



ENBRIDGE INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS

December 31, 2018

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

INTRODUCTION

The following discussion and analysis of our financial condition and results of operations is based on and should be read in conjunction with "Forward-Looking Information", Part I. *Item 1A. Risk Factors* and our consolidated financial statements and the accompanying notes included in Part II. *Item 8. Financial Statements and Supplementary Data* of this Annual Report on Form 10-K.

SIMPLIFICATION OF CORPORATE STRUCTURE

On May 17, 2018, we announced four separate non-binding all-share proposals to the respective boards of directors of our sponsored vehicles, Spectra Energy Partners, LP (SEP), Enbridge Energy Partners, L.P. (EEP), Enbridge Energy Management, L.L.C. (EEM) and Enbridge Income Fund Holdings Inc. (ENF), (collectively, the Sponsored Vehicles), to acquire, in separate combination transactions, all of the outstanding equity securities of those sponsored vehicles not beneficially owned by us.

On August 24, 2018, we announced that we entered into a definitive agreement with SEP under which we would acquire all of the outstanding public common units of SEP on the basis of 1.111 of our common shares for each common unit of SEP. Closing of the transaction occurred on December 17, 2018, resulting in us acquiring all of the outstanding public common units of SEP and SEP becoming a wholly-owned subsidiary of Enbridge Inc. (Enbridge). The transaction is valued at \$3.9 billion based on the closing price of our common shares on the New York Stock Exchange (NYSE) on December 14, 2018.

On September 18, 2018, we announced that we entered into definitive agreements with each of EEP and EEM under which we would acquire all of the outstanding public class A common units of EEP and all of the outstanding public listed shares of EEM. EEP public unitholders will receive 0.335 of our common shares for each class A common unit of EEP, and EEM public shareholders will receive 0.335 of our common shares for each listed share of EEM. Closing of the transactions occurred on December 20, 2018. The closing of the EEP transaction resulted in us acquiring all of the outstanding public class A common units of EEP and EEP becoming a wholly-owned subsidiary of Enbridge. The closing of the EEM transaction resulted in us acquiring all of the outstanding public listed shares of EEM and EEM becoming a wholly-owned subsidiary of Enbridge. The EEP and EEM transactions are valued at \$3.0 billion and \$1.3 billion, respectively, based on the closing price of our common shares on the NYSE on December 19, 2018.

On September 18, 2018, we announced that we entered into a definitive agreement with ENF under which we would acquire all of the issued and outstanding public common shares of ENF on the basis of 0.735 of our common shares and cash of \$0.45 for each common share of ENF. Closing of the transaction occurred on November 8, 2018, resulting in us acquiring all of the issued and outstanding public common shares of ENF and ENF becoming a wholly-owned subsidiary of Enbridge. The transaction, excluding the cash portion, is valued at \$4.5 billion based on the closing price of our common shares on the Toronto Stock Exchange on November 7, 2018.

ASSET MONETIZATION

Renewable Assets

On August 1, 2018, we closed the sale of a 49% interest in all of our Canadian renewable assets, a 49% interest in two United States renewable assets and 49% of our interest in the Hohe See Offshore wind power project and its subsequent expansion, both concurrently under construction in Germany, (collectively, the Renewable Assets) to the Canada Pension Plan Investment Board (CPPIB). Total cash proceeds from the transaction were \$1.75 billion. In addition, CPPIB will fund their pro-rata share of the

remaining capital expenditures on the Hohe See Offshore wind project. We maintain a 51% interest in the Renewable Assets and will continue to manage, operate and provide administrative services for these assets.

Midcoast Operating, L.P.

On August 1, 2018, we closed the sale of Midcoast Operating, L.P. and its subsidiaries (collectively, MOLP) to AL Midcoast Holdings, LLC (an affiliate of ArcLight Capital Partners, LLC) for total cash proceeds of \$1.4 billion (US\$1.1 billion).

Canadian Natural Gas Gathering and Processing Businesses

On July 4, 2018, we entered into agreements to sell our Canadian natural gas gathering and processing businesses for a cash purchase price of approximately \$4.3 billion to Brookfield Infrastructure Partners L.P. and its institutional partners. Separate agreements were entered into for those facilities currently governed by provincial regulations and those governed by federal regulations. On October 1, 2018, we closed the sale of the provincially regulated facilities for proceeds of approximately \$2.5 billion. The sale of the federally regulated facilities is expected to close in mid-2019 for proceeds of approximately \$1.8 billion.

Enbridge Gas New Brunswick Business

On December 4, 2018, we announced that we entered into a definitive agreement for the sale of Enbridge Gas New Brunswick Limited Partnership and Enbridge Gas New Brunswick Inc. (together, EGNB) to Liberty Utilities (Canada) LP, a wholly-owned subsidiary of Algonquin Power and Utilities Corp., for a cash purchase price of \$331 million. Closing of the transaction remains subject to the receipt of regulatory approvals and other customary closing conditions expected to occur in 2019.

Refer to *Liquidity and Capital Resources - Sources and Uses of Cash* for details on the use of proceeds from our asset monetization activity discussed above.

ONTARIO ENERGY BOARD DECISION ON AMALGAMATION

On August 30, 2018, we received a decision from the Ontario Energy Board (OEB) approving the application to amalgamate Enbridge Gas Distribution Inc. (EGD) and Union Gas Limited (Union Gas). On October 15, 2018, we announced that we will proceed with the amalgamation of EGD and Union Gas, with an expected effective date of January 1, 2019. On January 1, 2019, the amalgamation was completed and the amalgamated company continued as Enbridge Gas Inc. (EGI).

MINNESOTA PUBLIC UTILITIES COMMISSION APPROVAL OF U.S. LINE 3 REPLACEMENT PROGRAM

On June 28, 2018, the Minnesota Public Utilities Commission (MNPU) approved the issuance of a Certificate of Need (Certificate) and pipeline route (Route Permit) for construction of the United States Line 3 Replacement Program (U.S. L3R Program) in Minnesota. The Route Permit adopted our preferred route, with minor modifications and subject to certain conditions. For further details refer to *Growth Projects - Regulatory Matters - United States Line 3 Replacement Program*.

REVISED FERC POLICY ON TREATMENT OF INCOME TAXES

On March 15, 2018, the Federal Energy Regulatory Commission (FERC) revised a long standing policy announcing that it would no longer permit entities organized as Master Limited Partnerships (MLPs) to recover an income tax allowance for interstate pipeline assets with cost-of-service rates. The announcement of the Revised Policy Statement was accompanied by: (i) a Notice of Proposed Rulemaking proposing interstate natural gas pipelines 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 pipeline; and (ii)

a Notice of Inquiry seeking comment on how FERC should address changes related to accumulated deferred income taxes and bonus depreciation.

We hold our United States liquids and natural gas pipelines through a number of different ownership structures. We responded to the FERC announcement regarding tax allowance, both directly and through industry associations, objecting to the change in FERC policy and requesting a re-hearing. On April 27, 2018, the FERC issued a tolling order for the purpose of affording it additional time for consideration of matters raised on rehearing. These FERC announcements have adversely affected MLPs generally.

On July 18, 2018, the FERC issued an Order that: (1) dismissed all requests for rehearing of its March 15, 2018 revised policy statement and explained that its revised policy statement does not establish a binding rule, but is instead an expression of general policy that the Commission intends to follow in the future; and (2) provides guidance that if an MLP or other tax pass-through pipeline eliminates its income tax allowance from its cost of service pursuant to FERC's Revised Policy Statement, then Accumulated Deferred Income Taxes (ADIT) will similarly be removed from its cost of service and MLP pipelines may also eliminate previously-accumulated sums in ADIT. As a statement of general policy, the FERC will consider alternative application of its tax allowance and ADIT policy on a case-by-case basis.

There are many uncertainties with regards to the implementation of the recent FERC actions, including the potential for different outcomes as the result of a rate case or customer challenges. We expect that the elimination of our MLP structures, resulting from the buy-in of our Sponsored Vehicles, will allow for all applicable pipelines, 100% owned by us, to qualify for an income tax allowance.

UNITED STATES TAX REFORM

On December 22, 2017, the United States enacted the Tax Cuts and Jobs Act (TCJA or United States Tax Reform). As disclosed in our Annual Report on Form 10-K, filed with the Securities and Exchange Commission on February 16, 2018, for the year ending December 31, 2017, we recognized reasonable estimates for 1) effects to our deferred tax balances for the impact of the tax rate decrease; and 2) the one time impact for the repatriation tax. While our accounting for tax reform pursuant to SAB 118 is complete, the ultimate impact from the TCJA, whether adverse or favorable, is still uncertain. While the United States Treasury has issued substantial guidance in 2018 in the form of proposed regulations, uncertainty will still exist until the regulations are finalized.

During the first quarter of 2018 we refined our calculation of the regulatory liability associated with the TCJA which resulted in a \$30 million reduction to the overall regulatory liability. An additional reduction to the regulatory liability in the amount of \$223 million was recorded in the fourth quarter of 2018 in connection with rate cases filed that eliminated a portion of the regulatory liability formerly included in our US Gas Transmission businesses rate base.

We recorded \$43 million in tax expense for the year ended December 31, 2018, in connection with the Base Erosion and Anti-abuse Tax (BEAT), and we recorded no provision for the Global Intangible Low Taxed Income Tax (GILTI).

FORWARD-LOOKING INFORMATION

Forward-looking information, or forward-looking statements, have been included in this MD&A to provide information about us and our subsidiaries and affiliates, including management's assessment of our and our subsidiaries' future plans and operations. This information may not be appropriate for other purposes. Forward-looking statements are typically identified by words such as "anticipate", "believe", "estimate", "expect", "forecast", "intend", "likely", "plan", "project", "target" and similar words suggesting future outcomes or statements regarding an outlook. Forward-looking information or statements included or incorporated by reference in this document include, but are not limited to, statements with respect to the following: expected earnings before interest, income taxes and depreciation and amortization (EBITDA); expected earnings/(loss); expected earnings/(loss) per share; expected future cash flows; expected performance of the Liquids Pipelines, Gas Transmission and Midstream, Gas Distribution, Green Power and Transmission, and Energy Services businesses; financial strength and flexibility; expectations on sources of liquidity and sufficiency of financial resources; expected costs related to announced projects and projects under construction; expected in-service dates for announced projects and projects under construction; expected capital expenditures; expected equity funding requirements for our commercially secured growth program; expected future growth and expansion opportunities; expectations about our joint venture partners' ability to complete and finance projects under construction; expected closing of acquisitions and dispositions and expected timing thereof; estimated future dividends; expected future actions of regulators; expected costs related to leak remediation and potential insurance recoveries; expectations regarding commodity prices; supply forecasts; expectations regarding the impact of the stock-for-stock merger transaction completed on February 27, 2017 between Enbridge and Spectra Energy Corp (the Merger Transaction) including our combined scale, financial flexibility, growth program, future business prospects and performance; United States Line 3 Replacement Program (U.S. L3R Program); expected impact of the Federal Energy Regulatory Commission (FERC) policy on treatment of income taxes; the sponsored vehicle strategy, including the simplification of our corporate structure; our dividend payout policy; dividend growth and dividend payout expectation; expectations on impact of our hedging program; and expectations resulting from the successful execution of our 2018-2020 Strategic Plan.

Although we believe these forward-looking statements are reasonable based on the information available on the date such statements are made and processes used to prepare the information, such statements are not guarantees of future performance and readers are cautioned against placing undue reliance on forward-looking statements. By their nature, these statements involve a variety of assumptions, known and unknown risks and uncertainties and other factors, which may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such statements. Material assumptions include assumptions about the following: the expected supply of and demand for crude oil, natural gas, natural gas liquids (NGL) and renewable energy; prices of crude oil, natural gas, NGL and renewable energy; exchange rates; inflation; interest rates; availability and price of labor and construction materials; operational reliability; customer and regulatory approvals; maintenance of support and regulatory approvals for our projects; anticipated in-service dates; weather; the timing and closing of dispositions; the realization of anticipated benefits and synergies of the Merger Transaction; governmental legislation; acquisitions and the timing thereof; the success of integration plans; impact of our dividend policy on our future cash flows; our credit ratings; capital project funding; expected EBITDA; expected earnings/(loss); expected earnings/(loss) per share; expected future cash flows and estimated future dividends. Assumptions regarding the expected supply of and demand for crude oil, natural gas, NGL and renewable energy, and the prices of these commodities, are material to and underlie all forward-looking statements, as they may impact current and future levels of demand for our services. Similarly, exchange rates, inflation and interest rates impact the economies and business environments in which we operate and may impact levels of demand for our services and cost of inputs, and are therefore inherent in all forward-looking statements. Due to the interdependencies and correlation of these macroeconomic factors, the impact of any one assumption on a forward-looking statement cannot be determined with certainty, particularly with respect to the impact of the Merger Transaction on us, expected EBITDA, expected earnings/(loss), expected earnings/(loss) per share, expected future cash flows or estimated future dividends. The most relevant assumptions associated with forward-looking statements on announced projects and projects under construction, including estimated completion dates and expected capital expenditures, include the following: the availability and price of labor and construction materials; the effects of inflation and foreign exchange rates on labor and material costs; the effects of interest rates on borrowing costs; the impact of weather and customer, government and regulatory approvals on construction and in-service schedules and cost recovery regimes.

