



ENBRIDGE INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS

December 31, 2017

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITIONS 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 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 our Annual Report on Form 10-K.

We are a Canadian company and a North American leader in delivering energy. As a transporter of energy, we operate, in Canada and the United States, the world's longest crude oil and liquids transportation system. Following the combination of Enbridge and Spectra Energy Corp. (Spectra Energy) through a stock-for-stock merger transaction on February 27, 2017 (the Merger Transaction), we are also a leader in the natural gas transmission and midstream business moving approximately 20% of all natural gas in the United States, serving key supply basins and markets. As a distributor of energy, we own and operate Canada's largest natural gas distribution company and provide distribution services in Ontario, Quebec and New Brunswick. As a generator of energy, we have interests in approximately 3,500 megawatts (MW) (2,500 MW net) of renewable and alternative energy generating capacity which is operating, secured or under construction, and we continue to expand our interests in wind, solar and geothermal power.

DOMESTIC ISSUER REPORTING REQUIREMENTS

Effective January 1, 2018, we began to comply with the Securities and Exchange Commission reporting requirements applicable to United States domestic issuers and, accordingly, we are filing our annual report on Form 10-K for the year ended December 31, 2017 and regular periodic reports under both Canadian and United States law thereafter.

MERGER WITH SPECTRA ENERGY

On February 27, 2017, we announced the closing of the Merger Transaction.

Under the terms of the Merger Transaction, Spectra Energy shareholders received 0.984 shares of Enbridge for each share of Spectra Energy common stock they held. Upon closing of the Merger Transaction, Enbridge shareholders owned approximately 57% of the combined company and Spectra Energy shareholders owned approximately 43%.

Spectra Energy, which we now wholly-own, is one of North America's leading natural gas delivery companies owning and operating a large, diversified and complementary portfolio of gas transmission, midstream gathering and processing and distribution assets. Spectra Energy also owns and operates a crude oil pipeline system that connects Canadian and United States producers to refineries in the United States Rocky Mountain and Midwest regions. Our combination with Spectra Energy has created the largest energy infrastructure company in North America with an extensive portfolio of energy assets that are well positioned to serve key supply basins and end use markets and multiple business platforms through which to drive future growth.

A more detailed description of each of the businesses and underlying assets acquired through the Merger Transaction is provided under Part I. Item 1. *Business*. The results of operations from assets acquired through the Merger Transaction are included in our financial statements and in this management's discussion and analysis (MD&A) on a prospective basis from the closing date of the Merger Transaction.

Subsequent to the completion of the Merger Transaction, our activities continue to be carried out through five business segments: Liquids Pipelines; Gas Transmission and Midstream (previously known as Gas Pipelines and Processing); Gas Distribution; Green Power and Transmission; and Energy Services. Effective February 27, 2017, as a result of the Merger Transaction:

- Liquids Pipelines also includes results from the operation of the Express-Platte System;
- Gas Transmission and Midstream also includes Spectra Energy's United States Storage and Transmission Assets, Canadian Pipeline & Field Services, Canadian Gas Transmission and Midstream and Maritimes & Northeast U.S. and Canada businesses, as well as the results of the Company's 50% interest in DCP Midstream, LLC (DCP Midstream); and
- Gas Distribution also includes results from the operation of Union Gas Limited (Union Gas).

UNITED STATES TAX REFORM

On December 22, 2017, the United States enacted the "Tax Cuts and Jobs Act" (TCJA). Substantially all of the provisions in the TCJA are effective for taxation years beginning after December 31, 2017. The TCJA includes significant changes to the Internal Revenue Code of 1986 (as amended, the Code), including amendments which significantly change the taxation of individuals and business entities, and includes specific provisions related to regulated public utilities which includes our various regulated gas pipeline businesses. The most significant changes that impact us, included in the TCJA, are reductions in the corporate federal income tax rate from 35% to 21%, and several technical provisions including, among others, a onetime deemed repatriation or "toll" tax on undistributed earnings and profits of US controlled foreign affiliates, including Canadian subsidiaries. The specific provisions related to regulated public utilities in the TCJA generally allow for the continued deductibility of interest expense, the elimination of full expensing for tax purposes of certain property acquired after September 27, 2017, and the continuance of certain rate normalization requirements for accelerated depreciation benefits. For other operations, immediate full expensing of capital expenditures placed into service after September 27, 2017 and before January 1, 2023 (before January 1, 2024 for qualified long production period property) will be available under the TCJA. Inversely to the regulated public utility operations, interest deductions will be more restrictive for other operations as existing interest expense limitations are broadened to apply to all interest paid and the allowable deduction is reduced from 50% to 30% of adjusted taxable income.

Changes in the Code from the TCJA had a material impact on our consolidated financial statements as at and for the year ended December 31, 2017. Under generally accepted accounting principles in the United States of America (U.S. GAAP), the tax effects of changes in tax laws must be recognized in the period in which the law is enacted, or December 22, 2017 for the TCJA. Thus, at the date of enactment, our deferred tax liability was re-measured based upon the new tax rate. For some of our gas pipeline entities with regulated cost of service rate mechanisms, the change in the deferred tax liability is offset by a regulatory liability. In the event of a future rate case, and subject to further regulatory guidance, we anticipate that the regulatory liability may be required to be amortized over the remaining useful life of the affected assets and would be one of many factors to be considered in establishing go forward rates. For all other operations, the change in the deferred tax liability is recorded as an adjustment to our deferred tax provision.

While certain elements of the TCJA require clarification through more detailed regulation or interpretive guidance, based on the information and guidance available and our analysis (including computations of income tax effects) completed to date, at this time, we do not expect that the TCJA will have a material economic impact on us going forward.

For additional information, refer to Item 8. *Financial Statements and Supplementary Data - Note 24. Income Taxes.*

UNITED STATES SPONSORED VEHICLE STRATEGY

In 2017, we continued the ongoing evaluation of our investment in our United States sponsored vehicles, and alternatives to such investment, and we completed or announced certain strategic reviews and transactions. We intend to review our United States sponsored vehicle strategy on a continuing basis. From time to time, we may formulate plans or proposals with respect to such matters and hold discussions with or make formal proposals to the board of directors of the sponsored vehicles or other third parties. These plans or proposals may, subject to price, market and general economic and fiscal conditions and other factors, include potential consolidations, acquisition or sale of assets or securities, changes to capital structure or other transactions.

On April 28, 2017, we announced the completion of a strategic review of Enbridge Energy Partners, L.P. (EEP). The following actions, together with the measures announced in January 2017 and disclosed in our 2016 annual MD&A, have been taken to date to enhance EEP's value proposition to its unitholders and to us:

Acquisition of Midcoast Assets and Privatization of Midcoast Energy Partners, L.P.

On April 27, 2017, we completed our previously-announced merger through which we privatized Midcoast Energy Partners, L.P. (MEP) by acquiring all of the outstanding publicly-held common units of MEP, through a wholly-owned subsidiary, for total consideration of approximately US\$170 million.

On June 28, 2017, through a wholly-owned subsidiary, we acquired all of EEP's interest in the MEP gas gathering and processing business for cash consideration of US\$1.3 billion plus existing indebtedness of MEP of US\$953 million.

As a result of the above transactions, we now own 100% of the MEP gas gathering and processing business.

Finalization of Bakken Pipeline System Joint Funding Agreement

On February 15, 2017, EEP acquired an effective 27.6% interest in the Dakota Access and Energy Transfer Crude Oil Pipelines (collectively, the Bakken Pipeline System). On April 27, 2017, we entered into a joint funding arrangement with EEP whereby we own 75% and EEP owns 25% of the combined 27.6% effective interest in the Bakken Pipeline System (our jointly held interest). Under this arrangement, EEP has retained a five-year option to acquire from us an additional 20% interest of the jointly held interest. On finalization of this joint funding arrangement, EEP repaid the outstanding balance on its US\$1.5 billion credit agreement with us, which it had drawn upon to fund the initial purchase.

EEP Strategic Restructuring Actions

On April 27, 2017, EEP redeemed all of its outstanding Series 1 Preferred Units held by us at face value of US\$1.2 billion through the issuance of 64.3 million Class A common units to us. Further, we irrevocably waived all of our rights associated with our ownership of 66.1 million Class D units and 1,000 Incentive Distribution Units (IDUs) of EEP, in exchange for the issuance of 1,000 Class F units. The Class F units are entitled to (i) 13% of all distributions in excess of US\$0.295 per EEP unit, but equal to or less than US\$0.35 per EEP unit, and (ii) 23% of all distributions in excess of US\$0.35 per EEP unit. The irrevocable waiver was effective with respect to distributions declared with a record date after April 27, 2017. In connection with these strategic restructuring actions, EEP reduced its quarterly distribution from US\$0.583 per unit to US\$0.35 per unit.

The irrevocable waiver of the Class D units and IDUs, the redemption of the Series 1 Preferred Units and the reduction in the quarterly distributions will result in a lower contribution of earnings from EEP. This lower contribution will be partially offset by an increased contribution of earnings as a result of our increased ownership in the Class A common units post restructuring.

Restructuring of SEP Incentive Distribution Rights

On January 22, 2018, Enbridge and Spectra Energy Partners, LP (SEP) announced the execution of a definitive agreement, resulting in us converting all of our incentive distribution rights (IDRs) and general partner economic interests in SEP into 172.5 million newly issued SEP common units. As part of the transaction, all of the IDRs have been eliminated. We now hold a non-economic general partner interest in SEP and own approximately 403 million of SEP common units, representing approximately 83% of SEP's outstanding common units.

ASSET MONETIZATION

In conjunction with the announcement of the Merger Transaction in September 2016, we announced our intention to divest \$2 billion of assets over the ensuing 12 months in order to further strengthen our post-combination balance sheet and enhance the financial flexibility of the combined entity. With the completion of the Secondary Offering noted below, the Ozark pipeline system sale, the Olympic refined products pipeline sale and other divestitures completed in 2016 and previously disclosed, we exceeded the \$2 billion monetization target established on announcement of the Merger Transaction.

On April 18, 2017, Enbridge Income Fund Holdings Inc. (ENF) completed a secondary offering of 17,347,750 ENF common shares to the public at a price of \$33.15 per share, for gross proceeds to us of approximately \$0.6 billion (the Secondary Offering). To effect the Secondary Offering, we exchanged 21,657,617 Enbridge Income Fund (Fund) units we owned for an equivalent amount of ENF common shares. In order to maintain our 19.9% ownership interest in ENF, we retained 4,309,867 of the common shares we received in the exchange, and sold the balance to the public through the Secondary Offering. We used the proceeds from the Secondary Offering to pay down short-term debt, pending reinvestment in our growing portfolio of secured projects. Upon closing of the Secondary Offering, our total economic interest in ENF decreased from 86.9% to 84.6%.

On November 29, 2017, we finalized our 2018-2020 Strategic Plan and announced that we have identified a further \$10 billion of non-core assets, of which a minimum of \$3 billion we intend to sell or monetize in 2018. As a result of the announcement, we are in the process of selling certain assets within the US Midstream business of our Gas Transmission and Midstream segment. Refer to Item 8. *Financial Statements and Supplementary Data - Note 7. Acquisitions and Dispositions.*

ALBERTA CLIPPER (LINE 67) PRESIDENTIAL PERMIT

On October 16, 2017, we received a Presidential permit for Line 67, following a nearly five-year process of review. Line 67 currently operates under an existing Presidential permit that was issued by the State Department in 2009 and the 2017 Presidential permit authorizes us to fully utilize Line 67's capacity across the United States/Canada border.

Line 67 is a key component of our mainline system, which United States refineries rely on to provide vital products to consumers across the Midwest United States.

For additional information on Line 67, refer to *Growth Projects - Commercially Secured Projects - Liquids Pipelines - Lakehead System Mainline Expansion.*

CANADIAN RESTRUCTURING PLAN

Effective September 1, 2015, under an agreement with the Fund and ENF, Enbridge transferred its Canadian Liquids Pipelines business, held by Enbridge Pipelines Inc. (EPI) and Enbridge Pipelines (Athabasca) Inc. (EPAI), and certain Canadian renewable energy assets to the Fund Group (comprising the Fund, Enbridge Commercial Trust, Enbridge Income Partners LP (EIPLP) and the subsidiaries of EIPLP) for consideration valued at \$30.4 billion plus incentive distribution and performance rights (the Canadian Restructuring Plan). The consideration that we received included \$18.7 billion of units in the Fund Group, comprised of \$3 billion of Fund units and \$15.7 billion of equity units of EIPLP, in which the Fund has an interest. The Fund Group also assumed debt of EPI and EPAI of approximately \$11.7 billion.

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 Enbridge and its 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", "expect", "project", "estimate", "forecast", "plan", "intend", "target", "believe", "likely" and similar words suggesting future outcomes or statements regarding an outlook. Forward-looking information or statements included or incorporated by reference in this document include, but are not limited to, statements with respect to the following: expected earnings before interest, income taxes and depreciation and amortization (EBITDA); expected earnings/(loss); expected earnings/(loss) per share; expected future cash flows; expected performance of the Liquids Pipelines, Gas Transmission and Midstream, Gas Distribution, Green Power and Transmission, and Energy Services businesses; financial strength and flexibility; expectations on sources of liquidity and sufficiency of financial resources; expected costs related to announced projects and projects under construction; expected in-service dates for announced projects and projects under construction; expected capital expenditures; expected equity funding requirements for our commercially secured growth program; expected future growth and expansion opportunities; expectations about our joint venture partners' ability to complete and finance projects under construction; expected closing of acquisitions and dispositions; estimated future dividends; recovery of the costs of the Canadian portion of the Line 3 Replacement Program (Canadian L3R Program); expected expansion of the T-South System and Spruce Ridge Program; expected capacity of the Hohe See Expansion Offshore Wind Project; expected costs in connection with Line 6A and Line 6B crude oil releases; expected effect of Aux Sable Consent Decree; expected future actions of regulators; expected costs related to leak remediation and potential insurance recoveries; expectations regarding commodity prices; supply forecasts; expectations regarding the impact of the Merger Transaction including our combined scale, financial flexibility, growth program, future business prospects and performance; impact of the Canadian L3R Program on existing integrity programs; the sponsored vehicle strategy; dividend payout policy; dividend growth and dividend payout expectation; expectations on impact of hedging program; and expectations resulting from the successful execution of our 2018-2020 Strategic Plan.

