ENBRIDGE INC
Form 10-K
February 16, 2018

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

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x ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2017
or
o TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from to
Commission file number 1-10934

ENBRIDGE INC.
(Exact Name of Registrant as Specified in Its Charter)

Canada	None
(State or Other Jurisdiction of Incorporation or Organization)	(I.R.S. Employer Identification No.)

200, 425 - 1st Street S.W.
Calgary, Alberta, Canada T2P 3L8
(Address of Principal Executive Offices) (Zip Code)
Registrant's telephone number, including area code (403) 231-3900

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Shares	New York Stock Exchange

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.Yes x No o
Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.Yes o No x
Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.Yes x No o
Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).Yes x No o
Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405) is not contained herein, and will not be contained, to the best of the registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. x

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of “large accelerated filer,” “accelerated filer”, “smaller reporting company” and "emerging growth company" in Rule 12b-2 of the Exchange Act. (Check one):

Large Accelerated Filer x	Accelerated Filer o
Non-Accelerated Filer o (Do not check if a smaller reporting company)	Smaller reporting company o
Emerging growth company o	

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).Yes o No x

The aggregate market value of the registrant’s common shares held by non-affiliates computed by reference to the price at which the common equity was last sold on June 30, 2017, was approximately US$65,416,118,124.

As at February 9, 2018, the registrant had 1,695,190,292 common shares outstanding.

DOCUMENTS INCORPORATED BY REFERENCE:

Portions of the proxy statement for the 2018 Annual Meeting of Shareholders are incorporated by reference in Part III.

GLOSSARY

AOCI	Accumulated other comprehensive income/(loss)
ARO	Asset retirement obligations
ASU	Accounting Standards Update
BC	British Columbia
bcf/d	Billion cubic feet per day
bpd	Barrels per day
Canadian L3R Program	Canadian portion of the Line 3 Replacement Program
Canadian Restructuring Plan	Transfer of Enbridge's Canadian Liquids Pipelines business, held by EPI and Enbridge Pipelines (Athabasca) Inc., and certain Canadian renewable energy assets to the Fund Group, which was effective on September 1, 2015
CTS	Competitive Toll Settlement
Dawn	Dawn Hub
DCP Midstream	DCP Midstream, LLC
Duke Energy	Duke Energy Corporation
EaR	Earnings-at-Risk
EBITDA	Earnings before interest, income taxes and depreciation and amortization
ECT	Enbridge Commercial Trust
EEP	Enbridge Energy Partners, L.P.
EGD	Enbridge Gas Distribution Inc.
EIPLP	Enbridge Income Partners LP
EIS	Environmental Impact Statement
Enbridge	Enbridge Inc.
ENF	Enbridge Income Fund Holdings Inc.
EPI	Enbridge Pipelines Inc.
EUB	New Brunswick Energy and Utilities Board
FERC	Federal Energy Regulatory Commission
Flanagan South	Flanagan South Pipeline
GHG	Greenhouse gas
HLBV	Hypothetical Liquidation at Book Value
IDR	Incentive Distribution Rights
IJT	International Joint Tariff
IR Plan	EGD's Incentive Rate Plan
ISO	Incentive Stock Options
L3R Program	Line 3 Replacement Program
Lakehead System	Lakehead Pipeline System
LIBOR	London Interbank Offered Rate
LMCI	Land Matters Consultation Initiative
LNG	Liquefied natural gas

MD&A	Management’s Discussion and Analysis
MEP	Midcoast Energy Partners, L.P.
Merger Transaction	Combination of Enbridge and Spectra Energy through a stock-for-stock merger transaction which closed on February 27, 2017
MNPUC	Minnesota Public Utilities Commission

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MW	Megawatts
NEB	National Energy Board
NGL	Natural gas liquids
Noverco	Noverco Inc.
NYSE	New York Stock Exchange
OCI	Other comprehensive income/(loss)
OEB	Ontario Energy Board
OPEB	Other postretirement benefit obligations
OPEC	Organization of Petroleum Exporting Countries
PennEast	PennEast Pipeline Company LLC
ROE	Return on equity
RSU	Restricted Stock Units
Sabal Trail	Sabal Trail Transmission, LLC
Sandpiper	Sandpiper Project
Seaway Pipeline	Seaway Crude Pipeline System
Secondary Offering	ENF's secondary offering of 17,347,750 ENF common shares to the public on April 18, 2017
SEP	Spectra Energy Partners, LP
Spectra Energy	Spectra Energy Corp
TCJA	the “Tax Cuts and Jobs Act”
Texas Eastern	Texas Eastern Transmission, L.P.
the Court	United States District Court for the District of Columbia
the Fund	Enbridge Income Fund
the Fund Group	The Fund, ECT, EIPLP and the subsidiaries and investees of EIPLP
TSX	Toronto Stock Exchange
the Tupper Plants	Tupper Main and Tupper West gas plants
Union Gas	Union Gas Limited
U.S. GAAP	Generally accepted accounting principles in the United States of America
U.S. L3R Program	United States portion of the Line 3 Replacement Program
Vector	Vector Pipeline L.P.
VIE	Variable interest entities
WCSB	Western Canadian Sedimentary Basin

CONVENTIONS

The terms "we", "our", "us" and "Enbridge" as used in this report refer collectively to Enbridge Inc. unless the context suggests otherwise. These terms are used for convenience only and are not intended as a precise description of any separate legal entity within Enbridge.

Unless otherwise specified, all dollar amounts are expressed in Canadian dollars, all references to “dollars”, “$” or “C$” are to Canadian dollars and all references to “US$” are to United States dollars. All amounts are provided on a before tax basis, unless otherwise stated.

FORWARD-LOOKING INFORMATION

Forward-looking information, or forward-looking statements, have been included in this annual report on Form 10-K 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 annual report on Form 10-K 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 annual report on Form 10-K 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.

PART I
ITEM 1. BUSINESS

Enbridge is a North American energy infrastructure company with strategic business platforms that include an extensive network of crude oil, liquids and natural gas pipelines, regulated natural gas distribution utilities and renewable power generation assets. We deliver an average of 2.8 million barrels of crude oil each day through our Mainline and Express Pipeline, and account for approximately 65% of United States-bound Canadian crude oil exports. We also move approximately 20% of all natural gas consumed in the United States, serving key supply basins and demand markets. Our regulated utilities serve approximately 3.7 million retail customers in Ontario, Quebec and New Brunswick. We also have interests in more than 2,500 megawatts (MW) of net renewable power generation capacity in North America and Europe. We have ranked on the Global 100 Most Sustainable Corporations index for the past eight years. Our common shares trade on the Toronto Stock Exchange (TSX) and the New York Stock Exchange (NYSE) under the symbol ENB. We were incorporated on April 13, 1970 under the Companies Ordinance of the Northwest Territories and were continued under the Canada Business Corporations Act on December 15, 1987.

On February 27, 2017, we announced the closing of the combination of Enbridge and Spectra Energy Corp. (Spectra Energy) through a stock-for-stock merger transaction (the Merger Transaction).

Spectra Energy, now wholly-owned by Enbridge, 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. The 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 below under Business Segments.

CORPORATE VISION AND STRATEGY

VISION
Our vision is to be the leading energy delivery company in North America. In pursuing this vision, we play a critical role in enabling the economic well-being and quality of life of North Americans, who depend on access to plentiful energy. We transport, distribute and generate energy, and our primary purpose is to deliver the energy North Americans need, in the safest, most reliable and most efficient way possible.

Among our peers, we strive to be the leader, which means not only leadership in value creation for shareholders, but also leadership with respect to worker and public safety and environmental protection associated with our energy delivery infrastructure, as well as in customer service, community investment and employee satisfaction.

STRATEGY
Today, our business is balanced between oil and natural gas. The Merger Transaction combined Spectra Energy’s natural gas transmission franchise, with our liquids pipeline business. Further, the Merger Transaction doubled the size of our utility business and now delivers energy to more than 3.7 million customers. This footprint provides us with scale and diversity to compete, to grow and to provide the energy people need and want.

Our 2018-2020 Strategic Plan (the Strategic Plan) sets a course for us for the next three years. Our focus, as set out in our Strategic Plan, is on what we do best - growing our pipeline and utility assets, and selling or monetizing assets that do not fit this model. Our core assets have highly predictable cash flows, align with our low risk value proposition and are expected to create a large set of organic growth opportunities through which to expand and extend our existing assets. With a significant amount of growth capital already secured through 2020, project execution, cost management and maintaining our financial strength and flexibility remain critical to our long-term success.

To achieve our objectives, we are focused on delivering on the strategic priorities outlined below.

Commitment to Safety and Operational Reliability

Safety and operational reliability remain the foundation for the Strategic Plan. The commitment to safety and operational reliability means achieving and maintaining industry leadership in safety (process, public and personal) and ensuring the reliability and integrity of the systems we operate in order to generate, transport and deliver energy and to protect the environment.

Maximize Value of Core Businesses

We are re-positioning our asset mix to a pure regulated pipeline and utility business model focusing on our core businesses: liquids pipelines and terminals; gas transmission and storage; and natural gas distribution. Our core assets have similar characteristics:

- Strategic positioning - between key supply basins with large, growing demand markets;
- Strong commercial underpinnings - long-term contracts, established customers, strong risk-adjusted returns; and
- Organic growth opportunities - the ability to create value by extending, expanding, repurposing, reconfiguring and replacing assets already in the ground.

By focusing on our core businesses and a regulated pipeline and utility model, we believe we will continue to deliver on the low-risk, reliable value proposition that has served our shareholders well over the years.

Complete Integration and Transformation

In 2017 we made substantial progress on the integration of Spectra Energy including operations and support functions, policies, management systems and establishment of a new, streamlined and lower cost organizational structure soon after close of the transaction. Simultaneous capture of cost savings due to combination synergies remain on track and slightly ahead of plan. Execution of planned synergies in 2018 and integration activities relating to information systems and other capabilities will continue. Prior to and in conjunction with this integration, given the increasingly competitive nature of our business, we established a target of top quartile cost performance. To achieve this, in conjunction with the integration we launched several projects to transform various processes, organizational capabilities and information systems infrastructure to improve how we do business and continuously drive cost efficiencies. Integration, these transformation projects, and our focus on cost leadership represent key priorities through the planning horizon.

Execute Capital Program

Our objective is to safely deliver projects on time and on budget and at the lowest practical cost while maintaining the highest standards for safety, quality, customer satisfaction and environmental and regulatory compliance. Project execution is integral to our near-term financial performance and balance sheet strength, but also to positioning the business for the long-term. Over the next three years, we plan to spend $22 billion on previously secured organic growth opportunities within our core businesses. Our secured capital program includes projects such as the Line 3 Replacement Program (L3R Program), NEXUS, Valley Crossing and the Hohe See Offshore Wind Project.

Through our major projects group, we continue to build upon and enhance the key elements of our project management processes, including: employee and contractor safety; long-term supply chain agreements; quality design, materials and construction; extensive regulatory and public consultation; robust cost, schedule and risk controls; and efficient transition of projects to operating units. Ensuring our project execution costs remain competitive in any market environment is a priority.

Strengthen Financial Position

The maintenance of financial strength is crucial to our growth strategy. Our financing strategies are designed to ensure we have sufficient financial flexibility to meet our capital requirements. To support this objective, we develop financing plans and strategies to diversify our funding sources and maintain substantial standby bank credit capacity and access to capital markets in both Canada and the United States. For further discussion on our financing strategies, refer to Part II. Item 7. Management's Discussion and Analysis and Results of Operations - Liquidity and Capital Resources.