Our forward-looking statements are subject to risks and uncertainties pertaining to the realization of anticipated benefits and synergies of the Merger Transaction, operating performance, regulatory parameters, changes in regulations applicable to our business, dispositions, the transactions undertaken to simplify our corporate structure, our dividend policy, project approval and support, renewals of rights-of-way, weather, economic and competitive

conditions, public opinion, changes in tax laws and tax rates, changes in trade agreements, exchange rates, interest rates, commodity prices, political decisions and supply of and demand for commodities, including but not limited to those risks and uncertainties discussed in this MD&A and in our other filings with Canadian and United States securities regulators. The impact of any one risk, uncertainty or factor on a particular forward-looking statement is not determinable with certainty as these are interdependent and our future course of action depends on management's assessment of all information available at the relevant time. Except to the extent required by applicable law, Enbridge Inc. assumes no obligation to publicly update or revise any forward-looking statement made in this MD&A or otherwise, whether as a result of new information, future events or otherwise. All forward-looking statements, whether written or oral, attributable to us or persons acting on our behalf, are expressly qualified in their entirety by these cautionary statements.

RESULTS OF OPERATIONS

	Year ended December 31,		
	2018	2017	2016
<i>(millions of Canadian dollars, except per share amounts)</i>			
Segment earnings/(loss) before interest, income taxes and depreciation and amortization			
Liquids Pipelines	5,331	6,395	4,926
Gas Transmission and Midstream	2,334	(1,269)	464
Gas Distribution	1,711	1,390	831
Green Power and Transmission	369	372	344
Energy Services	482	(263)	(183)
Eliminations and Other	(708)	(337)	(101)
Depreciation and amortization	(3,246)	(3,163)	(2,240)
Interest expense	(2,703)	(2,556)	(1,590)
Income tax recovery/(expense)	(237)	2,697	(142)
Earnings attributable to noncontrolling interests and redeemable noncontrolling interests	(451)	(407)	(240)
Preference share dividends	(367)	(330)	(293)
Earnings attributable to common shareholders	2,515	2,529	1,776
Earnings per common share	1.46	1.66	1.95
Diluted earnings per common share	1.46	1.65	1.93

EARNINGS ATTRIBUTABLE TO COMMON SHAREHOLDERS

Year ended December 31, 2018 compared with year ended December 31, 2017

Earnings Attributable to Common Shareholders for the year ended December 31, 2018 were positively impacted by contributions in the first two months of 2018 of approximately \$364 million from assets whose performance was not reflected in Earnings Attributable to Common Shareholders for the first two months of 2017 due to the timing of the completion of the stock-for-stock merger transaction on February 27, 2017 between Enbridge and Spectra Energy Corp (the Merger Transaction).

After taking into consideration the contribution of additional earnings from the Merger Transaction, Earnings Attributable to Common Shareholders was negatively impacted by \$1,600 million due to certain unusual, infrequent or other factors, primarily explained by the following:

- a goodwill impairment charge of \$1,019 million in 2018 resulting from the classification of our Canadian natural gas gathering and processing businesses as held for sale, refer to *Item 8. Financial Statements and Supplementary Data - Note 8. Acquisitions and Dispositions - Dispositions*;
- a loss in 2018 of \$913 million (\$701 million after-tax attributable to us) on MOLP resulting from a revision to the fair value of the assets held for sale based on the sale price; refer to *Item 8. Financial Statements and Supplementary Data - Note 8. Acquisitions and Dispositions - Dispositions*;
- a non-cash, unrealized derivative fair value loss of \$894 million (\$568 million after-tax attributable to us) in 2018, compared with a gain of \$1,109 million (\$624 million after-tax attributable to us) in the corresponding 2017 period, reflecting net fair value gains and losses arising from changes in the mark-to-market value of derivative financial instruments used to manage foreign exchange and commodity prices risks;
- a loss of \$154 million (\$95 million after-tax attributable to us) in 2018 related to the Line 10 crude oil pipeline (Line 10), which is a component of our mainline system, resulting from its classification as an asset held for sale and the subsequent measurement at the lower of carrying value or fair value less costs to sell;
- asset monetization transaction costs of \$88 million (\$80 million after-tax attributable to us) recorded in 2018 attributable to divestiture activity in the year, refer to *Asset Monetization*;
- the absence in 2018 of a non-cash, \$1,936 income tax benefit (\$2,045 million federal tax recovery net of a \$109 million state deferred tax expense) due to the enactment of the TCJA by the United States in December 2017, refer to *Item 8. Financial Statements and Supplementary Data - Note 25. Income Taxes*; partially offset by
- the absence in 2018 of a loss of \$4,391 million (\$2,753 after-tax attributable to us) and related goodwill impairment of \$102 million recorded in 2017 resulting from the classification of MOLP assets as held for sale and the subsequent measurement at the lower of their carrying value or fair value less costs to sell, refer to *Item 8. Financial Statements and Supplementary Data - Note 8. Acquisitions and Dispositions - Dispositions*;
- a deferred income tax recovery of \$267 million (\$196 million after-tax attributable to us) in 2018 related to a change in the assertion for the investment in Canadian renewable energy generation assets due to the pending sale which resulted in a revaluation of the related deferred tax liability to the capital gains tax rate and recognition of previously unrecognized tax basis;
- employee severance, transition and transformation costs of \$203 million (\$181 million after-tax attributable to us) in 2018, compared with \$354 million (\$273 million after-tax attributable to us) in the corresponding 2017 period;
- the absence in 2018 of transaction costs of \$180 million (\$131 million after-tax attributable to us) recorded in 2017 related to the Merger Transaction;
- a recovery of \$223 million after-tax attributable to us in 2018 related to rate cases filed that eliminated a portion of the regulated liability formerly included in our US Gas Transmission businesses rate base, refer to *United States Tax Reform*; and

- a gain of \$63 million after-tax attributable to us in 2018 resulting from the impact of United States Tax Reform on our United States Green Power and Transmission assets.

The non-cash, unrealized derivative fair value gains and losses discussed above, generally arise as a result of a comprehensive long-term economic hedging program to mitigate interest rate, foreign exchange and commodity price risks. This program creates volatility in reported short-term earnings through the recognition of unrealized non-cash gains and losses on financial derivative instruments used to hedge these risks. Over the long-term, we believe our hedging program supports the reliable cash flows and dividend growth upon which our investor value proposition is based.

After taking into consideration the factors above, the remaining \$1,222 million increase in Earnings Attributable to Common Shareholders is primarily explained by the following significant business factors:

- stronger contributions from our Liquids Pipelines segment due to a higher foreign exchange hedge rate used to lock-in United States dollar denominated Canadian Mainline revenues, a higher IJT Benchmark Toll and higher throughput driven by the full year impact of capacity optimization initiatives implemented in 2017;
- contributions from new Liquids Pipelines assets placed into service in 2017;
- contributions from new Gas Transmission and Midstream assets placed into service in 2017 and 2018;
- increased earnings from some of our Gas Transmission and Midstream equity investments due to favorable margins, favorable commodity prices and increased volume commitments;
- increased earnings from our Gas Distribution segment due to colder weather, expansion projects and higher distribution charges resulting from growth in rate base; and
- increased earnings from our Energy Services segment due to the widening of certain location differentials, which increased opportunities to generate profitable margins; partially offset by
- higher interest expense primarily due to long-term debt issuances in 2017 and the first half of 2018 to finance capital expansions; and
- higher income tax expense driven by higher earnings from the business factors described above.

Lower earnings per common share for 2018 is primarily due to the increase in the number of common shares outstanding following the issuance of approximately 297 million common shares in the fourth quarter of 2018 resulting from the buy-in of our Sponsored Vehicles, refer to *Simplification of Corporate Structure*, the issuance of approximately 33 million common shares in December 2017 in a private placement offering, and the issuance of approximately 691 million common shares in February 2017 as part of the consideration for the Merger Transaction. This dilutive effect was partially offset by the increase in Earnings Attributable to Common Shareholders resulting from the factors discussed above.

Year ended December 31, 2017 compared with year ended December 31, 2016

Earnings Attributable to Common Shareholders for the year ended December 31, 2017 were positively impacted by contributions in the last ten months of 2017 of approximately \$2,574 million from assets whose performance was not reflected in Earnings Attributable to Common Shareholders for 2016 due to the timing of the completion of the Merger Transaction.

After taking into consideration the contribution of additional earnings from the Merger Transaction, Earnings Attributable to Common Shareholders decreased by \$151 million due to certain unusual, infrequent or other factors, primarily explained by the following:

- a loss of \$4,391 million (\$2,753 million after-tax attributable to us) and related goodwill impairment of \$102 million resulting from the classification of certain assets as held for sale and the subsequent measurement at the lower of their carrying value or fair value less costs to sell, refer to *Item 8. Financial Statements and Supplementary Data - Note 8. Acquisitions and Dispositions - Dispositions*;
- employee severance, transition and transformation costs of \$354 million (\$273 million after-tax attributable to us) in 2017, compared with \$82 million in the corresponding 2016 period;

- transaction costs of \$180 million (\$131 million after-tax attributable to us) in 2017, compared with \$86 million in the corresponding 2016 period, related to the Merger Transaction; and
- the absence in 2017 of a gain of \$850 million (\$520 million after-tax attributable to us) recorded in 2016 related to the disposition of the South Prairie Region assets; partially offset by
- a non-cash, \$1,936 million income tax benefit (\$2,045 million federal tax recovery net of a \$109 million state deferred tax expense) due to the enactment of the TCJA by the United States in December 2017, refer to *Item 8. Financial Statements and Supplementary Data - Note 25. Income Taxes*;
- a non-cash, unrealized derivative fair value gain of \$1,109 million in 2017 (\$624 million after-tax attributable to us), compared with a gain of \$543 million (\$459 million after-tax attributable to us) in the corresponding 2016 period reflecting net fair value gains and losses arising from changes in the mark-to-market value of derivative financial instruments used to manage foreign exchange and commodity prices risks; and
- the absence in 2017 of cumulative asset impairment charges of \$1,561 million (\$456 million after-tax attributable to us) recorded in 2016 related to EEP's Sandpiper Project, the Northern Gateway Project and Eddystone Rail.

After taking into consideration the factors above, the remaining \$1,670 million decrease in Earnings Attributable to Common Shareholders is primarily explained by the following significant business factors:

- increased depreciation and amortization expense primarily resulting from a significant number of new assets placed into service in 2017;
- increased interest expense primarily resulting from the settlement of certain pre-issuance hedges;
- increased earnings attributable to noncontrolling interests and redeemable noncontrolling interests in 2017, compared with the corresponding 2016 period. The increase was driven by higher earnings attributable to noncontrolling interests in EEP during 2017 as a result of the EEP strategic restructuring actions; and
- the absence of earnings from certain assets that were divested since the third quarter of 2016; partially offset by
- strong contributions from our Liquids Pipelines segment due to higher throughput primarily attributable to capacity optimization initiatives implemented in 2017 which significantly reduced heavy crude oil apportionment allowing incremental heavy crude oil barrels to be shipped;
- contributions from new Liquids Pipelines assets placed into service in 2017; and
- increased earnings from our Gas Transmission and Midstream segment in 2017 due to favorable seasonal firm revenue and a full year of contributions from assets acquired in 2016.

Lower earnings per common share for 2017 is primarily due to the increase in common shares from the issuance of approximately 33 million common shares in December 2017 in a private placement offering, the issuance of approximately 691 million common shares in February 2017 as part of the consideration for the Merger Transaction, the issuance of approximately 75 million common shares in 2016 through the public offering of 56 million common shares in the first quarter of 2016, and ongoing quarterly issuances under our Dividend Reinvestment Program. Additional earnings from the assets acquired in the Merger Transaction were offset by certain unusual, infrequent or other factors, as discussed above.

REVENUES

We generate revenues from three primary sources: transportation and other services, gas distribution sales and commodity sales.

Transportation and other services revenues of \$14,358 million, \$13,877 million and \$9,258 million for the years ended December 31, 2018, 2017 and 2016, respectively, were earned from our crude oil and natural gas pipeline transportation businesses and also include power production revenues from our portfolio of renewable and power generation assets. For our transportation assets operating under market-based arrangements, revenues are driven by volumes transported and the corresponding tolls for transportation services. For assets operating under take-or-pay contracts, revenues reflect the terms of the underlying contract for services or capacity. For rate-regulated assets, revenues are charged in

accordance with tolls established by the regulator, and in most cost-of-service based arrangements are reflective of our cost to provide the service plus a regulator-approved rate of return. Higher transportation and other services revenues reflected increased throughput on our core liquids pipeline assets combined with the incremental revenues associated with assets placed into service over the past two years.

Gas distribution sales revenues of \$4,360 million, \$4,215 million and \$2,486 million for the years ended December 31, 2018, 2017 and 2016, respectively, were recognized in a manner consistent with the underlying rate-setting mechanism mandated by the regulator. Revenues generated by the gas distribution businesses are primarily driven by volumes delivered, which vary with weather and customer composition and utilization, as well as regulator-approved rates. The cost of natural gas is passed through to customers through rates and does not ultimately impact earnings due to its flow-through nature.

Commodity sales of \$27,660 million, \$26,286 million and \$22,816 million for the years ended December 31, 2018, 2017 and 2016, respectively, were generated primarily through our Energy Services operations. Energy Services includes the contemporaneous purchase and sale of crude oil, natural gas, power and Natural Gas Liquids (NGLs) to generate a margin, which is typically a small fraction of gross revenue. While sales revenue generated from these operations are impacted by commodity prices, net margins and earnings are relatively insensitive to commodity prices and reflect activity levels which are driven by differences in commodity prices between locations, grades and points in time, rather than on absolute prices. Any residual commodity margin risk is closely monitored and managed. Revenues from these operations depend on activity levels, which vary from year-to-year depending on market conditions and commodity prices.