Although we believe these forward-looking statements are reasonable based on the information available on the date such statements are made and processes used to prepare the information, such statements are not guarantees of future performance and readers are cautioned against placing undue reliance on forward-looking statements. By their nature, these statements involve a variety of assumptions, known and unknown risks and uncertainties and other factors, which may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such statements. Material assumptions include assumptions about the following: the expected supply of and demand for crude oil, natural gas, natural gas liquids (NGL) and renewable energy; prices of crude oil, natural gas, NGL and renewable energy; exchange rates; inflation; interest rates; availability and price of labor and construction materials; operational reliability; customer and regulatory approvals; maintenance of support and regulatory approvals for our projects; anticipated in-service dates; weather; the realization of anticipated benefits and synergies of the Merger Transaction; governmental legislation; acquisitions and the timing thereof; the success of integration plans; impact of the dividend policy on our future cash flows; credit ratings; capital project funding; expected EBITDA; expected earnings/(loss); expected earnings/(loss) per share; expected future cash flows and estimated future dividends. Assumptions regarding the expected supply of and demand for crude oil, natural gas, NGL and renewable energy, and the prices of these commodities, are material to and underlie all forward-looking statements, as they may impact current and future levels of demand for our services. Similarly, exchange rates, inflation and interest rates impact the economies and business environments in which we operate and may impact levels of demand for our services and cost of inputs, and are therefore inherent in all forward-looking statements. Due to the interdependencies and correlation of these macroeconomic factors, the impact of any one assumption on a forward-looking statement cannot be determined with certainty, particularly with respect to the impact of the Merger Transaction on us, expected EBITDA, earnings/(loss), earnings/(loss) per share, 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 impact of the Merger Transaction, operating performance, regulatory parameters, 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 statements made in this MD&A or otherwise, whether as a result of new information, future events or otherwise. All subsequent 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,		
	2017	2016	2015
<i>(millions of Canadian dollars, except per share amounts)</i>			
Segment earnings before interest, income taxes and depreciation and amortization			
Liquids Pipelines	6,395	4,926	3,033
Gas Transmission and Midstream	(1,269)	464	43
Gas Distribution	1,390	831	763
Green Power and Transmission	372	344	363
Energy Services	(263)	(183)	324
Eliminations and Other	(337)	(101)	(867)
Depreciation and amortization	(3,163)	(2,240)	(2,024)
Interest expense	(2,556)	(1,590)	(1,624)
Income tax recovery/(expense)	2,697	(142)	(170)
(Earnings)/loss attributable to noncontrolling interests and redeemable noncontrolling interests	(407)	(240)	410
Preference share dividends	(330)	(293)	(288)
Earnings/(loss) attributable to common shareholders	2,529	1,776	(37)
Earnings/(loss) per common share	1.66	1.95	(0.04)
Diluted earnings/(loss) per common share	1.65	1.93	(0.04)

EARNINGS/(LOSS) ATTRIBUTABLE TO COMMON SHAREHOLDERS

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

Earnings Attributable to Common Shareholders for the year ended December 31, 2017 were positively impacted by contributions of approximately \$2,574 million from new assets following the completion of the Merger Transaction.

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

- a loss of \$4,391 million (\$2,753 million after-tax attributable to us) and related goodwill impairment of \$102 million resulting from the classification of certain assets as held for sale and the subsequent measurement at the lower of their carrying value or fair value less costs to sell, refer to Item 8. *Financial Statements and Supplementary Data - Note 7. Acquisitions and Dispositions*;
- employee severance and restructuring costs of \$354 million (\$273 million after-tax attributable to us) in 2017, compared with \$82 million in the corresponding 2016 period, related to a corporate reorganization initiative and the Merger Transaction, refer to *Merger with Spectra Energy*;
- project development and transaction costs of \$205 million (\$155 after-tax attributable to us) in 2017, compared with \$86 million in the corresponding 2016 period, related to the Merger Transaction, refer to *Merger with Spectra Energy*;
- the absence of a gain of \$850 million (\$520 million after-tax attributable to us) recorded in 2016 related to the disposition of the South Prairie Region assets, as discussed below; partially offset by
- a non-cash, \$1,936 million income tax benefit (\$2,045 million federal tax recovery net of a \$109 million state deferred tax expense) due to the enactment of the TCJA by the United States in December 2017, refer to Item 8. *Financial Statements and Supplementary Data - Note 24. Income Taxes*;
- a non-cash, unrealized derivative fair value gain of \$1,109 million in 2017 (\$624 million after-tax attributable to us), compared with \$543 million (\$459 million after-tax attributable to us) in the corresponding 2016 period reflecting net fair value gains and losses arising from changes in the mark-to-market value of derivative financial instruments used to manage foreign exchange and commodity prices risks; and
- the absence of cumulative asset impairment charges of \$1,561 million (\$456 million after-tax attributable to us) recorded in 2016 related to EEP's Sandpiper Project, the Northern Gateway Project and Eddystone Rail, as discussed below.

We have a comprehensive long-term economic hedging program to mitigate interest rate, foreign exchange and commodity price risks which creates volatility in 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 investors value proposition is based.

After taking into consideration the factors above, the remaining \$1,670 million decrease is primarily explained by the following significant business factors:

- increased depreciation and amortization expense primarily resulting from a significant number of new assets placed into service in 2017;
- increased interest expense primarily resulting from the settlement of certain pre-issuance hedges;
- increased earnings attributable to noncontrolling interests and redeemable noncontrolling interests in 2017, compared with the corresponding 2016 period. The increase was driven by higher earnings attributable to noncontrolling interests in EEP during 2017 as a result of the EEP strategic restructuring actions;

- the absence of earnings from certain assets that were divested since the third quarter of 2016; partially offset by
- strong contributions from our Liquids Pipelines segment due to higher throughput primarily attributable to capacity optimization initiatives implemented in 2017 which significantly reduced heavy crude oil apportionment allowing incremental heavy crude oil barrels to be shipped;
- contributions from new Liquids Pipelines assets placed into service in 2017; and
- increased earnings from our Gas Transmission and Midstream segment in 2017 due to favorable seasonal firm revenue and a full year of contributions from assets acquired in 2016.

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

Year ended December 31, 2016 compared with year ended December 31, 2015

Earnings Attributable to Common Shareholders increased by \$1,601 million due to certain unusual, infrequent or other factors, primarily explained by the following:

- a gain of \$850 million (\$520 million after-tax attributable to us) within the Liquids Pipelines segment related to the disposition of the South Prairie Region assets in December 2016;
- a non-cash, unrealized derivative fair value gain of \$543 million in 2016, compared with a \$2,017 million unrealized derivative fair value loss in the corresponding 2015 period reflecting net fair value gains and losses arising from changes in the mark-to-market value of derivative financial instruments used to manage foreign exchange and commodity price risks;
- the absence of a goodwill impairment charge of \$440 million (\$167 million after-tax attributable to us) recognized in the second quarter of 2015 related to EEP's natural gas and natural gas liquids (NGL) businesses as a result of the prolonged decline in commodity prices which reduced producers' expected drilling programs and negatively impacted volumes on EEP's natural gas and NGL pipelines and processing systems; partially offset by
- an impairment charge of \$1,004 million (\$81 million after-tax attributable to us) in 2016, including related project costs, on EEP's Sandpiper Project resulting from the withdrawal of regulatory applications for the project in September 2016 that were pending with the Minnesota Public Utilities Commission (MNPUC);
- an impairment charge of \$373 million (\$272 million after-tax attributable to us) related to the Northern Gateway Project recorded in the fourth quarter of 2016, after the Canadian Federal Government directed the National Energy Board (NEB) to dismiss our Northern Gateway Project application and rescind the Certificates of Public Convenience and Necessity for the project; and
- an impairment charge of \$184 million (\$108 million after-tax attributable to us) recorded in 2016 related to our 75% joint venture interest in Eddystone Rail, located in the Philadelphia, Pennsylvania area. Demand for Eddystone Rail services declined as a result of a significant decrease in Bakken crude oil and West Africa/Brent crude oil and increased competition in the region.

After taking into consideration the factors above, the remaining \$212 million increase is primarily explained by the following significant business factors:

- strong contributions from our Liquids Pipelines segment which benefited from a number of new assets that were placed into service in 2015;
- throughput growth period over period on the Canadian Mainline, Lakehead Pipeline System (Lakehead System) and Regional Oil Sands System primarily due to strong oil sands production growth in western Canada enabled by completed pipeline expansion projects;

- contributions from the United States Gulf Coast and Mid-Continent systems in 2016, attributable to increased transportation revenues mainly resulting from an increase in the level of committed take-or-pay volumes on the Flanagan South Pipeline (Flanagan South);
- contributions from Enbridge Offshore Pipelines' Heidelberg Oil Pipeline (Heidelberg Pipeline) which was placed into service in January 2016 and Canadian Gas Transmission and Midstream's Tupper Main and Tupper West gas plants (the Tupper Plants) which were acquired on April 1, 2016; partially offset by
- higher earnings attributable to noncontrolling interests and redeemable noncontrolling interests in 2016 compared with 2015 driven by stronger operating performance at EEP as a result of stronger contributions from its liquids business;
- the impact of extreme wildfires in northeastern Alberta during the second quarter of 2016 which led to a temporary shutdown of certain of our upstream pipelines and terminal facilities resulting in a disruption of service on our Regional Oil Sands System with corresponding impacts into and out of our downstream pipelines, including Canadian Mainline and the Lakehead System;
- a combination of a lower average International Joint Tariff (IJT) Residual Benchmark Toll and a lower foreign exchange hedge rate period over period used to convert Canadian Mainline United States dollar toll revenues to Canadian dollars;
- the performance of the United States portion of the Bakken Pipeline System where contributions decreased period over period primarily due to a lower surcharge on tolls subject to annual adjustment;
- lower contributions in 2016 from EEP's Berthold rail facility as a result of declining volumes on expiration of contracts;
- the compression of certain crude oil location and quality differentials and the impact of a weaker NGL market; and
- depreciation and amortization expense increased period over period primarily as a result of a significant number of new assets placed into service in 2016.

REVENUES

We generate revenues from three primary sources: transportation and other services, gas distribution sales and commodity sales. Transportation and other services revenues are earned from our crude oil and natural gas pipeline transportation businesses and also include power production revenues from our portfolio of renewable and power generation assets. For our transportation assets operating under market-based arrangements, revenues are driven by volumes transported and the corresponding tolls for transportation services. For assets operating under take-or-pay contracts, revenues reflect the terms of the underlying contract for services or capacity. For rate-regulated assets, revenues are charged in accordance with tolls established by the regulator, and in most cost-of-service based arrangements are reflective of our cost to provide the service plus a regulator-approved rate of return. Higher transportation and other services revenues reflected increased throughput on our core liquids pipeline assets combined with the incremental revenues associated with assets placed into service over the past two years.

Gas distribution sales revenues are 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 \$26,286 million, \$22,816 million and \$23,842 million for the year ended December 31, 2017, 2016 and 2015, respectively, were generated primarily through our Energy Services operations. Energy Services includes the contemporaneous purchase and sale of crude oil, natural gas, power and NGLs to generate a margin, which is typically a small fraction of gross revenue. While sales revenue generated from these operations are impacted by commodity prices, net margins and earnings are relatively insensitive to commodity prices and reflect activity levels which are driven by differences in commodity prices between locations, grades and points in time, rather than on absolute prices. Any residual commodity margin risk is closely monitored and managed. Revenues from these operations depend on activity levels, which vary from year-to-year depending on market conditions and commodity prices.

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

DIVIDENDS

We have paid common share dividends in every year since we became a publicly traded company in 1953. In November 2017, we announced a 10% increase in our quarterly dividend to \$0.671 per common share, or \$2.684 annualized, effective with the dividend payable on March 1, 2018.

BUSINESS SEGMENTS

Effective December 31, 2017, we changed our segment-level profit measure to EBITDA from the previous measure of Earnings before interest and income taxes. We also renamed the Gas Pipelines and Processing segment to Gas Transmission and Midstream. The presentation of the prior years' tables has been revised in order to align with the current presentation.

LIQUIDS PIPELINES

EARNINGS BEFORE INTEREST, INCOME TAXES AND DEPRECIATION AND AMORTIZATION

	2017	2016	2015
<i>(millions of Canadian dollars)</i>			
Earnings before interest, income taxes and depreciation and amortization	6,395	4,926	3,033

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

EBITDA for the year ended December 31, 2017 was positively impacted by \$285 million of contributions from new assets following the completion of the Merger Transaction.

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

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

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

- a lower contribution of \$46 million from Mid-Continent assets primarily due to lower contracted storage revenues and the sale of the Ozark Pipeline system in the first quarter of 2017;
- a lower contribution of \$76 million resulting from the sale of the South Prairie Region assets in December 2016;
- higher Lakehead System operating costs including costs to implement EEP's signed settlement agreement regarding the Lines 6A and 6B crude oil releases (the Consent Decree) approved by the United States Department of Justice (DOJ) in May 2017;
- the unfavorable effect of translating United States dollar EBITDA at a lower United States to Canadian dollar average exchange rate (Average Exchange Rate) as compared with 2016, inclusive of the impact of settlements under our foreign exchange hedging program; partially offset by
- contributions of from new assets placed into service including the Regional Oil Sands Optimization Project and the Norlite Pipeline System and the acquisition of a minority interest in the Bakken Pipeline System that went into service in June 2017; and
- higher Canadian Mainline and Lakehead System throughput period over period resulting from capacity optimization initiatives.

Year ended December 31, 2016 compared with year ended December 31, 2015

EBITDA increased by \$1,177 million due to certain unusual, infrequent or other factors, primarily explained by the following:

- a non-cash, unrealized gain of \$474 million in 2016 compared with an unrealized loss of \$1,500 million in 2015 reflecting net fair value gains and losses on derivative financial instruments used to manage foreign exchange and commodity price risks;
- a gain of \$850 million in 2016 related to the sale of non-core South Prairie Region assets;
- the absence of an impairment charge of \$86 million recorded in 2015 related to EEP's Berthold rail facility due to contracts that were not renewed beyond 2016;
- hydrostatic testing recoveries of \$15 million in 2016 compared with charges of \$72 million in 2015; partially offset by
- an impairment charge of \$1,004 million in 2016, including related project costs, on EEP's Sandpiper Project resulting from the withdrawal of the regulatory applications in September 2016 that were pending with the MNPUC;
- an impairment charge of \$373 million in 2016 related to the Northern Gateway Project due to our conclusion that the project could not proceed as envisioned as a result of the Federal Government's decision to dismiss the application for Certificate of Public Convenience and Necessity;
- an impairment charge of \$184 million in 2016 related to our 75% joint venture interest in Eddystone Rail attributable to market conditions which impacted volumes at the rail facility; and
- the absence of a gain of \$91 million recorded in 2015 related to the sale of non-core assets.

