



ENBRIDGE INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS

December 31, 2019

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.

This section of our Annual Report on Form 10-K discusses 2019 and 2018 items and year-over-year comparisons between 2019 and 2018. For discussion of 2017 items and year-over-year comparisons between 2018 and 2017, refer to Part II. *Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations* of our Annual Report on Form 10-K for the year ended December 31, 2018.

RECENT DEVELOPMENTS

CANADIAN LINE 3 REPLACEMENT PROGRAM PLACED INTO SERVICE

The Canadian Line 3 Replacement Program was placed into service on December 1, 2019, with an interim surcharge on Mainline System volumes of US\$0.20 per barrel. This safety-driven maintenance project reflects the importance of protecting the environment and ensuring the continued safe and reliable operations of our Mainline System well into the future. For further details refer to *Growth Projects - Commercially Secured Projects - Liquids Pipelines*.

STATE OF MINNESOTA PERMITTING TIMELINE FOR U.S. LINE 3 REPLACEMENT PROGRAM

On June 3, 2019, the Minnesota Court of Appeals rendered a decision on the Minnesota Public Utilities Commission's (MNPUC's) adequacy determination of the Final Environmental Impact Statement (FEIS) for the U.S. L3R Program. While denying eight of the nine appealed items, the Minnesota Court of Appeals identified one issue that led it to reverse the adequacy determination. On July 3, 2019, certain project opponents sought further appellate review from the Minnesota Supreme Court. On September 17, 2019, based on the respective responses of the MNPUC and the Company, the Minnesota Supreme Court denied the opponents' petitions thus restoring the MNPUC with jurisdiction. At a hearing on October 1, 2019, the MNPUC directed the Department of Commerce to submit a revised FEIS by December 9, 2019. The Department of Commerce issued the revised FEIS on December 9, 2019, and the MNPUC gathered public comment on that document through January 16, 2020. On February 3, 2020, the MNPUC approved the adequacy of the revised FEIS and reinstated the Certificate of Need and Route Permit, clearing the way for construction of the pipeline to commence following the issuance of required permits.

At this time, we cannot determine when all necessary permits to commence construction will be issued. For further details refer to *Growth Projects - Regulatory Matters - United States Line 3 Replacement Program*.

MAINLINE SYSTEM CONTRACTING

On August 2, 2019, we launched an open season for transportation services on our Mainline System. The open season provided shippers with the opportunity to enter into long-term contracts for priority access on the Mainline System upon maturity of the current CTS agreement on June 30, 2021.

On September 27, 2019, after receiving complaints, the CER ordered that we may not offer firm service to prospective shippers on our Mainline System until such firm service, including all associated tolls and terms and conditions of service, has been approved by the CER. While this decision was a significant departure from past regulatory precedents, the CER noted that its decision to hold a regulatory review prior to the open season does not prejudice our ability to offer long term priority access contracts on the Mainline System.

On December 19, 2019, we submitted an application to the CER to implement contracting on our Mainline System. The application for contracted and uncommitted service included the associated terms, conditions and tolls of each service, which would be offered in an open season following approval by the CER. The tolls and services would replace the current CTS that is in place until June 30, 2021. If a replacement agreement is not in place by that time, the CTS tolls will continue on an interim basis.

The application that we filed is the result of over two years of extensive negotiations with a diverse group of shippers and has been designed to align the interests of us and our shippers. Shippers, which represent over 70 percent of our current Mainline System throughput, have filed letters supporting the application with the CER, demonstrating the strong shipper backing for the offering.

On February 7, 2020, we replied to the letters solicited by the CER regarding comments from interested parties both in opposition and support of our application. We expect a thorough regulatory process to continue through substantially all of 2020.

ASSET MONETIZATION

Enbridge Gas New Brunswick Business

On October 1, 2019, we closed the sale of EGNB to Liberty Utilities (Canada) LP, a wholly-owned subsidiary of Algonquin Power & Utilities Corp., for proceeds of approximately \$331 million.

St. Lawrence Gas Company Inc.

On November 1, 2019, we closed the sale of the issued and outstanding shares of St. Lawrence Gas for proceeds of approximately \$72 million.

Canadian Natural Gas Gathering and Processing Businesses

On December 31, 2019, we closed the sale of the federally regulated Canadian natural gas gathering and processing businesses to Brookfield Infrastructure Partners L.P. and its institutional partners (collectively, Brookfield) for proceeds of approximately \$1.7 billion, after closing adjustments. These federally regulated businesses represent the second and final phase of the \$4.3 billion transaction that was previously announced on July 4, 2018.

Montana-Alberta Tie Line

In the fourth quarter of 2019, we committed to a plan to sell the MATL transmission assets. The purchase and sale agreement was signed in January 2020. Subject to certain regulatory approvals and customary closing conditions, the transaction is expected to close in the first quarter of 2020.

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.

ENBRIDGE GAS INC. 2019 RATE APPLICATION

In September 2019, Enbridge Gas received a Decision and Order from the OEB on its application for 2019 rates. The 2019 rate application was filed in December 2018 in accordance with the parameters of Enbridge Gas's OEB approved Price Cap Incentive Regulation rate setting mechanism and represents the first year of a five-year term. The Decision and Order approved an effective date for base rates of April 1, 2019, and the inclusion of incremental capital module amounts to allow for the recovery of incremental capital investments.

ENBRIDGE GAS INC. 2020 RATE APPLICATION

In October 2019, Enbridge Gas filed an application with the OEB for the setting of rates for 2020 and for the funding of discrete incremental capital investments through the incremental capital module mechanism. The 2020 rate application was filed in accordance with the parameters of Enbridge Gas' OEB approved Price Cap Incentive Regulation rate setting mechanism and represents the second year of a five-year term. In December 2019, Enbridge Gas received a Decision and Order from the OEB which approved 2020 rates on an interim basis effective January 1, 2020. A decision on Enbridge Gas' application for incremental capital module amounts is expected in the second quarter of 2020.

TEXAS EASTERN PIPELINE RUPTURE

On August 1, 2019, a rupture occurred on Line 15, a 30-inch natural gas pipeline that is a component of the Texas Eastern natural gas pipeline system in Lincoln County, Kentucky. While the two adjacent pipelines have been returned to service, Line 15 remains shut down in the affected area and the timeline for its return to service has not yet been determined. There was one fatality. We are continuing to support the National Transportation Safety Board in its investigation, the community and the community members who were impacted by the rupture. The Texas Eastern natural gas pipeline system extends approximately 1,700 miles from producing fields in the Gulf Coast region of Texas and Louisiana to Ohio, Pennsylvania, New Jersey and New York.

Due to the incident, before expected recoveries, we experienced lower revenues and higher operating costs of \$34 million in 2019. Texas Eastern Transmission, LP (Texas Eastern) is included in a comprehensive insurance program that is maintained for our subsidiaries and affiliates, which includes liability, property and business interruption insurance.

TEXAS EASTERN RATE CASE

On June 1, 2019, Texas Eastern put into effect its updated rates. These increased recourse rates are subject to refund and interest. Following extensive negotiations on the Texas Eastern rate case, we reached an agreement with shippers and filed a Stipulation and Agreement with the FERC on October 28, 2019. On January 13, 2020, the Administrative Law Judge certified this uncontested Stipulation and Agreement to the FERC and we expect a decision from the FERC in the second quarter of 2020. Upon receipt of a decision from the FERC we will begin recognizing updated rates within our results of operations.