Our funding plan is designed to sustain strong investment grade credit ratings, which are key to cost-effectively funding future growth. We have already begun taking actions to accelerate planned deleveraging and balance sheet strengthening, including the issuance of approximately $2 billion of new common equity and $500 million in preferred equity financing in late 2017. Over the remainder of the current planning horizon (2018-2020) we plan to continue to strengthen the balance sheet while building out the balance of our secured growth program. We plan to accomplish this through issuing additional hybrid securities, issuance of common equity through our Dividend Reinvestment Program and the sale or monetization of non-core assets.

Consistent with our risk management policy, we have implemented a comprehensive long-term economic hedging program to mitigate the impact of fluctuations in interest rates, foreign exchange and commodity price on our earnings and cash flow. This economic hedging program together with ongoing management of credit exposures to customers, suppliers and counterparties helps reinforce our reliable business model, which is one of the key tenets of our investor value proposition. For further details, refer to Part II. Item 7A. Quantitative and Qualitative Disclosures About Market Risk.

We continually assess ways to generate value for shareholders, including reviewing opportunities that may lead to acquisitions, dispositions or other strategic transactions, some of which may be material. Opportunities are screened, analyzed and assessed using strict operating, strategic and financial criteria with the objective of ensuring effective deployment of capital and enduring financial strength and stability.

Secure the Longer-Term Future

A key strategic priority is the development and enhancement of strategic growth platforms from which to secure our long-term future. We expect to benefit from a diversified set of strategic growth platforms, including liquids and gas pipelines, an attractive portfolio of regulated natural gas distribution utilities and a growing offshore renewable power generation business. The strength of the combined assets and geographic footprint will generate highly transparent and predictable cash flows underpinned by high quality commercial constructs that align closely with our investor value proposition and significant ongoing organic growth potential.

MAINTAIN THE FOUNDATION

Uphold Enbridge Values

We adhere to a strong set of core values that govern how we conduct our business and pursue strategic priorities, as articulated in our value statement: “Enbridge employees demonstrate integrity, safety and respect in support of our communities, the environment and each other”. Employees are expected to uphold these values in their interactions with each other, customers, suppliers, landowners, community members and all others with whom we deal and ensure our business decisions are consistent with these values. Employees and contractors are required, on an annual basis, to certify their compliance with our Statement on Business Conduct.

Maintain Our License to Operate
Earning and sustaining the trust of our stakeholders is critical to our ability to execute on our growth plans and ensure that our business strategy, as well as our corporate policies and management systems, are continuously informed by the social and environmental context surrounding our projects and operations. A key priority is to establish and maintain constructive relationships with local stakeholders over the life-cycle of our assets. The linear nature of our energy infrastructure puts us in contact with a large number of diverse communities, landowners and regulatory bodies across North America. Because Indigenous communities have distinct rights, we have dedicated resources focused on Indigenous consultation and inclusion. Early identification of local concerns enables us to respond quickly and take a proactive approach to problem solving. Early engagement also enables us to provide expanded opportunities for socio-economic participation through employment, training, and procurement, as well as through the development of joint initiatives on safety, environmental and cultural protection. More broadly, our goal is to build awareness and balanced dialogue on the role and value of the energy we deliver to our society and economy. We communicate with different stakeholders, decision makers, customers and other interested groups - including investors, employees and the public - about the access we provide to safe, reliable, affordable energy.

We provide annual progress updates related to the above initiatives in our annual CSR Report which can be found at http://csr.enbridge.com. Unless otherwise specifically stated, none of the information contained on, or connected to, the Enbridge website is incorporated by reference in, or otherwise part of, this Annual Report on Form 10-K.

Attract, Retain and Develop Highly Capable People
Investing in the attraction, retention and development of employees and future leaders is fundamental to executing our growth strategy and creating sustainability for future success. We focus on enhancing the capability of our people to maximize the potential of our organization and undertake various activities such as offering accelerated leadership development programs, enhancing career opportunities and building change management capabilities throughout the enterprise so that projects and initiatives achieve intended benefits. Furthermore, we strive to maintain industry competitive compensation and retention programs that provide both short-term and long-term performance incentives to our employees.

BUSINESS SEGMENTS

Our activities are carried out through five business segments: Liquids Pipelines; Gas Transmission and Midstream; Gas Distribution; Green Power and Transmission; and Energy Services, as discussed below.

LIQUIDS PIPELINES

Liquids Pipelines consists of common carrier and contract pipelines that transport crude oil, natural gas liquids (NGL) and refined products and terminals in Canada and the United States, including the Canadian Mainline, Lakehead Pipeline System (Lakehead System), Regional Oil Sands System, Gulf Coast and Mid-Continent, Southern Lights Pipeline, Express-Platte System, Bakken System and other feeder pipelines.

MAINLINE SYSTEM

The mainline system is comprised of the Canadian Mainline and the Lakehead System. The Canadian Mainline is a common carrier pipeline system which transports various grades of oil and other liquid hydrocarbons within western Canada and from western Canada to the Canada/United States border near Gretna, Manitoba and Neche, North Dakota and from the United States/Canada border near Port Huron, Michigan and Sarnia, Ontario to eastern Canada and the northeastern United States. The Canadian Mainline includes six adjacent pipelines, with a combined operating capacity of approximately 2.85 million barrels per day (bpd) that connect with the Lakehead System at the Canada/United States border, as well as five pipelines that deliver crude oil and refined products into eastern Canada and the northeastern United States. It also includes certain related pipelines and infrastructure, including decommissioned and deactivated pipelines. We have operated, and frequently expanded, the Canadian Mainline since 1949. Effective September 1, 2015, the closing date of the Canadian Restructuring Plan (as defined below), we transferred the Canadian Mainline to the Fund Group (comprising Enbridge Income Fund (the Fund), Enbridge Commercial Trust, Enbridge Income Partners LP (EIPLP) and the subsidiaries of EIPLP) - refer to Part II. Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Canadian Restructuring Plan. The Lakehead System is the portion of the mainline system in the United States that continues to be managed by us through our subsidiaries, Enbridge Energy Partners, L.P. (EEP) and Enbridge Energy, Limited Partnership. It is an interstate common carrier pipeline system regulated by the Federal Energy Regulatory Commission (FERC), and is the primary transporter of crude oil and liquid petroleum from Western Canada to the United States.

Competitive Toll Settlement

The Competitive Toll Settlement (CTS) is the current framework governing tolls paid for products shipped on the Canadian Mainline, with the exception of Lines 8 and 9 which are tolled on a separate basis. The 10-year settlement was negotiated by representatives of Enbridge, the Canadian Association of Petroleum Producers and shippers on the Canadian Mainline. It was approved by the National Energy Board (NEB) on June 24, 2011 and took effect on July 1, 2011. The CTS provides for a Canadian Local Toll (CLT) for deliveries within western Canada, which is based on the 2011 Incentive Tolling Settlement toll, as well as an International Joint Tariff (IJT) for crude oil shipments originating in western Canada on the Canadian Mainline and delivered into the United States, via the Lakehead System, and into eastern Canada. These tolls are denominated in United States dollars. The IJT is designed to provide shippers on the mainline system with a stable and competitive long-term toll, thereby preserving and enhancing throughput on both the Canadian Mainline and the Lakehead System. The CLT and the IJT were both established at the time of implementation of the CTS and are adjusted annually, on July 1 of each year, at a rate equal to 75% of the Canada Gross Domestic Product at Market Price Index published by Statistics Canada. Two years prior to the end of the term of the CTS, we and the shippers will establish a group for the purposes of negotiating a new settlement to replace the CTS once it expires.

Although the CTS has a 10-year term, it does not require shippers to commit to certain volumes. Shippers nominate volumes on a monthly basis and we allocate capacity to maximize the efficiency of the Canadian Mainline.

Local tolls for service on the Lakehead System are not affected by the CTS and continue to be established pursuant to the Lakehead System’s existing toll agreements, as described below. Under the terms of the IJT agreement between us and EEP, the Canadian Mainline’s share of the IJT relating to pipeline transportation of a batch from any western Canada receipt point to the United States border is equal to the IJT applicable to that batch’s United States delivery point less the Lakehead System’s local toll to that delivery point. This amount is referred to as the Canadian Mainline IJT Residual Benchmark Toll and is denominated in United States dollars.

Lakehead System Local Tolls
Transportation rates are governed by the FERC for deliveries from the Canada/United States border near Neche, North Dakota and from Clearbrook, Minnesota to certain principal delivery points. The Lakehead System periodically adjusts these transportation rates as allowed under the FERC's index methodology and tariff agreements, the main components of which are base rates and Facilities Surcharge Mechanism. Base rates, the base portion of the transportation rates for the Lakehead System, are subject to an annual adjustment which cannot exceed established ceiling rates as approved by the FERC. The Facilities Surcharge Mechanism allows the Lakehead System to recover costs associated with certain shipper-requested projects through an incremental surcharge in addition to the existing base rates, and is subject to annual adjustment on April 1.

REGIONAL OIL SANDS SYSTEM
The Regional Oil Sands System includes four intra-Alberta long haul pipelines, the Athabasca Pipeline, Waupisoo Pipeline, Woodland Pipeline and the recently completed Wood Buffalo Extension/Athabasca Twin pipeline system as well as two large terminals: the Athabasca Terminal located north of Fort McMurray, Alberta and the Cheecham Terminal, located south of Fort McMurray. The Regional Oil Sands System also includes numerous laterals and related facilities which provide access for oil sands production to the system, and a long-haul intra-Alberta pipeline that transports diluent from the Edmonton, Alberta region into the oil sands producing regions located north and south of Fort McMurray, Alberta. The Regional Oil Sands System currently serves twelve producing oil sands projects.

The Athabasca Pipeline is a 540-kilometer (335-mile) synthetic and heavy oil pipeline. Built in 1999, it links the Athabasca oil sands in the Fort McMurray region to the major Alberta crude oil pipeline hub at Hardisty, Alberta. The Athabasca Pipeline's capacity is 570,000 bpd, depending on crude slate. We have long-term take-or-pay and non take-or-pay agreements with multiple shippers on the Athabasca Pipeline. Revenues are recorded based on the contract terms negotiated with the major shippers, rather than the cash tolls collected.

In 2017, we completed the twinning of the Athabasca Pipeline and the Wood Buffalo Extension, which were key components of our Regional Oil Sands Optimization Project. The Athabasca Pipeline Twin, completed in January 2017, twinned the southern section of the Athabasca Pipeline with a 36-inch diameter pipeline from Kirby Lake, Alberta to the major Alberta pipeline hub at Hardisty, Alberta. The initial capacity of the Athabasca Pipeline Twin is 450,000 bpd and it can be further expanded in the future to 800,000 bpd through additional pumping horsepower. In December 2017, the Wood Buffalo Extension, a 36-inch diameter pipeline between Cheecham, Alberta and Kirby Lake, Alberta, went into service. The integrated Wood Buffalo Extension and Athabasca Pipeline Twin transports diluted bitumen from multiple oil sands producers.

The Waupisoo Pipeline is a 380-kilometer (236-mile) synthetic and heavy oil pipeline that entered service in 2008 and provides access to the Edmonton market for oil sands producers. The Waupisoo Pipeline originates at the Cheecham Terminal and terminates at the major Alberta pipeline hub at Edmonton. The pipeline has a capacity of 550,000 bpd, depending on the crude slate. We have long-term take-or-pay agreements with multiple shippers on the Waupisoo Pipeline who have collectively contracted for 80% to 90% of the capacity, subject to the timing of when shippers' commitments commence and expire.

