
- higher interest expense primarily as a result of long-term debt and junior subordinated notes issuances, net of maturities
- lower interest income and other as a result of realized losses in 2018 compared to realized gains in 2017 on derivatives used to manage net exposure to foreign exchange rate fluctuations on U.S. dollar-denominated income.

Comparable earnings per common share for the three months ended December 31, 2018 also reflect the dilutive impact of common shares issued in 2017 and 2018 under our DRP and our Corporate ATM program.

Highlights by business segment

Canadian Natural Gas Pipelines

Canadian Natural Gas Pipelines segmented earnings increased by $117 million for the three months ended December 31, 2018 compared to the same period in 2017 and are equivalent to comparable EBIT.

Net income for the NGTL System increased by $18 million for the three months ended December 31, 2018 compared to the same period in 2017 mainly due to a higher average investment base as a result of continued system expansions and higher OM&A incentive earnings.

Net income for the Canadian Mainline increased by $11 million for the three months ended December 31, 2018 compared to the same period in 2017 primarily due to higher incentive earnings as a result of recording the full year impact of the Canadian Mainline 2018-2020 toll review upon receipt of the Mainline NEB 2018 Decision.

Comparable EBITDA increased by $249 million for the three months ended December 31, 2018 compared to the same period in 2017 primarily due to the recovery of increased depreciation as a result of higher rates approved in both the Mainline NEB 2018 Decision and the NGTL 2018-2019 Settlement, as well as higher flow-through taxes and incentive earnings. The full year impact of higher depreciation, flow-through taxes and incentive earnings as a result of the Canadian Mainline NEB 2018 Decision was reflected in fourth quarter 2018.

Depreciation and amortization increased by $132 million for the three months ended December 31, 2018 compared to the same period in 2017 mainly due to the increase in depreciation rates approved in the Mainline NEB 2018 Decision and the NGTL 2018-2019 Settlement, as well as NGTL System facilities that were placed in service in 2018.

U.S. Natural Gas Pipelines

U.S. Natural Gas Pipelines segmented earnings decreased by $495 million for the three months ended December 31, 2018 compared to the same period in 2017.

Segmented earnings for the three months ended December 31, 2018 included:

- a $722 million non-cash asset impairment charge related to Bison
- a $79 million non-cash goodwill impairment charge related to Tuscarora
- $130 million of termination payments received on two of Bison's transportation contracts which was recorded in Revenues.

The amounts for each of these specified items are pre-tax and before reduction for the 74.5 per cent non-controlling interests in TC PipeLines, LP and have been excluded from our calculation of comparable EBIT. A stronger U.S. dollar in fourth quarter 2018 had a positive impact on the Canadian dollar equivalent segmented earnings from our U.S. operations compared to the same period in 2017.

Comparable EBITDA for U.S. Natural Gas Pipelines increased by US$138 million for the three months ended December 31, 2018 compared to the same period in 2017 and was primarily the net effect of:

- increased earnings from Columbia Gas and Columbia Gulf growth projects placed in service and additional contract sales on ANR and Great Lakes
- increased earnings due to the amortization of the net regulatory liabilities recognized in 2017, partially offset by a reduction in certain rates on Columbia Gas, as a result of U.S. Tax Reform.

Depreciation and amortization increased by US$18 million for the three months ended December 31, 2018 compared to the same period in 2017 mainly due to new projects placed in service.

Mexico Natural Gas Pipelines

Mexico Natural Gas Pipelines segmented earnings increased by $35 million for the three months ended December 31, 2018 compared to the same period in 2017 and are equivalent to comparable EBIT.

Comparable EBITDA for Mexico Natural Gas Pipelines increased by US$24 million for the three months ended December 31, 2018 compared to the same period in 2017 primarily due to:

- higher revenues from operations as a result of changes in timing of revenue recognition
- equity earnings from our investment in the Sur de Texas pipeline which records AFUDC during construction, net of interest expense on an inter-affiliate loan from TransCanada. The interest expense on this inter-affiliate loan is fully offset in Interest income and other in the Corporate segment
- incremental earnings from a CRE tariff increase.

Depreciation and amortization remained largely consistent for the three months ended December 31, 2018 compared to the same period in 2017.

Liquids Pipelines

Liquids Pipelines segmented earnings increased by $1,464 million for the three months ended December 31, 2018 compared to the same period in 2017 and included the following specific items:

- a $1,256 million pre-tax impairment charge in 2017 for the Energy East pipeline and related projects
- $11 million of pre-tax costs in 2017 related to Keystone XL for the maintenance and liquidation of project assets which were expensed pending further advancement of the project
- unrealized gains from changes in the fair value of derivatives related to our liquids marketing business.

Comparable EBITDA for Liquids Pipelines increased by $137 million for the three months ended December 31, 2018 compared to the same period in 2017 primarily due to:

- higher contracted and uncontracted volumes on the Keystone Pipeline System
- higher contribution from liquids marketing activities from improved margins and volumes
- incremental contributions from intra-Alberta pipelines, Grand Rapids and Northern Courier, which began operations in the second half of 2017
- lower business development costs as a result of capitalizing Keystone XL expenditures in 2018
- a stronger U.S. dollar which had a positive impact on the Canadian dollar equivalent earnings from our U.S. operations.