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: our corporate vision and strategy, including strategic priorities and enablers; expected earnings before interest, income taxes and depreciation and amortization (EBITDA); expected earnings/(loss); expected future cash flows; expected distributable cash flow; expected debt-to-EBITDA ratio; financial strength and flexibility; expectations on sources of liquidity and sufficiency of financial resources; expected strategic priorities and performance of the Liquids Pipelines, Gas Transmission and Midstream, Gas Distribution and Storage, Renewable Power Generation and Energy Services businesses; 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 the timing thereof; expected benefits of transactions, including the realization of efficiencies and synergies; expected future actions of regulators and related court proceedings and other litigation; expectations regarding commodity prices; supply and demand forecasts; anticipated utilization of our existing assets; anticipated competition; United States Line 3 Replacement Program (U.S. L3R Program); Line 5 related matters; Mainline System contracting; Texas Eastern rate case; estimated future dividends; our dividend payout policy; dividend growth and dividend payout expectation; and expectations on impact of our hedging program.

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 acquisitions and dispositions; the realization of anticipated benefits and synergies of transactions; governmental legislation; impact of our dividend policy on our future cash flows; our credit ratings; capital project funding; expected EBITDA; expected earnings/(loss); expected future cash flows; expected distributable cash flow; 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 expected EBITDA, expected earnings/(loss), expected future cash flows, expected distributable cash flow 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 successful execution of our strategic priorities, operating performance, regulatory parameters, changes in regulations applicable to our business, acquisitions, dispositions and other transactions, 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,		
	2019	2018	2017
<i>(millions of Canadian dollars, except per share amounts)</i>			
Segment earnings/(loss) before interest, income taxes and depreciation and amortization			
Liquids Pipelines	7,681	5,331	6,395
Gas Transmission and Midstream	3,371	2,334	(1,269)
Gas Distribution and Storage	1,747	1,711	1,390
Renewable Power Generation	111	369	372
Energy Services	250	482	(263)
Eliminations and Other	429	(708)	(337)
Depreciation and amortization	(3,391)	(3,246)	(3,163)
Interest expense	(2,663)	(2,703)	(2,556)
Income tax expense	(1,708)	(237)	2,697
Earnings attributable to noncontrolling interests and redeemable noncontrolling interests	(122)	(451)	(407)
Preference share dividends	(383)	(367)	(330)
Earnings attributable to common shareholders	5,322	2,515	2,529
Earnings per common share	2.64	1.46	1.66
Diluted earnings per common share	2.63	1.46	1.65

EARNINGS ATTRIBUTABLE TO COMMON SHAREHOLDERS

Year ended December 31, 2019 compared with year ended December 31, 2018

Earnings Attributable to Common Shareholders were net positively impacted by \$2,034 million due to certain unusual, infrequent or other non-operating factors, primarily explained by the following:

- a non-cash, unrealized derivative fair value gain of \$1,806 million (\$1,276 million after-tax attributable to us) in 2019, compared with a loss of \$660 million (\$397 million after-tax attributable to us) in 2018, 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 non-cash, write-down of crude oil and natural gas inventories to the lower of cost or market in our Energy Services business segment of \$188 million (\$144 million after-tax attributable to us) in 2019, compared with \$327 million (\$239 million after-tax attributable to us) in 2018;
- the absence in 2019 of a goodwill impairment charge of \$1,019 million after-tax attributable to us in 2018 resulting from the classification of our Canadian natural gas gathering and processing businesses as held for sale;
- the absence in 2019 of a loss of \$913 million (\$701 million after-tax attributable to us) in 2018 on Midcoast Operating, L.P. and its subsidiaries (MOLP) resulting from a revision to the fair value of the assets held for sale based on the sale price;
- the absence in 2019 of a loss of \$154 million (\$95 million after-tax attributable to us) in 2018 related to the Line 10 crude oil pipeline, 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; and
- employee severance, transition and transformation costs of \$140 million (\$127 million after-tax attributable to us) in 2019, compared with \$203 million (\$181 million after-tax attributable to us) in 2018.

The positive factors above were partially offset by the following unusual, infrequent or other non-operating factors:

- a loss of \$467 million after-tax attributable to us in 2019 (\$268 million loss on sale and \$199 million tax expense) resulting from the sale of the federally regulated portion of our Canadian natural gas gathering and processing businesses;
- a loss of \$310 million (\$229 million after-tax attributable to us) in 2019 resulting from the review of our comprehensive long-term economic hedging program and a payment to certain hedge counterparties to pre-settle and reset the hedge rate on a portion of our hedging program;
- a loss of \$297 million (\$218 million after-tax attributable to us) in 2019 resulting from the classification of our MATL assets as held for sale and the subsequent measurement at the lower of their carrying value or fair value less costs to sell;
- a loss of \$105 million (\$79 million after-tax attributable to us) in 2019 resulting from the write-off of project costs related to the Access Northeast pipeline project;
- a loss of \$86 million (\$68 million after-tax attributable to us) in 2019 related to sale of assets, asset write-down and goodwill impairment losses at our equity investee, DCP Midstream;
- the absence in 2019 of a recovery of \$223 million after-tax in 2018 related to rate cases filed that eliminated a portion of the regulated liability formerly included in our US Gas Transmission business rate base; and
- the absence in 2019 of a deferred income tax recovery of \$267 million (\$196 million attributable to us) in 2018 related to a change in the assertion for the investment in Canadian renewable energy generation 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 \$773 million increase in Earnings Attributable to Common Shareholders is primarily explained by the following significant business factors:

- increased earnings from our Liquids Pipelines segment due to higher Flanagan South, Seaway Pipeline and Bakken Pipeline System throughput year-over-year;
- stronger contributions from our Liquids Pipelines segment due to a higher IJT Benchmark Toll and higher Mainline System ex-Gretna throughput driven by an increase in supply and continuous capacity optimization;
- contributions from new Gas Transmission and Midstream assets placed into service in the fourth quarter of 2018 and 2019;
- increased earnings from our Gas Distribution and Storage segment due to colder weather experienced in our franchise areas, higher distribution rates and customer base, and the absence in 2019 of earnings sharing which was recognized in 2018;
- increased earnings from our Energy Services segment due to the widening of certain location and quality differentials during the second half of 2018 and the first half of 2019, which increased opportunities to generate profitable transportation margins that were realized during 2019;
- lower earnings attributable to noncontrolling interests in 2019 following the completion of the Sponsored Vehicles buy-in in the fourth quarter of 2018; and
- the net favorable effect of translating United States dollar EBITDA at a higher Canadian to United States dollar average exchange rate (Average Exchange Rate) of \$1.33 in 2019 compared with \$1.30 in 2018, partially offset by realized losses arising from our foreign exchange risk management program.

The positive business factors above were partially offset by the following:

- the absence in 2019 of earnings from MOLP and the provincially regulated portion of our Canadian natural gas gathering and processing businesses which were sold in the second half of 2018;
- higher operating costs on our Gas Transmission and Midstream assets primarily due to higher pipeline integrity costs;
- higher depreciation and amortization expense as a result of placing new assets into service, partially offset by depreciation no longer recorded for assets which were classified as held for sale or sold during the second half of 2018; and
- higher income tax expense due to higher earnings, the buy-in of our United States sponsored vehicles in the fourth quarter of 2018 and lower foreign tax rate differentials in 2019.

REVENUES

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

Transportation and other services revenues of \$16,555 million, \$14,358 million and \$13,877 million for the years ended December 31, 2019, 2018 and 2017, respectively, were earned from our crude oil and natural gas pipeline transportation businesses and also include power generation 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 three years.

Gas distribution sales revenues of \$4,205 million, \$4,360 million and \$4,215 million for the years ended December 31, 2019, 2018 and 2017, 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 \$29,309 million, \$27,660 million and \$26,286 million for the years ended December 31, 2019, 2018 and 2017, 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.

DIVIDENDS

We have paid common share dividends in every year since we became a publicly traded company in 1953. In December 2019, we announced a 9.8 percent increase in our quarterly dividend to \$0.81 per common share, or \$3.24 annualized, effective with the dividend payable on March 1, 2020.