The Woodland Pipeline is a 50/50 joint venture between us and Imperial Oil Resources Ventures Limited and ExxonMobil Canada Properties that was constructed in two phases. The first phase, completed in 2013, consists of a 140-kilometer (87-mile) 36-inch diameter pipeline from the Kearl oil sands mine to the Cheecham Terminal, and service on our existing Waupisoo Pipeline from Cheecham to the Edmonton area. The second phase extended the Woodland Pipeline south from our Cheecham Terminal to our Edmonton Terminal. Completed in 2014, the extension involved the construction of a 385-kilometer (239-mile) 36-inch diameter pipeline adding 379,000 bpd of capacity to the Regional Oil Sands System. The Woodland Pipeline is anchored by long-term commitments.

The Norlite Pipeline System (Norlite) was placed into service in May 2017, offering a new diluent supply alternative to meet the needs of multiple producers in the Athabasca oil sands region. Norlite is a 24-inch-diameter pipeline, originating at Enbridge’s Stonefell Terminal, in Strathcona County near Edmonton, Alberta and terminating at Enbridge’s Fort McMurray South facility, near Fort McMurray, Alberta, with a transfer line to Suncor's East Tank Farm. The pipeline has a capacity of approximately 218,000 bpd of diluent, with the potential to be further expanded to approximately 465,000 bpd of capacity with the addition of pump stations. Under an agreement with Keyera Corp. (Keyera), Norlite has the right to access certain existing capacity on Keyera’s pipelines between Edmonton, Alberta and Stonefell, Alberta and, in exchange, Keyera has elected to participate in the new pipeline infrastructure project as a 30% non-operating owner. Norlite is anchored by long-term throughput commitments from a number of oil sands producers.

GULF COAST AND MID-CONTINENT
Gulf Coast includes Seaway and Flanagan South Pipeline (Flanagan South), Spearhead Pipeline, as well as the Mid-Continent System comprised of Cushing Terminal and the recently sold Ozark Pipeline that is managed by us through our subsidiary, EEP.

Seaway Pipeline
In 2011, we acquired a 50% interest in the 1,078-kilometer (670-mile) Seaway Crude Pipeline System (Seaway Pipeline), including the 805-kilometer (500-mile), 30-inch diameter long-haul system between Cushing, Oklahoma and Freeport, Texas, as well as the Texas City Terminal and Distribution System which serve refineries in the Houston and Texas City areas. Seaway Pipeline also includes 8.8 million barrels of crude oil storage tank capacity on the Texas Gulf Coast.

The flow direction of Seaway Pipeline was reversed in 2012, enabling it to transport crude from the oversupplied hub in Cushing, Oklahoma to the Gulf Coast. Further pump station additions and modifications were completed early 2013, increasing capacity available to shippers from an initial 150,000 bpd to up to approximately 400,000 bpd, depending on the crude slate. In late 2014, a second line, the Seaway Pipeline Twin, was placed into service to more than double the existing capacity to 850,000 bpd. Seaway Pipeline also includes a 161-kilometer (100-mile) pipeline from the Enterprise Crude Houston crude oil terminal in Houston, Texas to the Port Arthur/Beaumont, Texas refining center.

Flanagan South Pipeline
Flanagan South is a 950-kilometer (590-mile), 36-inch diameter interstate crude oil pipeline that originates at our terminal at Flanagan, Illinois and terminates in Cushing, Oklahoma. Flanagan South and associated pumping stations were completed in the fourth quarter of 2014. Flanagan South has an initial design capacity of approximately 600,000 bpd.

Spearhead Pipeline
Spearhead Pipeline is a long-haul pipeline that delivers crude oil from Flanagan, Illinois, a delivery point on the Lakehead System to Cushing, Oklahoma. The Spearhead pipeline was originally placed into service in 2006 and has an initial capacity of 193,300 bpd.

Mid-Continent System
The Mid-Continent System is comprised of the storage terminals at Cushing, Oklahoma and the recently sold Ozark Pipeline. The storage terminals consist of over 80 individual storage tanks ranging in size from 78,000 to 570,000 barrels. Total storage shell capacity of Cushing Terminal is approximately 20 million barrels. A portion of the storage facilities are used for operational purposes, while the remainder is contracted to various crude oil market participants for their term storage requirements. Contract fees include fixed monthly storage fees, throughput fees for receiving and delivering crude to and from connecting pipelines and terminals, and blending fees.

In December 2016, we entered into an agreement to sell the Ozark Pipeline to a subsidiary of MPLX LP for cash proceeds of approximately $294 million (US$220 million), including $13 million (US$10 million) in reimbursable costs for additional capital spent by us up to the closing date of the transaction. Sale of the Ozark Pipeline system closed on March 1, 2017.

SOUTHERN LIGHTS PIPELINE

Southern Lights Pipeline is a fully-contracted single stream pipeline that ships diluent from the Manhattan Terminal near Chicago, Illinois to three western Canadian delivery facilities, located at the Edmonton and Hardisty terminals in Alberta and the Kerrobert terminal in Saskatchewan. This 180,000 bpd 16/18/20-inch diameter pipeline was placed into service in 2010. Both the Canadian portion of Southern Lights Pipeline (Southern Lights Canada) and the United States portion of Southern Lights Pipeline (Southern Lights US) receive tariff revenues under long-term contracts with committed shippers. Tariffs provide for recovery of all operating and debt financing costs plus a return on equity (ROE) of 10%. Southern Lights Pipeline has assigned 10% of the capacity (18,000 bpd) for shippers to ship uncommitted volumes.

As part of the Canadian Restructuring Plan, effective September 1, 2015, we transferred all Class B units of Southern Lights Canada to the Fund Group. Following the closing of the Transaction, the Fund Group holds all the ownership, economic interests and voting rights, direct and indirect, in Southern Lights Canada. We continue to indirectly own all of the Class B Units of Southern Lights US.

EXPRESS-PLATTE SYSTEM

The Express-Platte system is comprised of both the Express pipeline and the Platte pipeline, and crude oil storage of approximately 5.6 million barrels. It is an approximate 2,736-kilometer (1,700-mile) crude oil transportation system, which begins in Hardisty, Alberta, and terminates in Wood River, Illinois. The Express pipeline carries crude oil to United States refining markets in the Rockies area, including Montana, Wyoming, Colorado and Utah. The Platte pipeline, which interconnects with the Express pipeline in Casper, Wyoming, transports crude oil predominantly from the Bakken shale and western Canada to refineries in the Midwest. Express pipeline capacity is typically committed under long-term take-or-pay contracts with shippers. A small portion of Express pipeline capacity and all of the Platte pipeline capacity is used by uncommitted shippers who pay only for the pipeline capacity they actually use in a given month.

BAKKEN SYSTEM

Our Bakken assets consist of the North Dakota System and the Bakken Pipeline System. The North Dakota System is a joint operation that includes a Canadian entity and a United States entity. The United States portion of the North Dakota System is comprised of a crude oil gathering and interstate pipeline transportation system servicing the Williston Basin in North Dakota and Montana, which includes the Bakken and Three Forks formation. The gathering pipelines collect crude oil from nearly 80 different receipt facilities located throughout western North Dakota and eastern Montana, with delivery to Clearbrook for service on the Lakehead system or a variety of interconnecting pipeline and rail export facilities. The United States interstate portion of the system extends from Berthold, North Dakota to the International Boundary near North Portal, North Dakota, and connects to the Canadian entity at the border to bring the crude oil into Cromer, Manitoba.

Tariffs on the United States portion of the North Dakota System are governed by FERC and include a local tariff. The Canadian portion is categorized as a Group 2 pipeline, and as such its tolls are regulated by the NEB on a complaint basis. Tolls are based on long-term take-or-pay agreements with anchor shippers.

In February 2017, we closed a transaction to acquire a 49% equity interest in the holding company that owns 75% of the Bakken Pipeline System from an affiliate of Energy Transfer Partners, L.P. and Sunoco Logistics Partners, L.P. The Bakken Pipeline System connects the prolific Bakken formation in North Dakota to markets in eastern PADD II and the United States Gulf Coast, providing customers with access to premium markets at a competitive cost. The

Bakken Pipeline System consists of the Dakota Access

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Pipeline and the Energy Transfer Crude Oil Pipeline projects. The Dakota Access Pipeline consists of 1,886-kilometers (1,172-miles) of 30-inch pipe from the Bakken/Three Forks production area in North Dakota to Patoka, Illinois. Initial capacity is in excess of 470,000 bpd of crude oil with the potential to be expanded to 570,000 bpd. The Energy Transfer Crude Oil Pipeline consists of 100-kilometers (62-miles) of new 30-inch diameter pipe, 1,104-kilometers (686-miles) of converted 30-inch diameter pipe, and 64-kilometers (40-miles) of converted 24-inch diameter pipe from Patoka, Illinois to Nederland, Texas. The Bakken Pipeline System is anchored by long-term throughput commitments from a number of producers.

FEEDER PIPELINES AND OTHER

Feeder Pipelines and Other includes a number of liquids storage assets and pipeline systems in Canada and the United States.

Key assets included in Feeder Pipelines and Other are the Hardisty Contract Terminal and Hardisty Storage Caverns located near Hardisty, Alberta, a key crude oil pipeline hub in western Canada and Southern Access Extension (SAX) pipeline which originates out of Flanagan, Illinois and delivers to Patoka, Illinois. On July 1, 2014, Marathon executed an agreement with Enbridge to become an owner (35%) in SAX forming the Illinois Extension Pipeline Company (IEPC). Enbridge has 65% ownership in IEPC. SAX was placed into service December 2015 with the majority of its capacity commercially secured under long-term take-or-pay contracts with shippers.

Feeder Pipelines and Other also includes Patoka Storage, the Toledo pipeline system and the NW System. Patoka Storage is comprised of 4 storage tanks with 480,000 barrels of shell capacity located in Patoka, Illinois. The Toledo pipeline system connects with the Lakehead System and delivers to Ohio and Michigan. The majority of Toledo pipeline’s capacity is commercially secured under long-term take-or-pay contracts with shippers. The NW System transports crude oil from Norman Wells in the Northwest Territories to Zama, Alberta. NW System has a cost of service rate structure based on established terms with shippers.

Feeder Pipelines and Other includes contributions from assets which were divested during 2017 and the fourth quarter of 2016, including investments in Olympic Pipeline Company (Olympic), Eddystone Rail and the South Prairie Region assets.

On October 19, 2017, we sold all assets related to our Eddystone rail facility to our partner Canopy in exchange for their 25% share of the joint venture valued at $5 million. These assets primarily included the unit-train unloading facility and related local pipeline infrastructure near Philadelphia, Pennsylvania that delivered Bakken and other light sweet crude oil to Philadelphia area refineries.

On July 31, 2017, we completed the sale of our 85% interest in Olympic, the largest refined products pipeline in the State of Washington, to an unrelated party for $0.2 billion.

On December 1, 2016, EIPLP completed the sale of the South Prairie Region assets to an unrelated party for cash proceeds of $1.08 billion. The South Prairie Region assets transport crude oil and NGL from producing fields and facilities in southeastern Saskatchewan and southwestern Manitoba to Cromer, Manitoba where products enter the mainline system to be transported to the United States or eastern Canada.

COMPETITION

Competition may result in a reduction in demand for our services, fewer project opportunities or assumption of risk that results in weaker or more volatile financial performance than expected. Competition among existing pipelines is based primarily on the cost of transportation, access to supply, the quality and reliability of service, contract carrier alternatives and proximity to markets.