After taking into consideration the factors above, the remaining \$716 million increase is primarily explained by the following significant business factors:

- higher throughput period over period resulting from strong oil sands production in western Canada enabled by pipeline capacity expansion projects placed into service in 2015;
- increased transportation revenues in 2016 resulting from an increase in the level of committed take-or-pay volumes on Flanagan South;
- the favorable effect of translating United States dollar earnings at a higher Average Exchange Rate in 2016, inclusive of the impact of settlements under our foreign exchange hedging program; partially offset by
- the impact of extreme wildfires in northeastern Alberta during the second quarter of 2016 which led to a temporary shutdown of certain of our upstream pipelines and terminal facilities resulting in a disruption of service.

Supplemental information on Liquids Pipelines EBITDA for the years ended December 31, 2017, 2016 and 2015 is provided below.

December 31, (United States dollars per barrel)	2017	2016	2015
IJT Benchmark Toll ¹	\$4.07	\$4.05	\$4.07
Lakehead System Local Toll ²	\$2.43	\$2.58	\$2.44
Canadian Mainline IJT Residual Benchmark Toll ³	\$1.64	\$1.47	\$1.63

¹ The IJT Benchmark Toll is per barrel of heavy crude oil transported from Hardisty, Alberta to Chicago, Illinois. A separate distance adjusted toll applies to shipments originating at receipt points other than Hardisty and lighter hydrocarbon liquids pay a lower toll than heavy crude oil. Effective July 1, 2015, this toll increased from US\$4.02 to US\$4.07. Effective July 1, 2016, this toll decreased to US\$4.05. Effective July 1, 2017, this toll increased to US\$4.07.

² The Lakehead System Local Toll is per barrel of heavy crude oil transported from Neche, North Dakota to Chicago, Illinois. Effective April 1, 2015, the Lakehead System Local Toll decreased from US\$2.49 to US\$2.39 and effective July 1, 2015, this toll increased to US\$2.44. Effective April 1, 2016, this toll increased to US\$2.61 and effective July 1, 2016, this toll decreased to US\$2.58. Effective April 1, 2017, this toll decreased to US\$2.43.

³ The Canadian Mainline IJT Residual Benchmark Toll is per barrel of heavy crude oil transported from Hardisty, Alberta to Gretna, Manitoba. For any shipment, this toll is the difference between the IJT Benchmark Toll and the Lakehead System Local Toll. Effective April 1, 2015, this toll increased from US\$1.53 to US\$1.63. Effective April 1, 2016, this toll decreased to US\$1.46, coinciding with the revised Lakehead System Local Toll. Effective July 1, 2016, this toll increased to US\$1.47. Effective April 1, 2017, this toll increased to US\$1.62, coinciding with the revised Lakehead System Local Toll. Effective July 1, 2017, this toll increased to US\$1.64.

Throughput Volume

	Q1	Q2	Q3	Q4	Full Year
<i>(thousands of barrels per day (bpd))</i>					
Canadian Mainline¹					
2017	2,593	2,449	2,492	2,586	2,530
2016	2,543	2,242	2,353	2,481	2,405
2015	2,210	2,073	2,212	2,243	2,185
Lakehead System²					
2017	2,748	2,604	2,620	2,724	2,673
2016	2,735	2,440	2,495	2,624	2,574
2015	2,330	2,208	2,338	2,388	2,315

¹ Average throughput volume represents mainline deliveries ex-Gretna, Manitoba which is made up of United States and eastern Canada deliveries originating from western Canada.

² Average throughput volume represents mainline system deliveries to the United States midwest and eastern Canada.

Average Exchange Rate

	Q1	Q2	Q3	Q4	Full Year
<i>(United States dollar to Canadian dollar)</i>					
2017	1.32	1.34	1.25	1.27	1.30
2016	1.37	1.29	1.31	1.33	1.32
2015	1.24	1.23	1.31	1.34	1.28

GAS TRANSMISSION AND MIDSTREAM

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

	2017	2016	2015
<i>(millions of Canadian dollars)</i>			
Earnings/(loss) before interest, income taxes and depreciation and amortization	(1,269)	464	43

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

EBITDA for the year ended December 31, 2017 was positively impacted by \$2,557 million of contributions from new assets following the completion of the Merger Transaction. When compared to pre-merger results from the prior year, operating results from the new assets include higher earnings primarily from business expansion projects on Algonquin Gas Transmission, Sabal Trail Transmission and Texas Eastern Transmission.

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

- a loss of \$4,391 million and related goodwill impairment of \$102 million resulting from the classification of certain United States Midstream assets as held for sale and the subsequent measurement at the lower of their carrying value or fair value less costs to sell, refer to Item 8. *Financial Statements and Supplementary Data - Note 7. Acquisitions and Dispositions*; partially offset by
- a non-cash, unrealized loss of \$1 million in 2017 compared with \$139 million in 2016 reflecting net fair value gains and losses arising from the change in the mark-to-market of derivative financial instruments used to manage foreign exchange and commodity price risk.

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

- lower earnings of \$127 million period over period due to lower commodity prices which impacted production volume in areas served by some of our US Midstream assets; partially offset by
- increased earnings of \$19 million period over period from our Alliance joint venture due to favorable seasonal firm revenues that resulted from wider basis differentials;
- increased earnings of \$16 million due to a full year of contributions from the Tupper Plants that were acquired in April 2016;
- increased fractionation margins of \$45 million period over period driven by higher NGL prices and increased demand from our Aux Sable joint venture; and
- increased earnings of \$41 million period over period from our Offshore assets driven by higher volumes and higher earnings from certain joint venture pipelines.

Year ended December 31, 2016 compared with year ended December 31, 2015

EBITDA increased by \$370 million due to certain unusual, infrequent or other market factors primarily explained by the following:

- the absence of a goodwill impairment charge of \$440 million recorded in 2015 related to our United States natural gas and NGL businesses due to a prolonged decline in commodity prices which reduced producers' expected drilling programs and negatively impacted volumes on our natural gas and NGL systems; partially offset by
- a non-cash, unrealized loss of \$139 million in 2016 compared with \$77 million in 2015 reflecting net fair value gains and losses arising from the change in the mark-to-market of derivative financial instruments used to manage foreign exchange and commodity price risk.

After taking into consideration the factors above, the remaining \$51 million increase is primarily explained by the following significant business factors:

- operational efficiencies achieved in 2016 on Alliance Pipeline due to lower operating costs;
- contributions from the Heidelberg Pipeline which was placed into service in January 2016;
- contributions from the Tupper Plants acquired in April 2016; partially offset by
- unfavorable market conditions in 2016 resulting from lower volumes due to reduced drilling by producers on our United States Midstream assets.

GAS DISTRIBUTION

EARNINGS BEFORE INTEREST, INCOME TAXES AND DEPRECIATION AND AMORTIZATION

	2017	2016	2015
<i>(millions of Canadian dollars)</i>			
Earnings before interest, income taxes and depreciation and amortization	1,390	831	763

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

EBITDA for the year ended December 31, 2017 was positively impacted by \$545 million of contributions from Union Gas following the completion of the Merger Transaction. When compared to pre-merger results from prior years, Union Gas' operating results benefited mainly from higher transportation revenue from the Dawn-Parkway expansion projects, increased storage optimization and increases in delivery rates, partially offset by higher operating costs.

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

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

Year ended December 31, 2016 compared with year ended December 31, 2015

EBITDA decreased by \$11 million due to certain unusual, infrequent and other market factors, primarily explained by the following:

- warmer than normal weather experienced during 2016 which negatively impacted EBITDA by \$18 million compared with colder than normal weather during 2015 of \$15 million; partially offset by
- other regulatory adjustments at Noverco of \$17 million recorded in 2016 compared with \$6 million in 2015.

After taking into consideration the factors above, the remaining \$79 million increase is primarily explained by the following significant business factor:

- higher distribution charges arising from growth in rate base, including customer growth in excess of expectations embedded in rates.

GREEN POWER AND TRANSMISSION

EARNINGS BEFORE INTEREST, INCOME TAXES AND DEPRECIATION AND AMORTIZATION

	2017	2016	2015
<i>(millions of Canadian dollars)</i>			
Earnings before interest, income taxes and depreciation and amortization	372	344	363

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

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

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

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

- stronger wind resources of \$12 million at Canadian and United States wind farms period over period; and
- contributions of \$9 million from new United States wind projects placed into service in 2016 and 2017.

Year ended December 31, 2016 compared with year ended December 31, 2015

EBITDA decreased by \$13 million due to an unusual and infrequent investment impairment loss in 2016.

After taking into consideration the factor above, the remaining \$6 million decrease is primarily explained by the following significant business factors:

- disruptions at certain eastern Canadian wind farms in the first quarter and fourth quarter of 2016 due to weather conditions which caused a higher degree of icing on wind turbine blades;
- weaker wind resources experienced at certain facilities in Canada period over period; partially offset by
- stronger wind resources at United States wind farms during the second half of 2016.

ENERGY SERVICES

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

	2017	2016	2015
<i>(millions of Canadian dollars)</i>			
Earnings/(loss) before interest, income taxes and depreciation and amortization	(263)	(183)	324

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, 2017 compared with year ended December 31, 2016

EBITDA increased by \$2 million due to certain unusual, infrequent or other factors, primarily explained by the following:

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

After taking into consideration the factors above, the remaining \$82 million decrease is primarily explained by the following significant business factor:

- weaker performance from Energy Services' Canadian and United States operations due to the compression of certain crude oil and NGL location and quality differentials in 2017 which limited opportunities to generate profitable margins.

Year ended December 31, 2016 compared with year ended December 31, 2015

EBITDA decreased by \$477 million due to certain unusual, infrequent or other factors, primarily explained by the following:

- a non-cash, unrealized loss of \$205 million in 2016 compared with an unrealized gain of \$264 million in 2015 reflecting the revaluation of financial derivatives used to manage the profitability of transportation and storage transactions and exposure to movements in commodity prices.

After taking into consideration the factor above, the remaining \$30 million decrease is primarily explained by the following significant business factor:

- weaker performance from Energy Services' Canadian and United States operations due to the compression of certain crude oil and NGL location and quality differentials in 2016 which limited opportunities to generate profitable margins.

ELIMINATIONS AND OTHER

LOSS BEFORE INTEREST, INCOME TAXES AND DEPRECIATION AND AMORTIZATION

	2017	2016	2015
<i>(millions of Canadian dollars)</i>			
Loss before interest, income taxes and depreciation and amortization	(337)	(101)	(867)

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

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

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

- project development and transaction costs of \$197 million incurred in 2017 compared with \$81 million in 2016 related to the Merger Transaction;
- employee severance and restructuring costs of \$292 million in 2017 compared with \$92 million in 2016 related to a corporate reorganization initiative and the Merger Transaction; partially offset by
- a non-cash, unrealized intercompany foreign exchange loss of \$29 million in 2017 compared with \$43 million in 2016 under our foreign exchange risk management program.

After taking into consideration the factors above, the remaining \$79 million increase is primarily explained by the following significant business factor:

- a realized loss of \$173 million in 2017 compared with \$281 million in 2016 related to settlements under our foreign exchange risk management program.

Year ended December 31, 2016 compared with year ended December 31, 2015

EBITDA increased by \$854 million due to certain unusual, infrequent and other factors, primarily explained by the following:

- a non-cash, unrealized gain of \$417 million in 2016 compared with an unrealized loss of \$694 million in 2015 resulting from our foreign exchange hedging program; partially offset by
- a non-cash, unrealized intercompany foreign exchange loss of \$43 million in 2016 compared with a gain of \$131 million in 2015;
- project development and transaction costs of \$81 million incurred in 2016 in relation to the Merger Transaction; and
- employee severances costs of \$92 million in 2016 compared with \$47 million in 2015 related to a corporate reorganization initiative.

After taking into consideration the factors above, the remaining \$88 million decrease is primarily explained by the following significant business factor:

- a realized loss of \$281 million in 2016 compared with \$203 million in 2015 related to settlements under our foreign exchange risk management program.

GROWTH PROJECTS – COMMERCIALY SECURED PROJECTS

A key element of our corporate strategy is the successful execution of our growth capital program. In 2017, we successfully placed into service approximately \$12 billion of growth projects across several business units and we expect to place a further \$22 billion of commercially secured projects into service through 2020.