Our revenues also include changes in unrealized derivative fair value gains and losses related to foreign exchange and commodity price contracts used to manage exposures from movements in foreign exchange rates and commodity prices. The mark-to-market accounting creates volatility and impacts the comparability of revenues in the short-term, but we believe over the long-term, the economic hedging program supports reliable cash flows and dividend growth.

DIVIDENDS

We have paid common share dividends in every year since we became a publicly traded company in 1953. In December 2018, we announced a 10% increase in our quarterly dividend to \$0.738 per common share, or \$2.952 annualized, effective with the dividend payable on March 1, 2019.

BUSINESS SEGMENTS

LIQUIDS PIPELINES

EARNINGS BEFORE INTEREST, INCOME TAXES AND DEPRECIATION AND AMORTIZATION

	2018	2017	2016
<i>(millions of Canadian dollars)</i>			
Earnings before interest, income taxes and depreciation and amortization	5,331	6,395	4,926

Year ended December 31, 2018 compared with year ended December 31, 2017

Earnings before interest, income taxes and depreciation and amortization (EBITDA) for the year ended December 31, 2018 was positively impacted by contributions in the first two months of 2018 of approximately \$53 million from assets whose performance was not reflected in EBITDA for the first two months of 2017 due to the timing of the completion of the Merger Transaction.

After taking into consideration the contribution of additional earnings from the Merger Transaction, EBITDA was negatively impacted by \$2,197 million due to certain unusual, infrequent or other factors, primarily explained by the following:

- a non-cash, unrealized loss of \$1,077 million in 2018 compared with a gain of \$875 million in 2017 reflecting net fair value gains and losses arising from changes in the mark-to-market value of derivative financial instruments used to manage foreign exchange and commodity price risks;
- a loss of \$154 million in 2018 related to Line 10, which is a component of our mainline system, resulting from its classification as an asset held for sale and the subsequent measurement at the lower of carrying value or fair value less costs to sell;
- a gain of \$27 million in 2018 compared with a \$72 million gain in 2017 on the sale of pipe offset by project wind-down costs related to EEP's Sandpiper Project (Sandpiper);
- a loss of \$27 million in 2018 related to the Wood Buffalo extension pipeline resulting from a revision to the fair value of excess material based on the estimated sale price; and
- the absence in 2018 of a \$27 million gain recorded in 2017 on the sale of the Olympic refined products pipeline.

After taking into consideration the factors above, the remaining \$1,080 million increase is primarily explained by the following significant business factors:

- a higher foreign exchange hedge rate used to lock-in United States dollar denominated Canadian Mainline revenues of \$1.26 in 2018 compared with \$1.06 in 2017;
- a higher average IJT Benchmark Toll of \$4.11 in 2018 compared with \$4.06 in 2017;
- higher Canadian Mainline ex-Gretna throughput of 2,631 kbpd in 2018 compared with 2,530 kbpd in 2017 driven by the full year impact of capacity optimization initiatives implemented in 2017 and greater supply;
- contributions from assets placed into service during 2017, including the Wood Buffalo Extension Pipeline and the Norlite Pipeline System and the acquisition of a minority interest in the Bakken Pipeline System;
- higher Bakken Pipeline System and Waupisoo Pipeline throughput period-over-period; and
- increased transportation revenues resulting from higher spot volumes on Flanagan South Pipeline driven by strong demand in the United States Gulf Coast.

Year ended December 31, 2017 compared with year ended December 31, 2016

EBITDA for the year ended December 31, 2017 was positively impacted by contributions in the last ten months of 2017 of approximately \$285 million from assets whose performance was not reflected in EBITDA for 2016 due to the timing of the completion of the Merger Transaction.

After taking into consideration the contribution of additional earnings from the Merger Transaction, EBITDA increased by \$1,312 million due to certain unusual, infrequent or other factors, primarily explained by the following:

- a non-cash, unrealized gain of \$875 million in 2017 compared with a gain of \$474 million in 2016 reflecting net fair value gains and losses arising from changes in the mark-to-market value of derivative financial instruments used to manage foreign exchange and commodity price risks;
- the absence in 2017 of a \$1,004 million impairment charge recorded in 2016, including related project costs, on EEP's Sandpiper resulting from the withdrawal of the regulatory applications in September 2016 that were pending with the MNPUC;
- the absence in 2017 of a \$373 million impairment charge recorded in 2016 related to the Northern Gateway Project due to our conclusion that the project could not proceed as envisioned as a result of the Federal Government's decision to dismiss the application for Certificate of Public Convenience and Necessity;
- the absence in 2017 of a \$184 million impairment charge recorded in 2016 related to our 75% joint venture interest in Eddystone Rail attributable to market conditions which impacted volumes at the rail facility; and
- a gain of \$72 million on sale of pipe partially offset by project wind-down costs related to EEP's Sandpiper; partially offset by
- the absence in 2017 of a \$850 million gain recorded in 2016 related to the sale of non-core South Prairie Region assets.

After taking into consideration the factors above, the remaining \$128 million decrease is primarily explained by the following significant business factors:

- lower contributions from Mid-Continent assets primarily due to lower contracted storage revenues and the sale of the Ozark Pipeline system in the first quarter of 2017;
- lower contributions resulting from the sale of the South Prairie Region assets in December 2016;
- higher Lakehead Pipeline System (Lakehead System) operating costs including costs to implement EEP's signed settlement agreement regarding the Lines 6A and 6B crude oil releases (the Consent Decree) approved by the United States Department of Justice (DOJ) in May 2017; and
- the unfavorable effect of translating United States dollar EBITDA at a lower Average Exchange Rate of \$1.30 in 2017 compared with \$1.32 in 2016, inclusive of the impact of settlements under our foreign exchange hedging program; partially offset by
- contributions from new assets placed into service including the Regional Oil Sands Optimization Project and the Norlite Pipeline System and the acquisition of a minority interest in the Bakken Pipeline System that went into service in June 2017;
- higher Canadian Mainline ex-Gretna throughput of 2,530 kbpd in 2017 compared with 2,405 kbpd in 2016 driven by capacity optimization initiatives implemented in 2017; and
- higher Lakehead System throughput of 2,673 kbpd in 2017 compared with 2,574 in 2016 driven by capacity optimization initiatives implemented in 2017.

GAS TRANSMISSION AND MIDSTREAM

EARNINGS/(LOSS) BEFORE INTEREST, INCOME TAXES AND DEPRECIATION AND AMORTIZATION

	2018	2017	2016
<i>(millions of Canadian dollars)</i>			
Earnings/(loss) before interest, income taxes and depreciation and amortization	2,334	(1,269)	464

Year ended December 31, 2018 compared with year ended December 31, 2017

EBITDA for the year ended December 31, 2018 was positively impacted by contributions in the first two months of 2018 of approximately \$570 million from assets whose performance was not reflected in EBITDA for the first two months of 2017 due to the timing of the completion of the Merger Transaction.

After taking into consideration the contribution of additional earnings from the Merger Transaction, EBITDA increased by \$2,885 million due to certain unusual, infrequent or other market factors primarily explained by the following:

- a net positive impact of \$3,539 million related to the sale of MOLP due to the following:
 - the absence in 2018 of a loss of \$4,391 million and related goodwill impairment of \$102 million recorded in 2017 resulting from the classification of assets as held for sale and the subsequent measurement at the lower of their carrying value or fair value less costs to sell; partially offset by
 - a loss of \$913 million in 2018 resulting from the further revision to the fair value of the assets held for sale based on the sale price; and
 - a loss of \$41 million in 2018 resulting from the sale of the assets.
- a recovery of \$223 million in 2018 related to rate cases filed that eliminated a portion of the regulated liability formerly included in our US Gas Transmission businesses rate base, refer to *United States Tax Reform*;
- a non-cash, equity earnings adjustment of \$12 million in 2018 compared with \$28 million in 2017 related to asset write-down losses and changes in the mark-to-market fair value of derivative financial instruments at our equity investee, DCP Midstream, LLC (DCP Midstream);
- a gain of \$34 million in 2018 resulting from the sale of the provincially regulated portion of our Canadian natural gas gathering and processing businesses;
- a non-cash, unrealized gain of \$24 million in 2018 compared with a loss of \$1 million in 2017 reflecting net fair value gains and losses arising from the change in the mark-to-market fair value of derivative financial instruments used to manage foreign exchange and commodity price risk; and
- the absence in 2018 of pipeline inspection and repair costs of \$26 million recorded in 2017 primarily due to the 2017 Texas Eastern Transmission, L.P. (Texas Eastern) pipeline incident; partially offset by
- a goodwill impairment charge of \$1,019 million in 2018 resulting from the classification of our Canadian natural gas gathering and processing businesses as held for sale; and
- asset monetization transaction costs of \$20 million recorded in 2018 resulting from the termination of MOLP commodity hedges.

After taking into consideration the factors above, the remaining \$148 million increase is primarily explained by the following significant business factors:

- contributions from assets placed into service in 2018, including NEXUS, Valley Crossing, High Pine and Wyndwood pipelines;

- contributions from assets placed into service in the second half of 2017, including Sabal Trail Transmission, LLC (Sabal Trail), Access South, Adair Southwest and Lebanon Extension pipelines;
- increased fractionation margins at our Aux Sable joint venture driven by higher NGL prices and increased demand;
- favorable seasonal firm and interruptible revenues from our Alliance joint venture that resulted from wider basis differentials; and
- increased earnings from our DCP Midstream LP joint venture driven by favorable commodity prices and increased volumes.

Year ended December 31, 2017 compared with year ended December 31, 2016

EBITDA for the year ended December 31, 2017 was positively impacted by contributions in the last ten months of 2017 of approximately \$2,557 million from assets whose performance was not reflected in EBITDA for 2016 due to the timing of the completion of the Merger Transaction. When compared to pre-merger results from the prior year, operating results from the new assets include higher earnings primarily from business expansion projects on Algonquin Gas Transmission, Sabal Trail and Texas Eastern.

After taking into consideration the contribution of additional earnings from the Merger Transaction, EBITDA decreased by \$4,287 million due to certain unusual, infrequent or other market factors primarily explained by the following:

- a loss of \$4,391 million and related goodwill impairment of \$102 million resulting from the classification of MOLP assets as held for sale and the subsequent measurement at the lower of their carrying value or fair value less costs to sell; partially offset by
- a non-cash, unrealized loss of \$1 million in 2017 compared with a loss of \$139 million in 2016 reflecting net fair value gains and losses arising from the change in the mark-to-market of derivative financial instruments used to manage foreign exchange and commodity price risk.

After taking into consideration the factors above, the remaining \$3 million decrease is primarily explained by the following significant business factors:

- lower commodity prices which impacted production volume in areas served by some of our United States Midstream assets; partially offset by
- favorable seasonal firm revenues from our Alliance joint venture that resulted from wider basis differentials;
- contributions from the Tupper Main and Tupper West gas plants that were acquired in April 2016;
- increased fractionation margins driven by higher NGL prices and increased demand from our Aux Sable joint venture; and
- higher volumes from our Offshore assets and higher earnings from certain joint venture pipelines.

GAS DISTRIBUTION

EARNINGS BEFORE INTEREST, INCOME TAXES AND DEPRECIATION AND AMORTIZATION

	2018	2017	2016
<i>(millions of Canadian dollars)</i>			
Earnings before interest, income taxes and depreciation and amortization	1,711	1,390	831

Year ended December 31, 2018 compared with year ended December 31, 2017

EBITDA for the year ended December 31, 2018 was positively impacted by contributions in the first two months of 2018 of approximately \$180 million from Union Gas whose performance was not reflected in EBITDA for the first two months of 2017 due to the timing of the completion of the Merger Transaction.

After taking into consideration the contribution of additional earnings from the Merger Transaction, EBITDA was negatively impacted by \$26 million due to certain unusual, infrequent and other business factors, primarily explained by the following:

- a non-cash, unrealized gain of \$6 million in 2018 compared with a gain of \$16 million in 2017 arising from the change in the mark-to-market value of our equity investee's, Noverco Inc.'s (Noverco) derivative financial instruments;
- a negative equity earnings adjustment of \$9 million of our equity investee, Noverco in 2018 arising from United States Tax Reform; and
- employee severance, transition and transformation costs of \$12 million in 2018 compared with \$5 million in 2017.

After taking into consideration the factors above, the remaining \$167 million increase is primarily explained by the following significant business factors:

- increased earnings of \$47 million period-over-period resulting from colder weather experienced in our franchise service areas when compared to the corresponding period in 2017; and
- higher earnings from expansion projects, and higher distribution charges primarily resulting from increases in rate base and customer base.

Year ended December 31, 2017 compared with year ended December 31, 2016

EBITDA for the year ended December 31, 2017 was positively impacted by contributions in the last ten months of 2017 of approximately \$545 million from Union Gas whose performance was not reflected in EBITDA for 2016 due to the timing of the completion of the Merger Transaction. When compared to pre-merger results from prior years, Union Gas' operating results benefited mainly from higher transportation revenue from the Dawn-Parkway expansion projects, increased storage optimization and increases in delivery rates, partially offset by higher operating costs.