BUSINESS SEGMENTS

LIQUIDS PIPELINES

	2019	2018	2017
<i>(millions of Canadian dollars)</i>			
Earnings before interest, income taxes and depreciation and amortization	7,681	5,331	6,395

Year ended December 31, 2019 compared with year ended December 31, 2018

EBITDA was positively impacted by \$1,926 million due to certain unusual, infrequent or other non-operating factors, primarily explained by the following:

- a non-cash, unrealized gain of \$976 million in 2019 compared with a loss of \$1,077 million in 2018 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; and
- the absence in 2019 of 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.

The positive factors above were partially offset by the following unusual, infrequent or other non-operating factors:

- a loss of \$310 million in 2019 resulting from the review of our comprehensive long-term economic hedging program and a payment to certain hedge counterparties to pre-settle and reset the hedge rate on a portion of our hedging program; and
- a loss of \$21 million in 2019 related to the write-off of project development costs resulting from the withdrawal of our permit application for the Texas COLT Offshore Loading Project.

After taking into consideration the factors above, the remaining \$424 million increase is primarily explained by the following significant business factors:

- higher Flanagan South and Seaway Pipeline throughput year-over-year driven by the redirection of throughput to the Gulf Coast resulting from refinery outages in the United States Midwest in the first half of 2019 and strong Gulf Coast demand resulting from favorable price differentials;
- higher Bakken Pipeline System throughput year-over-year driven by strong production in the region;
- higher Mainline System ex-Gretna throughput of 2,705 kbpd in 2019 compared with 2,631 kbpd in 2018 driven by an increase in supply and continuous capacity optimization;
- a higher average IJT Benchmark Toll of \$4.18 in 2019 compared with \$4.11 in 2018; and
- the net favorable effect of translating United States dollar EBITDA at a higher Average Exchange Rate of \$1.33 in 2019 compared with \$1.30 in 2018.

The positive business factors above were partially offset by the unfavorable effect of a lower foreign exchange hedge rate used to lock-in United States dollar denominated Canadian Mainline revenues of US\$1.19 in 2019 compared with US\$1.26 in 2018.

GAS TRANSMISSION AND MIDSTREAM

	2019	2018	2017
<i>(millions of Canadian dollars)</i>			
Earnings/(loss) before interest, income taxes and depreciation and amortization	3,371	2,334	(1,269)

Year ended December 31, 2019 compared with year ended December 31, 2018

EBITDA was negatively impacted by the absence of contributions in 2019 of approximately \$240 million from the sale of MOLP on August 1, 2018 and the sale of the provincially regulated portion of our Canadian natural gas gathering and processing businesses on October 1, 2018.

EBITDA was positively impacted by \$1,237 million due to certain unusual, infrequent or other non-operating factors primarily explained by the following:

- the absence in 2019 of 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
- the absence in 2019 of a loss of \$913 million in 2018 resulting from the further revision to the fair value of our MOLP assets held for sale based on the sale price.

The positive factors above were partially offset by the following unusual, infrequent or other non-operating factors:

- a loss of \$268 million in 2019 resulting from the sale of the federally regulated portion of our Canadian natural gas gathering and processing businesses;
- a loss of \$105 million in 2019 resulting from the write-off of project costs related to the Access Northeast pipeline project;
- a loss of \$86 million in 2019 related to the sale of assets, asset write-downs and goodwill impairment losses at our equity investee, DCP Midstream; and
- the absence in 2019 of 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 business rate base.

After taking into consideration the factors above, the remaining \$40 million increase is primarily explained by the following significant business factors:

- contributions from Valley Crossing Pipeline and certain other Offshore and US Gas Transmission assets that were placed into service during the fourth quarter of 2018 and 2019; and
- the net favorable effect of translating United States dollar EBITDA at a higher Average Exchange Rate of \$1.33 in 2019 compared with \$1.30 in 2018.

The positive business factors above were partially offset by the following:

- higher operating costs on our US Gas Transmission assets primarily due to higher pipeline integrity costs;
- lower revenues and higher operating costs from US Gas Transmission due to the Texas Eastern natural gas pipeline system incident in Lincoln County, Kentucky, refer to *Recent Developments - Texas Eastern Rupture*; and
- decreased fractionation margins at our Aux Sable joint venture driven by lower NGL prices.

GAS DISTRIBUTION AND STORAGE

	2019	2018	2017
<i>(millions of Canadian dollars)</i>			
Earnings before interest, income taxes and depreciation and amortization	1,747	1,711	1,390

EGD and Union Gas were amalgamated on January 1, 2019. The amalgamated company has continued as Enbridge Gas. Post amalgamation the financial results of Enbridge Gas reflect the combined performance of EGD and Union Gas.

Year ended December 31, 2019 compared with year ended December 31, 2018

EBITDA was negatively impacted by \$57 million due to certain unusual, infrequent or other non-operating factors, primarily explained by the following:

- employee severance costs of \$39 million in 2019 related to the amalgamation of EGD and Union Gas;
- a loss of \$10 million in 2019 resulting from the sale of St. Lawrence Gas; and
- a non-cash, unrealized loss of \$12 million in 2019 compared with a gain of \$6 million in 2018 arising from the change in the mark-to-market value of our equity investee's, Noverco's derivative financial instruments.

The negative factors above were partially offset by the absence in 2019 of a negative equity earnings adjustment of \$9 million in 2018 at our equity investee, Noverco, arising from the Tax Cuts and Jobs Act in the United States.

After taking into consideration the factors above, the remaining \$93 million increase is primarily explained by the following significant business factors:

- increased earnings of \$36 million resulting from colder weather experienced in our franchise service areas when compared with the corresponding period in 2018;
- increased earnings from higher distribution charges primarily resulting from increases in distribution rates and customer base;
- the absence in 2019 of earnings sharing which was recognized in 2018 under EGD's previous incentive rate structure; and
- synergy captures realized from the amalgamation of EGD and Union Gas.

The positive business factors above were partially offset by the following:

- the effects of the accelerated capital cost allowance deductions reflected as a pass through to customers, consistent with the OEB's prescribed deferral account treatment; and
- the absence of contributions in 2019 from EGNB and St. Lawrence Gas which were sold on October 1, 2019 and November 1, 2019, respectively.

RENEWABLE POWER GENERATION

	2019	2018	2017
<i>(millions of Canadian dollars)</i>			
Earnings before interest, income taxes and depreciation and amortization	111	369	372

Year ended December 31, 2019 compared with year ended December 31, 2018

EBITDA was negatively impacted by \$247 million due to certain unusual, infrequent or other non-operating factors, primarily explained by the following:

- a loss of \$297 million in 2019 resulting from the classification of our MATL assets as held for sale and the subsequent measurement at the lower of their carrying value or fair value less costs to sell; and
- a loss of \$10 million in 2019 related to the write-down of offshore transmission assets anticipated to be disposed of in 2020 at our equity investee, Rampion Offshore Wind Limited.

The negative factors above were partially offset by the following unusual, infrequent or other non-operating factors:

- the absence in 2019 of a loss of \$20 million in 2018 resulting from the sale of 49% of our interest in the Hohe See Offshore wind facility and its expansion;
- the absence in 2019 of 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
- the absence in 2019 of 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 power transmission cables.

After taking into consideration the factors above, the remaining \$11 million decrease is primarily explained by the following significant business factors:

- weaker wind resources at United States wind facilities;
- higher mechanical repair costs at certain United States wind facilities, net of insurance recoveries; and
- the absence in 2019 of \$11 million in 2018 from a positive arbitration settlement related to our Canadian wind facilities.

The negative business factors above were partially offset by the following:

- contributions from the Hohe See Offshore Wind Project, which generated first power in July 2019 and reached full operating capacity in October 2019; and
- stronger wind resources at Canadian wind facilities.

ENERGY SERVICES

	2019	2018	2017
<i>(millions of Canadian dollars)</i>			
Earnings/(loss) before interest, income taxes and depreciation and amortization	250	482	(263)

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, 2019 compared with year ended December 31, 2018

EBITDA was net negatively impacted by \$334 million due to certain unusual, infrequent or other non-operating factors, primarily explained by a non-cash, unrealized gain of \$169 million in 2019 compared with a gain of \$642 million in 2018 reflecting the revaluation of derivatives used to manage the profitability of transportation and storage transactions and manage the exposure to movements in commodity prices. This negative factor was partially offset by a non-cash, write-down of crude oil and natural gas inventories to the lower of cost or market of \$188 million in 2019 compared with \$327 million in 2018.