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	Norlite Pipeline System (the Fund Group)	70%	\$1.3 billion	\$1.1 billion	Complete	In service
2	Bakken Pipeline System (EEP) ³	27.6%	US\$1.5 billion	US\$1.5 billion	Complete	In service
3	Regional Oil Sands Optimization Project (the Fund Group)	100%	\$2.6 billion	\$2.3 billion	Complete	In service
4	Lakehead System Mainline Expansion - Line 61 (EEP) ⁴	100%	US\$0.4 billion	US\$0.4 billion	Substantially complete	2H - 2019
5	Canadian Line 3 Replacement Program (the Fund Group)	100%	\$5.3 billion	\$2.3 billion	Under construction	2H - 2019
6	U.S. Line 3 Replacement Program (EEP) ⁴	100%	US\$2.9 billion	US\$0.7 billion	Under construction	2H - 2019
7	Other - Canada	100%	\$0.2 billion	\$0.2 billion	Various stages	2018
GAS TRANSMISSION & MIDSTREAM						
8	Sabal Trail (SEP) ⁵	50%	US\$1.6 billion	US\$1.5 billion	Complete	In service
9	Access South, Adair Southwest and Lebanon Extension (SEP) ⁵	100%	US\$0.5 billion	US\$0.3 billion	Complete	In service
10	Atlantic Bridge (SEP) ⁵	100%	US\$0.5 billion	US\$0.3 billion	Under construction	Q4 - 2018
11	NEXUS (SEP) ⁵	50%	US\$1.3 billion	US\$0.6 billion	Under construction	Q3 - 2018
12	Reliability and Maintainability Project ⁵	100%	\$0.5 billion	\$0.4 billion	Under construction	Q3 - 2018
13	Valley Crossing Pipeline ⁵	100%	US\$1.5 billion	US\$1.1 billion	Under construction	Q4 - 2018
14	Spruce Ridge Program ⁵	100%	\$0.5 billion	\$0.1 billion	Pre-construction	2019
15	T-South Expansion Program ⁵	100%	\$1.0 billion	No significant expenditures to date	Pre-construction	2020
16	Other - United States ⁵	100%	US\$1.9 billion	US\$1.0 billion	Various stages	2017-2019
17	Other - Canada ⁵	100%	\$0.9 billion	\$0.7 billion	Various stages	2017-2018
GAS DISTRIBUTION						
18	2017 Dawn ⁵ -Parkway Expansion	100%	\$0.6 billion	\$0.6 billion	Complete	In service
19	Panhandle Reinforcement Project ⁵	100%	\$0.3 billion	\$0.2 billion	Complete	In service

GREEN POWER & TRANSMISSION

20	Chapman Ranch Wind Project	100%	US\$0.4 billion	US\$0.3 billion	Complete	In service
21	Rampion Offshore Wind Project	24.9%	\$0.8 billion (£0.37 billion)	\$0.6 billion (£0.3 billion)	Under construction	Q2 - 2018
22	Hohe See Offshore Wind Project and Expansion	50%	\$2.1 billion (€1.34 billion)	\$0.5 billion (€0.4 billion)	Pre-construction	2H - 2019

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, 2017.

3 On February 15, 2017, EEP acquired an effective 27.6% interest in the Bakken Pipeline System for a purchase price of \$2.0 billion (US\$1.5 billion). On April 27, 2017, Enbridge entered into a joint funding arrangement with EEP whereby Enbridge owns 75% and EEP owns 25% of the combined 27.6% effective interest in the Bakken Pipeline System.

4 The Lakehead System Mainline Expansion project is funded 75% by Enbridge and 25% by EEP, and the project will be operated by EEP on a cost-of-service basis. The U.S. L3R Program is being funded 99% by Enbridge and 1% by EEP.

5 Project acquired as part of the Merger Transaction. For additional information, refer to Merger with Spectra Energy.

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 placed into service in 2017:

- **Norlite Pipeline System (the Fund Group)** - a diluent pipeline originating from our Stonefell Terminal and terminating at our Fort McMurray South facility, with a transfer line to Suncor's East Tank Farm. The project provides an initial capacity of approximately 218,000 bpd, with the potential to be further expanded to approximately 465,000 bpd with the addition of pump stations. The project was placed into commercial service on May 1, 2017.
- **Bakken Pipeline System (EEP)** - a pipeline system that transports crude oil from the Bakken formation in North Dakota to markets in eastern PADD II, and the United States Gulf Coast. The system's initial capacity is approximately 470,000 bpd of crude oil and has the potential to be expanded to 570,000 bpd. The system was placed into service on June 1, 2017.
- **Regional Oil Sands Optimization Project (the Fund Group)** - the Athabasca Pipeline Twin portion of the project, which includes twinning of the southern section of the crude oil Athabasca Pipeline from Kirby Lake, Alberta to the crude oil hub at Hardisty, Alberta provides an initial capacity of approximately 450,000 bpd, with the potential to be further expanded to approximately 800,000 bpd. This portion of the project was placed into service on January 1, 2017. The Wood Buffalo Extension portion of the project includes a crude oil pipeline expansion between Cheecham, Alberta and Kirby Lake, Alberta that provides an initial capacity of approximately 635,000 bpd, with the potential to be further expanded to approximately 800,000 bpd. This portion of the project was placed into service on December 1, 2017.
- **JACOS Hangingstone Project (the Fund Group)** - a crude oil pipeline connecting the Japan Canada Oil Sands Limited (JACOS) Hangingstone project site to our existing Cheecham Terminal that provides an initial capacity of approximately 40,000 bpd. The project was placed into service on August 29, 2017.




The following commercially secured growth projects are expected to be placed into service in 2018 and 2019:

- **Lakehead System Mainline Expansion (EEP)** - the remaining scope of the project includes the Southern Access expansion between Superior, Wisconsin and Flanagan, Illinois that will increase capacity from 950,000 bpd to 1,200,000 bpd, which was substantially completed in June of 2017. We currently anticipate an in-service date in the second half of 2019 for this phase to more closely align with the anticipated in-service date for the Line 3 Replacement Program (U.S. L3R Program). For additional updates on the project, refer to *Growth Projects - Regulatory Matters*.
- **Canadian Line 3 Replacement Program (the Fund Group)** - replacement of the existing Line 3 crude oil pipeline between Hardisty, Alberta and Gretna, Manitoba. The L3R Program will not provide an increase in the overall capacity of the mainline system, but will restore approximately 370,000 bpd and supports the safety and operational reliability of the overall system, enhances flexibility and will allow us to optimize throughput from western Canada into Superior, Wisconsin. The L3R Program is expected to achieve the original capacity of approximately 760,000 bpd. Construction commenced in early August 2017. For additional updates on the project, refer to *Growth Projects - Regulatory Matters*.
- **United States Line 3 Replacement Program (EEP)** - replacement of the existing Line 3 crude oil pipeline between Neche, North Dakota and Superior, Wisconsin. The U.S. L3R Program, along with the Canadian L3R Program discussed above, will support the safety and operational reliability of the mainline system, enhance system flexibility, and allow the Company and EEP to optimize throughput on the mainline. The L3R Program is expected to achieve the original capacity of approximately 760,000 bpd. Construction commenced on the Wisconsin portion of the U.S. L3R Program in late June 2017 and will be substantially complete in February 2018. For additional updates on the project, refer to *Growth Projects - Regulatory Matters*.



Liquids Pipelines

- 1 Norlite Pipeline System (the Fund Group)
- 2 Bakken Pipeline System (EEP)
- 3 Regional Oil Sands Optimization Project (the Fund Group)
- 4 Lakehead System Mainline Expansion (EEP)
- 5 Canadian Line 3 Replacement Program (the Fund Group)
- 6 U.S. Line 3 Replacement Program (EEP)

	Assets in Operation
	Projects Placed into Service in 2017
	Growth Projects

GAS TRANSMISSION AND MIDSTREAM

The following commercially secured growth projects were placed into service in 2017:

- **Sabal Trail (SEP)** - a natural gas pipeline connecting Alexander City, Alabama to the Central Florida Hub in Kissimmee, Florida that provides capacity of approximately 1.1 billion cubic feet per day (bcf/d) of new capacity to access onshore shale gas supplies once approved future expansions are completed. Facilities include a new 749-kilometer (465-mile) pipeline, laterals and various compressor stations. The project was placed into service on July 3, 2017.
- **Access South, Adair Southwest and Lebanon Extension (SEP)** - natural gas pipeline extensions connecting the Appalachian region of the United States to markets in the Midwest and Southeast regions of the United States. The combined projects provide an initial capacity of 622 million cubic feet per day (mmcf/d) of gas to customers in Ohio, Kentucky and Mississippi. The Lebanon extension was placed into service early, on August 1, 2017 and the majority of the Access and Adair portions of the project were placed in service in November 2017 with the final 20 mmcf/d expected to be placed in service in the first quarter of 2018.

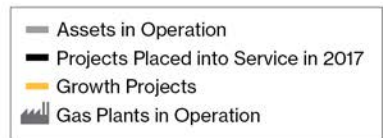
The following commercially secured growth projects are expected to be placed into service in 2018 to 2020:

- **Atlantic Bridge (SEP)** - expansion of SEP's Algonquin Gas Transmission systems to transport 133 mmcf/d of natural gas to the New England Region. The expansion primarily consists of the replacement of a natural gas pipeline, meter station additions, compression additions in Connecticut, and a new compressor station in Massachusetts. The Connecticut portion of the project was placed into service in the fourth quarter of 2017. The remainder of the project is expected to be in-service during the fourth quarter of 2018.
- **NEXUS (SEP)** - a natural gas pipeline system connecting SEP's Texas Eastern pipeline system in Ohio to the Union Gas Dawn hub in Ontario, via Vector Pipeline L.P., that will provide capacity of up to approximately 1.5 bcf/d. The project received a Notice to Proceed from the Federal Energy Regulatory Commission (FERC) in August 2017 and construction activities have commenced.
- **Reliability and Maintainability Project** - a natural gas pipeline project designed to enhance the performance of the southern segment of the British Columbia Pipeline system to accommodate the increased base load on the system. The project involves adding new compressor units at three compressor stations along the pipeline system as well as upgrading existing pipeline crossovers and adding new crossovers at key locations. During 2017, six crossovers were placed into service.
- **Valley Crossing Pipeline** - a natural gas pipeline connecting the Agua Dulce hub in Texas to an offshore tie-in with the Sur de Texas-Tuxpan project, which is being constructed by a third party. The project will help Mexico meet its growing gas fired electric generation needs by providing capacity of up to approximately 2.6 bcf/d.
- **Spruce Ridge Program** - natural gas pipeline expansion of Westcoast Energy Inc.'s British Columbia Pipeline in northern British Columbia, which consists of the Aitken Creek Looping project and the Spruce Ridge Expansion project. The combined projects will provide additional capacity of up to 402 mmcf/d.
- **T-South Expansion Program** - natural gas pipeline expansion of Westcoast Energy Inc.'s T-South system that will provide additional capacity of approximately 190 mmcf/d into the Huntington/Sumas market at the United States/Canada border.



Gas Transmission and Midstream

- 8 Sabal Trail (SEP)
- 9 Access South, Adair Southwest and Lebanon Extension (SEP)
- 10 Atlantic Bridge (SEP)
- 11 NEXUS (SEP)
- 12 Reliability and Maintainability Project
- 13 Valley Crossing Pipeline
- 14 Spruce Ridge Program
- 15 T- South Expansion Program



GAS DISTRIBUTION

In addition to normal course investment to support customer additions, the following commercially secured growth projects were placed into service in 2017:

- **2017 Dawn-Parkway Expansion** - the expansion of the existing Dawn-Parkway pipeline system, which provides transportation service from Dawn to the Greater Toronto Area, through the addition of new compressors at each of the Dawn, Lobo and Bright compressor stations in Ontario. The project provides additional capacity of approximately 419 mmcf/d and was placed into service in October 2017.
- **Panhandle Reinforcement Project** - the expansion of the existing Panhandle pipeline from Dawn to the Dover transmission station in Chatham-Kent, Ontario. The project serves firm demand growth in southwestern Ontario and was placed into service in November 2017.



Gas Distribution

18 Dawn-Parkway Expansion

19 Panhandle Reinforcement Project

GREEN POWER AND TRANSMISSION

The following commercially secured growth project was placed into service in 2017:

- **Chapman Ranch Wind Project** - a wind project that consists of 81 Acciona Windpower North America, LLC (Acciona) turbines located in Nueces County, Texas which generate approximately 249-MW of power and were placed into service on October 25, 2017. Acciona provides turbine operations and maintenance services under a five-year fixed-price contract with an option to extend. The project is backed by a 12-year power offtake agreement.





The following commercially secured growth projects are expected to be placed into service in 2018 and 2019:

- **Rampion Offshore Wind Project** - a wind project located off the Sussex coast in the United Kingdom, consisting of 116 turbines, which will generate approximately 400-MW when complete. We hold an effective 24.9% interest, United Kingdom's Green Investment Bank plc holds a 25% interest and E.ON SE holds the remaining 50.1% interest in the project, which was developed and is being constructed by E.ON Climate & Renewables UK Limited, a subsidiary of E.ON SE. The Rampion Offshore Wind Project is backed by revenues from the United Kingdom's fixed-price Renewable Obligation certificates program and a 15-year power purchase agreement. The project generated first power in November 2017 and is currently in the commissioning phase.
- **Hohe See Offshore Wind Project and Expansion** - a wind project located in the North Sea, off the coast of Germany that will generate approximately 497-MW, with an additional 112-MW from the expansion. The Hohe See Offshore Wind Project and Expansion will be constructed under fixed-price engineering, procurement, construction and installation contracts, which have been secured with key suppliers. The Hohe See Project and Expansion is backed by a government legislated 20-year revenue support mechanism.



Green Power and Transmission

- 20 Chapman Ranch Wind Project
- 21 Rampion Offshore Wind Project
- 22 Hohe See Offshore Wind Project

	Power Transmission in Operation
	Wind Assets in Operation
	Solar Assets in Operation
	Growth Projects – Wind

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

- **Gray Oak Pipeline Project** - a 385,000 bpd pipeline system to provide producers and other shippers the opportunity to secure crude oil transportation from West Texas to the destination markets of Corpus Christi, Freeport, and Houston, Texas with connectivity to over 3 million bpd of refining capacity and multiple dock facilities capable of crude oil exports. The project is a joint development with Phillips 66 and would be placed into service during the second half of 2019 depending on shipper interest expressed in the recently closed open season.

GAS TRANSMISSION AND MIDSTREAM

- **Gulf Coast Express Pipeline Project** - a natural gas pipeline connecting the Waha, Texas area to Agua Dulce, Texas that will provide capacity up to approximately 1.7 bcf/d. The project is a joint development between our equity investment DCP Midstream, Kinder Morgan Texas Pipeline LLC and an affiliate of Targa Resources Corp, and is expected to be placed into service during the second half of 2019, subject to obtaining sufficient shipper commitments.
- **Alliance Pipeline Expansion Project** - Alliance Pipeline announced a non-binding request for expressions of interest for additional transportation service on the Alliance Pipeline Canada and Alliance Pipeline US systems. Alliance Pipeline continues to engage with interested parties and assess the addition of more compression facilities along the system in order to increase throughput capacity by up to 500 mmcf/d. The projected in-service date for the potential capacity expansion is the second half of 2021.
- **Access Northeast** - Access Northeast is a project that will bring affordable energy to New England consumers. Natural gas pipeline capacity scarcity and system reliability remains a primary issue for New England and one that must be resolved for the region to meet its energy supply needs. The project's partners continue to pursue a viable commercial and operational model to provide natural gas to the region.