After taking into consideration the contribution of additional earnings from the Merger Transaction, EBITDA increased by \$14 million due to certain unusual, infrequent and other business factors, primarily explained by the following:

- a non-cash, unrealized gain of \$16 million in 2017 compared with a loss of \$6 million in 2016 arising from the change in the mark-to-market value of Noverco's derivative financial instruments; and
- warmer than normal weather experienced during 2017 which negatively impacted EBITDA by \$15 million compared with \$18 million in 2016; partially offset by
- the absence in 2017 of other regulatory adjustments at Noverco of \$17 million recorded in 2016.

GREEN POWER AND TRANSMISSION

EARNINGS BEFORE INTEREST, INCOME TAXES AND DEPRECIATION AND AMORTIZATION

	2018	2017	2016
<i>(millions of Canadian dollars)</i>			
Earnings before interest, income taxes and depreciation and amortization	369	372	344

Year ended December 31, 2018 compared with year ended December 31, 2017

EBITDA was negatively impacted by \$59 million due to certain unusual, infrequent and other factors, primarily explained by the following:

- a loss of \$20 million in 2018 resulting from the sale of 49% of our interest in the Hohe See Offshore wind facilities and its subsequent expansion;
- an asset impairment charge of \$22 million in 2018 from our equity investment in NRGreen Power Limited Partnership related to the Chickadee Creek waste heat recovery facility in Alberta; and
- a loss of \$25 million in 2018 representing our share of losses incurred by our equity investee, Rampion Offshore Wind Limited, primarily due to the repair and restoration of damaged cables; partially offset by
- the absence in 2018 of a \$9 million loss recorded in 2017 resulting from the sale of an investment.

After taking into consideration the factors above, the remaining \$56 million increase is primarily explained by the following significant business factors:

- stronger wind resources and lower operating costs at Canadian and United States wind facilities;
- contributions from the Rampion Offshore Wind Project, which generated first power in November 2017 and reached full operating capacity in the second quarter of 2018; and
- a net gain of \$11 million from an arbitration settlement related to our Canadian wind facilities.

Year ended December 31, 2017 compared with year ended December 31, 2016

EBITDA increased by \$4 million due to certain unusual, infrequent and other factors, primarily explained by the following:

- the absence in 2017 of a \$13 million loss recorded in 2016 resulting from an investment impairment; partially offset by
- a \$9 million loss that resulted from the sale of an investment recorded in 2017.

After taking into consideration the factors above, the remaining \$24 million increase is primarily explained by the following significant business factors:

- stronger wind resources at Canadian and United States wind facilities; and
- contributions from new United States wind projects placed into service in 2016 and 2017.

ENERGY SERVICES

EARNINGS/(LOSS) BEFORE INTEREST, INCOME TAXES AND DEPRECIATION AND AMORTIZATION

	2018	2017	2016
<i>(millions of Canadian dollars)</i>			
Earnings/(loss) before interest, income taxes and depreciation and amortization	482	(263)	(183)

EBITDA from Energy Services is dependent on market conditions and results achieved in one period may not be indicative of results to be achieved in future periods.

Year ended December 31, 2018 compared with year ended December 31, 2017

EBITDA increased by \$526 million due to certain unusual, infrequent and other factors, primarily explained by the following:

- a non-cash, unrealized gain of \$408 million in 2018 compared with a loss of \$200 million in 2017 reflecting the revaluation of financial derivatives used to manage the profitability of transportation and storage transactions and exposure to movements in commodity prices; partially offset by
- a non-cash loss of \$93 million in 2018 resulting from the write-down of inventory to the lower of cost or market.

After taking into consideration the factor above, the remaining \$219 million increase is primarily due to increased earnings from Energy Services' Canadian and United States crude operations due to the widening of certain location differentials in 2018, which increased opportunities to generate profitable margins.

Year ended December 31, 2017 compared with year ended December 31, 2016

EBITDA increased by \$2 million primarily due to a non-cash, unrealized loss of \$200 million in 2017 compared with a loss of \$205 million in 2016 reflecting the revaluation of financial derivatives used to manage the profitability of transportation and storage transactions and exposure to movements in commodity prices.

After taking into consideration the factor above, the remaining \$82 million decrease is primarily due to weaker performance from Energy Services' Canadian and United States operations due to the compression of certain crude oil and NGL location and quality differentials in 2017 which limited opportunities to generate profitable margins.

ELIMINATIONS AND OTHER

LOSS BEFORE INTEREST, INCOME TAXES AND DEPRECIATION AND AMORTIZATION

	2018	2017	2016
<i>(millions of Canadian dollars)</i>			
Loss before interest, income taxes and depreciation and amortization	(708)	(337)	(101)

Eliminations and Other includes operating and administrative costs and the impact of foreign exchange hedge settlements which are not allocated to business segments. Eliminations and Other also includes new business development activities, general corporate investments and reflect a portion of the synergies on the integration of corporate functions in relation to the Merger Transaction.

Year ended December 31, 2018 compared with year ended December 31, 2017

EBITDA decreased by \$430 million due to certain unusual, infrequent and other factors, primarily explained by the following:

- a non-cash, unrealized loss of \$256 million in 2018 compared with a gain of \$417 million in 2017 reflecting net fair value gains and losses arising from the change in the mark-to-market fair value of derivative financial instruments used to manage foreign exchange risk; and
- asset monetization transaction costs of \$68 million recorded in 2018; partially offset by
- employee severance, transition and transformation costs of \$152 million in 2018 compared with \$292 million in 2017; and
- the absence in 2018 of transaction costs compared with \$174 million of costs recorded in 2017 related to the Merger Transaction.

After taking into consideration the factors above, the remaining \$59 million increase is primarily explained by the following significant business factors:

- synergies achieved on the integration of corporate functions; partially offset by
- a realized loss of \$219 million in 2018 compared with a loss of \$184 million in 2017 related to settlements under our foreign exchange risk management program.

Year ended December 31, 2017 compared with year ended December 31, 2016

EBITDA decreased by \$315 million due to certain unusual, infrequent and other factors, primarily explained by the following:

- transaction costs of \$174 million incurred in 2017 compared with \$81 million in 2016 related to the Merger Transaction;
- employee severance, transition and transformation costs of \$292 million in 2017 compared with \$92 million in 2016; and
- project development costs of \$23 million in 2017; partially offset by
- a non-cash, unrealized intercompany foreign exchange loss of \$29 million in 2017 compared with a loss of \$43 million in 2016 under our foreign exchange risk management program.

After taking into consideration the factors above, the remaining \$79 million increase is primarily explained by a realized loss of \$173 million in 2017 compared with a loss of \$281 million in 2016 related to settlements under our foreign exchange risk management program.

GROWTH PROJECTS – COMMERCIALY SECURED PROJECTS

The following table summarizes the status of our commercially secured projects, organized by business segment:

		Enbridge's Ownership Interest	Estimated Capital Cost ¹	Expenditures to Date ²	Status	Expected In-Service Date
<i>(Canadian dollars, unless stated otherwise)</i>						
LIQUIDS PIPELINES						
1	Canadian Line 3 Replacement Program	100%	\$5.3 billion	\$4.1 billion	Under construction	2H - 2019
2	U.S. Line 3 Replacement Program	100%	US\$2.9 billion	US\$1.0 billion	Pre-construction ³	2H - 2019
3	Gray Oak Pipeline Project	22.8%	US\$0.6 billion	No significant expenditures to date	Under construction	2H - 2019
4	Other - United States ⁴	100%	US\$0.4 billion	US\$0.4 billion	Substantially complete	2H - 2019
5	Other - Canada ⁵	100%	\$0.4 billion	\$0.1 billion	Various stages	1H - 2019
GAS TRANSMISSION & MIDSTREAM						
6	Atlantic Bridge	100%	US\$0.6 billion	US\$0.5 billion	Under construction	1H - 2020
7	NEXUS	50%	US\$1.3 billion	US\$1.1 billion	Complete	In service
8	Reliability and Maintainability Project	100%	\$0.5 billion	\$0.5 billion	Complete	In service
9	Valley Crossing Pipeline	100%	US\$1.6 billion	US\$1.6 billion	Complete	In service
10	Spruce Ridge Program	100%	\$0.5 billion	\$0.1 billion	Pre-construction	2H - 2020
11	T-South Expansion Program	100%	\$1.0 billion	\$0.1 billion	Pre-construction	2H - 2021
12	Other - United States ⁶	100%	US\$2.7 billion	US\$1.1 billion	Various stages	2019 - 2023
13	Other - Canada ⁷	100%	\$0.6 billion	\$0.6 billion	Complete	In service
GREEN POWER & TRANSMISSION						
14	Rampion Offshore Wind Project	24.9%	\$0.8 billion (£0.37 billion)	\$0.6 billion (£0.3 billion)	Complete	In service
15	Hohe See Offshore Wind Project and Expansion ⁸	25%	\$1.1 billion (€0.67 billion)	\$0.6 billion (€0.4 billion)	Under construction	2H - 2019
16	Other - Canada	25%	\$0.2 billion	No significant expenditures to date	Pre-construction	2H - 2021

1 These amounts are estimates and are subject to upward or downward adjustment based on various factors. Where appropriate, the amounts reflect our share of joint venture projects.

2 Expenditures to date reflect total cumulative expenditures incurred from inception of the project up to December 31, 2018.

3 Construction of the Wisconsin portion of the project is complete as noted below. The remaining project is in pre-construction status.

4 Includes the Lakehead System Mainline Expansion - Line 61. Estimated in-service date will be adjusted to coincide with the in-service date of the U.S. L3R Program.

5 Includes the \$0.1 billion Line 45 Cheecham connectivity placed into service in the second quarter of 2018.

6 Includes the US\$0.2 billion Stampede Offshore oil lateral placed into service in the first quarter of 2018, the US\$0.2 million Texas Eastern Appalachian Lease project placed into service in the fourth quarter of 2018, and the US\$0.4 million South Texas Expansion Project and Pomelo Connector Pipeline Project placed into service in the fourth quarter of 2018.

7 Includes the \$0.4 billion High Pine and the \$0.2 billion Wyndwood pipeline expansion, both placed into service in the first quarter of 2018.

8 Upon closing of the sale of our Renewable Assets, our ownership interest was reduced to approximately 25%. Refer to Asset Monetization.

Risks related to the development and completion of growth projects are described under Part I. *Item 1A. Risk Factors*.

LIQUIDS PIPELINES

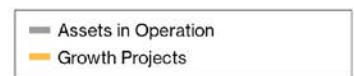
The following commercially secured growth projects are expected to be placed into service in 2019:

- **Canadian Line 3 Replacement Program** - replacement of the existing Line 3 crude oil pipeline between Hardisty, Alberta and Gretna, Manitoba. The Canadian L3R Program will restore the original capacity of 760,000 bpd, an increase of approximately 370,000 bpd. This will support the safety and operational reliability of the overall system, enhancing flexibility and allowing us to optimize throughput from western Canada into Superior, Wisconsin. Construction commenced in early August 2017 and is nearing completion.
- **United States Line 3 Replacement Program** - replacement of the existing Line 3 crude oil pipeline between Neche, North Dakota and Superior, Wisconsin. The U.S. L3R Program will support the safety and operational reliability of the mainline system, enhance system flexibility, and allow us to optimize throughput on the mainline. The L3R Program is expected to achieve the original capacity of approximately 760,000 bpd. The Wisconsin portion of the U.S. L3R Program is in service. For additional updates on the project, refer to *Growth Projects - Regulatory Matters*.
- **Gray Oak Pipeline Project** - a crude oil pipeline project connecting West Texas to destinations in the Corpus Christi and Sweeny/Freeport markets. The pipeline is a joint development with Phillips 66 and could have an ultimate capacity of approximately 900,000 bpd, subject to additional shipper commitments.



Liquids Pipelines

- 1 Canadian Line 3 Replacement Program
- 2 US Line 3 Replacement Program
- 3 Gray Oak Pipeline Project



GAS TRANSMISSION AND MIDSTREAM

The following commercially secured growth projects were placed into service in 2018:

- **NEXUS** - a natural gas pipeline system connecting the Texas Eastern pipeline system in Ohio to the Union Gas Dawn Hub in Ontario, via Vector Pipeline L.P., that provides capacity of up to approximately 1.5 billion cubic feet per day (bcf/d). The project was placed into service in October 2018.
- **Reliability and Maintainability Project** - a natural gas pipeline project designed to enhance the performance of the southern segment of the British Columbia (BC) Pipeline system to accommodate the increased base load on the system. The project involved adding new compressor units at three compressor stations along the pipeline system as well as upgrading existing pipeline crossovers and adding new crossovers at key locations. The project was placed into service in August 2018.
- **Valley Crossing Pipeline** - a natural gas pipeline connecting the Agua Dulce hub in Texas to an offshore tie-in with the Sur de Texas-Tuxpan project. The project will help Mexico meet its growing gas fired electric generation needs by providing capacity of up to approximately 2.6 bcf/d. The project was placed into service in October 2018.

The following commercially secured growth projects are expected to be placed into service in 2020:

- **Atlantic Bridge** - expansion of the Algonquin Gas Transmission systems to transport 133 mmcf/d of natural gas to the New England Region. The expansion primarily consists of various meter station additions, the replacement of a natural gas pipeline in Connecticut and Massachusetts, compression additions in Connecticut, and a new compressor station in Massachusetts. The meter stations were placed into service in 2017 and 2018. The Connecticut portion of the project was placed into service in the fourth quarter of 2017. The New York portion of the project achieved partial in-service in November 2018 and full in-service is expected in the first quarter of 2019, upon which we will begin earning incremental revenues. Due to ongoing permitting delays in Massachusetts, the revised expected in-service date for the Massachusetts portion is the first half of 2020.
- **Spruce Ridge Program** - a natural gas pipeline expansion of Westcoast Energy Inc.'s BC Pipeline in northern BC, which consists of the Aitken Creek Looping project and the Spruce Ridge Expansion project. The combined projects will provide additional capacity of up to 402 mmcf/d. As a result of regulatory delays, the revised expected in-service date for the program is the second half of 2020.