Other competing carriers available to ship western Canadian liquid hydrocarbons to markets in Canada, the United States and internationally represent competition to our liquids pipelines network. Competition

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also arises from proposed pipelines that seek to access markets currently served by our liquids pipelines, such as proposed projects to the Gulf Coast and from proposed projects enhancing infrastructure in the Alberta regional oil sands market. The Mid-Continent and Bakken systems also face competition from existing competing pipelines, proposed future pipelines and existing and alternative gathering facilities. Competition for storage facilities in the United States includes large integrated oil companies and other midstream energy partnerships. Additionally, volatile crude price differentials and insufficient pipeline capacity on either our or other competitor pipelines can make transportation of crude oil by rail competitive, particularly to markets not currently serviced by pipelines.

We believe that our liquids pipelines continue to provide attractive options to producers in the Western Canadian Sedimentary Basin (WCSB) and North Dakota due to our competitive tolls and flexibility through our multiple delivery and storage points. Our current complement of growth projects to expand market access and to enhance capacity on our pipeline system combined with our commitment to project execution is expected to further provide shippers reliable and long-term competitive solutions for oil transportation. Our existing right-of-way for the mainline system also provides a competitive advantage as it can be difficult and costly to obtain rights of way for new pipelines traversing new areas. We also employ long-term agreements with shippers, which also mitigate competition risk by ensuring consistent supply to our liquids pipelines network.

SUPPLY AND DEMAND

We have an established and successful history of being the largest transporter of crude oil to the United States, the world’s largest market. While United States’ demand for Canadian crude oil production will support the use of our infrastructure for the foreseeable future, North American and global crude oil supply and demand fundamentals are shifting, and we have a role to play in this transition by developing long-term transportation options that enable the efficient flow of crude oil from supply regions to end-user markets.

The downturn in crude oil prices which began in 2014 has impacted our liquids pipelines’ customers, who responded by reducing their exploration and development spending for 2016 and 2017 in higher cost basins. However, the international market for crude oil has continued to see an increase in production from the North American shale oil producing basins and increased production from specific Organization of Petroleum Exporting Countries (OPEC). The West Texas Intermediate (WTI) crude price has been strengthening from US$30 per barrel at the beginning of 2016 as the market has fought to re-balance supply and demand. Prices began to recover in response to cuts in OPEC and non-OPEC production and have continued to recover through 2017. The WTI crude prices averaged US$51 per barrel for 2017 and ended the year above US$60 per barrel.

Notwithstanding the current price environment, our mainline system has thus far continued to be highly utilized and in fact, mainline throughput as measured at the Canada/United States border at Gretna, Manitoba saw record throughput of 2.7 million bpd in December 2017. The mainline system continues to be subject to apportionment of heavy crude oil, as nominated volumes currently exceed capacity on portions of the system. The impact of a low crude oil price environment on the financial performance of our liquids pipelines business is expected to be relatively modest given the commercial arrangements which underpin many of the pipelines that make up our liquids system and provide a significant measure of protection against volume fluctuations. In addition, our mainline system is well positioned to continue to provide safe and efficient transportation which will enable western Canadian and Bakken production to reach attractive markets in the United States and eastern Canada at a competitive cost relative to other alternatives. The fundamentals of oil sands production and low crude oil prices have caused some sponsors to reconsider the timing of their upstream oil sands development projects. However, recently updated forecasts continue to reflect long-term supply growth from the WCSB, although the projected pace of growth is slower than previous forecasts as companies continue to assess the viability of certain capital investments in the current price environment and with the ongoing uncertainty related to timing and completion of competing pipeline systems.

Over the long term, global energy consumption is expected to continue to grow, with the growth in crude oil demand primarily driven by emerging economies in regions outside the Organization for Economic Cooperation and Development (OECD), mainly India and China. While OECD countries, including Canada, the United States and western European nations, will experience population growth, the emphasis placed on energy efficiency, conservation and a shift to lower carbon fuels, such as natural gas and renewables, is expected to reduce crude oil demand over the long term. Accordingly, there is a strategic opportunity for North American producers to grow production to displace foreign imports and participate in the growing global demand outside North America.

In terms of supply, long-term global crude oil production is expected to continue to grow through 2035, with growth in supply primarily contributed by North America, Brazil and OPEC. The expected growth in North America is largely driven by production from the oil sands and the continued development of tight oil plays including the Permian, Bakken and Eagle Ford formations. Growth in supply from OPEC is primarily a result of a shift in OPEC’s strategy from ‘balancing supply’ to ‘competing for market share’ in Asia and Europe. However, political uncertainty in certain oil producing countries, including Venezuela, Libya, Nigeria and Iraq, increases risk in those regions’ supply growth forecasts and makes North America one of the most secure supply sources of crude oil. As witnessed throughout 2016 and 2017, North American supply growth can be influenced by macro-economic factors that drive down the global crude prices. Over the longer term, North American production from tight oil plays, including the Bakken, is expected to grow as technology continues to improve well productivity and efficiencies. The WCSB, in Canada, is viewed as one of the world’s largest and most secure supply sources of crude oil. However, the pace of growth in North America and level of investment in the WCSB could be tempered in future years by a number of factors including a sustained period of low crude oil prices and corresponding production decisions by OPEC, increasing environmental regulation, and prolonged approval processes for new pipelines with access to tide-water for export.

In recent years, the combination of relatively flat domestic demand, growing supply and long-lead time to build pipeline infrastructure led to a fundamental change in the North American crude oil landscape. The inability to move increasing inland supply to tide-water markets resulted in a divergence between WTI and world pricing, resulting in lower netbacks for North American producers than could otherwise be achieved if selling into global markets. The impact of price differentials has been even more pronounced for western Canadian producers as insufficient pipeline infrastructure resulted in a further discounting of Alberta crude against WTI. With a number of market access initiatives completed by the industry in recent years, including those introduced by us, the crude oil price differentials significantly narrowed in 2015, and resulted in higher netbacks for producers. The capacity from these initiatives was for the most part exhausted by the end of 2017 from growth in the Oil Sands and has resulted in crude differentials widening once more. Canadian pipeline export capacity is expected to remain essentially full, resulting in incremental production utilizing non-pipeline transportation services until such time as pipeline capacity is made available. As the supply in North America continues to grow, the growth and flexibility of pipeline infrastructure will need to keep pace with the sensitive demand and supply balance. Over the longer term, we believe pipelines will continue to be the most cost-effective means of transportation in markets where the differential between North American and global oil prices remain narrow. Utilization of rail to transport crude is expected to be substantially limited to those markets not readily accessible by pipelines.

Our role in helping to address the evolving supply and demand fundamentals and alleviating price discounts for producers and supply costs to refiners is to provide expanded pipeline capacity and sustainable connectivity to alternative markets. As discussed in Part II. Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Growth Projects - Commercially Secured Projects, in 2017, we continue to execute our growth projects plan in furtherance of this objective.

GAS TRANSMISSION & MIDSTREAM

Gas Transmission and Midstream (formerly referred to as Gas Pipelines and Processing) consists of our investments in natural gas pipelines and gathering and processing facilities in Canada and the United States, including US Gas Transmission, Canadian Gas Transmission and Midstream, Alliance Pipeline, US Midstream and other assets.

US GAS TRANSMISSION
The majority of assets that comprise US Gas Transmission were acquired through the Merger Transaction and consist of natural gas transmission and storage assets that are held primarily through Spectra Energy Partners, LP (SEP). US Gas Transmission includes indirect ownership interests in Texas Eastern, Algonquin, M&N U.S., East Tennessee Natural Gas, Gulfstream, Sabal Trail, Vector Pipeline L.P. (Vector) and certain other gas pipeline and storage assets. The US Gas Transmission business primarily provides transmission and storage of natural gas through interstate pipeline systems for customers in various regions of the midwestern, northeastern and southern United States.

As a result of the Merger Transaction, Enbridge held a 75% equity interest in SEP, a natural gas and crude oil infrastructure master limited partnership. As a result of 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, we now hold a 83% equity interest in SEP. Refer to Part II. Item 7. Management's Discussion and Analysis of Financial Conditions and Results of Operations - United States Sponsored Vehicle Strategy. SEP owns 100% of Texas Eastern Transmission, L.P. (Texas Eastern), 92% of Algonquin Gas Transmission, L.L.C. (Algonquin), 100% of East Tennessee Natural Gas, L.L.C. (East Tennessee), 100% of Saltville Gas Storage Company L.L.C. (Saltville), 100% of Ozark Gas Gathering, L.L.C. and Ozark Gas Transmission, L.L.C., 100% of Big Sandy Pipeline, L.L.C., 100% of Market Hub Partners Holding, 100% of Bobcat Gas Storage, 78% of Maritimes & Northeast Pipeline, L.L.C. (M&N U.S.), 50% of Southeast Supply Header, L.L.C., 50% of Steckman Ridge, L.P., 50% of Gulfstream Natural Gas System, L.L.C. (Gulfstream) and 50% of Sabal Trail Transmission, LLC (Sabal Trail).

The Texas Eastern natural gas transmission system extends approximately 2,735-kilometers (1,700-miles) from producing fields in the Gulf Coast region of Texas and Louisiana to Ohio, Pennsylvania, New Jersey and New York. Texas Eastern's onshore system consists of approximately 14,597-kilometers (9,070-miles) of pipeline and associated compressor stations. Texas Eastern is also connected to four affiliated storage facilities that are partially or wholly-owned by other entities within the US Gas Transmission business.

The Algonquin natural gas transmission system connects with Texas Eastern’s facilities in New Jersey and extends approximately 402-kilometers (250-miles) through New Jersey, New York, Connecticut, Rhode Island and Massachusetts where it connects to M&N U.S. The system consists of approximately 1,835-kilometers (1,140-miles) of pipeline with associated compressor stations.

M&N U.S. is an approximately 563-kilometer (350-mile) mainline interstate natural gas transmission system, including associated compressor stations, which extends from northeastern Massachusetts to the border of Canada near Baileyville, Maine. M&N U.S. is connected to the Canadian portion of the Maritimes & Northeast Pipeline system, M&N Canada (see Gas Transmission and Midstream - Canadian Gas Transmission and Midstream).

East Tennessee’s natural gas transmission system crosses Texas Eastern’s system at two locations in Tennessee and consists of two mainline systems totaling approximately 2,414-kilometers (1,500-miles) of pipeline in Tennessee, Georgia, North Carolina and Virginia, with associated compressor stations. East Tennessee has a Liquefied Natural Gas (LNG) storage facility in Tennessee and also connects to the Saltville storage facilities in Virginia.

Gulfstream is an approximately 1,199-kilometer (745-mile) interstate natural gas transmission system, with associated compressor stations, operated jointly by SEP and The Williams Companies, Inc. Gulfstream transports natural gas from Mississippi, Alabama, Louisiana and Texas, crossing the Gulf of Mexico to markets in central and southern Florida. Gulfstream is accounted for under the equity method of accounting.

Sabal Trail provides firm natural gas transportation to Florida Power & Light Company for its power generation needs and will deliver to Duke Energy Florida's natural gas plant currently under construction

in Florida. Facilities include a new 829-kilometer (515-mile) pipeline, laterals and various compressor stations. The pipeline infrastructure is located in Alabama, Georgia and Florida, and adds 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. Sabal Trail is accounted for under the equity method of accounting.

We also hold a 60% ownership interest in Vector, which is a 560-kilometer (348-mile) pipeline that transports 1.3 bcf/d of natural gas from Joliet, Illinois in the Chicago area to parts of Indiana, Michigan and Ontario.