GREEN POWER AND TRANSMISSION

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

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

GROWTH PROJECTS - REGULATORY MATTERS

Lakehead System Mainline Expansion (EEP)

On October 16, 2017, the United States Department of State issued a Presidential permit to EEP to operate Line 67 at its design capacity of 888,889 bpd at the international border of the United States and Canada near Neche, North Dakota.

Canadian Line 3 Replacement Program (the Fund Group)

In December 2016, the Manitoba Metis Federation (MMF) and the Association of Manitoba Chiefs (AMC) applied to the Federal Court of Appeal for leave, which was subsequently granted, to judicially review the Government of Canada's decision to approve the Canadian L3R Program. On July 4, 2017, the MMF discontinued its judicial review application. On October 25, 2017, the AMC discontinued its judicial review application. As a result, no further challenges to the Government of Canada's decision to approve the Canadian L3R Program may be brought by any party.

All required pre-construction filings have been approved by the NEB.

United States Line 3 Replacement Program (EEP)

EEP is in the process of obtaining the appropriate permits for constructing the U.S. L3R Program in Minnesota. The project requires both a Certificate of Need and an approval of the pipeline's route (Route Permit) from the MNPUC. The MNPUC found both the Certificate of Need and Route Permit applications for the U.S. L3R Program through Minnesota to be complete. On February 1, 2016, the MNPUC issued a written order requiring the Minnesota Department of Commerce (DOC) to prepare an Environmental Impact Statement (EIS) before the filing of intervenor testimony in the Certificate of Need and Route Permit processes. The DOC issued the final EIS on August 17, 2017. The MNPUC determined the final EIS to be inadequate in four specific areas on December 7, 2017. The DOC provided a supplemental EIS on February 12, 2018, and the MNPUC will determine its adequacy in the second quarter of 2018. In the parallel Certificate of Need and Route Permit dockets, public and evidentiary hearings were held at locations along the proposed route and in Saint Paul, Minnesota from September to November 2017 and are now complete. The MNPUC is expected to vote on the Certificate of Need and Route Permit at the end of the second quarter of 2018.

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, including utilization of our sponsored vehicles. For additional information, refer to *Sponsored Vehicles* below.

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 2017:

Entity	Type of Issuance	Amount
<i>(in millions of Canadian dollars, unless stated otherwise)</i>		
Enbridge Inc.	Common shares (via share exchange*)	37,429
Enbridge Inc.	Common shares (by private placement)	1,500
Enbridge Inc.	Preference shares	500
Enbridge Inc.	Fixed-to-floating rate subordinated notes	1,650
Enbridge Inc.	Floating rate notes	750
Enbridge Inc.	Medium-term notes	1,200
Enbridge Inc.	US\$ Fixed-to-floating rate subordinated notes	US\$1,000
Enbridge Inc.	US\$ Floating rate notes	US\$1,200
Enbridge Inc.	US\$ Senior notes	US\$1,400
Enbridge Income Fund Holdings Inc.	Common shares	575
Enbridge Income Fund Holdings Inc.	Common shares (Secondary offering by Enbridge)	575
Enbridge Gas Distribution Inc. (EGD)	Medium-term notes	300
Spectra Energy Partners, LP	Floating rate notes	US\$400
Union Gas Limited	Medium-term notes	500

* In connection with the Merger Transaction

On January 9, 2018, Texas Eastern Transmission, LP, a wholly-owned operating subsidiary of SEP, completed an offering of US\$800 million of senior notes, which consisted of two US\$400 million tranches with fixed interest rates of 3.50% and 4.15% which mature in 2028 and 2048, respectively.

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, 2017.

December 31, <i>(millions of Canadian dollars)</i>	Maturity	2017		
		Total Facilities	Draws ¹	Available
Enbridge Inc. ²	2019-2022	7,353	2,737	4,616
Enbridge (U.S.) Inc.	2019	3,590	490	3,100
Enbridge Energy Partners, L.P. ³	2019-2022	3,289	1,820	1,469
Enbridge Gas Distribution Inc.	2019	1,016	972	44
Enbridge Income Fund	2020	1,500	766	734
Enbridge Pipelines (Southern Lights) L.L.C.	2019	25	—	25
Enbridge Pipelines Inc.	2019	3,000	1,438	1,562
Enbridge Southern Lights LP	2019	5	—	5
Spectra Energy Partners, LP ^{4,5}	2022	3,133	2,824	309
Union Gas Limited ⁵	2021	700	485	215
Westcoast Energy Inc. ⁵	2021	400	—	400
Total committed credit facilities		24,011	11,532	12,479

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

² Includes \$135 million, \$157 million (US\$125 million) and \$150 million of commitments that expire in 2018, 2018 and 2020, respectively.

³ Includes \$219 million (US\$175 million) and \$232 million (US\$185 million) of commitments that expire in 2018 and 2020, respectively.

⁴ Includes \$421 million (US\$336 million) of commitments that expire in 2021.

⁵ Committed credit facilities acquired on February 27, 2017 in conjunction with the Merger Transaction. For additional information, refer to Merger with Spectra Energy.

During the first quarter of 2017, Enbridge established a five-year, term credit facility for \$239 million (¥20,000 million) with a syndicate of Japanese banks. Principal and interest on this facility have been converted to United States dollars using a cross currency interest rate swap.

In addition to the committed credit facilities noted above, we have \$792 million of uncommitted demand facilities, of which \$518 million were unutilized as at December 31, 2017. As at December 31, 2016, we had \$335 million of uncommitted credit facilities, of which \$177 million were unutilized.

Our net available liquidity of \$12,959 million at December 31, 2017 was inclusive of \$480 million of unrestricted cash and cash equivalents as reported on the Consolidated Statements of Financial Position.

Our credit facility agreements and term debt indentures include standard events of default and covenant provisions whereby accelerated repayment and/or termination of the agreements may result if we were to default on payment or violate certain covenants. As at December 31, 2017, we were in compliance with all debt covenants and expect to continue to comply with such covenants.

Strong growth in internal cash flow, ready access to liquidity from diversified sources and a stable business model have enabled us to manage our credit profile. We actively monitor and manage key financial metrics with the objective of sustaining investment grade credit ratings from the major credit rating agencies and ongoing access to bank funding and term debt capital on attractive terms. Key measures of financial strength that are closely managed include the ability to service debt obligations from operating cash flow and the ratio of debt to total capital. As at December 31, 2017, our debt capitalization ratio was 48.3% compared with 61.8% as at December 31, 2016. The improvement in the ratio reflected an increase in equity that resulted from the Merger Transaction.

During 2017, our credit ratings were affirmed as follows:

- DBRS Limited confirmed our issuer rating and medium-term notes and unsecured debentures rating of BBB (high), fixed-to-floating subordinated notes rating of BBB (low), preference share rating of Pfd-3 (high) and commercial paper rating of R-2 (high), and changed their rating outlook from under review with developing implications to stable.
- 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.
- In June 2017, we obtained Fitch 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 December 22, 2017, Moody's Investor Services, Inc. downgraded our issuer and senior unsecured ratings from Baa2 to Baa3, subordinated rating from Ba1 to Ba2, preference share rating from Ba1 to Ba2, commercial paper rating for Enbridge (U.S.) Inc. from P-2 to P-3, and changed the outlook on all of these ratings from negative to stable.

We invest surplus cash in short-term investment grade money market instruments with highly creditworthy counterparties. Short-term investments were \$70 million as at December 31, 2017 compared with \$800 million as at December 31, 2016. The higher short-term investment balances at the end of 2016 reflect the temporary investment of a portion of the proceeds of capital markets offerings undertaken by us in the fourth quarter of 2016, pending its redeployment in our growth capital program.

There are no material restrictions on our cash. Total restricted cash of \$107 million includes EGD's and Union Gas' receipt of cash from the Government of Ontario to fund its Green Investment Fund program. In addition, our restricted cash includes cash collateral and amounts received in respect of specific shipper commitments. Cash and cash equivalents held by EEP, the Fund Group and SEP are generally not readily accessible by us until distributions are declared and paid by these entities, which occurs quarterly for EEP and SEP, and monthly for the Fund Group. Further, cash and cash equivalents held by certain foreign subsidiaries may not be readily accessible for alternative uses by us.

Excluding current maturities of long-term debt, at December 31, 2017 and 2016 we had a negative working capital position of \$2,538 million and \$456 million, respectively. In both periods, the major contributing factor to the negative working capital position was the ongoing funding of our growth capital program.

To address this negative working capital position, we maintain significant liquidity in the form of committed credit facilities and other sources as previously discussed, which enable the funding of liabilities as they become due. As at December 31, 2017 and 2016, our net available liquidity totaled \$12,959 million and \$14,274 million, respectively, on a consolidated basis. It is anticipated that any current maturities of long-term debt will be refinanced upon maturity.

SOURCES AND USES OF CASH

December 31, <i>(millions of Canadian dollars)</i>	2017	2016	2015
Operating activities	6,584	5,211	4,571
Investing activities	(11,002)	(5,192)	(7,933)
Financing activities	3,476	840	3,074
Effect of translation of foreign denominated cash and cash equivalents	(72)	(19)	143
Increase/(decrease) in cash and cash equivalents	(1,014)	840	(145)

Significant sources and uses of cash for the years ended December 31, 2017 and 2016 are summarized below:

Operating Activities

2017

- The growth in cash flow delivered by operations in 2017 is a reflection of the positive operating factors discussed under *Results of Operations*, which primarily included contributions from new assets of approximately \$2,574 million following the completion of the Merger Transaction.
- For the year ended, partially offsetting the increase in cash flows from operating activities are transaction costs in connection with the Merger Transaction, as well as employee severance costs in relation to our enterprise-wide reduction of workforce.
- Changes in operating assets and liabilities to \$314 million from \$358 million for the years ended December 31, 2017 and 2016, respectively, reflected negative working capital in each of those years. Our operating assets and liabilities fluctuate in the normal course due to various factors including fluctuations in commodity prices and activity levels within the Energy Services and Gas Distribution segments, the timing of tax payments, as well as timing of cash receipts and payments.

2016

- The growth in cash flow delivered by operations in 2016 was a reflection of the positive operating factors discussed under *Results of Operations*, which primarily included stronger contributions from the Liquids Pipelines segment, partially offset by higher financing costs resulting from the incurrence of incremental debt to fund asset growth and the impact of refinancing construction debt with longer-term debt financing.
- Changes in operating assets and liabilities included within operating activities were \$358 million for the year ended December 31, 2016 compared with \$645 million for the comparative 2015 year. Our operating assets and liabilities fluctuate in the normal course due to various factors including fluctuations in commodity prices and activity levels within the Energy Services and Gas Distribution segments, the timing of tax payments, general variations in activity levels within our businesses, as well as timing of cash receipts and payments.

Investing Activities

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

A summary of additions to property, plant and equipment for the years ended December 31, 2017, 2016 and 2015 is set out below:

Year ended December 31, <i>(millions of Canadian dollars)</i>	2017	2016	2015
Liquids Pipelines	2,797	3,956	5,882
Gas Transmission and Midstream	3,883	176	385
Gas Distribution	1,177	713	858
Green Power and Transmission	321	251	68
Energy Services	1	—	—
Eliminations and Other	108	32	80
Total capital expenditures	8,287	5,128	7,273

2017

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

2016

- The timing of projects approval, construction and in-service dates impacted the timing of cash requirements. For the year ended December 31, 2016, additions to property, plant and equipment resulted in cash expenditures of \$5,128 million compared with \$7,273 million for the year ended December 31, 2015. The year-over-year decrease reflected the successful completion of growth projects in 2015, including the Edmonton to Hardisty Expansion, Southern Access Extension and phases of the Eastern Access Program.
- Also contributing to the decrease in year-over-year cash used in investing activities were proceeds received from disposition of assets. For the year ended December 31, 2016, proceeds from dispositions were \$1,379 million compared with \$146 million for the year ended December 31, 2015. The majority of the proceeds in 2016 related to the sale of the South Prairie Region assets completed in December 2016.
- Partially offsetting the above factors was higher spending in 2016 for acquisitions. During the second quarter of 2016, we made an initial equity investment in and advanced an affiliate loan to acquire a 50% interest in a French offshore wind development company and fund the ongoing development costs of that company.

Financing Activities

2017

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

- We issued a series of medium term fixed and floating rate notes, the proceeds of which were used to repay maturing term notes and credit facilities and to finance growth capital programs. For the year ended 2017, proceeds from term note issuances were primarily used to repay credit facilities and redeem tender offers for Spectra Energy's outstanding senior unsecured notes as discussed in *Liquidity and Capital Resources - Capital Market Access*.
- The change in cash generated from financing activities reflected overall higher cash contributions from redeemable noncontrolling interests of \$1,178 million compared with \$591 million in the comparable period attributable to our holdings in ENF equity. Cash contributions were also higher for noncontrolling interests, which now include noncontrolling interests acquired through the Merger Transaction, which is more than offset by the increase in distributions to noncontrolling interests. The increase in distributions to noncontrolling interests was primarily attributable to the acquired assets, which were partially offset by the decrease in distributions resulting from the EEP strategic restructuring discussed under *United States Sponsored Vehicle Strategy*.
- Cash provided from financing activities further increased as we completed the issuance of 33.5 million common shares for gross proceeds of approximately \$1.5 billion along with the issuance of 4 million preferred shares for gross proceeds of \$0.5 billion.
- For the year ended 2017, the above increases in cash were partially offset by \$227 million paid to acquire all of the outstanding publicly-held common units of MEP during the second quarter of 2017, as well as higher cash received from the issuance of common shares in the first quarter of 2016, as a result of the issuance of 56 million common shares in March 2016.
- Finally, our common share dividend payments increased in the first half of 2017, primarily due to the increase in the common share dividend rate effective March 2017, as well as higher number of common shares outstanding as a result of the issuance of approximately 75 million common shares in 2016 and 691 million common shares issued in connection with the Merger Transaction. In addition, we paid \$414 million in common share dividends to the shareholders of Spectra Energy. These dividends were declared before the closing of the Merger Transaction but were paid after the closing of the Merger Transaction.