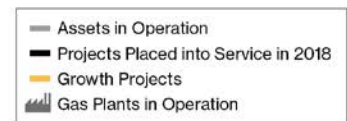
The following commercially secured growth project is expected to be placed into service in 2021:

- **T-South Expansion Program** - a natural gas pipeline expansion of Westcoast Energy Inc.'s T-South system that will provide additional capacity of approximately 190 mmcf/d into the Huntington/Sumas market at the United States/Canada border. As a result of regulatory delays, the revised expected in-service date for the program is the second half of 2021.



Gas Transmission and Midstream

- 6 Atlantic Bridge
- 7 NEXUS
- 8 Reliability and Maintainability Program
- 9 Valley Crossing Pipeline
- 10 Spruce Ridge Program
- 11 T-South Expansion Program



GREEN POWER AND TRANSMISSION

The following commercially secured growth project was placed into service in 2018:

- **Rampion Offshore Wind Project** - a wind project located off the Sussex coast in the United Kingdom, consisting of 116 turbines, which will generate approximately 400-MW. We hold an effective 24.9% interest, United Kingdom's Green Investment Bank plc holds a 25% interest and E.ON SE holds the remaining 50.1% interest in the project, which was developed and is being constructed by E.ON Climate & Renewables UK Limited, a subsidiary of E.ON SE. The Rampion Offshore Wind Project is backed by revenues from the United Kingdom's fixed-price Renewable Obligation certificates program and a 15-year power purchase agreement. The project generated first power in November 2017 and full operating capacity was reached in the second quarter of 2018.

The following commercially secured growth project is expected to be placed into service in 2019:

- **Hohe See Offshore Wind Project and Expansion** - a wind project located in the North Sea, off the coast of Germany that will generate approximately 497-MW, with an additional 112-MW from the expansion. The Hohe See Offshore Wind Project and Expansion will be constructed under fixed-price engineering, procurement, construction and installation contracts, which have been secured with key suppliers. The Hohe See Project and Expansion is backed by a government legislated 20-year revenue support mechanism.



Growth Projects

- 14 Rampion Offshore Wind Project
- 15 Hohe See Offshore Wind Project



GROWTH PROJECTS - REGULATORY MATTERS

United States Line 3 Replacement Program

The MNPUC approved the Certificate and Route Permit and denied petitions to reconsider the decisions. All related Certificate conditions have been finalized and are being addressed. In addition, agreement was reached with the Fond du Lac Band of Lake Superior Chippewa granting a new 20 year easement for the entire Mainline including the Line 3 Replacement Project through their Reservation. The remaining permit applications have been submitted to the various federal and state agencies, including the United States Army Corps of Engineers (Army Corps), the Minnesota Department of Natural Resources, the Minnesota Pollution Control Agency and other local government agencies in Minnesota.

We anticipate that the agencies will process all of these applications in the coming months, and with timely approvals continue to expect an in-service date for the project before the end of 2019.

OTHER ANNOUNCED PROJECTS UNDER DEVELOPMENT

The following projects have been announced by us, but have not yet met our criteria to be classified as commercially secured:

LIQUIDS PIPELINES

- **Texas COLT Offshore Loading Project** - the Texas COLT Offshore Loading Project will facilitate the direct loading of very large crude carriers from Freeport, Texas. The project consists of a terminal, a 42-inch offshore pipeline, platform and two single point mooring systems with connectivity to all key North American supply basins. The project is a joint development with Kinder Morgan Inc. and Oiltanking, and is expected to be in service by 2022.

GREEN POWER AND TRANSMISSION

- **Éolien Maritime France SAS** - a 50% interest in Éolien Maritime France SAS (EMF), a French offshore wind development company, which is co-owned by EDF Energies Nouvelles, a subsidiary of Électricité de France S.A. EMF holds licenses for three large-scale offshore wind facilities off the coast of France that would generate approximately 1,428 MW. The development of these projects is subject to a final investment decision and regulatory approvals, the timing of which is not yet certain.

We also have a large portfolio of additional projects under development that have not yet progressed to the point of public announcement.

LIQUIDITY AND CAPITAL RESOURCES

The maintenance of financial strength and flexibility is fundamental to our growth strategy, particularly in light of the significant number and size of capital projects currently secured or under development. Access to timely funding from capital markets could be limited by factors outside our control, including but not limited to financial market volatility resulting from economic and political events both inside and outside North America. To mitigate such risks, we actively manage financial plans and strategies to ensure we maintain sufficient liquidity to meet routine operating and future capital requirements. In the near term, we generally expect to utilize cash from operations together with commercial paper issuance and/or credit facility draws and the proceeds of capital market offerings to fund liabilities as they become due, finance capital expenditures, fund debt retirements and pay common and preference share dividends. We target to maintain sufficient liquidity through securement of committed credit facilities with a diversified group of banks and financial institutions to enable us to fund all anticipated requirements for approximately one year without accessing the capital markets.

Our financing plan is regularly updated to reflect evolving capital requirements and financial market conditions and identifies a variety of potential sources of debt and equity funding alternatives.

CAPITAL MARKET ACCESS

We ensure ready access to capital markets, subject to market conditions, through maintenance of shelf prospectuses that allow for issuance of long-term debt, equity and other forms of long-term capital when market conditions are attractive. In accordance with our funding plan and the simplification of corporate structure, we completed the following issuances in 2018:

Entity	Type of Issuance	Amount
<i>(in millions of Canadian dollars, unless stated otherwise)</i>		
Enbridge Inc.	Common shares ¹	\$12,727
Enbridge Inc.	US\$ Fixed-to-floating rate subordinated notes	US\$1,450
Enbridge Inc.	Fixed-to-floating rate subordinated notes	\$750
Texas Eastern Transmission, LP	Senior notes	US\$800

¹ In connection with the Sponsored Vehicles buy-in, refer to Simplification of Corporate Structure.

Credit Facilities, Ratings and Liquidity

To ensure ongoing liquidity and to mitigate the risk of capital market disruption, we maintain ready access to funds through committed bank credit facilities and actively manage our bank funding sources to optimize pricing and other terms. The following table provides details of our committed credit facilities at December 31, 2018.

		2018		
December 31,	Maturity	Total Facilities	Draws ¹	Available
<i>(millions of Canadian dollars)</i>				
Enbridge Inc.	2019-2023	5,751	2,008	3,743
Enbridge (U.S.) Inc.	2020	1,932	1,065	867
Enbridge Energy Partners, L.P. ²	2022	2,493	1,044	1,449
Enbridge Gas Distribution Inc.	2019-2020	1,018	760	258
Enbridge Pipelines Inc.	2020	3,000	2,200	800
Spectra Energy Partners, LP ³	2022	3,414	2,065	1,349
Union Gas Limited	2021	700	275	425
Total committed credit facilities		18,308	9,417	8,891

¹ Includes facility draws, letters of credit and commercial paper issuances that are back-stopped by the credit facility.

² Includes \$253 million (US\$185 million) of facilities that expire in 2020.

³ Includes \$459 million (US\$336 million) of facilities that expire in 2021.

Enbridge terminated a US\$650 million credit facility, which was scheduled to mature in 2019, and repaid drawn amounts. In addition, an unutilized Enbridge US\$100 million credit facility expired.

Enbridge (U.S.) Inc. terminated an unutilized US\$950 million credit facility, which was scheduled to mature in 2019. In addition, Enbridge (U.S.) Inc. terminated a US\$500 million credit facility, which was scheduled to mature in 2019, and repaid drawn amounts.

An unutilized EEP US\$625 million credit facility matured on December 31, 2018.

Enbridge Income Fund substantially terminated its \$1,500 million credit facility, which was scheduled to mature in 2020, and repaid drawn amounts.

Westcoast Energy Inc. terminated an unutilized \$400 million credit facility, which was scheduled to mature in 2021.

On February 7, 2019 and February 8, 2019, we terminated certain Canadian and United States dollar credit facilities, including facilities held by Enbridge, Union Gas, EEP and SEP. We also increased existing facilities or obtained new facilities to replace the terminated ones under Enbridge, Enbridge (U.S.) Inc. and EGI. As a result, our total credit facility availability increased by approximately \$390 million Canadian dollar equivalent, when translated using the year end December 31, 2018 spot rate.

In addition to the committed credit facilities noted above, we have \$807 million of uncommitted demand facilities, of which \$548 million were unutilized as at December 31, 2018. As at December 31, 2017, we had \$792 million of uncommitted credit facilities, of which \$518 million were unutilized.

Our net available liquidity of \$9,409 million at December 31, 2018 was inclusive of \$518 million of unrestricted cash and cash equivalents as reported on the Consolidated Statements of Financial Position.

Our credit facility agreements and term debt indentures include standard events of default and covenant provisions whereby accelerated repayment and/or termination of the agreements may result if we were to default on payment or violate certain covenants. As at December 31, 2018, we were in compliance with all debt covenants and expect to continue to comply with such covenants.

Strong growth in internal cash flow, ready access to liquidity from diversified sources and a stable business model have enabled us to manage our credit profile. We actively monitor and manage key financial metrics with the objective of sustaining investment grade credit ratings from the major credit rating agencies and ongoing access to bank funding and term debt capital on attractive terms. Key measures of financial strength that are closely managed include the ability to service debt obligations from operating cash flow and the ratio of debt to total capital. As at December 31, 2018, our debt capitalization ratio was 46.8% compared with 48.3% as at December 31, 2017.

During 2018, our credit ratings were affirmed as follows:

- DBRS Limited confirmed our issuer rating and medium-term notes and unsecured debentures rating of BBB (high), fixed-to-floating subordinated notes rating of BBB (low), preference share rating of Pfd-3 (high) and commercial paper rating of R-2 (high), all with stable outlooks.
- Standard & Poor's Rating Services (S&P) affirmed our corporate credit rating and senior unsecured debt rating of BBB+, preference share rating of P-2 (low) and commercial paper rating of A-1 (low), and reaffirmed a stable outlook. S&P also affirmed our global overall short-term rating of A-2.
- Fitch Rating services affirmed long-term issuer default rating and senior unsecured debt rating of BBB+, preference share rating of BBB-, junior subordinated note rating of BBB-, and short-term and commercial paper rating of F2 with a stable rating outlook.

- On January 25, 2019 Moody's Investor Services, Inc. upgraded our issuer and senior unsecured ratings from Baa3 to Baa2 with outlook revised to positive, upgraded our subordinated rating from Ba2 to Ba1, preference share rating from Ba2 to Ba1 and the commercial paper rating for Enbridge (U.S.) Inc. from P-3 to P-2.

We invest surplus cash in short-term investment grade money market instruments with highly creditworthy counterparties. Short-term investments were \$76 million as at December 31, 2018 compared with \$70 million as at December 31, 2017.

There are no material restrictions on our cash. Total restricted cash of \$119 million, as reported on the Consolidated Statements of Financial Position, includes EGD's and Union Gas' receipt of cash from the Government of Ontario to fund its Green Investment Fund program. In addition, our restricted cash includes cash collateral and amounts received in respect of specific shipper commitments. Cash and cash equivalents held by certain subsidiaries may not be readily accessible for alternative uses by us.

Excluding current maturities of long-term debt, at December 31, 2018 and 2017 we had a negative working capital position of \$3,024 million and \$2,538 million, respectively. In both periods, the major contributing factor to the negative working capital position was the ongoing funding of our growth capital program.

To address this negative working capital position, we maintain significant liquidity in the form of committed credit facilities and other sources as previously discussed, which enable the funding of liabilities as they become due. As at December 31, 2018 and 2017, our net available liquidity totaled \$9,409 million and \$12,959 million, respectively, on a consolidated basis. It is anticipated that any current maturities of long-term debt will be refinanced upon maturity.

SOURCES AND USES OF CASH

December 31, (millions of Canadian dollars)	2018	2017	2016
Operating activities	10,502	6,658	5,205
Investing activities	(3,017)	(11,037)	(5,152)
Financing activities	(7,503)	3,476	840
Effect of translation of foreign denominated cash and cash equivalents	68	(72)	(19)
Net increase/(decrease) in cash and cash equivalents and restricted	50	(975)	874

Significant sources and uses of cash for the years ended December 31, 2018 and 2017 are summarized below:

Operating Activities 2018

- The increase in cash flow delivered by operations in 2018 is a reflection of the positive operating factors discussed under *Results of Operations*.
- Changes in operating assets and liabilities increased to a positive \$915 million from a negative \$338 million for the years ended December 31, 2018 and 2017, respectively. Our operating assets and liabilities fluctuate in the normal course due to various factors including fluctuations in commodity prices and activity levels within the Energy Services and Gas Distribution segments, the timing of tax payments, as well as timing of cash receipts and payments.

2017

- The growth in cash flow delivered by operations in 2017 is a reflection of the positive operating factors discussed under *Results of Operations*, which included contributions from new assets of approximately \$2,574 million following the completion of the Merger Transaction.

- For the year ended, partially offsetting the increase in cash flows from operating activities are transaction costs in connection with the Merger Transaction, as well as employee severance costs in relation to our enterprise-wide reduction of workforce.
- Changes in operating assets and liabilities increased to \$338 million from \$368 million for the years ended December 31, 2017 and 2016, respectively, reflected negative working capital in each of those years. Our operating assets and liabilities fluctuate in the normal course due to various factors including fluctuations in commodity prices and activity levels within the Energy Services and Gas Distribution segments, the timing of tax payments, as well as timing of cash receipts and payments.