Transmission and storage services are generally provided under firm agreements where customers reserve capacity in pipelines and storage facilities. The vast majority of these agreements provide for fixed reservation charges that are paid monthly regardless of the actual volumes transported on the pipelines or injected or withdrawn from our storage facilities, plus a small variable component that is based on volumes transported, injected or withdrawn, which is intended to recover variable costs.

Interruptible transmission and storage services are also available where customers can use capacity if it exists at the time of the request. Interruptible revenues depend on the amount of volumes transported or stored and the associated rates for this service. Storage operations also provide a variety of other value-added services including natural gas parking, loaning and balancing services to meet customers' needs.

CANADIAN GAS TRANSMISSION AND MIDSTREAM

Canadian Gas Transmission and Midstream consists of natural gas pipelines, processing plants and gathering systems, located primarily in Western Canada. Upon completion of the Merger Transaction, Canadian Gas Transmission and Midstream now includes the Western Canada Transmission & Processing businesses, which is comprised of British Columbia Pipeline & Field Services, M&N Canada and certain other midstream gas pipelines, gathering, processing and storage assets.

British Columbia Pipeline and British Columbia Field Services provide fee-based natural gas transmission and gas gathering and processing services. British Columbia Pipeline has approximately 2,816-kilometers (1,750-miles) of transmission pipeline in British Columbia and Alberta, as well as associated mainline compressor stations. The British Columbia Field Services business includes eight gas processing plants located in British Columbia, associated field compressor stations and approximately 2,253-kilometers (1,400-miles) of gathering pipelines.

M&N Canada is an approximately 885-kilometer (550-mile) interprovincial natural gas transmission mainline system which extends from Goldboro, Nova Scotia to the United States border near Baileyville, Maine. M&N Canada is connected to M&N U.S. - refer to Gas Transmission and Midstream - US Gas Transmission.

Canadian Gas Transmission and Midstream also includes the wholly-owned Tupper Main and Tupper West gas plants (the Tupper Plants) located within the Montney shale play in northeastern British Columbia, our 71% interest in the Cabin Gas Plant located 60-kilometers (37-miles) northeast of Fort Nelson, British Columbia in the Horn River Basin, as well as interests in the Pipestone and Sexsmith gathering systems. We are the operator of the Tupper Plants and the Cabin Gas Plant. We have almost 100% interest in Pipestone and varying interests (55% to 100%) in Sexsmith and its related sour gas gathering, compression and NGL handling facilities, located in the Peace River Arch region of northwest Alberta. The primary producer and operator of Pipestone holds a nominal 0.01% interest.

The majority of transportation services provided by Canadian Gas Transmission and Midstream are under firm agreements, which provide for fixed reservation charges that are paid monthly regardless of actual volumes transported on the pipeline, plus a small variable component that is based on volumes transported to recover variable costs. We also provide interruptible transmission services where customers can use capacity if it is available at the time of request. Payments under these services are based on volumes transported.

ALLIANCE PIPELINE

We have a 50% interest in the Alliance Pipeline, a 3,000-kilometer (1,864-mile) integrated, high-pressure natural gas transmission pipeline and approximately 860-kilometers (534-miles) of lateral pipelines and related infrastructure. Alliance Pipeline transports liquids-rich natural gas from northeast British Columbia, northwest Alberta and the Bakken area in North Dakota to the Alliance Chicago gas exchange hub downstream of the Aux Sable NGL extraction and fractionation plant at Channahon, Illinois. The majority of transportation services provided by Alliance pipeline are under firm agreements, which provide for fixed reservation charges that are paid monthly regardless of actual volumes transported on the pipeline. Alliance pipeline also provides interruptible transmission services where customers can use capacity if it is available at the time of request.

US MIDSTREAM

US Midstream consists of our Midcoast assets, including the Anadarko, East Texas, North Texas and Texas Express NGL systems. These assets include natural gas and NGL gathering and transportation pipeline systems, natural gas processing and treating facilities, condensate stabilizers and an NGL fractionation facility. Midcoast also has rail and liquids marketing operations. During 2017, we acquired all of the noncontrolling interests in these assets. For further information, refer to Part II. Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations - United States Sponsored Vehicle Strategy - Acquisition of Midcoast Assets and Privatization of Midcoast Energy Partners, L.P.

US Midstream also includes our 42.7% interest in Aux Sable Liquid Products LP and Aux Sable Midstream LLC, and a 50% interest in Aux Sable Canada LP (together, Aux Sable). Aux Sable Liquid Products LP owns and operates an NGL extraction and fractionation plant at Channahon, Illinois, outside Chicago, near the terminus of Alliance Pipeline. Aux Sable also owns facilities upstream of Alliance Pipeline that facilitate deliveries of liquids-rich gas volumes into the pipeline for further processing at the Aux Sable plant. These facilities include the Palermo Conditioning Plant and the Prairie Rose Pipeline in the Bakken area of North Dakota, owned and operated by Aux Sable Midstream US; and Aux Sable Canada’s interests in the Montney area of British Columbia, comprising the Septimus Pipeline and the Septimus and Wilder Gas Plants.

US Midstream also includes a 50% investment in DCP Midstream, LLC (DCP Midstream), which is accounted for as an equity investment. DCP Midstream gathers, compresses, treats, processes, transports, stores and sells natural gas. It also produces, fractionates, transports, stores and sells NGLs, recovers and sells condensate, and trades and markets natural gas and NGLs.

OTHER

Other consists primarily of our offshore assets. Enbridge Offshore Pipelines is comprised of 11 active natural gas gathering and transmission pipelines and two active oil pipelines, including the Heidelberg Oil Pipeline that was placed in service in January 2016. These pipelines are located in four major corridors in the Gulf of Mexico, extending to deepwater developments, and include almost 2,100-kilometers (1,300-miles) of underwater pipe and onshore facilities with total capacity of approximately 6.5 bcf/d.

COMPETITION

Our natural gas transmission and storage businesses compete with similar facilities that serve our supply and market areas in the transmission and storage of natural gas. The flow pattern of natural gas is changing across North America due to emerging supply sources and evolving demand centers, which creates a highly competitive market to secure new growth opportunities. The principal elements of competition are location, rates, terms of service, flexibility and reliability of service.

The natural gas transported in our business competes with other forms of energy available to our customers and end-users, including electricity, coal, propane, fuel oils, and renewable energy. Factors that influence the demand for natural gas include price changes, the availability of natural gas and other

forms of energy, levels of business activity, long-term economic conditions, conservation, legislation, governmental regulations, the ability to convert to alternative fuels, weather and other factors.

Competition in our business exists in all of the markets we serve. Competitors include interstate and intrastate pipelines or their affiliates and other midstream businesses that transport, gather, treat, process and market natural gas or NGLs. Because pipelines are generally the most efficient mode of transportation for natural gas over land, the most significant competitors of our natural gas pipelines are other pipeline companies. Pipelines typically compete with each other based on location, capacity, reputation, price and reliability.

SUPPLY AND DEMAND

Global energy demand is expected to increase approximately 30 percent by 2040, according to the International Energy Agency, driven primarily by economic growth in non-OECD countries. Natural gas will play an important role in meeting this energy demand as gas consumption is anticipated to grow by nearly 50 percent during this period as one of the world’s fastest growing energy sources, second only to renewables. Globally, most natural gas demand will stem from the need for greater power generation capacity, as natural gas is a cleaner alternative to coal, which currently has the largest market share for power generation.

Within North America, United States natural gas demand growth is expected to be driven by the next wave of gas-intensive petrochemical facilities which are now starting to enter service, along with power generation, an increase in the volume of LNG exports and additional pipeline exports to Mexico. Within Canada, natural gas demand growth is expected to be largely tied to oil sands development and growth in gas-fired power generation. Canadian gas demand growth will be accelerated with implementation of proposed government regulations to replace coal fired power, designed to meet emissions targets.

North American supply from tight formations continues to create a demand and supply imbalance for natural gas and some NGL products. North American gas supply continues to be significantly impacted by development in the northeastern United States, primarily the prolific Marcellus and Utica shales in Appalachia. The abundance of supply from these shale plays continues to alter natural gas flow patterns in North America, as this region has largely displaced flows from the Gulf Coast and WCSB that historically supplied eastern markets. Similar pressures are also being felt in the Midwest United States and southern markets.

Beyond growing Appalachian production, natural gas supply growth has been largely tied to crude oil and NGL production. In the Permian Basin, for example, rapid expansion of crude oil drilling activity has increased associated gas supplies from the region by approximately 2.0 bcf/d over the past two years and growth is forecasted to continue for the next decade. Similarly, WCSB natural gas production growth has been primarily attributable to production of NGLs, which provide strong producer netbacks. However, growing local demand from gas-fired power generation and continued oil sands development should stabilize WCSB natural gas economics, even as regional exports face steeper competition in Eastern Canada and the Midwest United States.

The continued increase in North American gas production and the resulting surplus supply has limited gas price advances, which remained largely within range throughout 2017. In response to low prices, producers have introduced new technologies and more efficient drilling and completion techniques to maximize production and improve break-even economics on new wells. While domestic gas demand and growing North American gas exports provide support for future prices, abundant low cost supplies are likely to continue to limit high prices through the next decade.

Growth in global demand for natural gas will necessitate growing LNG trade to facilitate the movement of gas supply from producing regions to consuming regions. North America and the USGC in particular are positioned to benefit from this trend as low-cost tight gas production from the Permian, Eagle Ford and Appalachia continues to enable growing LNG exports. The United States exported approximately 3.0 bcf/

d of natural gas from the United States Gulf Coast at the end of 2017 with export capacity of approximately 9.0 bcf/d scheduled to be in service by 2020. While the short term outlook for LNG fundamentals points to a continued global oversupply, as the market absorbs the large volumes of new supply coming online, forecasts indicate demand will exceed projected LNG supply in the early 2020s as growing markets seek to diversify supply sources. In addition to LNG export facilities under construction, the United States remains well positioned to serve this next round of global trade expansion. Canada is well positioned to provide LNG export facilities, although these facilities are not likely to be in service in the near term.

NGL production growth is increasingly linked to growing associated gas volumes related to the development of tight oil plays such as the Permian. NGLs that can be extracted from liquids-rich gas streams include ethane, propane, butane and natural gasoline, which are used in a variety of industrial, commercial and other applications. Robust gas production has created regional supply imbalances for some NGL products and weakened the economics of NGL extraction, although these imbalances modestly improved over 2017 as crude prices have rebounded and NGL export capacity has expanded. Over the longer term, the growth in NGL demand is expected to be robust, driven largely by incremental ethane demand and exports. Ethane is the key feedstock to the United States Gulf Coast petrochemical industry, which is among the world’s lowest-cost ethylene producing regions and is currently undergoing significant expansion. As this new infrastructure is completed, ethane prices and resulting extraction margins are expected to improve, reducing the amount of ethane retained in the gas stream.

In addition to ethane, the outlook for abundant propane supplies has prompted the development and expansion of export facilities for liquefied petroleum gas. Over a few short years, the United States has become the world’s largest liquefied petroleum gas exporter, which has helped to reduce the inventory overhang and provide support for propane prices.

In Canada, the WCSB is well situated to capitalize on the evolving NGL fundamentals over the longer term as the Montney and Duvernay shale plays contain significant liquids-rich resources at highly competitive extraction costs. In response to growing regional NGL supply, several propane export solutions are being developed to move WCSB NGLs from Western Canada to global markets.

Longer term, NGL fundamentals indicate a positive outlook for demand growth and would be further supported with a continued recovery in crude oil prices. Consequently, the crude-to-gas price ratio is expected to remain well above energy conversion value levels and continue to be supportive of NGL extraction over the longer term.