After taking into consideration the factors above, the remaining \$102 million increase is primarily due to increased earnings from Energy Services crude operations as a result of the widening of certain location and quality differentials during the second half of 2018 and the first half of 2019, which increased opportunities to generate profitable transportation margins that were realized during 2019.

ELIMINATIONS AND OTHER

	2019	2018	2017
<i>(millions of Canadian dollars)</i>			
Earnings/(loss) before interest, income taxes and depreciation and amortization	429	(708)	(337)

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 the impact of new business development activities and corporate investments.

Year ended December 31, 2019 compared with year ended December 31, 2018

EBITDA was positively impacted by \$1,123 million due to certain unusual, infrequent or other-non-operating factors, primarily explained by the following:

- a non-cash, unrealized gain of \$671 million in 2019 compared with a loss of \$256 million in 2018 reflecting net fair value gains and losses arising from the change in the mark-to-market value of derivative financial instruments used to manage foreign exchange risk;
- employee severance, transition and transformation costs of \$84 million in 2019 compared with \$152 million in 2018; and
- the absence in 2019 of asset monetization transaction costs of \$68 million in 2018.

After taking into consideration the factors above, the remaining \$14 million increase is primarily explained by lower operating and administrative costs in 2019.

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. AOC Lateral Acquisition	100%	\$0.3 billion	\$0.3 billion	Complete	In-service
2. Gray Oak Pipeline Project	22.8%	US\$0.7 billion	US\$0.4 billion	Complete	In-service
3. Canadian Line 3 Replacement Program	100%	\$5.3 billion	\$4.9 billion	Complete	In-service
4. United States Line 3 Replacement Program	100%	US\$2.9 billion	US\$1.3 billion	Pre- construction	Under review ³
5. Other - United States ⁴	100%	US\$0.6 billion	US\$0.5 billion	Various stages	2020 - 2021
GAS TRANSMISSION AND MIDSTREAM					
6. Atlantic Bridge ⁵	100%	US\$0.6 billion	US\$0.5 billion	Various stages	2H - 2020
7. Spruce Ridge Project	100%	\$0.5 billion	\$0.2 billion	Pre- construction	2H - 2021
8. T-South Reliability & Expansion Program	100%	\$1.0 billion	\$0.4 billion	Pre- construction	2H - 2021
9. Other - United States ⁶	Various	US\$1.2 billion	US\$0.5 billion	Various stages	2020 - 2023
GAS DISTRIBUTION AND STORAGE					
10. Other - Canada	100%	\$0.2 billion	No significant expenditures to date	Pre- construction	2H - 2020
11. Dawn-Parkway Expansion	100%	\$0.2 billion	No significant expenditures to date	Pre- construction	2H - 2021
RENEWABLE POWER GENERATION					
12. Hohe See Offshore Wind Project and Expansion	25%	\$1.1 billion (€0.67 billion)	\$0.9 billion (€0.6 billion)	Complete	In-service
13. East-West Tie Line	25%	\$0.2 billion	No significant expenditures to date	Under construction	2H - 2021
14. Saint-Nazaire Offshore Wind Project ⁷	50%	\$1.8 billion (€1.2 billion)	\$0.1 billion (€0.04 billion)	Under construction	2H - 2022

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, 2019.

³ Update to in-service date pending receipt of all permits required to commence construction.

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 Connecticut and New York portions of the project that were placed into service in 2017 and in the fourth quarter of 2019, respectively.

⁶ Includes the US\$0.2 billion Stratton Ridge Project placed into service in the second quarter of 2019 and the US\$0.1 billion Generation Pipeline Acquisition closed in the third quarter of 2019.

⁷ Our equity contribution is \$0.3 billion, with the remainder of the project financed through non-recourse project level debt.

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 were acquired or placed into service in 2019:

- **AOC Lateral Acquisition** - in January 2019, we acquired 75-kilometers (47-miles) of existing lateral pipelines and tankage infrastructure supporting Athabasca Oil Corporation's (AOC's) Leismer oil sands asset.
- **Gray Oak Pipeline Project** - a crude oil pipeline project connecting the Permian Basin and Eagle Ford 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. Initial in-service for the pipeline commenced in November 2019 with full in-service expected in the second quarter of 2020.
- **Canadian Line 3 Replacement Program** - replacement of the existing Line 3 crude oil pipeline between Hardisty, Alberta and Gretna, Manitoba. 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.

At this time, we cannot determine when all necessary permits will be issued for the following project:

- **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 U.S. 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 - United States Line 3 Replacement Program*.



Liquids Pipelines

- 1 AOC Lateral Acquisition
- 2 Gray Oak Pipeline Project
- 3 Canadian Line 3 Replacement Program
- 4 United States Line 3 Replacement Program

—	Assets in Operation
—	Projects Placed into Service in 2019
—	Growth Projects

GAS TRANSMISSION AND MIDSTREAM

The following commercially secured growth project is expected to be placed into service in 2020:

- **Atlantic Bridge** - expansion of the Algonquin natural gas transmission systems to transport 133 million cubic feet per day (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 New York, 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 reached full in-service in October 2019, upon which we began earning incremental revenues. Due to ongoing permitting delays in Massachusetts, the revised expected in service date for the Massachusetts portion of the project is the second half of 2020.

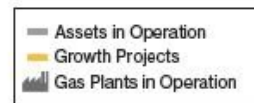
The following commercially secured growth projects are expected to be placed into service in 2021:

- **Spruce Ridge Project** - a natural gas pipeline expansion of Westcoast Energy Inc.'s BC Pipeline in northern BC. The project will provide additional capacity of up to 402 mmcf/d. Due to commercial delays, the revised expected in-service date is the second half of 2021.
- **T-South Reliability & Expansion Program** - a natural gas pipeline expansion of Westcoast Energy Inc.'s BC Pipeline in southern BC that will provide improved compressor reliability and additional capacity of approximately 190 mmcf/d into the Huntington/Sumas market at the United States/ Canada border. The projects were approved by the CER in September 2019.



Gas Transmission

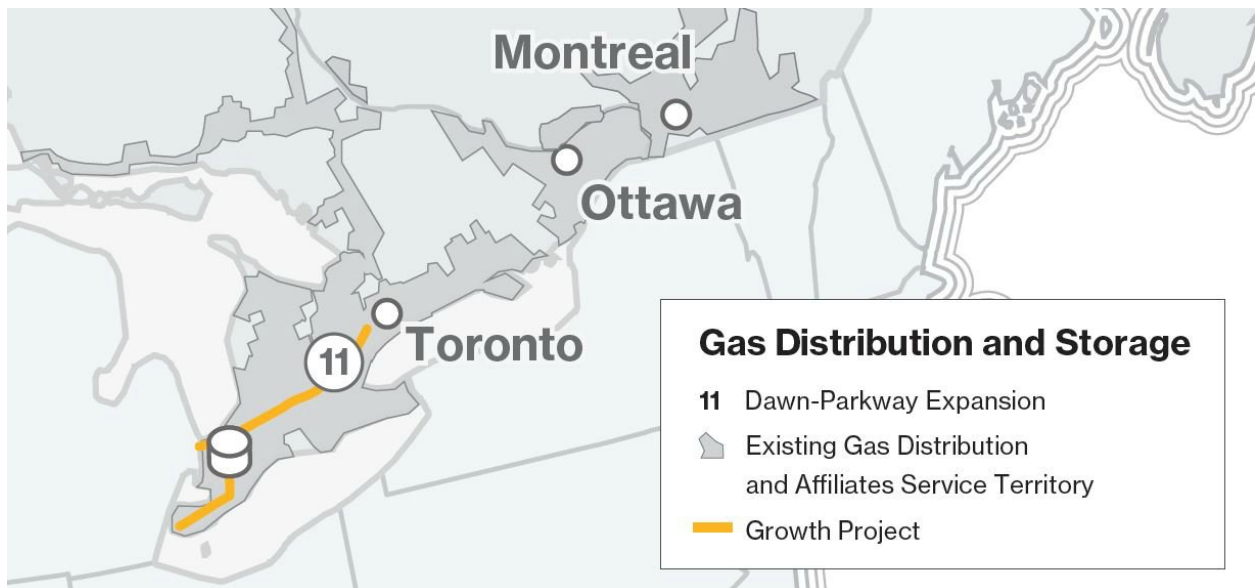
- 6 Atlantic Bridge
- 7 Spruce Ridge Project
- 8 T-South Reliability & Expansion Program



GAS DISTRIBUTION AND STORAGE

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

- **Dawn-Parkway Expansion** - the expansion of the existing Dawn to Parkway gas transmission system, which provides transportation service from Dawn to the Greater Toronto Area. The project is expected to provide additional capacity of approximately 83 mmcf/d.