Investing Activities

We continue with the execution of our growth capital program which is further described in *Growth Projects – Commercially Secured Projects*. The timing of project approval, construction and in-service dates impacts the timing of cash requirements.

A summary of additions to property, plant and equipment for the years ended December 31, 2018, 2017 and 2016 is set out below:

Year ended December 31, (millions of Canadian dollars)	2018	2017	2016
Liquids Pipelines	3,102	2,797	3,956
Gas Transmission and Midstream	2,578	3,883	176
Gas Distribution	1,066	1,177	713
Green Power and Transmission	33	321	251
Energy Services	—	1	—
Eliminations and Other	27	108	32
Total capital expenditures	6,806	8,287	5,128

2018

- The decrease in cash used in investing activities in 2018 was primarily attributable to proceeds from asset dispositions of \$4,452 million compared with \$628 million in 2017. This increase primarily reflected the sale of MOLP, international renewable assets and the provincially regulated portion of our Canadian Natural Gas Gathering and Processing Businesses assets. Please see *Financing Activities* below for further details on the use of these proceeds.
- Further contributing to the decrease in cash used in investing activities was activity in 2017 that was not present in 2018, relating primarily to the acquisition of an interest in the Bakken Pipeline System.
- We are continuing with the execution of our growth capital program which is further described in *Growth Projects - Commercially Secured Projects*. Capital expenditures of \$6,806 million in 2018 compared with \$8,287 million in 2017 reflected the timing of projects approvals, construction and in-service dates which impacts the timing of cash requirements.

2017

- The increase in cash used in investing activities was primarily attributable to capital expenditures of \$8,287 million compared with \$5,128 million for the comparable period, which include capital expenditures on assets and growth projects acquired through the Merger Transaction, and increased investment in equity investments. During the first half of 2017, we paid cash consideration of \$2.0 billion (US \$1.5 billion) for the acquisition of an interest in the Bakken Pipeline System. In addition, we also made an equity investment of \$0.5 billion in connection with our 50% interest in the Hohe See Offshore Wind Project.
- The above increase in cash usage was partially offset by cash acquired in the Merger Transaction in the first quarter of 2017, proceeds from the disposition of the Ozark Pipeline, Sandpiper and Olympic Pipeline in 2017.

Financing Activities

2018

The increase in net cash used in financing activities resulted from the following factors:

- Repayments of maturing term notes and credits facilities, and a decrease in long-term debt issued in 2018 when compared to 2017.
- During 2018, we sold an interest in our Canadian and US renewable assets to the CPPIB. The proceeds of these dispositions and the dispositions of MOLP, the provincially regulated portion of our Canadian Natural Gas Gathering and Processing Businesses assets and international renewable assets discussed in *Investing Activities* above, were primarily used to repay maturing term notes and credit facilities, while proceeds from hybrid securities issued during the first half of 2018 were primarily used to repay credit facilities and to repurchase or redeem Spectra Energy Capital, LLC's outstanding senior unsecured notes.
- Cash from financing activities further decreased as a result of decreased contributions from noncontrolling interests and redeemable noncontrolling interests. Noncontrolling interest contributions received in 2017 related to completed projects for which there were no contributions received from noncontrolling interests in 2018. In April 2017, contributions from redeemable noncontrolling interests were received from a secondary public offering attributable to our holdings in ENF. There were no similar offerings in 2018.
- Our common share dividend payments increased in the year ended 2018, primarily due to the increase in the common share dividend rate in the first quarter of 2018, as well as an increase in the number of common shares outstanding as a result of common shares issued in connection with the Merger Transaction and the issuance of approximately 33 million common shares in December 2017 in a private placement offering.

2017

The increase in net cash generated from financing activities resulted from the following factors:

- We issued a series of medium term fixed and floating rate notes, the proceeds of which were used to repay maturing term notes and credit facilities and to finance growth capital programs. For the year ended 2017, proceeds from term note issuances were primarily used to repay credit facilities and redeem tender offers for Spectra Energy's outstanding senior unsecured notes as discussed in *Liquidity and Capital Resources - Capital Market Access*.
- The change in cash generated from financing activities reflected overall higher cash contributions from redeemable noncontrolling interests of \$1,178 million compared with \$591 million in the comparable period attributable to our holdings in ENF equity. Cash contributions were also higher for noncontrolling interests, which now include noncontrolling interests acquired through the Merger Transaction, which is more than offset by the increase in distributions to noncontrolling interests. The increase in distributions to noncontrolling interests was primarily attributable to the acquired assets, which were partially offset by the decrease in distributions resulting from the EEP strategic restructuring discussed under *United States Sponsored Vehicle Strategy*.
- Cash provided from financing activities further increased as we completed the issuance of 33.5 million common shares for gross proceeds of approximately \$1.5 billion along with the issuance of 4 million preferred shares for gross proceeds of \$0.5 billion.
- For the year ended 2017, the above increases in cash were partially offset by \$227 million paid to acquire all of the outstanding publicly-held common units of MEP during the second quarter of 2017, as well as higher cash received from the issuance of common shares in the first quarter of 2016, as a result of the issuance of 56 million common shares in March 2016.
- Finally, our common share dividend payments increased in the first half of 2017, primarily due to the increase in the common share dividend rate effective March 2017, as well as higher number of common shares outstanding as a result of the issuance of approximately 75 million common shares in 2016 and 691 million common shares issued in connection with the Merger Transaction.

In addition, we paid \$414 million in common share dividends to the shareholders of Spectra Energy. These dividends were declared before the closing of the Merger Transaction but were paid after the closing of the Merger Transaction.

Preference Share Issuances

Since July 2011, we have issued 315 million preference shares for gross proceeds of approximately \$7.9 billion with the following characteristics.

	Gross Proceeds	Dividend Rate	Dividend ^{1,7}	Per Share Base Redemption Value ²	Redemption and Conversion Option Date ^{2,3}	Right to Convert Into ^{3,4}
<i>(Canadian dollars, unless otherwise stated)</i>						
Series A	\$125 million	5.50%	\$1.37500	\$25	—	—
Series B	\$457 million	3.42%	\$0.85360	\$25	June 1, 2022	Series C
Series C ⁵	\$43 million	3-month treasury bill plus 2.40%	—	\$25	June 1, 2022	Series B
Series D ⁶	\$450 million	4.46%	\$1.11500	\$25	March 1, 2023	Series E
Series F ⁶	\$500 million	4.69%	\$1.17225	\$25	June 1, 2023	Series G
Series H ⁶	\$350 million	4.38%	\$1.09400	\$25	September 1, 2023	Series I
Series J	US\$200 million	4.89%	US\$1.22160	US\$25	June 1, 2022	Series K
Series L	US\$400 million	4.96%	US\$1.23972	US\$25	September 1, 2022	Series M
Series N ⁶	\$450 million	5.09%	\$1.27150	\$25	December 1, 2023	Series O
Series P	\$400 million	4.00%	\$1.00000	\$25	March 1, 2019	Series Q
Series R	\$400 million	4.00%	\$1.00000	\$25	June 1, 2019	Series S
Series 1 ⁶	US\$400 million	5.95%	US\$1.48728	US\$25	June 1, 2023	Series 2
Series 3	\$600 million	4.00%	\$1.00000	\$25	September 1, 2019	Series 4
Series 5	US\$200 million	4.40%	US\$1.10000	US\$25	March 1, 2019	Series 6
Series 7	\$250 million	4.40%	\$1.10000	\$25	March 1, 2019	Series 8
Series 9	\$275 million	4.40%	\$1.10000	\$25	December 1, 2019	Series 10
Series 11	\$500 million	4.40%	\$1.10000	\$25	March 1, 2020	Series 12
Series 13	\$350 million	4.40%	\$1.10000	\$25	June 1, 2020	Series 14
Series 15	\$275 million	4.40%	\$1.10000	\$25	September 1, 2020	Series 16
Series 17	\$750 million	5.15%	\$1.28750	\$25	March 1, 2022	Series 18
Series 19	\$500 million	4.90%	\$1.22500	\$25	March 1, 2023	Series 20

- 1 The holder is entitled to receive a fixed, cumulative, quarterly preferential dividend, as declared by the Board. With the exception of Series A and Series C Preference Shares, such fixed dividend rate resets every five years beginning on the initial redemption and conversion option date. The Series 17 and Series 19 Preference Shares contain a feature where the fixed dividend rate, when reset every five years, will not be less than 5.15% and 4.90%, respectively. No other series of Preference Shares has this feature.
- 2 Preference Shares, Series A may be redeemed any time at our option. For all other series of Preference Shares, we may, at our option, redeem all or a portion of the outstanding Preference Shares for the Base Redemption Value per share plus all accrued and unpaid dividends on the Redemption Option Date and on every fifth anniversary thereafter.
- 3 The holder will have the right, subject to certain conditions, to convert their shares into Cumulative Redeemable Preference Shares of a specified series on a one-for-one basis on the Conversion Option Date and every fifth anniversary thereafter at an ascribed issue price equal to the Base Redemption Value.
- 4 With the exception of Series A Preference Shares, after the redemption and conversion option dates, holders may elect to receive quarterly floating rate cumulative dividends per share at a rate equal to: \$25 x (number of days in quarter/365) x 90 day Government of Canada treasury bill rate + 2.4% (Series C), 2.4% (Series E), 2.5% (Series G), 2.1% (Series I), 2.7% (Series O), 2.5% (Series Q), 2.5% (Series S), 2.4% (Series 4), 2.6% (Series 8), 2.7% (Series 10), 2.6% (Series 12), 2.7% (Series 14), 2.7% (Series 16), 4.1% (Series 18) or 3.2% (Series 20); or US\$25 x (number of days in quarter/365) x three-month United States Government treasury bill rate + 3.1% (Series K), 3.2% (Series M), 3.1% (Series 2) or 2.8% (Series 6).
- 5 The floating quarterly dividend amount for the Series C Preference Shares was increased to \$0.22685 from \$0.20342 on March 1, 2018, was increased to \$0.22748 from \$0.22685 on June 1, 2018, was increased to \$0.23934 from \$0.22748 on September 1, 2018 and was increased to \$0.25459 from \$0.23934 on December 1, 2018, due to reset on a quarterly basis following the issuance thereof.
- 6 No Series D, F, H, N, or 1 Preference shares were converted on the March 1, 2018, June 1, 2018, September 1, 2018, December 1, 2018 or June 1, 2018 conversion option dates, respectively. However, the quarterly dividend amounts for Series D, F, H, N, and 1, were reset to \$0.27875 from \$0.25000 on March 1, 2018, \$0.29306 from \$0.25000 on June 1, 2018, \$0.27350 from \$0.25000 on September 1, 2018, \$0.31788 from \$0.25000 on December 1, 2018 and US\$0.37182 from US\$0.25000 on June 1, 2018, respectively, due to reset on every fifth anniversary thereafter.
- 7 For dividends declared, see Liquidity and Capital Resources – Sources and Uses of Cash – Dividend Reinvestment and Share Purchase Plan.

Common Share Issuances

In the fourth quarter of 2018, we completed the issuance of 297 million common shares with a value of \$12.7 billion in connection with the Sponsored Vehicles buy-in. For further information refer to *Simplification of Corporate Structure* and *Item 8. Financial Statements and Supplementary Data - Note 21. Share Capital*.

On December 7, 2017, we completed the issuance of 33.5 million common shares for gross proceeds of approximately \$1.5 billion. The proceeds were used to reduce short-term indebtedness pending reinvestment in secured capital projects.

On February 27, 2017, we completed the issuance of 691 million common shares with a value of \$37.4 billion in exchange for shares of Spectra Energy in connection with the Merger Transaction. For further information, refer to *Item 8. Financial Statements and Supplementary Data - Note 8. Acquisitions and Dispositions*.

Dividend Reinvestment and Share Purchase Plan

On November 2, 2018, we announced the suspension of our Dividend Reinvestment and Share Purchase Plan (DRIP), effective immediately. Prior to the announcement, our shareholders were able to participate in the DRIP, which enabled participants to reinvest their dividends in our common shares at a 2% discount to market price and to make additional optional cash payments to purchase common shares at the market price, free of brokerage or other charges.

As a result of the announcement, shareholders only received dividends in cash effective with the dividend paid on December 1, 2018, to shareholders of record on November 15, 2018. If we elect to reinstate the DRIP in the future, the shareholders that were enrolled in the DRIP at the time of suspension and remain enrolled at the time of its reinstatement will automatically resume participation in the DRIP.

For the years ended December 31, 2018 and 2017, total dividends paid were \$4,661 million and \$3,562 million, respectively, of which \$3,480 million and \$2,336 million, respectively, were paid in cash and reflected in financing activities. The remaining \$1,181 million and \$1,226 million, respectively, of dividends paid were reinvested pursuant to the DRIP and resulted in the issuance of common shares rather than a cash payment. In addition to amounts paid in cash and reflected in financing activities for the year ended December 31, 2017, were \$414 million in dividends declared to Spectra Energy shareholders prior to the Merger Transaction that were paid after the Merger Transaction.

Our Board of Directors has declared the following quarterly dividends. All dividends are payable on March 1, 2019 to shareholders of record on February 15, 2019.