2016

- Our financing requirements decreased for the year ended December 31, 2016 compared with December 31, 2015, primarily reflecting lower expenditures on growth capital projects and the proceeds of asset sales. Our funding requirements are a reflection of the timing of various growth projects.
- In 2016, our overall debt decreased by \$149 million compared with an overall increase in debt of \$3,663 million in 2015. The decrease was mainly due to lower debt requirements resulting from the timing of completion of various growth projects and other sources of funds, primarily the proceeds from our common share issuance in March 2016, which were partly utilized to reduce drawn credit facilities and outstanding commercial paper draws.
- The increase in common share dividends paid in 2016 was attributable to the increase in the common share dividend rate effective March 2016 and a higher number of common shares outstanding primarily as a result of the common share issuance noted above.
- Distributions to redeemable noncontrolling interests in the Fund Group increased during 2016 compared with the corresponding 2015 period mainly due to a higher per share distribution rate and a larger number of public shares outstanding in ENF. Higher distributions to noncontrolling interests in EEP reflected an increase to the per unit distribution in the first half of 2016 as well as the effects of a strengthening United States dollar versus the Canadian dollar.

Preference Share Issuances

Since July 2011, we have issued 310 million preference shares for gross proceeds of approximately \$7.8 billion with the following characteristics.

	Gross Proceeds	Dividend Rate	Dividend ^{1,9}	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 B ⁵	\$500 million	3.42%	\$0.85360	\$25	June 1, 2022	Series C
Series C ⁵	—	3-month treasury bill plus 2.400%	—	\$25	June 1, 2022	Series B
Series D ⁶	\$450 million	4.00%	\$1.00000	\$25	March 1, 2018	Series E
Series F	\$500 million	4.00%	\$1.00000	\$25	June 1, 2018	Series G
Series H	\$350 million	4.00%	\$1.00000	\$25	September 1, 2018	Series I
Series J ⁷	US\$200 million	4.89%	US\$1.22160	US\$25	June 1, 2022	Series K
Series L ⁷	US\$400 million	4.96%	US\$1.23972	US\$25	September 1, 2022	Series M
Series N	\$450 million	4.00%	\$1.00000	\$25	December 1, 2018	Series O
Series P	\$400 million	4.00%	\$1.00000	\$25	March 1, 2019	Series Q
Series R	\$400 million	4.00%	\$1.00000	\$25	June 1, 2019	Series S
Series 1	US\$400 million	4.00%	US\$1.00000	US\$25	June 1, 2018	Series 2
Series 3	\$600 million	4.00%	\$1.00000	\$25	September 1, 2019	Series 4
Series 5	US\$200 million	4.40%	US\$1.10000	US\$25	March 1, 2019	Series 6
Series 7	\$250 million	4.40%	\$1.10000	\$25	March 1, 2019	Series 8
Series 9	\$275 million	4.40%	\$1.10000	\$25	December 1, 2019	Series 10
Series 11	\$500 million	4.40%	\$1.10000	\$25	March 1, 2020	Series 12
Series 13	\$350 million	4.40%	\$1.10000	\$25	June 1, 2020	Series 14
Series 15	\$275 million	4.40%	\$1.10000	\$25	September 1, 2020	Series 16
Series 17	\$750 million	5.15%	\$1.28750	\$25	March 1, 2022	Series 18
Series 19 ⁸	\$500 million	4.90%	\$1.22500	\$25	March 1, 2023	Series 20

1 The holder is entitled to receive a fixed, cumulative, quarterly preferential dividend, as declared by the Board. With the exception of Series A and Series C Preference Shares, such fixed dividend rate resets every five years beginning on the initial redemption and conversion option date. The Series 17 and Series 19 Preference Shares contain a feature where the fixed dividend rate, when reset every five years, will not be less than 5.15% and 4.90%, respectively. No other series of Preference Shares has this feature.

2 Preference Shares, Series A may be redeemed any time at our option. For all other series of Preference Shares, we may, at our option, redeem all or a portion of the outstanding Preference Shares for the Base Redemption Value per share plus all accrued and unpaid dividends on the Redemption Option Date and on every fifth anniversary thereafter.

3 The holder will have the right, subject to certain conditions, to convert their shares into Cumulative Redeemable Preference Shares of a specified series on a one-for-one basis on the Conversion Option Date and every fifth anniversary thereafter at an ascribed issue price equal to the Base Redemption Value.

4 With the exception of Series A Preference Shares, after the redemption and conversion option dates, holders may elect to receive quarterly floating rate cumulative dividends per share at a rate equal to: \$25 x (number of days in quarter/365) x 90 day Government of Canada treasury bill rate + 2.4% (Series C), 2.4% (Series E), 2.5% (Series G), 2.1% (Series I), 2.7% (Series O), 2.5% (Series Q), 2.5% (Series S), 2.4% (Series 4), 2.6% (Series 8), 2.7% (Series 10), 2.6% (Series 12), 2.7% (Series 14), 2.7% (Series 16), 4.1% (Series 18) or 3.2% (Series 20); or US\$25 x (number of days in quarter/365) x three-month United States Government treasury bill rate + 3.1% (Series K), 3.2% (Series M), 3.1% (Series 2) or 2.8% (Series 6).

5 On June 1, 2017, 1,730,188 of Series B fixed rate Preference Shares were converted to Series C floating rate Preference Shares based upon preference share holder elections under the terms of the Series B Preference Shares. The quarterly dividend amount for the Series B Preference Shares was decreased to \$0.21340 from \$0.25000 on June 1, 2017, due to the reset of the annual dividend rate on every fifth anniversary of the date of issuance of the Series B Preference Shares. The quarterly dividend amount for the Series C Preference Shares was set at \$0.18600 on June 1, 2017, \$0.19571 on September 1, 2017 and \$0.20342 on December 1, 2017, due to reset on a quarterly basis following the issuance thereof.

6 On January 30, 2018, we announced that we do not intend to exercise our right to redeem our Series D Preference Shares on March 1, 2018. As a result, until February 14, 2018, the holders of such shares had the right to convert all or part of their Series D fixed rate Preference Shares on a one-for-one basis into Series E floating rate Preference Shares. As of February 14, 2018, less than the 1,000,000 Series D Preference Shares required to give effect to conversions into Series E Preference Shares were tendered for conversion. As a result, none of our outstanding Series D Preference Shares will be converted into Series E Preference Shares on March 1, 2018. However, on March 1, 2018, the quarterly dividend amount for the Series D Preference Shares will be increased to \$0.27875 from \$0.25000, due to the reset of the annual dividend rate on every fifth anniversary of the date of issuance of the Series D Preference Shares.

7 No Series J or Series L Preference Shares were converted on the June 1, 2017 and September 1, 2017 conversion option dates, respectively. However, the quarterly dividend amounts for the Series J and Series L Preference Shares were increased to US\$0.30540 from US\$0.25000 on June 1, 2017, and to US\$0.30993 from US\$0.25000 on September 1, 2017, respectively, due to the reset of the annual dividend rate on every fifth anniversary of the date of issuance of the Series J and Series L Preference Shares.

8 On December 11, 2017, 20 million Series 19 Preferred Shares, inclusive of 4 million Series 19 Preferred Shares issued on full exercise of the underwriters' option, were issued for gross proceeds of \$500 million.

9 For dividends declared, see Liquidity and Capital Resources – Sources and Uses of Cash – Dividend Reinvestment and Share Purchase Plan.

Common Share Issuances

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

On February 27, 2017, we completed the issuance of 691 million common shares with a value of \$37.4 billion in exchange for shares of Spectra Energy in connection with the Merger Transaction. For further information, see *Merger with Spectra Energy* and Item 8. *Financial Statements and Supplementary Data - Note 7. Acquisitions and Dispositions*.

On March 1, 2016, we completed the issuance of 56.5 million common shares for gross proceeds of approximately \$2.3 billion, inclusive of the shares issued on exercise of the full amount of the underwriters' over-allotment option to purchase an additional 7.4 million common shares. The proceeds were used to reduce short-term indebtedness pending reinvestment in secured capital projects.

Dividend Reinvestment and Share Purchase Plan

Participants in our Dividend Reinvestment and Share Purchase Plan (DRIP) receive a 2% discount on the purchase of common shares with reinvested dividends. For the years ended December 31, 2017 and 2016, total dividends paid were \$3,562 million and \$1,945 million, respectively, of which \$2,336 million and \$1,150 million, respectively, were paid in cash and reflected in financing activities. The remaining \$1,226 million and \$795 million, respectively, of dividends paid were reinvested pursuant to the DRIP and resulted in the issuance of common shares rather than a cash payment. For the years ended December 31, 2017 and 2016, 34.4% and 40.9%, respectively, of total dividends paid were reinvested through the DRIP. In addition to amounts paid in cash and reflected in financing activities for the year ended December 31, 2017, were \$414 million in dividends declared to Spectra Energy shareholders prior to the Merger Transaction that were paid after the Merger Transaction.

Our Board of Directors has declared the following quarterly dividends. All dividends are payable on March 1, 2018 to shareholders of record on February 15, 2018.

Common Shares	\$0.67100
Preference Shares, Series A	\$0.34375
Preference Shares, Series B ¹	\$0.21340
Preference Shares, Series C ²	\$0.20342
Preference Shares, Series D	\$0.25000
Preference Shares, Series F	\$0.25000
Preference Shares, Series H	\$0.25000
Preference Shares, Series J ³	US\$0.30540
Preference Shares, Series L ⁴	US\$0.30993
Preference Shares, Series N	\$0.25000
Preference Shares, Series P	\$0.25000
Preference Shares, Series R	\$0.25000
Preference Shares, Series 1	US\$0.25000
Preference Shares, Series 3	\$0.25000
Preference Shares, Series 5	US\$0.27500
Preference Shares, Series 7	\$0.27500
Preference Shares, Series 9	\$0.27500
Preference Shares, Series 11	\$0.27500
Preference Shares, Series 13	\$0.27500
Preference Shares, Series 15	\$0.27500
Preference Shares, Series 17	\$0.32188
Preference Shares, Series 19	\$0.26850

¹ The quarterly dividend amount of Series B was decreased to \$0.21340 from \$0.25000 on June 1, 2017, due to the reset of the annual dividend on every fifth anniversary of the date of issuance of the Series B Preference Shares.

² The quarterly dividend amount of Series C was set at \$0.18600 on June 1, 2017, \$0.19571 on September 1, 2017 and \$0.20342 on December 1, 2017, due to reset on a quarterly basis following the date of issuance of the Series C Preference Shares.

³ The quarterly dividend amount of Series J was increased to US\$0.30540 from US\$0.25000 on June 1, 2017, due to the reset of the annual dividend on every fifth anniversary of the date of issuance of the Series J Preference Shares.

⁴ The quarterly dividend amount of Series L was increased to US\$0.30993 from US\$0.25000 on September 1, 2017, due to the reset of the annual dividend on every fifth anniversary of the date of issuance of the Series L Preference Shares.

SPONSORED VEHICLES

We utilize Sponsored Vehicles to diversify our access to capital and enhance our costs of funds. When market conditions are supportive, we may also seek to raise capital and monetize the value of existing assets through drop-down transactions with our Sponsored Vehicles.

The Fund Group

	2017	2016	2015
Economic interest as at December 31,	82.5%	86.9%	89.2%
Distributions received by us for the year ended December 31,	\$1,539 million	\$1,555 million	\$601 million

Common Unit Issuance

On December 7, 2017, ENF completed the issuance of 20,683,900 common shares, inclusive of 2,697,900 common shares issued on full exercise of the underwriters' over-allotment option, at a price of \$27.80 for a gross proceeds of \$575 million. The proceeds will be used to repay short-term indebtedness and fund growth projects associated with the Fund's Canadian liquids pipeline assets.

On April 18, 2017, ENF completed the Secondary Offering of 17,347,750 common shares to the public at a price of \$33.15 per share, for gross proceeds of approximately \$575 million. For further information, refer to *Asset Monetization*.

Restructuring

In September 2015, we completed the Canadian Restructuring Plan. For further details, refer to *Canadian Restructuring Plan*.

EEP

	2017	2016	2015
Economic interest as at December 31,	34.6%	35.3%	35.7%
Distributions received by us for the year ended December 31, ¹	US\$713 million	US\$573 million	US\$499 million

¹ Includes distributions for our ownership interest in EEP and distributions from direct ownership in its jointly funded projects.

Strategic Review

In 2017, we continued the ongoing evaluation of our investment in EEP. For additional information, refer to *United States Sponsored Vehicle Strategy*.

Common Unit Issuance

In March 2015, EEP completed the issuance of eight million Class A common units for gross proceeds of approximately US\$294 million before underwriting discounts and commissions and offering expenses. We did not participate in the issuance; however, we made a capital contribution of US\$6 million to maintain our 2% general partner interest in EEP. EEP used the proceeds from the offering to fund a portion of its capital expansion projects and for general partnership purposes.

Alberta Clipper Drop Down

In January 2015, we completed the drop down of our 66.7% interest in the United States segment of the Alberta Clipper Pipeline to EEP. Aggregate consideration for the transaction was US\$1 billion, consisting of approximately US\$694 million of Class E equity units issued to us by EEP and the repayment of approximately US\$306 million of indebtedness owed to us.

SEP

	2017	2016	2015
Economic interest as at December 31,	83%	—	—
Distributions received by us for the year ended December 31,	US\$738 million	—	—

The Merger Transaction

As a result of the Merger Transaction, we acquired a 75% economic interest in SEP. For further information, refer to *Merger with Spectra Energy*.

Share Issuances

During the year ended December 31, 2017, SEP issued 3,991,977 million common units under its at-the-market program for total proceeds of US\$171 million.

Restructuring of Incentive Distribution Rights

Refer to *United States Sponsored Vehicle Strategy - Restructuring of SEP Incentive Distribution Rights*.

OFF-BALANCE SHEET ARRANGEMENTS

We enter into guarantee arrangements in the normal course of business to facilitate commercial transactions with third parties. These arrangements include financial guarantees, stand-by letters of credit, debt guarantees, surety bonds and indemnifications. See Item 8. Financial Statements and supplementary data - *Note 29. Guarantees* for further discussion of guarantee arrangements.