RENEWABLE POWER GENERATION

The following commercially secured growth project was 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 Project and Expansion is backed by a government legislated 20-year revenue support mechanism. The project generated first power in July 2019, and full operating capacity was reached in October 2019. The project expansion came into service in January 2020.

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

- **East-West Tie Line** - a transmission project that will parallel an existing double-circuit, 230 kilovolt transmission line that connects the Wawa Transformer Station to the Lakehead Transformer Station near Thunder Bay, Ontario, including a connection midway in Marathon, Ontario.

The following commercially secured growth projects are expected to be placed into service in 2022:

- **Saint-Nazaire Offshore Wind Project** - a wind project located off the west coast of France that is expected to generate approximately 480-MW. Project revenues are backed by a 20-year fixed price power purchase agreement with added power production protection. Our share of the total investment in the project is \$1.8 billion, with an equity contribution of \$0.3 billion. The remainder of the construction will be financed through non-recourse project level debt.



Renewable Power Generation

- 12 Hohe See Offshore Wind Project and Expansion
- 13 East-West Tie Line Project
- 14 Saint-Nazaire Offshore Wind Project

	Power Transmission in Operation
	Growth Projects – Power Transmission
	Wind Projects Placed Into Service in 2019
	Wind Assets in Operation
	Solar Assets in Operation
	Growth Projects – Wind

GROWTH PROJECTS - REGULATORY MATTERS

United States Line 3 Replacement Program

On June 3, 2019, the Minnesota Court of Appeals rendered a decision on the MNPUC's adequacy determination of the FEIS for the U.S. L3R Program. While denying eight of the nine issues on appeal, the Minnesota Court of Appeals identified one issue that led it to reverse the adequacy determination. The Minnesota Court of Appeals remanded and directed the MNPUC to perform spill modeling analysis within the Lake Superior Watershed. On July 3, 2019, certain project opponents sought further appellate review from the Minnesota Supreme Court. On September 17, 2019, based on the respective responses of the MNPUC and the Company, the Minnesota Supreme Court denied the opponents' petitions thus restoring the MNPUC with jurisdiction. At a hearing on October 1, 2019, the MNPUC directed the Department of Commerce to submit a revised FEIS by December 9, 2019. The Department of Commerce issued the revised FEIS on December 9, 2019 and the MNPUC gathered public comment on that document through January 16, 2020. On February 3, 2020, the MNPUC approved the adequacy of the revised FEIS and reinstated the Certificate of Need and Route Permit, clearing the way for construction of the pipeline to commence following the issuance of required permits.

As for environmental permits, the spill modeling required by the Minnesota Court of Appeals is a prerequisite to finalizing other state permits. On September 27, 2019, the Minnesota Pollution Control Agency (MPCA) issued a denial without prejudice of the U.S. L3R Program's 401 Water Quality Certification (WQC). This action was expected since the MPCA is prohibited by state law from issuing a final 401 WQC until the FEIS is found to be adequate by the MNPUC. On November 15, 2019, we submitted a revised 401 WQC to the MPCA. The MPCA is expected to release a draft of the revised 401 WQC on February 26, 2020, and a 30-day public comment period is expected to begin on March 2, 2020.

At this time, we cannot determine when all necessary permits to commence construction will be issued. Depending on the final in-service date, there is a risk that the project may exceed our total cost estimate of \$9 billion for the combined Line 3 Replacement Program. However, at this time, we do not anticipate any capital cost impacts that would be material to our financial position and outlook.

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

- **Sea Port Oil Terminal Project** - the Sea Port Oil Terminal (SPOT) project consists of onshore and offshore facilities, including a fixed platform located approximately 30 miles off the coast of Brazoria County, Texas. SPOT is designed to load very large crude carriers at rates of approximately 85,000 barrels per hour, or up to approximately 2 million bpd. Along with Enterprise Products Partners, L.P., we announced our intent to jointly develop and market SPOT, and we will work to finalize an equity participation agreement. The agreement will allow us to purchase an ownership interest in SPOT, subject to SPOT receiving a deep-water port license.
- **Jones Creek Crude Oil Storage Terminal** - the Jones Creek terminal is expected to have an ultimate capability of up to 15 million barrels of storage, access to crude oil from all major North American production basins and will be fully integrated with the Seaway Pipeline system to allow for access to Houston-area refineries, existing export facilities, the SPOT project and other facilities in the future.

GAS TRANSMISSION AND MIDSTREAM

- **Rio Bravo Pipeline** - the Rio Bravo Pipeline is designed to transport up to 4.5 bcf/d of natural gas from the Agua Dulce supply area to NextDecade's Rio Grande LNG export facility in the Port of Brownsville, Texas. We have executed an agreement with NextDecade to acquire the Rio Bravo Pipeline development project. In addition, we have negotiated a precedent agreement with NextDecade, to be executed at closing, under which we will provide firm transportation capacity on the Rio Bravo Pipeline to NextDecade's Rio Grande LNG export facility for a term of at least twenty years. Construction of the pipeline will be subject to the Rio Grande LNG export facility reaching a final investment decision.
- **Annova LNG** - we have executed a precedent agreement to supply the Annova LNG facilities in the Port of Brownsville, Texas for a term of at least twenty years, by expanding our existing Valley Crossing system. The expansion will be subject to the Annova LNG facilities reaching a final investment decision.
- **Texas Eastern Venice Extension Project** - a reversal and expansion of Texas Eastern's Line 40 from its existing New Roads compressor station to a new delivery point with the proposed Gator Express pipeline just south of Texas Eastern's Larose compressor station. The project is expected to deliver 1.26 bcf of feed gas to Venture Global's proposed Plaquemines LNG export facility located in Plaquemine Parish, Louisiana. The project is expected to be placed into service in 2022.

RENEWABLE POWER GENERATION

- **Éolien Maritime France SAS** - a 50% interest in 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 is expected to generate approximately 1,428 MW. One wind facility, the Saint-Nazaire Offshore Wind Project, achieved a positive final investment decision during the third quarter of 2019. The development of the remaining two wind facilities is subject to final investment decisions and regulatory approvals, the timing of which are 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. Our current financing plan does not include any issuances of additional common equity and was the leading principle behind the suspension of our Dividend Reinvestment and Share Purchase Plan in November 2018.

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 we completed the following issuances in 2019:

Entity	Type of Issuance	Amount
<i>(in millions of Canadian dollars, unless stated otherwise)</i>		
Enbridge Inc.	Medium-term notes	\$1,000
Enbridge Inc.	US\$ senior notes	US\$2,000
Enbridge Gas Inc.	Medium-term notes	\$700
Enbridge Pipelines Inc.	Medium-term notes	\$1,200
Spectra Energy Partners, LP ¹	US\$ senior notes	US\$500

¹ Issued through Algonquin Gas Transmission, LLC, an operating subsidiary of Spectra Energy Partners, LP (SEP).