Common Shares ¹	\$0.73800
Preference Shares, Series A	\$0.34375
Preference Shares, Series B	\$0.21340
Preference Shares, Series C ²	\$0.25459
Preference Shares, Series D ³	\$0.27875
Preference Shares, Series F ⁴	\$0.29306
Preference Shares, Series H ⁵	\$0.27350
Preference Shares, Series J	US\$0.30540
Preference Shares, Series L	US\$0.30993
Preference Shares, Series N ⁶	\$0.31788
Preference Shares, Series P	\$0.25000
Preference Shares, Series R	\$0.25000
Preference Shares, Series 1 ⁷	US\$0.37182
Preference Shares, Series 3	\$0.25000
Preference Shares, Series 5	US\$0.27500
Preference Shares, Series 7	\$0.27500
Preference Shares, Series 9	\$0.27500
Preference Shares, Series 11	\$0.27500
Preference Shares, Series 13	\$0.27500
Preference Shares, Series 15	\$0.27500
Preference Shares, Series 17	\$0.32188
Preference Shares, Series 19 ⁸	\$0.30625

¹ The quarterly dividend per common share was increased 10% to \$0.73800 from \$0.67100, effective March 1, 2019.

² The floating dividend on the Series C Preference Shares is reset each quarter. The quarterly dividend amount of Series C increased to \$0.22685 from \$0.20342 on March 1, 2018, increased to \$0.22748 from \$0.22685 on June 1, 2018, increased to \$0.23934 from \$0.22748 on September 1, 2018 and increased to \$0.25459 from \$0.23934 on December 1, 2018.

³ The quarterly dividend amount of Series D increased to \$0.27875 from \$0.25000 on March 1, 2018, due to the reset of the annual dividend on every fifth anniversary of the date of issuance of the Series D Preference Shares.

⁴ The quarterly dividend amount of Series F increased to \$0.29306 from \$0.25000 on June 1, 2018, due to the reset of the annual dividend on every fifth anniversary of the date of issuance of the Series F Preference Shares.

⁵ The quarterly dividend amount of Series H increased to \$0.27350 from \$0.25000 on September 1, 2018, due to the reset of the annual dividend on every fifth anniversary of the date of issuance of the Series H Preference Shares.

⁶ The quarterly dividend amount of Series N increased to \$0.31788 from \$0.25000 on December 1, 2018, due to the reset of the annual dividend on every fifth anniversary of the date of issuance of the Series N Preference Shares.

⁷ The quarterly dividend amount of Series 1 increased to US\$0.37182 from US\$0.25000 on June 1, 2018, due to the reset of the annual dividend on every fifth anniversary of the date of issuance of the Series 1 Preference Shares.

⁸ The quarterly dividend amount of Series 19 increased from the first dividend of \$0.26850 payable on March 1, 2018 to the regular quarterly dividend of \$0.30625, effective June 1, 2018.

OFF-BALANCE SHEET ARRANGEMENTS

We enter into guarantee arrangements in the normal course of business to facilitate commercial transactions with third parties. These arrangements include financial guarantees, stand-by letters of credit, debt guarantees, surety bonds and indemnifications. See *Item 8. Financial Statements and Supplementary Data - Note 30 Guarantees* for further discussion of guarantee arrangements.

Most of the guarantee arrangements that we enter into enhance the credit standings of certain subsidiaries, non-consolidated entities or less than 100%-owned entities, enabling them to conduct business. As such, these guarantee arrangements involve elements of performance and credit risk which are not included on our Consolidated Statements of Financial Position. The possibility of us having to honor our contingencies is largely dependent upon the future operations of our subsidiaries, investees and other third parties, or the occurrence of certain future events. Issuance of these guarantee arrangements is not required for the majority of our operations.

We do not have material off-balance sheet financing entities or structures, except for normal operating lease arrangements, guarantee arrangements and financings entered into by our equity investments. For additional information on these commitments, see *Item 8. Financial Statements and Supplementary Data - Note 29. Commitments and Contingencies* and *Note 30. Guarantees*.

We do not have material off-balance sheet arrangements that have or are reasonably likely to have a current or future effect on our financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources.

CONTRACTUAL OBLIGATIONS

Payments due under contractual obligations over the next five years and thereafter are as follows:

As at December 31, 2018	Total	Less than 1 year	1-3 years	3-5 years	After 5 years
<i>(millions of Canadian dollars)</i>					
Annual debt maturities ¹	62,967	3,255	11,651	10,534	37,527
Interest obligations ²	30,236	2,459	4,382	3,905	19,490
Operating leases ³	1,730	153	276	234	1,067
Capital leases	23	7	—	4	12
Pension obligations ⁴	162	162	—	—	—
Long-term contracts ⁵	10,970	3,885	2,575	1,232	3,278
Other long-term liabilities ⁶	—	—	—	—	—
Total contractual obligations	106,088	9,921	18,884	15,909	61,374

¹ Includes debentures, term notes, commercial paper and credit facility draws based on the facility's maturity date and excludes short-term borrowings, debt discount, debt issue costs and capital lease obligations. We have the ability under certain debt facilities to call and repay the obligations prior to scheduled maturities. Therefore, the actual timing of future cash repayments could be materially different than presented above.

² Includes debentures and term notes bearing interest at fixed, floating and fixed-to-floating rates.

³ Includes land leases.

⁴ Assumes only required payments will be made into the pension plans in 2019. Contributions are made in accordance with independent actuarial valuations as at December 31, 2018. Contributions, including discretionary payments, may vary depending on future benefit design and asset performance.

⁵ Included within long-term contracts, in the table above, are contracts that we have signed for the purchase of services, pipe and other materials totaling \$1,891 million which are expected to be paid over the next five years. Also consists of the following purchase obligations: gas transportation and storage contracts, firm capacity payments and gas purchase commitments, transportation, service and product purchase obligations, and power commitments.

⁶ We are unable to estimate deferred income taxes (Item 8. Financial Statements and Supplementary Data - Note 25. Income Taxes) since cash payments for income taxes are determined primarily by taxable income for each discrete fiscal year. We are also unable to estimate asset retirement obligations (ARO) (Item 8. Financial Statements and Supplementary Data - Note 19. Asset Retirement Obligations), environmental liabilities (Item 8. Financial Statements and Supplementary Data - Note 29. Commitments and Contingencies) and hedges payable (Item 8. Financial Statements and Supplementary Data - Note 24. Risk Management and Financial Instruments) due to the uncertainty as to the amount and, or, timing of when cash payments will be required.

LEGAL AND OTHER UPDATES

LIQUIDS PIPELINES

Renewal of Line 5 Easement

On January 4, 2017, the Tribal Council of the Bad River Band of Lake Superior Tribe of Chippewa Indians (the Band) issued a press release indicating that the Band had passed a resolution not to renew its interest in certain Line 5 easements through the Bad River Reservation. Line 5 is included within our mainline system. The Band's resolution calls for decommissioning and removal of the pipeline from all Bad River tribal lands and watershed and could impact our ability to operate the pipeline on the Reservation. Since the Band passed the resolution, the parties have agreed to ongoing discussions with the objective of understanding and resolving the Band's concerns on a long-term basis.

Eddystone Rail Legal Matter

In February 2017, our subsidiary Eddystone Rail Company, LLC (Eddystone Rail) filed an action against several defendants in the United States District Court for the Eastern District of Pennsylvania. Eddystone Rail alleges that the defendants transferred valuable assets from Eddystone Rail's counterparty in a maritime contract, so as to avoid outstanding obligations to Eddystone Rail. Eddystone Rail is seeking payment of compensatory and punitive damages in excess of US\$140 million. On July 19, 2017, the defendants' motions to dismiss Eddystone Rail's claims were denied. Defendants have filed Answers and Counterclaims, which together with subsequent amendments, seek damages from Eddystone Rail in excess of US\$32 million. Eddystone filed a motion to dismiss the counterclaims and defendants amended their Answer and Counterclaims on September 21, 2017. On October 12, 2017 Eddystone Rail moved to dismiss the latest version of defendants' counterclaims. On February 6, 2018, the court denied without prejudice Eddystone Rail's motion to dismiss the defendants' counterclaims. The defendants' chances of success on their counterclaims cannot be predicted at this time. On September 7, 2018, the court granted Eddystone's motion to amend its complaint to add several affiliates of the corporate defendants as additional defendants. Motions to dismiss Eddystone's amended complaint were subsequently denied by the court. On January 25, 2019, defendants moved to dismiss Eddystone Rail's claims from the court based on lack of subject matter jurisdiction, which motion remains pending.

Dakota Access Pipeline

In February 2017, the Standing Rock Sioux Tribe and the Cheyenne River Sioux Tribe filed motions with the Court contesting the validity of the process used by the Army Corps to permit the Dakota Access Pipeline (DAPL). The plaintiffs requested the Court order the operator to shut down the pipeline until the appropriate regulatory process is completed. The Oglala Sioux and Yankton Sioux Tribes also filed claims in the case to challenge the Army Corp permit and environmental review process.

On June 14, 2017, the Court ruled that the Army Corps did not sufficiently weigh the degree to which the project's effects would be highly controversial and the Army Corps failed to adequately consider the impact of an oil spill on the hunting and fishing rights of the Tribes and on environmental justice (the June 2017 Order). The Court ordered the Army Corps to reconsider those components of its environmental analysis. On October 11, 2017, the Court issued an order that allows DAPL to continue operating while the Army Corps completes the additional environmental review required by the June 2017 Order. The Court additionally ordered DAPL to implement certain interim measures pending the Army Corps' supplemental analysis. The Army Corps issued its decision on August 31, 2018, and found that no supplemental environmental analysis is required. All four Tribes amended their complaints to include claims challenging the adequacy of the Army Corps' supplemental environmental analysis and the Army Corps is required to file the administrative record of its analysis by January 31, 2019.

On February 4, 2019, the Army Corps produced its administrative record, which includes all documents pertaining to its remand process. The plaintiff Tribes are provided with the opportunity to challenge the completeness of the Army Corps' administrative record; briefing on such challenges, should any be filed, will be completed by March 6, 2019. A schedule for filing summary judgment briefs on the merits of the plaintiff Tribes' remaining claims will be established following resolution of any administrative record challenges.

Seaway Pipeline Regulatory Matters

Seaway Crude Pipeline System (Seaway Pipeline) filed an application for market-based rates in December 2011 and refiled in December 2014. Several parties filed comments in opposition alleging that the application should be denied because Seaway Pipeline has market power in both its receipt and destination markets. On December 1, 2016, the Administrative Law Judge issued its decision which concluded that the Commission should grant the application of Seaway Pipeline for authority to charge market-based rates. By order dated May 17, 2017, the Commission affirmed the Administrative Law Judge's finding that Seaway Pipeline lacks market power in the applicable markets and granted Seaway Pipeline's application for market based rate authority. No requests for rehearing or petitions for review were filed. The order is therefore now final.

GAS TRANSMISSION AND MIDSTREAM

Sabal Trail FERC Certificate Review

Sierra Club and two other non-governmental organizations filed a Petition for Review of Sabal Trail's FERC certificate on September 20, 2016 in the D.C. Circuit Court of Appeals. On August 22, 2017, the D.C. Circuit issued an opinion denying one of the petitions, and granting the other petition in part, vacating the certificates, and remanding the case to FERC to supplement the environmental impact statement for the project to estimate the quantity of green-house gases to be released into the environment by the gas-fired generation plants in Florida that will consume the gas transported by Sabal Trail. The court withheld issuance of the mandate requiring vacatur of the certificate until seven days after the disposition of any timely petition for rehearing. On October 6, 2017, Sabal Trail and FERC each filed timely petitions for rehearing. On January 31, 2018, the court denied FERC's and Sabal Trail's petitions for rehearing. On February 5, 2018, FERC issued its final supplemental environmental impact statement in compliance with the D.C. Circuit decision. In addition, on February 6, 2018, FERC filed a motion with the court requesting a 45-day stay of the mandate. On March 7, 2018, the court granted FERC's 45-day request for stay, and directed that issuance of the mandate be withheld through March 26, 2018. On March 14, 2018 FERC issued its Order on Remand Reinstating Certificate and Abandonment Authorizations which addressed the court's ruling in the August 22, 2017 decision (March 14, 2018 Order), and on March 30, 2018 the court issued its mandate.

Sierra Club and two other non-governmental organizations, as well as the two landowners, timely requested rehearing from the FERC of the March 14, 2018 Order. On August 10, 2018, the FERC issued an order denying the requests of Sierra Club and others seeking rehearing of FERC's order on remand. No appeals related to the March 14, 2018 Order were timely filed and the March 14, 2018 Order is now final and non-appealable.

GAS DISTRIBUTION

On July 3, 2018, the government of Ontario issued Ontario Regulation 386/18 which revoked the Cap and Trade program regulation and prohibits registered participants from purchasing, selling, trading or otherwise dealing with emission allowances and credits. Subsequently, on July 6, 2018, the OEB suspended its review of EGD and Union Gas' 2018 Cap and Trade Compliance Plans. On July 25, 2018, the government of Ontario introduced Bill 4 to wind down the Cap and Trade program. Subsequently, by letter dated August 30, 2018, the OEB instructed EGD and Union Gas to request the elimination of Cap and Trade charges as part of their October 2018 Quarterly Rate Adjustment Mechanism (QRAM) application, thereby removing Cap and Trade charges from customer bills effective October 1, 2018. The letter also instructed EGD and Union Gas to request the disposition of any projected aggregate net credit balance in their Cap and Trade related deferral and variance accounts as at September 30, 2018.