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

We do not have material off-balance sheet financing entities or structures, except for normal operating lease arrangements, guarantee arrangements and financings entered into by our equity investments. For additional information on these commitments, see Item 8. Financial Statements and supplementary data - *Note 28. Commitments and Contingencies* and *Note 29. 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, 2017	Total	Less than 1 year	1-3 years	3-5 years	After 5 years
<i>(millions of Canadian dollars)</i>					
Annual debt maturities ^{1,2}	62,927	2,831	12,995	11,344	35,757
Interest obligations ^{2,3}	42,083	2,485	4,415	3,794	31,389
Operating leases ⁴	1,151	106	198	184	663
Capital leases	35	9	10	4	12
Pension obligations ⁵	162	162	—	—	—
Long-term contracts ⁶	14,718	4,182	4,000	2,448	4,088
Other long-term liabilities ⁷	—	—	—	—	—
Total contractual obligations	121,076	9,775	21,618	17,774	71,909

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

2 Excludes the debt issuance of US\$800 million senior notes that occurred subsequent to December 31, 2017.

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

4 Includes land leases.

5 Assumes only required payments will be made into the pension plans in 2018. Contributions are made in accordance with independent actuarial valuations as at December 31, 2017. Contributions, including discretionary payments, may vary pending future benefit design and asset performance.

6 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 \$2,609 million which are expected to be paid over the next five years. Also consists of the following purchase obligations: gas transportation and storage contracts (EGD), firm capacity payments and gas purchase commitments (Spectra Energy), transportation, service and product purchase obligations (MEP), and power commitments (EEP).

7 We are unable to estimate deferred income taxes (Item 8. Financial Statements and supplementary data - Note 24. 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 (Item 8. Financial Statements and supplementary data - Note 18. Asset Retirement Obligations), environmental liabilities (Item 8. Financial Statements and supplementary data - Note 28. Commitments and Contingencies) and hedges payable (Item 8. Financial Statements and supplementary data - Note 23. Risk Management and Financial Instruments) due to the uncertainty as to the amount and, or, timing of when cash payments will be required.

LEGAL AND OTHER UPDATES

LIQUIDS PIPELINES

Renewal of Line 5 Easement

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

Eddystone Rail Legal Matter

In February 2017, Eddystone Rail filed an action against several defendants in the United States District Court for the Eastern District of Pennsylvania. Eddystone Rail alleges that the defendants transferred valuable assets from Eddystone Rail's counterparty in a maritime contract, so as to avoid outstanding obligations to Eddystone Rail. Eddystone Rail is seeking payment of compensatory and punitive damages in excess of US\$140 million. Eddystone Rail's chances of success in connection with the above noted action cannot be predicted and it is possible that Eddystone Rail may not recover any of the amounts sought. On July 19, 2017, the defendants' motions to dismiss Eddystone Rail's claims were denied. Defendants have filed Answers and Counterclaims, which together with subsequent amendments, seek damages from Eddystone Rail in excess of US\$32 million. Eddystone filed a motion to dismiss the counterclaims and defendants amended their Answer and Counterclaims on September 21, 2017. On October 12, 2017 Eddystone Rail moved to dismiss the latest version of defendants' counterclaims. The defendants' chances of success on their counterclaims cannot be predicted at this time.

Dakota Access Pipeline

As noted previously under *United States Sponsored Vehicle Strategy - Finalization of Bakken Pipeline System Joint Funding Agreement*, our investment in the Bakken Pipeline System is inclusive of the Dakota Access Pipeline. In February 2017, the Standing Rock Sioux Tribe and the Cheyenne River Sioux Tribe (the Tribes) filed motions with the United States District Court for the District of Columbia (the Court) contesting the validity of the process used by the United States Army Corps of Engineers (Army Corps) to permit the Dakota Access Pipeline. The plaintiffs requested the Court order the operator to shut down the pipeline until the appropriate regulatory process is completed.

On June 14, 2017, the Court ruled that the Army Corps did not sufficiently weigh the degree to which the project's effects would be highly controversial, and the Army Corps failed to adequately consider the impact of an oil spill on the hunting and fishing rights of the Tribes and on environmental justice. The Court ordered the Army Corps to reconsider those components of its environmental analysis. On October 11, 2017, the Court issued an order that allows the Dakota Access Pipeline to continue operating while the Army Corps completes the additional environmental review required by the Court's June 14, 2017 order and the Court ordered the Dakota Access Pipeline to implement certain interim measures pending the Army Corps' supplemental analysis.

Lakehead System Lines 6A and Line 6B Crude Oil Release

On July 26, 2010, a release of crude oil on Line 6B of EEP's Lakehead System was reported near Marshall, Michigan. Further, on September 9, 2010, a release of crude oil from Line 6A of EEP's Lakehead System was reported in an industrial area of Romeoville, Illinois.

As at December 31, 2017, EEP's cumulative cost estimate for the Line 6B crude oil release remains at US\$1.2 billion (\$195 million after-tax attributable to us) including those costs that were considered probable and that could be reasonably estimated at December 31, 2017. As at December 31, 2017, EEP's remaining estimated liability is approximately US\$62 million.

Insurance Recoveries

EEP is included in the comprehensive insurance program that is maintained by us for our subsidiaries and affiliates. As at December 31, 2017, EEP has recorded total insurance recoveries of US\$547 million (\$80 million after-tax attributable to us) for the Line 6B crude oil release out of the US\$650 million applicable limit. Of the remaining US\$103 million coverage limit, US\$85 million was the subject matter of a lawsuit against one particular insurer. In March 2015, we reached an agreement with that insurer to submit the US\$85 million claim to binding arbitration. On May 2, 2017, the arbitration panel issued a decision that was not favorable to us. As a result, EEP will not receive any additional insurance recoveries in connection with the Line 6B crude oil release.

Legal and Regulatory Proceedings

A number of United States governmental agencies and regulators initiated investigations into the Line 6B crude oil release. As at December 31, 2017, there are no claims pending against us, EEP or their affiliates in United States state courts in connection with the Line 6B crude oil release.

We have accrued a provision for future legal costs and probable losses associated with the Line 6B crude oil release as described above.

Line 6B Fines and Penalties

As at December 31, 2017, EEP's total estimated costs related to the Line 6B crude oil release include US\$69 million in previously paid fines and penalties, which includes fines and penalties paid to the DOJ as discussed below.

Consent Decree

On May 23, 2017, the United States District Court for the Western District of Michigan, Southern Division, approved EEP's signed settlement agreement with the United States Environmental Protection Agency and the DOJ regarding the Lines 6A and 6B crude oil releases (the Consent Decree). On June 15, 2017, we made a total payment of US\$68 million as required by the Consent Decree, which reflects US\$61 million for the civil penalty for the Line 6B release, US\$1 million for the Line 6A release, and US\$6 million for past removal costs and interest.

Seaway Pipeline Regulatory Matters

Seaway Crude Pipeline System (Seaway Pipeline) filed an application for market-based rates in December 2011 and refiled in December 2014. Several parties filed comments in opposition alleging that the application should be denied because Seaway Pipeline has market power in both its receipt and destination markets. On December 1, 2016, the Administrative Law Judge issued its decision which concluded that the Commission should grant the application of Seaway Pipeline for authority to charge market-based rates. The parties filed briefs during the first quarter of 2017 to defend the Administrative Law Judge's decision and to respond to criticisms of that decision. The Commissioners will now review the entire record and issue a decision. There is no timeline for the FERC to act and issue a decision.

GAS TRANSMISSION AND MIDSTREAM

Aux Sable Environmental Protection Agency Matter

On October 14, 2016, an amended claim was filed against Aux Sable by a counterparty to a NGL supply agreement. On January 5, 2017, Aux Sable filed a Statement of Defence with respect to this claim. While the final outcome of this action cannot be predicted with certainty, at this time management believes that the ultimate resolution of this action will not have a material impact on our consolidated financial position or results of operations.

Sabal Trail FERC Certificate Review

Sierra Club and two other non-governmental organizations filed a Petition for Review of Sabal Trail's FERC certificate on September 20, 2016 in the D.C. Circuit Court of Appeals. On August 22, 2017, the D.C. Circuit issued an opinion denying one of the petitions, and granting the other petition in part, vacating the certificates, and remanding the case to FERC to supplement the environmental impact statement for the project to estimate the quantity of green-house gases to be released into the environment by the gas-fired generation plants in Florida that will consume the gas transported by Sabal Trail. The court withheld issuance of the mandate requiring vacatur of the certificate until seven days after the disposition of any timely petition for rehearing. On October 6, 2017, Sabal Trail and FERC each filed timely petitions for rehearing. On January 31, 2018, the court denied FERC's and Sabal Trail's petitions for rehearing. Absent a stay, the court's mandate could have issued on February 7, 2018. However, on February 2, 2018, Sabal Trail filed with FERC a request for expedited issuance of its order on remand or, alternatively, temporary emergency certificates to permit continued operation of the pipeline absent a stay of the court's mandate. On February 5, 2018, FERC issued its final supplemental environmental impact statement in compliance with the D.C. Circuit decision. In addition, on February 6, 2018, FERC filed a motion with the court requesting a 45-day stay of the mandate, and stated in its motion that it intends to issue the order on remand within 45 days. Sabal Trail filed a motion with the court requesting a 90-day stay of the mandate. The February 6, 2018 motions automatically stay the issuance of the court's mandate until the later of seven days after the court denies the motions or the expiration of any stay granted by the court. Both motions are pending.

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.

OTHER LITIGATION

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

CRITICAL ACCOUNTING ESTIMATES

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

Business Combinations

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

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

On February 27, 2017, we acquired Spectra Energy for a purchase price of \$37.5 billion. In determining the valuation of tangible assets acquired, we applied the cost, market and income approaches. For intangible assets acquired, we used an income approach which included cash flow projections based on historical performance, terms found in contracts and assumptions on expected renewals. Discount rates used in the valuation were also developed using a weighted-average cost of capital based on risks specific to respective assets and returns that an investor would likely require given the expected cash flows, timing and risk.

Goodwill Impairment

We assess our goodwill for impairment at least annually unless events or changes in circumstances indicate that it is more likely than not that the fair value of a reporting unit is below its carrying value. For the purposes of impairment testing, reporting units are identified as business operations within an operating segment. We have the option to first assess qualitative factors to determine whether it is necessary to perform the quantitative goodwill impairment test. If the quantitative goodwill impairment test is performed, we determine the fair value of our reporting units inclusive of goodwill and compare those values to the carrying value of each reporting unit. If the carrying value of a reporting unit, including allocated goodwill, exceeds its fair value, goodwill impairment is measured at the amount by which the reporting unit's carrying value exceeds its fair value.

We also apply significant judgement when identifying the composition of disposal groups and determining which disposal groups meet the definition of a business. If the composition of disposal groups were to change as a result of a change in our marketing plans or a new agreement with a buyer, this could create a difference in the amount of goodwill allocated to assets held for sale. During 2017, we impaired \$102 million of goodwill allocated to assets held for sale.

For the year ended December 31, 2017, we elected to perform a qualitative assessment to test the goodwill acquired from the acquisition of Spectra Energy for impairment. We assessed macroeconomic conditions, industry and market considerations, cost factors and overall financial performance to determine whether it is more likely than not that the fair value of each of our reporting units is less than its carrying amount. Other than as discussed above, our goodwill impairment analysis performed as at December 31, 2017, did not result in an impairment charge.

Effective in the quarter ended December 31, 2017, we have elected to move the annual review of the goodwill balance from October 1 to April 1 to better align with the preparation and review of our business plan, which is used in the test. The change does not delay, accelerate or avoid an impairment charge.

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.

We are in the process of selling certain midstream assets within our gas transmission and midstream segment. Given the state of the divestiture plan for these assets, as at December 31, 2017, we classified them as held for sale and measured them at the lower of their carrying value and fair value less costs to sell, which resulted in a loss of \$4.4 billion (\$2.8 billion after-tax). We determined the fair value of these assets held for sale using present value techniques which required us to make projections and assumptions regarding future cash flows, discount rates, inflation rates and growth rates, which were impacted by prolonged decline in commodity prices and deteriorating business performance. These projections and assumptions are subject to uncertainty and could be negatively impacted by changes in market conditions, asset performance, legal environment, and other factors.

Regulatory Accounting

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

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

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

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, 2017 and 2016, our regulatory assets totaled \$3,477 million and \$1,865 million, respectively, and significant regulatory liabilities totaled \$2,366 million and \$844 million, respectively.

Depreciation

Depreciation of property, plant and equipment, our largest asset with a net book value at December 31, 2017 and 2016, of \$90,711 million and \$64,284 million, respectively, is charged in accordance with two primary methods. For distinct assets, depreciation is generally provided on a straight-line basis over the estimated useful lives of the assets commencing when the asset is placed in service. For largely homogeneous groups of assets with comparable useful lives, the pool method of accounting is followed whereby similar assets are grouped and depreciated as a pool. When group assets are retired or otherwise disposed of, gains and losses are not reflected in earnings but are booked as an adjustment to accumulated depreciation.

When it is determined that the estimated service life of an asset no longer reflects the expected remaining period of benefit, prospective changes are made to the estimated service life. Estimates of useful lives are based on third party engineering studies, experience and/or industry practice. There are a number of assumptions inherent in estimating the service lives of our assets including the level of development, exploration, drilling, reserves and production of crude oil and natural gas in the supply areas served by our pipelines as well as the demand for crude oil and natural gas and the integrity of our systems. Changes in these assumptions could result in adjustments to the estimated service lives, which could result in material changes to depreciation expense in future periods in any of our business segments. For certain rate-regulated operations, depreciation rates are approved by the regulator and the regulator may require periodic studies or technical updates on useful lives which may change depreciation rates.

Postretirement Benefits

We maintain pension plans, which provide defined benefit and/or defined contribution pension benefits and other postretirement benefits (OPEB) to eligible retirees. Pension costs and obligations for the defined benefit pension plans are determined using actuarial methods and are funded through contributions determined using the projected benefit method, which incorporates management's best estimates of future salary level, other cost escalations, retirement ages of employees and other actuarial factors including discount rates and mortality. We determine discount rates by reference to rates of high-quality long-term corporate bonds with maturities that approximate the timing of future payments we anticipate making under each of the respective plans. These assumptions are reviewed annually by our actuaries. Actual results that differ from assumptions are amortized over future periods and therefore could materially affect the expense recognized and the recorded obligation in future periods. The actual return on plan assets exceeded the expectation by \$174 million and \$19 million for the years ended December 31, 2017 and 2016, respectively, as disclosed in Part II. Item 8. *Financial Statements and Supplementary Data - Note 25 Pension and Other Postretirement Benefits*. The difference between the actual and expected return on plan assets is amortized over the remaining service period of the active employees.