In response to these evolving natural gas and NGL fundamentals, we believe we are well positioned to provide value-added solutions to producers. We are responding to the need for regional infrastructure with additional investment in Canadian and United States gas pipeline and midstream facilities.

GAS DISTRIBUTION

Gas Distribution consists of our natural gas utility operations, the core of which are Enbridge Gas Distribution Inc. (EGD) and Union Gas Limited (Union Gas), which serve residential, commercial and industrial customers, primarily located throughout Ontario. This business segment also includes natural gas distribution activities in Quebec and New Brunswick and our investment in Noverco Inc (Noverco).

On November 2, 2017, EGD and Union Gas filed an application with the Ontario Energy Board (OEB) to amalgamate the two utilities. If approved as filed, the application will provide a 10 year framework for the utilities to identify and leverage best practices and implement integrated solutions. A decision is expected in the second half of 2018.

ENBRIDGE GAS DISTRIBUTION

EGD is a rate regulated natural gas distribution utility serving approximately 2.2 million residential, commercial and industrial customers in its franchise areas of central and eastern Ontario. In addition, EGD currently serves areas in northern New York State through St. Lawrence Gas Company Inc. (St. Lawrence Gas). In August 2017, EGD entered into an agreement to sell the issued and outstanding shares of St. Lawrence Gas. The transaction is expected to close in 2018, subject to regulatory approval and certain pre-closing conditions.

EGD also owns and operates regulated and unregulated natural gas storage facilities in Ontario. The utility business is conducted under statutes and municipal bylaws which grant the right to operate in the areas served. The utility operations of EGD and St. Lawrence Gas are regulated by the OEB and by the New York State Public Service Commission, respectively.

As at December 31, 2017, EGD owned and operated a network of approximately 39,000-kilometers (24,233-miles) of mains for the transportation and distribution of natural gas, as well as the service pipes to transfer natural gas from mains to meters on customers' premises.

There are four principal interrelated aspects of the natural gas distribution business in which EGD is directly involved: Distribution Service, Gas Supply, Transportation and Storage.

Distribution Service
EGD's principal source of revenue arises from distribution of natural gas to customers. The services provided to residential, commercial and industrial heating customers are primarily on a general service basis (without a specific fixed term or fixed price contract). The services provided to larger commercial and industrial customers are usually on an annual contract basis under firm or interruptible service contracts.

Gas Supply
To acquire the necessary volume of natural gas to serve its customers, EGD maintains a diversified natural gas supply portfolio. EGD's system supply natural gas contracts have pricing structures responsive to supply and demand conditions in the North American natural gas market. The prices in these contracts may be indexed to Alberta, Chicago or New York based prices.

Transportation
EGD relies on its long-term contracts with Union Gas, an affiliated company under common control, for transportation of natural gas from the Dawn Hub (Dawn), the largest integrated underground storage facility in Canada and one of the largest in North America, located in south-western Ontario, to EGD’s major market in the Greater Toronto Area. These contracts effectively provide EGD with access to United States sourced natural gas at Dawn. These contracts also provide transportation for natural gas received at Dawn via Vector as well as natural gas stored at EGD’s and Union’s storage pools in the Sarnia, Ontario area to the market area.
Storage
EGD’s business is highly seasonal as daily market demand for natural gas fluctuates with changes in weather, with peak consumption occurring in the winter months. Utilization of storage facilities permits EGD to take delivery of natural gas on favorable terms during off peak summer periods for subsequent use during the winter heating season. This practice permits EGD to minimize the annual cost of transportation of natural gas from its supply basins, assists in reducing its overall cost of natural gas supply and adds a measure of security in the event of any short-term interruption of transportation of natural gas to EGD's franchise area.

EGD's principal storage facilities are located in south-western Ontario, near Dawn, and have a total working capacity of approximately 10.5 billion cubic feet (Bcf). Approximately 8.5 Bcf of the total working capacity is available to EGD for utility operations. EGD also has a storage contract with Union Gas for 2.0 Bcf of storage capacity.
UNION GAS
Union Gas is a rate regulated natural gas distribution utility now serving approximately 1.5 million residential, commercial and industrial customers in its franchise areas of northern, southwestern and eastern Ontario.

Union Gas' regulated and unregulated storage and transmission business offers storage and transmission services to customers at Dawn. It offers customers an important link in the movement of natural gas from western Canada and United States supply basins to markets in central Canada and the northeastern United States. The utility business is conducted under statutes and municipal by laws which grant the right to operate in the areas served. The utility operations of Union Gas are regulated by the OEB.

As at December 31, 2017, Union Gas owned and operated a network of approximately 66,000-kilometers (41,010-miles) of mains for the transportation and distribution of natural gas, as well as the service pipes to transfer natural gas from mains to meters on customers' premises.

Similar to EGD, there are four principal interrelated aspects of the natural gas distribution business in which Union Gas is directly involved: Distribution Service, Gas Supply, Transportation and Storage.

Distribution Service

Similar to EGD, Union Gas’ principal source of revenue arises from distribution of natural gas to customers. The services provided to residential, small commercial and industrial heating customers are primarily on a general service basis (without a specific fixed term or fixed price contract). The services provided to larger commercial and industrial customers underpinned by firm or interruptible service contracts.

Gas Supply

To acquire the necessary volume of natural gas to serve its customers, Union Gas maintains a diversified natural gas supply portfolio. Union Gas' system supply natural gas contracts have pricing structures responsive to supply and demand conditions in the North American natural gas market. The prices in these contracts may be indexed to Alberta, Michigan and Chicago based prices.

Transportation

Union Gas’ transmission system consists of approximately 4,900-kilometers (3,045-miles) of high-pressure pipeline and five mainline compressor stations. Key pipeline interconnects in Canada and the United States enabled Union Gas to deliver approximately 774 Bcf of gas through Union Gas’ transmission system in 2017. Union Gas’ transmission system also links an extensive network of underground storage pools at Dawn to major Canadian and United States markets. There are multiple pipelines providing access to Dawn. Customers can purchase both firm and interruptible transportation services on the Union Gas system. As the supply of natural gas in areas close to Ontario continues to grow, there is an increased demand to access these diverse supplies at Dawn and transport them along the Dawn-Parkway pipeline system to markets in Ontario, eastern Canada and the northeastern United States. To secure the continued reliable delivery of natural gas and to serve a growing demand for natural gas, Union Gas has invested $1.5 billion between 2015 and 2017 to expand the Dawn-Parkway natural gas transmission system. This has increased the takeaway capacity from Dawn to approximately 20 percent or from 6.3 bcf/d in 2014 to more than 7.5 bcf/d in 2017. A substantial amount of Union Gas’ transportation revenue is generated by fixed annual demand charges, with the average length of a long-term contract being approximately 11 years, with the longest remaining contract term being 15 years.

Storage

Union Gas’ underground natural gas storage facilities have a working capacity of approximately 165 Bcf in 25 underground facilities located in depleted gas fields. Union Gas’ storage pools give customers access to all Dawn storage capacity and deliverability. Dawn's configuration provides flexibility for injections, withdrawals and cycling. Customers can purchase both firm and interruptible storage services at Dawn. Dawn offers customers a wide range of market choices and options with easy access to upstream and downstream markets. During 2017, Dawn provided storage, balancing, gas loans, transport, exchange and peaking services to over 140 counterparties.

A substantial amount of Union Gas’ storage revenue is generated by fixed annual demand charges, with the average length of a long-term contract being approximately five years, with the longest remaining contract term being 19 years.

NOVERCO

We own an equity interest in Noverco through ownership of 38.9% of its common shares and an investment in preferred shares. Noverco is a holding company that owns approximately 71% of Energir LP, formerly known as Gaz Metro Limited Partnership, a natural gas distribution company operating in the province of Quebec with interests in subsidiary companies operating gas transmission, gas distribution and power distribution businesses in the Province of Quebec and the State of Vermont. Noverco also holds, directly and indirectly, an investment in our Common Shares.

OTHER GAS DISTRIBUTION AND STORAGE
Other Gas Distribution and Storage includes natural gas distribution utility operations in the Provinces of New Brunswick and Quebec.

Enbridge Gas New Brunswick Inc. operates the natural gas distribution franchise in the Province of New Brunswick, has approximately 11,800 customers and is regulated by the New Brunswick Energy and Utilities Board (EUB).

Gazifere is one of two distributors in Quebec serving more than 40,000 residential, commercial, institutional and industrial customers. Gazifere is regulated by the Quebec Regie de l'energie.

GREEN POWER & TRANSMISSION

Green Power and Transmission consists of our investments in renewable energy assets and transmission facilities. Renewable energy assets consist of wind, solar, geothermal and waste heat recovery facilities and are located in Canada primarily in the provinces of Alberta, Ontario and Quebec and in the United States primarily in Colorado, Texas, Indiana and West Virginia. We also have assets under development located in Europe.

Green Power and Transmission includes approximately 2,500 MW of net operating renewable and alternative energy sources. Of this amount, approximately 930 MW of net power generating capacity comes from wind farms located in the provinces of Alberta, Ontario and Quebec and approximately 1,040 MW of net power generating capacity comes from wind farms located in the states of Colorado, Texas, Indiana and West Virginia, including the 249 MW Chapman Ranch Wind Project (Chapman Ranch) in Texas, which was placed into service in late October 2017. The vast majority of the power produced from these wind farms is sold under long-term power purchase agreements. We also have three solar facilities located in Ontario and a solar facility located in Nevada, with 100 MW and 50 MW, respectively, of net power generating capacity. Also included in Green Power and Transmission is the Montana-Alberta Tie-Line, our first power transmission asset, a 300 MW transmission line from Great Falls, Montana to Lethbridge, Alberta.

In June 2017, we announced an additional 112 MW of investment in the partnership that holds the 610 MW Hohe See Offshore Wind Project in Germany, where we have an effective 50% interest. Earlier in 2016, we announced the acquisition of Chapman Ranch, as well as the acquisition of a 50% interest in a French offshore wind development company, Éolien Maritime France SAS. Chapman Ranch was subsequently placed into service in late October 2017. In late 2015, we announced acquisitions of the 103-MW New Creek Wind Project in West Virginia and a 24.9% interest in the 400 MW Rampion Offshore Wind Project in the United Kingdom. Including these acquisitions, we have invested over $5 billion in renewable power generation and transmission since 2002.

Competition

Our Green Power and Transmission assets operate in the North American and European power markets, which are subject to competition and the supply and demand balance for power in the provinces and states in which they operate. The renewable energy market sector includes large utilities and small independent power producers, which are expected to aggressively compete with us for project development opportunities.

Supply and Demand

The power generation and transmission network in North America is expected to undergo significant growth over the next 20 years. On the demand side, North American economic growth over the longer term is expected to drive growing electricity demand, although continued efficiency gains are expected to make the economy less energy-intensive and temper demand growth. On the supply side, impending legislation in Canada is expected to accelerate the retirement of aging coal-fired generation plants, resulting in a requirement for significant new generation capacity. While coal and nuclear facilities will continue to be core components of power generation in North America, gas-fired and renewable energy facilities, including biomass, hydro, solar and wind, are expected to be the preferred sources to replace coal-fired generation due to their lower carbon intensities.