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, 2019:

	Maturity	Total Facilities	Draws ¹	Available
<i>(millions of Canadian dollars)</i>				
Enbridge Inc.	2021-2024	6,993	5,210	1,783
Enbridge (U.S.) Inc.	2021-2024	7,132	1,734	5,398
Enbridge Pipelines Inc.	2021	3,000	2,030	970
Enbridge Gas Inc.	2021	2,000	898	1,102
Total committed credit facilities		19,125	9,872	9,253

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

On February 7, 2019 and February 8, 2019, we terminated certain Canadian and United States dollar credit facilities, including facilities held by Enbridge, Enbridge Gas, Enbridge Energy Partners, L.P. (EEP) and SEP. We also increased existing facilities or obtained new facilities to replace the terminated ones under Enbridge, Enbridge (U.S.) Inc. and Enbridge Gas. As a result, our total credit facility availability increased by approximately \$444 million.

On May 16, 2019, Enbridge Inc. entered into a three year, non-revolving, extendible credit facility for \$641 million (¥52.5 billion) with a syndicate of Japanese banks.

On July 18, 2019, Enbridge Inc. entered into a five year, non-revolving, bilateral credit facility for \$500 million with an Asian bank.

In addition to the committed credit facilities noted above, we have \$916 million of uncommitted demand facilities, of which \$476 million were unutilized as at December 31, 2019. As at December 31, 2018, we had \$807 million of uncommitted credit facilities, of which \$548 million were unutilized.

As at December 31, 2019 and 2018, our net available liquidity totaled \$9,901 million and \$9,409 million, respectively. As at December 31, 2019, the liquidity was inclusive of \$648 million of unrestricted Cash and cash equivalents as reported on the Consolidated Statements of Financial Position (2018 - \$518 million).

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, 2019, we were in compliance with all debt covenants and expect to continue to comply with such covenants.

Strong growth in internal cash flow, proceeds from non-core asset dispositions, 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 EBITDA.

During 2019, our credit ratings were affirmed as follows:

- On July 23, 2019, DBRS Limited affirmed 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.
- On April 15, 2019, 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.
- On December 30, 2019, 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.

We invest surplus cash in short-term investment grade money market instruments with highly creditworthy counterparties. Short-term investments were \$2 million as at December 31, 2019 compared with \$76 million as at December 31, 2018.

There are no material restrictions on our cash. Total restricted cash of \$28 million, as reported on the Consolidated Statements of Financial Position, primarily 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 use by us.

Excluding current maturities of long-term debt, as at December 31, 2019 and 2018, we had a negative working capital position of \$2,781 million and \$3,024 million, respectively. In both periods, the major contributing factor to the negative working capital position was the current liabilities associated with 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.

SOURCES AND USES OF CASH

December 31, <i>(millions of Canadian dollars)</i>	2019	2018	2017
Operating activities	9,398	10,502	6,658
Investing activities	(4,658)	(3,017)	(11,037)
Financing activities	(4,745)	(7,503)	3,476
Effect of translation of foreign denominated cash and cash equivalents	44	68	(72)
Net increase/(decrease) in cash and cash equivalents and restricted cash	39	50	(975)

Significant sources and uses of cash for the years ended December 31, 2019 and 2018 are summarized below:

Operating Activities

2019

- The decrease in cash flow provided by operations during 2019 was primarily driven by changes in operating assets and liabilities. Our operating assets and liabilities fluctuate in the normal course due to various factors, including the impact of fluctuations in commodity prices and activity levels on working capital within our business segments, the timing of tax payments, as well as timing of cash receipts and payments generally. Refer to Part II. *Item 8. Financial Statements and Supplementary Data - Note 28. Changes in Operating Assets and Liabilities.*
- The factor above was partially offset by stronger contributions from our operating segments and contributions from new assets placed into service as discussed under *Results of Operations.*

2018

- The increase in cash flow provided by operations during 2018 was primarily driven by changes in operating assets and liabilities and stronger contributions from our operating segments.

Investing Activities

We continue with the execution of our growth capital program which is further described in Part II. *Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - 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, 2019, 2018 and 2017 is set out below:

Year ended December 31, <i>(millions of Canadian dollars)</i>	2019	2018	2017
Liquids Pipelines	2,548	3,102	2,797
Gas Transmission and Midstream	1,695	2,578	3,883
Gas Distribution and Storage	1,100	1,066	1,177
Renewable Power Generation	23	33	321
Energy Services	2	—	1
Eliminations and Other	124	27	108
Total capital expenditures	5,492	6,806	8,287

2019

The increase in cash used in investing activities primarily resulted from the following factors:

- Lower proceeds from asset dispositions in 2019 compared with 2018. In 2019, the proceeds from dispositions reflects the sale of the federally regulated portion of our Canadian natural gas gathering and processing businesses assets, St. Lawrence Gas and EGNB. In 2018, the proceeds from dispositions reflects the sale of MOLP, a portion of our renewable assets and the provincially regulated portion of our Canadian natural gas gathering and processing businesses assets.
- The absence in 2019 of a distribution received from Sabal Trail in 2018 as a partial return of capital for construction and development costs previously funded by Sabal Trail's partners.

2018

The decrease in cash used in investing activities primarily resulted from the following factors:

- Higher proceeds from asset dispositions in 2018 compared with 2017 primarily due to the sale of MOLP, a portion of our renewable assets and the provincially regulated portion of our Canadian natural gas gathering and processing businesses assets in 2018.
- The absence in 2018 of the acquisition of an interest in the Bakken Pipeline System in 2017.

Financing Activities

2019

The decrease in cash used in financing activities primarily resulted from the following factors:

- Increased commercial paper and credit facility draws and increased long-term debt issued in 2019 compared with 2018, partially offset by higher repayments of maturing long-term debt.
- Decreased distributions to noncontrolling interests and redeemable noncontrolling interests in 2019 primarily as a result of the Sponsored Vehicles buy-in in the fourth quarter of 2018.
- The absence in 2019 of proceeds received from the sale of a portion of our interest in our Canadian and United States renewable assets to the Canada Pension Plan Investment Board (CPPIB) in the third quarter of 2018.
- The above factors were partially offset by higher common share dividend payments in 2019 due to the increase in the common share dividend rate and an increase in the number of common shares outstanding in connection with the Sponsored Vehicles buy-in in the fourth quarter of 2018.

2018

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

- Decreased long-term debt issuances and common shares issued in 2018 when compared with 2017, partially offset by lower repayments of maturing long-term debt.
- Higher common share dividend payments in 2018 due to the increase in the common share dividend rate and 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.
- Proceeds received from the sale of a portion of our interest in our Canadian and United States renewable assets to the CPPIB in the third quarter of 2018.
- Decreased contributions from noncontrolling interests and redeemable noncontrolling interests in 2018 primarily due to a secondary public offering in 2017 attributable to our holdings in Enbridge Income Fund Holdings Inc. (ENF).

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	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%	\$1.17224	\$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%	\$1.27152	\$25	December 1, 2023	Series O
Series P	\$400 million	4.38%	\$1.09476	\$25	March 1, 2024	Series Q
Series R	\$400 million	4.07%	\$1.01825	\$25	June 1, 2024	Series S
Series 1 ⁶	US\$400 million	5.95%	US\$1.48728	US\$25	June 1, 2023	Series 2
Series 3	\$600 million	3.74%	\$0.93425	\$25	September 1, 2024	Series 4
Series 5	US\$200 million	5.38%	US\$1.34383	US\$25	March 1, 2024	Series 6
Series 7	\$250 million	4.45%	\$1.11224	\$25	March 1, 2024	Series 8
Series 9	\$275 million	4.10%	\$1.02424	\$25	December 1, 2024	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 of Directors. 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 Series A Preference Shares 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 decreased to \$0.25395 from \$0.25459 on March 1, 2019, was increased to \$0.25647 from \$0.25395 on June 1, 2019, was decreased to \$0.25243 from \$0.25647 on September 1, 2019 and was increased to \$0.25305 from \$0.25243 on December 1, 2019, due to reset on a quarterly basis following the issuance thereof.