Depreciation and amortization increased by $6 million for the three months ended December 31, 2018 compared to the same period in 2017 as a result of new facilities being placed in service and the effect of a stronger U.S. dollar.

Energy

Energy segmented earnings were $157 million lower in the three months ended December 31, 2018 compared to the same period in 2017 and included the following specific items:

- a pre-tax gain in 2018 of $170 million related to the sale of our interests in the Cartier Wind power facilities
- a pre-tax net loss of $10 million related to our U.S. Northeast power marketing contracts. These results have been excluded from Energy's comparable earnings in 2018 as we do not consider the wind-down of the remaining contracts part of our underlying operations. The contract portfolio is scheduled to run-off through to mid-2020
- a pre-tax gain in 2017 of $127 million related to the sale of our Ontario solar assets
- a pre-tax net gain of $15 million in 2017 related to the monetization of our U.S. Northeast power generation assets
- unrealized gains and losses from changes in the fair value of derivatives used to reduce our exposure to certain commodity price risks.

Comparable EBITDA for Energy decreased by $47 million for the three months ended December 31, 2018 compared to the same period in 2017 mainly due to the net effect of:

- decreased earnings from Bruce Power primarily due to lower volumes resulting from higher outage days
- decreased Western and Eastern Power results due to the sales of our Cartier Wind power facilities in October 2018 and our Ontario solar assets in December 2017, partially offset by higher Western Power realized margins on higher generation volumes
- lower Natural Gas Storage results primarily due to pipeline constraints in the Alberta natural gas market which limited our ability to access our storage facilities and resulted in lower realized natural gas storage price spreads.

Depreciation and amortization decreased by $6 million for the three months ended December 31, 2018 compared to the same period on 2017 primarily due to the cessation of depreciation on our Cartier Wind power facilities upon classification as held for sale at June 30, 2018.

Corporate

Corporate segmented earnings decreased by $40 million for the three months ended December 31, 2018 compared to the same period in 2017 and included the following specific items:

- foreign exchange gains on a peso-denominated inter-affiliate loan to the Sur de Texas project for our proportionate share of the project's financing. There is a corresponding foreign exchange loss included in Interest income and other on the inter-affiliate loan receivable which fully offsets this gain.

Comparable EBITDA decreased by $33 million for the three months ended December 31, 2018 compared to the same period in 2017, primarily due to increased general and administrative costs.

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
MMcf/d	Million cubic feet per day
MW	Megawatt(s)
MWh	Megawatt hours
PJ/d	Petajoule per day
TJ/d	Terajoule per day

General terms and terms related to our operations

ATM	An at-the-market program allowing us to issue common shares from treasury at the prevailing market price
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
DRP	Dividend reinvestment plan
Empress	A major delivery/receipt point for natural gas near the Alberta/Saskatchewan border
FID	Final investment decision
force majeure	Unforeseeable circumstances that prevent a party to a contract from fulfilling it
GHG	Greenhouse gas
HSSE	Health, safety, sustainability and environment
investment base	Includes rate base as well as assets under construction
LDC	Local distribution company
LNG	Liquefied natural gas
LTAA	Long Term Adjustment Account
MLP	Master limited partnership
OM&A	Operating, maintenance and administration
PPA	Power purchase arrangement
rate base	Average assets in service, working capital and deferred amounts used in setting of regulated rates
TOMS	TransCanada Operational Management System
TSA	Transportation Service Agreement
WCSB	Western Canada Sedimentary Basin

Accounting terms

AFUDC	Allowance for funds used during construction
AOCI	Accumulated other comprehensive (loss)/income
FASB	Financial Accounting Standards Board (U.S.)
GAAP	U.S. generally accepted accounting principles
RRA	Rate-regulated accounting
ROE	Return on common equity

Government and regulatory bodies terms

AER	Alberta Energy Regulator
CCIR	Carbon Competitiveness Incentive Regulation
CEPA	Canadian Energy Pipeline Association
CFE	Comisión Federal de Electricidad (Mexico)
CGA	Canadian Gas Association
CRE	Comisión Reguladora de Energia, or Energy Regulatory Commission (Mexico)
DOJ	U.S. Department of Justice
DOS	U.S. Department of State
FERC	Federal Energy Regulatory Commission (U.S.)
IESO	Independent Electricity System Operator
NEB	National Energy Board (Canada)
NYSE	New York Stock Exchange
OBPS	Output Based Pricing System
OPEC	Organization of the Petroleum Exporting Countries
OPG	Ontario Power Generation
PHMSA	Pipeline and Hazardous Materials Safety Administration
SEC	U.S. Securities and Exchange Commission
SDDENR	South Dakota Department of Environment and Natural Resources
SGER	Specified Gas Emitters Regulations (replaced by the CCIR)
TSX	Toronto Stock Exchange