The following sensitivity analysis identifies the impact on the December 31, 2017 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	255	26	71	3
Decrease in expected return on assets	—	12	—	5
Decrease in rate of salary increase	(56)	(13)	(9)	(2)
OPEB				
Decrease in discount rate	27	1	18	(1)
Decrease in expected return on assets	—	—	—	1

Contingent Liabilities

Provisions for claims filed against us are determined on a case-by-case basis. Case estimates are reviewed on a regular basis and are updated as new information is received. The process of evaluating claims involves the use of estimates and a high degree of management judgment. Claims outstanding, the final determination of which could have a material impact on our financial results and certain subsidiaries and investments are detailed in Part II. Item 8. *Financial Statements and Supplementary Data - Note 28 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

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 present value the expected future cash flows range from 2.5% to 11.0% and 1.7% to 11.0% for the years ended December 31, 2017 and 2016, respectively. ARO is added to the carrying value of the associated asset and depreciated over the asset's useful life. The corresponding liability is accreted over time through charges to earnings and is reduced by actual costs of decommissioning and reclamation. Our estimates of retirement costs could change as a result of changes in cost estimates and regulatory requirements. Currently, for the majority of our assets, there is insufficient data or information to reasonably determine the timing of settlement for estimating the fair value of the ARO. In these cases, the ARO cost is considered indeterminate for accounting purposes, as there is no data or information that can be derived from past practice, industry practice or the estimated economic life of the asset.

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

CHANGES IN ACCOUNTING POLICIES

Goodwill

We previously performed our annual goodwill impairment test on October 1 of each fiscal year. Beginning with the quarter ended December 31, 2017, we moved the annual goodwill impairment test from October 1 to April 1 to better align with the preparation and review of our business plan, which is used in the test. The change does not delay, accelerate or avoid an impairment charge.

ADOPTION OF NEW STANDARDS

Simplifying the Measurement of Goodwill Impairment

Effective January 1, 2017, we early adopted Accounting Standards Update (ASU) 2017-04 and applied the standard on a prospective basis. Under the new guidance, goodwill impairment will now be the amount by which a reporting unit's carrying value exceeds its fair value; this amount should not exceed the carrying amount of goodwill. We applied this standard as at December 31, 2017 in the measurement of the goodwill impairment relating to the gas midstream reporting unit.

Clarifying the Definition of a Business in an Acquisition

Effective January 1, 2017, we early adopted ASU 2017-01 on a prospective basis. The new standard was issued with the objective of adding guidance to assist entities with evaluating whether transactions should be accounted for as acquisitions (disposals) of assets or businesses. This accounting update was applied to acquisitions and dispositions that occurred in the year.

Accounting for Intra-Entity Asset Transfers

Effective January 1, 2017, we early adopted ASU 2016-16 on a modified retrospective basis. The new standard was issued with the intent of improving the accounting for the income tax consequences of intra-entity asset transfers other than inventory. Under the new guidance, an entity should recognize the income tax consequences of an intra-entity transfer of an asset, other than inventory, when the transfer occurs. The adoption of the pronouncement did not have a material impact on our consolidated financial statements.

Improvements to Employee Share-Based Payment Accounting

Effective January 1, 2017, we adopted ASU 2016-09 and applied certain amendments on a modified retrospective basis with the remaining amendments applied on a prospective basis. The new standard was issued with the intent of simplifying and improving several aspects of accounting for share-based payment transactions including the income tax consequences, classification of awards as either equity or liabilities, and classification on the statement of cash flows. The adoption of the pronouncement did not have a material impact on our consolidated financial statements.

Simplifying the Embedded Derivatives Analysis for Debt Instruments

Effective January 1, 2017, we adopted ASU 2016-06 on a modified retrospective basis. The new guidance simplifies the embedded derivative analysis for debt instruments containing contingent call or put options. The adoption of the pronouncement did not have a material impact on our consolidated financial statements.

FUTURE ACCOUNTING POLICY CHANGES

Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income

ASU 2018-02 was issued in February 2018 to address a specific consequence of the TCJA. This accounting update allows a reclassification from accumulated other comprehensive income to retained earnings for stranded tax effects resulting from TCJA. The amendments eliminate the stranded tax effects that were created as a result of the reduction of historical U.S. federal corporate income tax rate to the newly enacted U.S. federal corporate income tax rate. The accounting update is effective January 1, 2019, with early adoption permitted, and is to be applied either in the period of adoption or retrospectively to each period in which the effect of the change in the U.S. federal corporate income tax rate in the TCJA is recognized. We are currently assessing the impact of the new standard on the consolidated financial statements.

Improvements to Accounting for Hedging Activities

ASU 2017-12 was issued in August 2017 with the objective of better aligning a company's risk management activities and the resulting hedge accounting reflected in the financial statements. The accounting update allows cash flow hedging of contractually specified components in financial and non-financial items. Under the new guidance, hedge ineffectiveness is no longer required to be measured and hedging instruments' fair value changes will be recorded in the same income statement line as the hedged item. The ASU also allows the initial quantitative hedge effectiveness assessment to be performed at any time before the end of the quarter in which the hedge is designated. After initial quantitative testing is performed, an ongoing qualitative effectiveness assessment is permitted. The accounting update is effective January 1, 2019 and is to be applied on a modified retrospective basis. We are currently assessing the impact of the new standard on our consolidated financial statements.

Clarifying Guidance on the Application of Modification Accounting on Stock Compensation

ASU 2017-09 was issued in May 2017 with the intent to clarify the scope of modification accounting and when it should be applied to a change to the terms or conditions of a share based payment award. Under the new guidance, modification accounting is required for all changes to share based payment awards, unless all of the following are met: 1) there is no change to the fair value of the award, 2) the vesting conditions have not changed, and 3) the classification of the award as an equity instrument or a debt instrument has not changed. The accounting update is effective January 1, 2018 and will be applied on a prospective basis. We do not expect the adoption of this accounting update to have a material impact on our consolidated financial statements.

Amending the Amortization Period for Certain Callable Debt Securities Purchased at a Premium

ASU 2017-08 was issued in March 2017 with the intent of shortening the amortization period to the earliest call date for certain callable debt securities held at a premium. The accounting update is effective January 1, 2019 and will be applied on a modified retrospective basis. We are currently assessing the impact of the new standard on our consolidated financial statements.

Improving the Presentation of Net Periodic Benefit Cost related to Defined Benefit Plans

ASU 2017-07 was issued in March 2017 primarily to improve the income statement presentation of the components of net periodic pension cost and net periodic postretirement benefit cost for an entity's sponsored defined benefit pension and OPEB plans. In addition, only the service cost component of net benefit cost is eligible for capitalization. The accounting update is effective January 1, 2018 and will be applied on a retrospective basis for the statement of earnings presentation component and a prospective basis for the capitalization component. We do not expect the adoption of this accounting update to have a material impact on our consolidated financial statements.

Clarifying Guidance on Derecognition and Partial Sales of Nonfinancial Assets

ASU 2017-05 was issued in February 2017 with the intent of clarifying the scope of asset derecognition guidance and accounting for partial sales of nonfinancial assets. The ASU clarifies the scope provisions of nonfinancial assets and how to allocate consideration to each distinct asset, and amends the guidance for derecognition of a distinct nonfinancial asset in partial sale transactions. The accounting update is effective January 1, 2018 and will be applied on a modified retrospective basis. We do not expect the adoption of this accounting update to have a material impact on our consolidated financial statements.

Clarifying the Presentation of Restricted Cash in the Statement of Cash Flows

ASU 2016-18 was issued in November 2016 with the intent to clarify guidance on the classification and presentation of changes in restricted cash and restricted cash equivalents within the statement of cash flows. The accounting update requires that changes in restricted cash and restricted cash equivalents be included within cash and cash equivalents when reconciling the opening and closing period amounts shown on the statement of cash flows. We currently present the changes in restricted cash and restricted cash equivalents under investing activities in the Consolidated Statement of Cash Flows. The accounting update is effective January 1, 2018 and will be applied on a retrospective basis. We will amend the presentation in the Consolidated Statement of Cash Flows to include restricted cash and restricted cash equivalents with cash and cash equivalents and we will retrospectively reclassify all periods presented.

Simplifying Cash Flow Classification

ASU 2016-15 was issued in August 2016 with the intent of reducing diversity in practice of how certain cash receipts and cash payments are classified in the Consolidated Statement of Cash Flows. The new guidance addresses eight specific presentation issues. The accounting update is effective January 1, 2018 and will be applied on a retrospective basis. We assessed each of the eight specific presentation issues and the adoption of this ASU does not have a material impact on our consolidated financial statements.

Accounting for Credit Losses

ASU 2016-13 was issued in June 2016 with the intent of providing financial statement users with more useful information about the expected credit losses on financial instruments and other commitments to extend credit held by a reporting entity at each reporting date. Current treatment uses the incurred loss methodology for recognizing credit losses that delays the recognition until it is probable a loss has been incurred. The accounting update adds a new impairment model, known as the current expected credit loss model, which is based on expected losses rather than incurred losses. Under the new guidance, an entity recognizes as an allowance its estimate of expected credit losses, which the Financial Accounting Standards Board believes will result in more timely recognition of such losses. We are currently assessing the impact of the new standard on our consolidated financial statements. The accounting update is effective January 1, 2020.

Recognition of Leases

ASU 2016-02 was issued in February 2016 with the intent to increase transparency and comparability among organizations. It requires lessees of operating lease arrangements to recognize lease assets and lease liabilities on the statement of financial position and disclose additional key information about lease agreements. The accounting update also replaces the current definition of a lease and requires that an arrangement be recognized as a lease when a customer has the right to obtain substantially all of the economic benefits from the use of an asset, as well as the right to direct the use of the asset. We are currently gathering a complete inventory of our lease contracts in order to assess the impact of the new standard on our consolidated financial statements. The accounting update is effective January 1, 2019 and will be applied using a modified retrospective approach.

Recognition and Measurement of Financial Assets and Liabilities

ASU 2016-01 was issued in January 2016 with the intent to address certain aspects of recognition, measurement, presentation and disclosure of financial assets and liabilities. Investments in equity securities, excluding equity method and consolidated investments, are no longer classified as trading or available-for-sale securities. All investments in equity securities with readily determinable fair values are classified as investments at fair value through net income. Investments in equity securities without readily determinable fair values are measured using the fair value measurement alternative and are recorded at cost minus impairment, if any, plus or minus changes resulting from observable price changes in orderly transactions for an identical or similar investment of the same issuer. Investments in equity securities measured using the fair value measurement alternative are reviewed for indicators of impairment each reporting period. Fair value of financial instruments for disclosure purposes is measured using exit price. The accounting update is effective January 1, 2018 and applied on a prospective basis. We do not expect the adoption of this accounting update to have a material impact on our consolidated financial statements.

Revenue from Contracts with Customers

ASU 2014-09 was issued in 2014 with the intent of significantly enhancing consistency and comparability of revenue recognition practices across entities and industries. The new standard establishes a single, principles-based five-step model to be applied to all contracts with customers and introduces new and enhanced disclosure requirements. It also requires the use of more estimates and judgments than the present standards in addition to additional disclosures. The new standard is effective January 1, 2018. The new standard permits either a full retrospective method of adoption with restatement of all prior periods presented, or a modified retrospective method with the cumulative effect of applying the new standard recognized as an adjustment to opening retained earnings in the period of adoption. We have decided to adopt the new standard using the modified retrospective method.

We have reviewed our revenue contracts in order to evaluate the effect of the new standard on our revenue recognition practices. Based on our assessment to-date, the adoption of the new standard will have the following impact to our financial statements:

- A change in presentation in the Gas Distribution business related to payments to customers under the earnings sharing mechanism which are currently shown as an expense in the Consolidated Statements of Earnings. Under the new standard, these payments will be reflected as a reduction of revenue.
- Estimates of variable consideration, required under the new standard for certain Liquids Pipelines, Gas Transmission and Midstream and Green Power and Transmission revenue contracts as well as the allocation of the transaction price for certain Liquids Pipelines revenue contracts, may result in changes to the pattern or timing of revenue recognition for those contracts.
- Non-cash consideration received in the form of a percentage of the products derived from processing natural gas in the Gas Transmission and Midstream business was previously accounted for as revenue when the commodity was sold to third parties. Under the new standard, the non-cash consideration will be accounted for as revenue when processing services are performed. The commodity will continue to be accounted for as revenue when it is subsequently sold to third parties. The impact of this change will be an increase in costs and revenues due to the recognition of this non-cash consideration.
- Service fee revenue, from processing natural gas for certain contracts in the Gas Transmission and Midstream business whereby Enbridge purchases natural gas at the wellhead, then processes and subsequently sells the gas, was previously presented as revenue. Under the new standard, processing fees charged on natural gas purchased by Enbridge are presented as a reduction of commodity costs upon the transfer of control of the natural gas at the wellhead.

- Revenue from certain contracts in the Gas Transmission and Midstream business that provide for Enbridge to process and sell customers' natural gas and retain a percentage of the resulting processed natural gas and/or NGLs as payment for processing services rendered, commonly referred to as Percentage of Proceeds and Percentage of Liquids contracts, was previously presented on a gross basis whereby Enbridge recorded one hundred percent of the value of the natural gas and products sold as revenue, with the cost of the natural gas purchased recorded as commodity cost. Under the new standard only Enbridge's share of the products retained and sold is presented as revenue and no commodity cost is recorded.
- Certain payments received from customers to offset the cost of constructing assets required to provide services to those customers, referred to as Contributions in Aid of Construction (CIAC) were previously recorded as reductions of property, plant and equipment regardless of whether the amounts were imposed by regulation or negotiated. Under the new standard, negotiated CIACs are deemed to be advance payments for services and must be recognized as revenue when those future services are provided. Negotiated CIACs will be accounted for as deferred revenue and recognized over the term of the associated revenue contract.

Upon adoption, we will recognize the significant cumulative effect of initially applying the new standard as an increase in the opening balance of retained deficit of approximately \$120 million, an increase in property, plant and equipment of \$130 million and an increase in deferred revenue of \$120 million, subject to final determination, as at January 1, 2018. The adoption of the new standard will also result in changes in classification between Revenue and Commodity costs as discussed above.

We have also developed and tested processes to generate the disclosures which will be required under the new standard commencing in the first quarter of 2018.