6 No Series P, R, 3, 5, 7 or 9 Preference shares were converted on the March 1, 2019, June 1, 2019, September 1, 2019, March 1, 2019, March 1, 2019 or December 1, 2019 conversion option dates, respectively. However, the quarterly dividend amounts for Series P, R, 3, 5, 7 or 9, was increased to \$0.27369 from \$0.25000 on March 1, 2019, increased to \$0.25456 from \$0.25000 on June 1, 2019, decreased to \$0.23356 from \$0.25000 on September 1, 2019, increased to US\$0.33625 from US\$0.27500 on March 1, 2019, increased to \$0.27806 from \$0.27500 on March 1, 2019 and decreased to \$0.25606 from \$0.27500 on December 1, 2019, respectively, due to reset on every fifth anniversary thereafter.

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 Part II. *Item 8. Financial Statements and Supplementary Data - Note 21. Share Capital.*

Dividends

For the years ended December 31, 2019 and 2018, total dividends paid were \$5,973 million and \$4,661 million, respectively, of which \$5,973 million and \$3,480 million, respectively, were paid in cash and reflected in financing activities. In 2018, \$1,181 million of dividends paid were reinvested pursuant to our previous dividend reinvestment program and resulted in the issuance of common shares rather than a cash payment.

On December 9, 2019, our Board of Directors declared the following quarterly dividends. All dividends are payable on March 1, 2020 to shareholders of record on February 14, 2020.

Common Shares ¹	\$0.81000
Preference Shares, Series A	\$0.34375
Preference Shares, Series B	\$0.21340
Preference Shares, Series C ²	\$0.25305
Preference Shares, Series D	\$0.27875
Preference Shares, Series F	\$0.29306
Preference Shares, Series H	\$0.27350
Preference Shares, Series J	US\$0.30540
Preference Shares, Series L	US\$0.30993
Preference Shares, Series N	\$0.31788
Preference Shares, Series P ³	\$0.27369
Preference Shares, Series R ⁴	\$0.25456
Preference Shares, Series 1	US\$0.37182
Preference Shares, Series 3 ⁵	\$0.23356
Preference Shares, Series 5 ⁶	US\$0.33596
Preference Shares, Series 7 ⁷	\$0.27806
Preference Shares, Series 9 ⁸	\$0.25606
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	\$0.30625

¹ The quarterly dividend per common share was increased 9.8% to \$0.81000 from \$0.73800, effective March 1, 2020.

² The quarterly dividend per share paid on Series C was decreased to \$0.25395 from \$0.25459 on March 1, 2019, increased to \$0.25647 from \$0.25395 on June 1, 2019, decreased to \$0.25243 from \$0.25647 on September 1, 2019, and increased to \$0.25305 from \$0.25243 on December 1, 2019, due to reset on a quarterly basis following the date of issuance of the Series C Preference Shares.

³ The quarterly dividend per share paid on Series P was increased to \$0.27369 from \$0.25000 on March 1, 2019, due to reset of the annual dividend on March 1, 2019, and every five years thereafter.

⁴ The quarterly dividend per share paid on Series R was increased to \$0.25456 from \$0.25000 on June 1, 2019, due to the reset of the annual dividend on June 1, 2019, and every five years thereafter.

⁵ The quarterly dividend per share paid on Series 3 was decreased to \$0.23356 from \$0.25000 on September 1, 2019, due to the reset of the annual dividend on September 1, 2019, and every five years thereafter.

⁶ The quarterly dividend per share paid on Series 5 was increased to US \$0.33596 from US \$0.27500 on March 1, 2019, due to reset of the annual dividend on March 1, 2019, and every five years thereafter.

⁷ The quarterly dividend per share paid on Series 7 was increased to \$0.27806 from \$0.27500 on March 1, 2019, due to reset of the annual dividend on March 1, 2019, and every five years thereafter.

⁸ The quarterly dividend per share paid on Series 9 was decreased to \$0.25606 from \$0.27500 on December 1, 2019, due to the reset of the annual dividend on December 1, 2019, and every five years thereafter.

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 Part II, *Item 8. Financial Statements and Supplementary Data - Note 31. 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 Part II. *Item 8. Financial Statements and Supplementary Data - Note 30. Commitments and Contingencies* and *Note 31. 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, 2019	Total	Less than 1 year	1-3 years	4-5 years	After 5 years
<i>(millions of Canadian dollars)</i>					
Annual debt maturities ¹	63,585	4,394	10,910	10,297	37,984
Interest obligations ²	29,498	2,416	4,512	3,991	18,579
Land leases	1,190	30	70	71	1,019
Pension obligations ³	135	135	—	—	—
Long-term contracts ⁴	9,883	2,947	2,832	1,179	2,925
Other long-term liabilities ⁵	—	—	—	—	—
Total contractual obligations	104,291	9,922	18,324	15,538	60,507

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 finance 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 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, 2019. Contributions, including discretionary payments, may vary depending on future benefit design and asset performance.

⁴ 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 \$2,237 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.

⁵ We are unable to estimate deferred income taxes (Part II. *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) (Part II. *Item 8. Financial Statements and Supplementary Data - Note 19. Asset Retirement Obligations*), environmental liabilities (Part II. *Item 8. Financial Statements and Supplementary Data - Note 30. Commitments and Contingencies*) and hedges payable (Part II. *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

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, seeking damages in excess of US\$140 million. On September 7, 2018, the United States District Court for the Eastern District of Pennsylvania granted Eddystone Rail's motion to amend its complaint to add several affiliates of the corporate defendants as additional defendants (the Amended Complaint). Eddystone Rail's chances of success on its Amended Complaint cannot be predicted at this time. Defendants have filed Answers and Counterclaims which, together with subsequent amendments, seek damages from Eddystone Rail in excess of US\$32 million. The defendants' chances of success on their counterclaims cannot be predicted at this time. The non-corporate defendants filed a Motion to Dismiss on October 25, 2019, based on alleged lack of standing. The motion has been fully briefed to the Court and decision is pending. The individual defendants' chances of success on this motion cannot be predicted at this time.

Dakota Access Pipeline

In February 2017, the Standing Rock Sioux Tribe and the Cheyenne River Sioux Tribe filed motions with the United States Court for the District of Columbia contesting the validity of the process used by the United States Army Corps of Engineers (Army Corps) to permit the Dakota Access Pipeline. The Oglala Sioux and Yankton Sioux Tribes also filed claims in the case to challenge the Army Corps permit and environmental review process. In August 2018, in response to a Court order to reconsider components of its environmental analysis, the Army Corps issued its decision that no supplemental environmental analysis was required. All four Tribes have since amended their complaints to include claims challenging the adequacy of the Army Corps' supplemental environmental analysis. The parties have filed cross-motions for summary judgment with the United States District Court for the District of Columbia on the merits of the plaintiffs claims challenging the adequacy of the Army Corps' remand process. Briefing on the parties' cross-motions for summary judgment was completed on November 25, 2019. These cross-motions remain pending for decision before the District Court.

Line 5 Dual Pipelines

In December 2018, Michigan law PA 359 was enacted which created the Mackinac Straits Corridor Authority (Corridor Authority) and authorized an agreement between us and the Corridor Authority for the construction of a tunnel under the Straits of Mackinac (Straits) to house a replacement for the Line 5 Dual Pipelines that currently cross the Straits (the Tunnel Project). On December 19, 2018, we entered into a Tunnel Project agreement with the Government of Michigan. On March 28, 2019, the Michigan Attorney General issued an opinion finding the Michigan law PA 359 unconstitutional and soon after, Michigan Governor Whitmer issued a directive to Michigan agencies to cease any action implementing the statute.