North American wind and solar resources fundamentals remain strong. In the United States, there is over 85 gigawatts (GW) of installed wind power capacity and in Canada over 12 GW of installed wind power capacity. Solar resources in southwestern states such as Arizona, California and Nevada are considered to be some of the best in the world for large-scale solar plants and the United States currently has over 35 GW of installed solar photovoltaic capacity. In late 2015, the United States passed legislation extending the availability of certain Federal tax incentives which have supported the profitability of wind and solar projects. However, expanding renewable energy infrastructure in North America is not without challenges. Growing renewable generation capacity is expected to necessitate substantial capital investment to upgrade existing transmission systems or, in many cases, build new transmission lines, as these high quality wind and solar resources are often found in regions that are not in close proximity to markets. In the near-term, uncertainty over the availability of tax or other government incentives in various jurisdictions, the ability to secure long-term power purchase agreements through government or investor-owned power authorities and low market prices of electricity may hinder the pace of future new renewable capacity development. However, continued improvement in technology and manufacturing capacity in the past few years has reduced capital costs associated with renewable energy infrastructure and has also

improved yield factors of power generation assets. These positive developments are expected to render renewable energy more competitive and support ongoing investment over the long term.

In Europe, the future outlook for renewable energy, especially from offshore wind in countries with long coastlines and densely populated areas, is very positive. According to the European Wind Energy Association, by 2030, wind energy capacity in Europe is expected to be 320 GW, including 66 GW of offshore capacity. There is also wide public support for carbon reduction targets and broader adoption of renewable generation across all governmental levels. Furthermore, governments in Europe are seeking to rationalize the contribution of nuclear power to the overall energy mix, which has resulted in an increased focus on alternative sources such as large scale offshore wind.

ENERGY SERVICES

The Energy Services businesses in Canada and the United States undertake physical commodity marketing activity and logistical services, oversee refinery supply services and manage our volume commitments on various pipeline systems.

Energy Services provides energy supply and marketing services to North American refiners, producers and other customers. Crude oil and NGL marketing services are provided by Tidal Energy Marketing Inc. (Tidal). We transact at many North American market hubs and provides our customers with various services, including transportation, storage, supply management, hedging programs and product exchanges. Tidal is primarily a physical barrel marketing company focused on capturing value from quality, time and location differentials when opportunities arise. To execute these strategies, Energy Services may lease storage or rail cars, as well as hold nomination or contractual rights on both third party and Enbridge-owned pipelines and storage facilities. Tidal also provides natural gas and power marketing services, including marketing natural gas to optimize commitments on certain natural gas pipelines. Additionally, Tidal provides natural gas supply, transportation, balancing and storage for third parties, leveraging its natural gas marketing expertise and access to transportation capacity.

Competition
Energy Services earnings are generated from arbitrage opportunities which, by their nature, can be replicated by other competitors. An increase in market participants entering into similar arbitrage transactions could have an impact on our earnings. Our efforts to mitigate competition risk includes diversification of our marketing business by trading at the majority of major hubs in North America and establishing long-term relationships with clients.

ELIMINATIONS AND OTHER

Eliminations and Other includes operating and administrative costs and foreign exchange costs which are not allocated to business segments. Eliminations and Other also includes new business development activities and general corporate investments.

INSURANCE

Our operations are subject to many hazards inherent in our industry. Our assets may experience physical damage as a result of an accident or natural disaster. These hazards can also cause personal injury and loss of life, severe damage to and destruction of property and equipment, pollution or environmental damage, and suspension of operations. We maintain a comprehensive insurance program for us, our subsidiaries and our affiliates. This program includes insurance coverage in types and amounts and with terms and conditions that are generally consistent with coverage customary for our industry.

Although we believe our current coverage is adequate for our purposes, we have in the past had occurrences that led to losses exceeding our then-applicable coverage limits, and there is no assurance

that the same may not happen in the future. In the unlikely event that multiple insurable incidents which in aggregate exceed coverage limits occur within the same insurance period, the total insurance coverage will be allocated among our entities on an equitable basis based on an insurance allocation agreement among us and our subsidiaries.

OPERATIONAL AND ECONOMIC REGULATION

LIQUIDS PIPELINES
Operational Regulation
Operational regulation risks relate to compliance with applicable operational rules and regulations mandated by governments or applicable regulatory authorities, breaches of which could result in fines, penalties, operating restrictions and an overall increase in operating and compliance costs.

Regulatory scrutiny over the integrity of liquids pipeline assets has the potential to increase operating costs or limit future projects. Potential regulatory changes could have an impact on our future earnings and the cost related to the construction of new projects. We believe operational regulation risk is mitigated by active monitoring and consulting on potential regulatory requirement changes with the respective regulators or through industry associations. We also develop robust response plans to regulatory changes or enforcement actions. While we believe the safe and reliable operation of our assets and adherence to existing regulations is the best approach to managing operational regulatory risk, the potential remains for regulators to make unilateral decisions that could have a financial impact on us.

In the United States, our interstate pipeline operations are subject to pipeline safety laws and regulations administered by the Pipeline and Hazardous Materials Safety Administration (PHMSA) of the United States Department of Transportation (DOT). These laws and regulations require us to comply with a significant set of requirements for the design, construction, maintenance and operation of our interstate pipelines. These laws and regulations, among other things, include requirements to monitor and maintain the integrity of our pipelines. The regulations determine the pressures at which our pipelines can operate.

PHMSA is designing an Integrity Verification Process intended to create standards to verify maximum allowable operating pressure, and to improve and expand integrity management processes. Additionally, PHMSA will establish standards for storage facilities. There remains uncertainty as to how these standards will be implemented, but it is expected that the changes will impose additional costs on new pipeline projects as well as on existing operations. In this climate of increasingly stringent regulation, pipeline failures or failures to comply with applicable regulations could result in reduction of allowable operating pressures as authorized by PHMSA, which would reduce available capacity on our pipelines. Should any of these risks materialize, it may have an adverse effect on our operations, earnings, financial condition and cash flows.

In Canada, our pipeline operations are subject to pipeline safety regulations overseen by the NEB or provincial regulators. Applicable legislation and regulation require us to comply with a significant set of requirements for the design, construction, maintenance and operation of our pipelines. Among other obligations, this regulatory framework imposes requirements to monitor and maintain the integrity of our pipelines.

As in the United States, several legislative changes addressing pipeline safety in Canada have recently come into force. The changes evidence an increased focus on the implementation of management systems to address key areas such as emergency management, integrity management, safety, security and environmental protection. Other legislative changes have created authority for the NEB to impose administrative monetary penalties for non-compliance with the regulatory regime it administers, as well as to impose financial requirements for future abandonment and major pipeline releases.

We are also subject to numerous environmental laws and regulations affecting many aspects of our present and future operations, including air emissions, water quality, wastewater discharges, solid waste and hazardous waste. These laws and regulations generally require us to obtain and comply with a wide variety of environmental licenses, permits, inspections and other approvals.

In particular, in the United States, compliance with major Clean Air Act regulatory programs is likely to cause us to incur significant capital expenditures to obtain permits, evaluate off-site impacts of our operations, install pollution control equipment, and otherwise assure compliance. Some states in which we operate are implementing new emissions limits to comply with 2008 ozone standards regulated under the National Ambient Air Quality Standards. In 2015, the ozone standards were lowered even further from 75 parts per billion (ppb) to 70 ppb, which may require states to implement additional emissions regulations. The precise nature of these compliance obligations at each of our facilities has not been finally determined and may depend in part on future regulatory changes. In addition, compliance with new and emerging environmental regulatory programs is likely to significantly increase our operating costs compared to historical levels.

In the United States, climate change action is evolving at state, regional and federal levels. The Supreme Court decision in Massachusetts v. EPA in 2007 established that greenhouse gas (GHG) emissions were pollutants subject to regulation under the Clean Air Act. Pursuant to federal regulations, we are currently subject to an obligation to report our GHG emissions at our largest emitting facilities, but are not generally subject to limits on emissions of GHGs, (except to the extent that some GHGs consist of volatile organic compounds and nitrous oxides that are subject to emission limits). In addition, a number of provinces and states have joined regional GHG initiatives, and a number are developing their own programs that would mandate reductions in GHG emissions. Public interest groups and regulatory agencies are increasingly focusing on the emission of methane associated with natural gas development and transmission as a source of GHG emissions. However, as the key details of future GHG restrictions and compliance mechanisms remain undefined, the likely future effects on our business are highly uncertain.

For its part, Canada has reaffirmed its strong preference for a harmonized approach with that of the United States. While federal GHG related regulatory design details remain forthcoming, provincial authorities have been actively pursuing related initiatives.

Failure to comply with environmental regulations may result in the imposition of fines, penalties and injunctive measures affecting our operating assets. In addition, changes in environmental laws and regulations or the enactment of new environmental laws or regulations could result in a material increase in our cost of compliance with such laws and regulations. We may not be able to obtain or maintain all required environmental regulatory approvals for our operating assets or development projects. If there is a delay in obtaining any required environmental regulatory approvals, if we fail to obtain or comply with them, or if environmental laws or regulations change or are administered in a more stringent manner, the operations of facilities or the development of new facilities could be prevented, delayed or become subject to additional costs. We expect that costs we incur to comply with environmental regulations in the future will have a significant effect on our earnings and cash flows.

Due to the speculative outlook regarding any United States federal and state policies, we cannot estimate the potential effect of proposed GHG policies on our future consolidated results of operations, financial position or cash flows. However, such legislation or regulation could materially increase our operating costs, require material capital expenditures or create additional permitting, which could delay proposed construction projects.

Economic Regulation
Our liquids pipelines also face economic regulatory risk. Broadly defined, economic regulation risk is the risk that governments or regulatory agencies change or reject proposed or existing commercial arrangements including permits and regulatory approvals for new projects. The Canadian Mainline, Lakehead System and other liquids pipelines are subject to the actions of various regulators, including the

NEB and FERC, with respect to the tariffs and tolls of those operations. The changing or rejecting of commercial arrangements, including decisions by regulators on the applicable tariff structure or changes in interpretations of existing regulations by courts or regulators, could have an adverse effect on our revenues and earnings. Delays in regulatory approvals on projects such as our L3R Program, could result in cost escalations and construction delays, which also negatively impact our operations.

We believe that economic regulatory risk is reduced through the negotiation of long-term agreements with shippers that govern the majority of our liquids pipeline assets. We also involve our legal and regulatory teams in the review of new projects to ensure compliance with applicable regulations as well as in the establishment of tariffs and tolls on new and existing pipelines. However, despite our efforts to mitigate economic regulation risk, there remains a risk that a regulator could overturn long-term agreements that we have entered into with shippers or deny the approval and permits for new projects.

GAS TRANSMISSION & MIDSTREAM

Operational Regulation

The span of regulatory risks that apply to the Liquids Pipeline business as described above under Liquids Pipelines also applies to the Gas Transmission and Midstream business. Additionally, most of our United States gas transmission operations are regulated by the FERC. The FERC regulates natural gas transmission in United States interstate commerce including the establishment of rates for services. The FERC also regulates the construction of United States interstate natural gas pipelines and storage facilities, including the extension, enlargement and abandonment of facilities. In addition, certain operations are subject to oversight by state regulatory commissions. To the extent that the natural gas intrastate pipelines that transport or store natural gas in interstate commerce provide services under Section 311 of the Natural Gas Policy Act of 1978, they are subject to FERC regulations. The FERC may propose and implement new rules and regulations affecting interstate natural gas transmission and storage companies, which remain subject to the FERC’s jurisdiction. These initiatives may also affect certain transmission of gas by intrastate pipelines.

Our SEP and DCP Midstream operations are subject to the jurisdiction of the Environmental Protection Agency and various other federal, state and local environmental agencies. Our United States interstate natural gas pipelines and certain of DCP Midstream’s gathering and transmission pipelines are also subject to the regulations of the DOT concerning pipeline safety.

The intrastate natural gas and NGL pipelines owned by us and DCP Midstream are subject to state regulation. The natural gas gathering and processing activities of DCP Midstream are not subject to FERC regulation.