In accordance with the OEB's direction, on September 11, 2018, EGD and Union Gas filed their October 2018 QRAM applications which included the requests to remove Cap and Trade charges from rates, and to refund Cap and Trade related deferral and variance account balances to customers, effective October 1, 2018. The OEB approved EGD's and Union Gas' QRAM applications on September 27, 2018.

On October 31, 2018, Bill 4 received Royal Assent from the government of Ontario, providing for the wind down of the Cap and Trade program. This resulted in a reduction of \$990 million in Intangible assets and Other long-term liabilities on the Consolidated Statements of Financial Position in the fourth quarter of 2018. There was no financial impact to the Consolidated Statements of Earnings.

OTHER LITIGATION

We and our subsidiaries are involved in various other legal and regulatory actions and proceedings which arise in the normal course of business, including interventions in regulatory proceedings and challenges to regulatory approvals and permits by special interest groups. While the final outcome of such actions and proceedings cannot be predicted with certainty, management believes that the resolution of such actions and proceedings will not have a material impact on our consolidated financial position or results of operations.

TAX MATTERS

We and our subsidiaries maintain tax liabilities related to uncertain tax positions. While fully supportable in our view, these tax positions, if challenged by tax authorities, may not be fully sustained on review.

CRITICAL ACCOUNTING ESTIMATES

Our consolidated financial statements are prepared in accordance with accounting principles generally accepted in the United States, which require management to make estimates, judgments and assumptions that affect the amounts reported in our consolidated financial statements and accompanying notes. In making judgments and estimates, management relies on external information and observable conditions, where possible, supplemented by internal analysis as required. We believe our most critical accounting policies and estimates discussed below have an impact across the various segments of our business.

Business Combinations

We apply the provisions of Accounting Standards Codification 805 *Business Combinations* in accounting for our acquisitions. The acquired long-lived assets and intangible assets and assumed liabilities are recorded at their estimated fair values at the date of acquisition. Goodwill represents the excess of the purchase price over the fair value of net assets. While we use our best estimates and assumptions to accurately value assets acquired and liabilities assumed at the date of acquisition, as well as any contingent consideration, our estimates are inherently uncertain and subject to refinement. During the measurement period, which may be up to one year from the acquisition date, we record adjustments to the assets acquired and liabilities assumed with the corresponding offset to goodwill. Upon the conclusion of the measurement period or final determination of values of assets acquired or liabilities assumed, whichever comes first, any subsequent adjustments are recorded to our consolidated statements of operations.

Accounting for business combinations requires significant judgment, estimates and assumptions at the acquisition date. In developing estimates of fair values at the acquisition date, we utilize a variety of factors including market data, historical and future expected cash flows, growth rates and discount rates. The subjective nature of our assumptions increases the risk associated with estimates surrounding the projected performance of the acquired entity.

On February 27, 2017, we acquired Spectra Energy for a purchase price of \$37.5 billion. In determining the valuation of tangible assets acquired, we applied the cost, market and income approaches. For intangible assets acquired, we used an income approach which included cash flow projections based on

historical performance, terms found in contracts and assumptions on expected renewals. Discount rates used in the valuation were also developed using a weighted-average cost of capital based on risks specific to respective assets and returns that an investor would likely require given the expected cash flows, timing and risk.

Goodwill Impairment

Goodwill represents the excess of the purchase price over the fair value of net identifiable assets on acquisition of a business. The carrying value of goodwill, which is not amortized, is assessed for impairment annually, or more frequently if events or changes in circumstances arise that suggest the carrying value of goodwill may be impaired.

We perform our annual review for impairment at the reporting unit level, which is identified by assessing whether the components of our operating segments constitute businesses for which discrete information is available, whether segment management regularly reviews the operating results of those components and whether the economic and regulatory characteristics are similar. We determined that our reporting units are equivalent to our reportable segments, with the exception of the gas transmission and gas midstream reportable segment which is divided at the component level into two reporting units. We have the option to first assess qualitative factors to determine whether it is necessary to perform the quantitative goodwill impairment test. The quantitative goodwill impairment test involves determining the fair value of our reporting units and comparing those values to the carrying value of each reporting unit. If the carrying value of a reporting unit, including allocated goodwill, exceeds its fair value, goodwill impairment is measured at the amount by which the reporting unit's carrying value exceeds its fair value. This amount should not exceed the carrying amount of goodwill. We performed our annual review of the goodwill balance at April 1, which did not result in an impairment charge.

The allocation of goodwill to held for sale and disposed businesses is based on the relative fair value of businesses included in the particular reporting unit. Fair value of our reporting unit is estimated using a combination of discounted cash flow model and earnings multiples techniques. The determination of fair value using the discounted cash flow model technique requires the use of estimates and assumptions related to discount rates, projected operating income, terminal value growth rates, capital expenditures and working capital levels. The cash flow projections included significant judgments and assumptions relating to revenue growth rates and expected future capital expenditure. The determination of fair value using the earnings multiples technique requires assumptions to be made in relation to maintainable earnings and earnings multipliers for reporting units.

During 2018, we impaired \$1,019 million of goodwill allocated to assets held for sale.

Asset Impairment

We evaluate the recoverability of our property, plant and equipment when events or circumstances such as economic obsolescence, business climate, legal or regulatory changes, or other factors indicate we may not recover the carrying amount of our assets. We continually monitor our businesses, the market and business environments to identify indicators that could suggest an asset may not be recoverable. If it is determined that the carrying value of an asset exceeds the undiscounted cash flows expected from the asset, we will assess the fair value of the asset. An impairment loss is recognized when the carrying amount of the asset exceeds its fair value as determined by quoted market prices in active markets or present value techniques. The determination of the fair value using present value techniques requires the use of projections and assumptions regarding future cash flows and weighted average cost of capital. Any changes to these projections and assumptions could result in revisions to the evaluation of the recoverability of the property, plant and equipment and the recognition of an impairment loss in the Consolidated Statements of Earnings.

Assets held for sale

We classify assets as held for sale when management commits to a formal plan to actively market an asset or a group of assets and when management believes it is probable the sale of the assets will occur within one year. We measure assets classified as held for sale at the lower of their carrying value and their estimated fair value less costs to sell.

Regulatory Accounting

Certain of our businesses are subject to regulation by various authorities, including but not limited to, the NEB, the FERC, the Alberta Energy Regulator, the NBEUB, La Régie de l'énergie du Québec and the Ontario Energy Board (OEB). Regulatory bodies exercise statutory authority over matters such as construction, rates and ratemaking and agreements with customers. To recognize the economic effects of the actions of the regulator, the timing of recognition of certain revenues and expenses in these operations may differ from that otherwise expected under Generally accepted accounting principle in the United States of America (U.S. GAAP) for non-rate-regulated entities. Key determinants in the ratemaking process are:

- Costs of providing service, including depreciation expense;
- Allowed rate of return, including the equity component of the capital structure and related income taxes; and
- Contract and volume throughput assumptions.

The allowed rate of return is determined in accordance with the applicable regulatory model and may impact our profitability. The rates for a number of our projects are based on a cost-of-service recovery model that follows the regulators' authoritative guidance. Under the cost-of-service tolling methodology, we calculate tolls based on forecast volumes and cost. A difference between forecast and actual results causes an over or under recovery in any given year. Regulatory assets represent amounts that are expected to be recovered from customers in future periods through rates. Regulatory liabilities represent amounts that are expected to be refunded to customers in future periods through rates or expected to be paid to cover future abandonment costs in relation to the NEB's Land Matters Consultation Initiative (LMCI) and for future removal and site restoration costs as approved by the OEB.

To the extent that the regulator's actions differ from our expectations, the timing and amount of recovery or settlement of regulatory balances could differ significantly from those recorded. In the absence of rate regulation, we would generally not recognize regulatory assets or liabilities and the earnings impact would be recorded in the period the expenses are incurred or revenues are earned. A regulatory asset or liability is recognized in respect of deferred income taxes when it is expected the amounts will be recovered or settled through future regulator-approved rates.

As at December 31, 2018 and 2017, our regulatory assets totaled \$4,073 million and \$3,477 million, respectively, and significant regulatory liabilities totaled \$2,252 million and \$2,366 million, respectively.

Depreciation

Depreciation of property, plant and equipment, our largest asset with a net book value at December 31, 2018 and 2017, of \$94,540 million and \$90,711 million, respectively, is charged in accordance with two primary methods. For distinct assets, depreciation is generally provided on a straight-line basis over the estimated useful lives of the assets commencing when the asset is placed in service. For largely homogeneous groups of assets with comparable useful lives, the pool method of accounting is followed whereby similar assets are grouped and depreciated as a pool. When group assets are retired or otherwise disposed of, gains and losses are not reflected in earnings but are booked as an adjustment to accumulated depreciation.

When it is determined that the estimated service life of an asset no longer reflects the expected remaining period of benefit, prospective changes are made to the estimated service life. Estimates of useful lives are based on third party engineering studies, experience and/or industry practice. There are a number of assumptions inherent in estimating the service lives of our assets including the level of development,

exploration, drilling, reserves and production of crude oil and natural gas in the supply areas served by our pipelines as well as the demand for crude oil and natural gas and the integrity of our systems. Changes in these assumptions could result in adjustments to the estimated service lives, which could result in material changes to depreciation expense in future periods in any of our business segments. For certain rate-regulated operations, depreciation rates are approved by the regulator and the regulator may require periodic studies or technical updates on useful lives which may change depreciation rates.

Postretirement Benefits

We maintain pension plans, which provide defined benefit and/or defined contribution pension benefits and other postretirement benefits (OPEB) to eligible retirees. Pension costs and obligations for the defined benefit pension plans are determined using actuarial methods and are funded through contributions determined using the projected benefit method, which incorporates management's best estimates of future salary level, other cost escalations, retirement ages of employees and other actuarial factors including discount rates and mortality. We determine discount rates by reference to rates of high-quality long-term corporate bonds with maturities that approximate the timing of future payments we anticipate making under each of the respective plans. These assumptions are reviewed annually by our actuaries. Actual results that differ from assumptions are amortized over future periods and therefore could materially affect the expense recognized and the recorded obligation in future periods. The actual return on plan assets was below the expectation by \$449 million and exceeded the expectation by \$174 million for the years ended December 31, 2018 and 2017, respectively, as disclosed in Part II. *Item 8. Financial Statements and Supplementary Data - Note 26. Pension and Other Postretirement Benefits.* The difference between the actual and expected return on plan assets is amortized over the remaining service period of the active employees.

The following sensitivity analysis identifies the impact on the December 31, 2018 Consolidated Financial Statements of a 0.5% change in key pension and OPEB assumptions.

	Canada		United States	
	Obligation	Expense	Obligation	Expense
<i>(millions of Canadian dollars)</i>				
Pension				
Decrease in discount rate	317	30	60	2
Decrease in expected return on assets	—	18	—	6
Decrease in rate of salary increase	(75)	—	(6)	(2)
OPEB				
Decrease in discount rate	22	1	15	(1)
Decrease in expected return on assets	—	—	—	1

Contingent Liabilities

Provisions for claims filed against us are determined on a case-by-case basis. Case estimates are reviewed on a regular basis and are updated as new information is received. The process of evaluating claims involves the use of estimates and a high degree of management judgment. Claims outstanding, the final determination of which could have a material impact on our financial results and certain subsidiaries and investments are detailed in Part II. *Item 8. Financial Statements and Supplementary Data - Note 29. Commitments and Contingencies.* In addition, any unasserted claims that later may become evident could have a material impact on our financial results and certain subsidiaries and investments.

Asset Retirement Obligations

ARO associated with the retirement of long-lived assets are measured at fair value and recognized as Accounts payable and other or Other long-term liabilities in the period in which they can be reasonably determined. The fair value approximates the cost a third party would charge to perform the tasks necessary to retire such assets and is recognized at the present value of expected future cash flows. Discount rates used to estimate the present value the expected future cash flows range from 1.8% to 9.0% and 1.7% to 9.0% for the years ended December 31, 2018 and 2017, respectively. ARO is added to the carrying value of the associated asset and depreciated over the asset's useful life. The corresponding liability is accreted over time through charges to earnings and is reduced by actual costs of decommissioning and reclamation. Our estimates of retirement costs could change as a result of changes in cost estimates and regulatory requirements. Currently, for the majority of our assets, there is insufficient data or information to reasonably determine the timing of settlement for estimating the fair value of the ARO. In these cases, the ARO cost is considered indeterminate for accounting purposes, as there is no data or information that can be derived from past practice, industry practice or the estimated economic life of the asset.

In 2009, the NEB issued a decision related to the LMCI, which required holders of an authorization to operate a pipeline under the NEB Act to file a proposed process and mechanism to set aside funds to pay for future abandonment costs in respect of the sites in Canada used for the operation of a pipeline. The NEB's decision stated that while pipeline companies are ultimately responsible for the full costs of abandoning pipelines, abandonment costs are a legitimate cost of providing service and are recoverable from the users of the pipeline upon approval by the NEB. Following the NEB's final approval of the collection mechanism and the set-aside mechanism for LMCI, we began collecting and setting aside funds to cover future abandonment costs effective January 1, 2015. The funds collected are held in trust in accordance with the NEB decision. The funds collected from shippers are reported within Transportation and other services revenues and Restricted long-term investments. Concurrently, we reflect the future abandonment cost as an increase to Operating and administrative expense and Other long-term liabilities.

CHANGES IN ACCOUNTING POLICIES

Refer to *Item 8. Financial Statements and Supplementary Data - Note 3. Changes in Accounting Policies.*