To resolve the legal uncertainty created by the Michigan Attorney General's opinion and the directive issued by Michigan Governor Whitmer, on June 6, 2019, we filed a complaint with the Michigan Court of Claims to establish the constitutional validity of Michigan law PA 359 and enforceability of various agreements entered into between us and the State of Michigan related to the construction of the Tunnel Project. On June 11, 2019, State officials confirmed that we had valid permits to conduct specified geotechnical work which has now been completed. This work was necessary to prepare for Tunnel Project construction. On June 27, 2019, the Michigan Attorney General requested the Michigan Court of Claims to dismiss our complaint and we opposed her request with our response filed on August 1, 2019. On October 31, 2019, the Michigan Court of Claims determined that Michigan law PA 359 is valid and is not unconstitutional. On November 5, 2019 the Michigan Attorney General filed an appeal of this decision. According to the expedited appeal schedule, briefing is anticipated to be completed in March 2020 with a decision expected later in 2020.

On June 27, 2019, the Michigan Attorney General filed a complaint in the Michigan Ingham County Circuit Court that requests the Court to declare the easement that we have for the operation of the dual pipelines in the Straits to be invalid and to prohibit continued operation of the dual pipelines in the Straits “as soon as possible after a reasonable notice period to allow orderly adjustments by affected parties”. We continue to vigorously defend this action and on September 16, 2019, we filed our motion for summary disposition and requested dismissal of the State’s Complaint in its entirety. On that same date, the State filed a motion for partial summary disposition and judgment in its favor on its claim that the easement was void from inception. The case is now fully briefed. Oral argument on the parties’ motions has been scheduled for May 22, 2020.

Line 5 Easement

For over six years, we have been in negotiations and discussions with the Bad River Band of the Lake Superior Tribe of Chippewa Indians (the Band) to resolve the Band’s concerns over our Line 5 pipeline and right-of-way across the Bad River Reservation (the Reservation). Only a small portion of the total easements across 12 miles of the Reservation are at issue. These negotiations and discussions did not resolve the Band’s concerns. On July 23, 2019, the Band filed a complaint in the United States District Court for the Western District of Wisconsin alleging that our continued use of Line 5 to transport crude oil and related liquids across the Reservation is a public nuisance under federal and state law and also alleging that the pipeline is in trespass on certain tracts of land in which the Band possesses undivided ownership interests. The Band also seeks an order prohibiting us from using Line 5 to transport crude oil and related liquids across the Reservation and requiring removal of the pipeline from the Reservation. On September 24, 2019, in response to the Band’s complaint, we filed an answer, defenses, and counterclaims against the Band, as well as a motion to dismiss. On October 15, 2019, the Band filed its first amended complaint against us, adding new assertions about allegedly unsafe conditions at a specific location of the pipeline on the Reservation and requesting a declaration by the court that the Band has regulatory authority over Line 5. On October 29, 2019, we filed our response, defenses and counterclaims to the Band’s first amended complaint. A trial date has been set for July 2021.

The Band has not sought a temporary injunction to immediately discontinue operation of Line 5. However, if successful, the Band’s lawsuit could impact our ability to operate the pipeline on the Reservation. We have been vigorously defending the Band’s action since it was filed and will continue to do so. Nevertheless, we also plan to continue working with the Band in an effort to address its concerns, and at the same time, as a contingency measure, we have begun taking steps to enable the construction of a reroute of Line 5 around the Reservation. To that end, we have identified a proposed route outside the Reservation and, on February 7, 2020, we initiated the permitting process for the proposed reroute by filing applications with federal and state regulatory authorities.

GAS TRANSMISSION

DCP Midstream, LP Definitive Agreement and Equity Restructuring

On November 6, 2019 DCP Midstream, LP (DCP MLP) announced the execution of a definitive agreement with its general partner, in which we indirectly own a 50% equity interest, and the concurrent closing of an equity restructuring transaction. The transaction resulted in the general partner converting all of its incentive distribution rights in DCP MLP, which were eliminated, and its 2% economic general partner interest in DCP MLP, while retaining a non-economic general partner interest, into newly-issued DCP MLP common units. As a result of this transaction, we increased our indirect ownership of outstanding DCP MLP common units from approximately 18% to approximately 28%, while retaining our indirect 50% ownership interest in the general partner of DCP MLP.

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. 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 generally accepted accounting principles in the United States of America (U.S. GAAP), 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 (ASC) 805 *Business Combinations* in accounting for our acquisitions. The acquired long-lived assets, 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 have the option to first assess qualitative factors to determine whether it is necessary to perform the quantitative goodwill impairment test. When performing a qualitative assessment, we determine the drivers of fair value for each reporting unit and evaluate whether those drivers have been positively or negatively affected by relevant events and circumstances since the last fair value assessment. Our evaluation includes, but is not limited to, assessment of macroeconomic trends, regulatory environments, capital accessibility, operating income trends, and industry conditions. Based on our assessment of the qualitative factors, if we determine it is more likely than not that the fair value of the reporting unit is less than its carrying amount, a quantitative goodwill impairment test is performed.

The quantitative goodwill impairment test involves determining the fair value of our reporting units and comparing those values to the carrying value of each corresponding 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. Fair value of our reporting units 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.

Our most recent annual review of the goodwill balance was performed on April 1, 2019, and this review did not result in an impairment charge. As at April 1, 2019, our reporting units were equivalent to our reportable segments, except for the Gas Transmission and Midstream reportable segment which was divided at the component level into two reporting units: Gas Transmission and Gas Midstream. We performed a quantitative goodwill impairment test of our Gas Midstream reporting unit. We elected to perform qualitative assessments of our Liquids Pipelines, Gas Distribution and Storage, and Gas Transmission and Midstream reporting units and concluded it was not more likely than not that these reporting units were impaired and that quantitative impairment tests were not necessary.

The allocation of goodwill to held for sale and disposed businesses is based on the fair value of businesses relative to their corresponding reporting unit. During the years ended December 31, 2019, and 2018, we impaired nil and \$1,019 million, respectively, 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 CER, the FERC, the Alberta Energy Regulator, La Régie de l'énergie du Québec and the 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 U.S. GAAP for non-rate-regulated entities. Key determinants in the ratemaking process are:

- Costs of providing service, including operating costs, capital invested and depreciation expense;
- Allowed rate of return, including the equity component of the capital structure and related income taxes;
- Interest costs on the debt component of the capital structure; 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 CER'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, 2019 and 2018, our significant regulatory assets totaled \$4,800 million and \$4,695 million, respectively, and significant regulatory liabilities totaled \$2,786 million and \$2,363 million, respectively.

Depreciation

Depreciation of property, plant and equipment, our largest asset with a net book value at December 31, 2019 and 2018, of \$93,723 million and \$94,540 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.

Pension and Other Postretirement Benefits

We use certain assumptions relating to the calculation of defined benefit pension and other postretirement liabilities and net periodic benefit costs. These assumptions comprise management's best estimates of expected return on plan assets, future salary levels, 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 anticipated to be made under each of the respective plans. The expected return on plan assets is determined using market-related values and assumptions on the asset mix consistent with the investment policy relating to the assets and their projected returns. The assumptions are reviewed annually by our independent actuaries. Actual results that differ from results based on assumptions are amortized over future periods and therefore could materially affect the expense recognized and the recorded obligation in future periods.

The following sensitivity analysis identifies the impact on the December 31, 2019 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	368	34	69	6
Decrease in expected return on assets	—	18	—	5
Decrease in rate of salary increase	(66)	(15)	(7)	(1)
OPEB				
Decrease in discount rate	23	1	15	—
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 30. 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 of the expected future cash flows range from 1.8% to 9.0% for the years ended December 31, 2019 and 2018. 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 CER issued a decision related to the LMCI, which required holders of an authorization to operate a pipeline under the CER 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 CER'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 CER. Following the CER'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 CER 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.*