Our Canadian operations are governed by various federal and provincial agencies with respect to pipeline safety, including the NEB and the Transportation Safety Board, the British Columbia Oil and Gas Commission, the Alberta Energy Regulator and the Ontario Technical Standards and Safety Authority.

Our Canadian natural gas transmission and distribution operations and approximately two-thirds of the storage operations in Canada are subject to regulation by the NEB or the provincial agencies in Canada, such as the OEB. These agencies have jurisdiction similar to the FERC for regulating rates, the terms and conditions of service, the construction of additional facilities and acquisitions. Our British Columbia Pipeline and British Columbia Field Services business in western Canada is regulated by the NEB pursuant to a framework for light-handed regulation under which the NEB acts on a complaints-basis for rates associated with that business. Similarly, the rates charged by our Canadian Gas Transmission and Midstream operations for gathering and processing services in western Canada are regulated on a complaints-basis by applicable provincial regulators.

GAS DISTRIBUTION

Economic Regulation

Our gas distribution utility operations are regulated by the OEB and the EUB among others. Regulators' future actions may differ from current expectations, or future legislative changes may impact the regulatory environments in which we operate. To the extent that the regulators' future actions are different from current expectations, the timing and amount of recovery or refund of amounts recorded on the Consolidated Statements of Financial Position, or that would have been recorded on the Consolidated Statements of Financial Position in absence of the effects of regulation, could be different from the amounts that are eventually recovered or refunded.

We seek to mitigate economic regulation risk. We retain dedicated professional staff and maintain strong relationships with customers, intervenors and regulators. The terms of rate negotiations are reviewed by our legal, regulatory and finance teams.

Enbridge Gas Distribution

Distribution rates are set under a five-year customized incentive rate plan (IR Plan) approved in 2014 and provide a level of stability by having a long-term agreement with the OEB which allows us to recover our expected capital investments under the agreement, as well as an opportunity to earn above the OEB allowed ROE. Under the customized IR Plan, we are permitted to recover, with OEB approval, certain costs that were beyond management control, but that were necessary for the maintenance of our services. The customized IR Plan also includes a mechanism to reassess the customized IR Plan and return to cost of service if there are significant and unanticipated developments that threaten the sustainability of the customized IR Plan.

Union Gas

Distribution rates, beginning in 2014, are set under a five-year incentive regulation framework using price cap methodology. The price cap framework establishes new rates at the beginning of each year through the use of a pricing formula rather than through the examination of revenue and cost forecasts. The framework allows for annual inflationary rate increases, offset by a productivity factor, as well as rate increases or decreases in the small volume customer classes where use declines or increases, and certain adjustments to base rates. Further, it allows for the continued pass-through of gas commodity, upstream transportation and demand side management costs, the additional pass-through of costs associated with major capital investments and certain fuel variances, an allowance for unexpected cost changes that are outside of management's control, and equal sharing of tax changes between Union Gas and customers, and finally an opportunity to earn above the OEB allowed ROE.

Environmental Regulation

Our workers, operations and facilities are subject to municipal, provincial and federal legislation which regulate the protection of the environment and the health and safety of workers. For the environment, primarily this includes the regulation of discharges to air, land and water; the management and disposal of solid and hazardous waste, and contaminated soil and groundwater; and the assessment of contaminated sites.

The operation of our gas distribution system and gas facilities comes with risk of incidents, abnormal operating conditions or other unplanned events that could result in spills or emissions to the environment that could exceed permitted levels. These events could result in injuries to workers or the public, fines, penalties, adverse impacts to the environment in which we operate within, and/or property damage. We could also incur future liability for environmental (soil and groundwater) contamination associated with past and present site activities.

In addition to the operation of the gas distribution system, we also operate unregulated operations including small oil and brine production and storage facilities in southwestern Ontario. Environmental risk associated with these facilities is the possibility of spills, releases or leaks. In the event of an incident (spill), remediation of the affected area would be required. There would also be potential for fines, orders

or charges under environmental legislation, and potential third-party liability claims by affected land owners.

The gas distribution system and our other operations must maintain a number of environmental approvals and permits from governmental authorities to operate. As a result, these facilities and the distribution network are subject to periodic inspection. An Annual Written Summary Report is submitted to the Ontario Ministry of Environment and Climate Change (MOECC) to demonstrate we are in good standing in relation to its Environmental Compliance Approvals. Failure to maintain regulatory compliance could result in operational interruptions, fines, penalties, and/or orders for additional pollution control technology or environmental remediation, etc. As environmental requirements and regulations become more stringent, the cost to maintain compliance and the time required to obtain approvals has consistently increased.

Ontario commenced a cap and trade system on January 1, 2017. Under the cap and trade regulation, EGD and Union Gas (together, the Utilities) are required to purchase emission allowances or credits for most of our customers' use of natural gas as well as for emissions from our own operations. This process is complex and requires ongoing monitoring of the carbon market and related climate change and carbon policies not only in Ontario but also in other newly linked jurisdictions as at January 1, 2018 - namely California and Quebec. This linkage which has been enabled in Ontario with various GHG reporting and cap and trade regulation amendments over the course of 2017 will create a larger and more liquid market for carbon allowances and credits, which may help to keep compliance costs for our customers down. However, non-compliance or unexpected policy changes may cause significant changes to the cost of maintaining compliance and needs to be closely monitored to ensure impacts are understood.

As required by the OEB Cap and Trade Framework, the Utilities each submitted 2017 Compliance Plans, which subsequently received supportive endorsement and approval of cost recovery in 2017 rates. The Utilities are in the process of defending their individually filed 2018 Compliance Plans. The OEB approved use of the 2017 final rate for recovery of 2018 cap and trade compliance costs until determined otherwise. Further, the OEB Cap and Trade Framework identifies that the Utilities are expected to file 2019/2020 Compliance Plans as well as an Annual Report summarizing 2017 results by August 1, 2018. The Compliance Plans detail how the Utilities will meet their respective carbon compliance obligations through carbon allowance and/or offset procurement as well as through customer and facility abatement projects that may be deemed cost effective. By creating prudent and thoughtful plans and executing with excellence, the Utilities can best mitigate the risk of cost disallowance.

As with previous years, in 2017 the Utilities each reported GHG emissions to the Ontario MOECC, Environment and Climate Change Canada, and a number of voluntary reporting programs. Emissions from Ontario combustion sources were verified in detail by a third party accredited verifier with no material discrepancies found. Additionally, operational emissions from venting, fugitive and natural gas distribution emissions were reported to the MOECC for the first time in 2017 in accordance with O. Reg. 143/16 - Quantification, Reporting, and Verification of Greenhouse Gas Emissions Regulation standard quantification methods ON. 350 and ON. 400, respectively. The Utilities continue to monitor developments and attend stakeholder consultations in Ontario.

The Utilities utilize emissions data management processes and systems to help with the data capture and mandatory and voluntary reporting needs. Quantification methodologies and emission factors will continually be updated in the system as required. Each Utility publicly reports its GHG emissions and has developed internal procedures for more frequent monthly Cap and Trade related GHG reporting. Collectively, the Utilities continue to work with industry associations to refine quantification methodologies and emissions factors, as well as best management practices to minimize emissions. The Utilities plans to reduce emissions in 2018 are outlined in the Facility Abatement Plan within their respective Compliance Plans.

EMPLOYEES

We had approximately 12,700 employees as at December 31, 2017, including approximately 8,500 employees in Canada. Approximately 1,800 of our employees are subject to collective bargaining agreements governing their employment with us. Approximately 48% of those employees are covered under agreements that either have expired or will expire by December 31, 2018. We are currently going through the process of collective bargaining in respect to the expired or expiring contracts. We have mature working relationships with our labor unions and the parties have traditionally committed themselves to the achievement of renewal agreements without a work stoppage.

EXECUTIVES AND OTHER OFFICERS

The following table sets forth information regarding our executive and other officers.

Name	Age	Position
Al Monaco	58	President & Chief Executive Officer
John K. Whelen	58	Executive Vice President & Chief Financial Officer
Cynthia L. Hansen	53	Executive Vice President, Utilities & Power Operations
D. Guy Jarvis	54	Executive Vice President, Liquids Pipelines
Byron C. Neiles	52	Executive Vice President, Corporate Services
Robert R. Rooney	61	Executive Vice President & Chief Legal Officer
William T. Yardley	53	Executive Vice President & President, Gas Transmission & Midstream
Vern D. Yu	51	Executive Vice President & Chief Development Officer
Allen C. Capps	47	Vice President & Chief Accounting Officer

Al Monaco was appointed President and Chief Executive Officer on October 1, 2012. He is also a member of the Enbridge Board of Directors. Prior to being appointed President of Enbridge, Mr. Monaco served as President, Gas Pipelines, Green Energy & International with responsibility for the growth and operations of our gas pipelines, including the gas gathering and processing operations in the United States, our gulf coast offshore assets and our investments in Alliance, Vector and Aux Sable, as well as our International business development and investment activities and Green Energy.

John K. Whelen was appointed Executive Vice President and Chief Financial Officer of Enbridge on October 15, 2014. Previously our Senior Vice President and Controller, Mr. Whelen retained executive leadership for our financial reporting function, while assuming responsibility for our tax and treasury functions. Mr. Whelen has been part of the Enbridge team since 1992, when he assumed the Manager of Treasury role at Consumers Gas (now EGD).

Cynthia L. Hansen was appointed Executive Vice President, Utilities and Power Operations, on February 27, 2017. Ms. Hansen is responsible for the overall leadership and operations of EGD and Union Gas, as well as Enbridge Gas New Brunswick Inc. and Gazifère. She also holds responsibility for the operations of our power generating assets, which currently include renewable energy investments in wind, solar, geothermal and hydroelectric, as well as waste heat recovery facilities and power transmission lines owned in whole or in part by us.

D. Guy Jarvis was appointed Executive Vice President, Liquids Pipelines and Major Projects on May 2, 2016. Mr. Jarvis has been President of our Liquids Pipelines group since March 1, 2014, with responsibility for all of our crude oil and liquids pipeline businesses across North America. Mr. Jarvis previously held the title of Chief Commercial Officer for Liquids Pipelines, with responsibility for strategic and integrated services, customer service, finance, and business and market development. Prior to Mr. Jarvis' work in Liquids Pipelines, he served as President, Gas Distribution, providing overall leadership to EGD, as well as Enbridge Gas New Brunswick Inc. and Gazifère.

Byron C. Neiles was appointed Executive Vice President, Corporate Services on May 2, 2016. Mr. Neiles has oversight of our Information Technology, Human Resources, Real Estate & Workplace Services, Supply Chain Management, Enterprise Safety and Operational Reliability, and aviation groups. Mr. Neiles had previously held the role of Senior Vice President, Major Projects, Enterprise Safety and Operational Reliability, and had been Senior Vice President of Major Projects since November 2011, after joining our Major Projects group in April 2008.

Robert R. Rooney was appointed Executive Vice President and Chief Legal Officer on February 1, 2017. Mr. Rooney leads our legal team across the organization, as well as Public Affairs and Communications (including Corporate Social Responsibility).

William T. Yardley was named Executive Vice President and President of Gas Transmission and Midstream on February 27, 2017. Mr. Yardley is also the President and Chairman of the Board of SEP. Mr. Yardley, based in Houston, was previously President of Spectra Energy's United States Transmission and Storage business, leading the business development, project execution, operations and environment, health and safety efforts associated with Spectra Energy's United States portfolio of assets.

Vern D. Yu was appointed Executive Vice President and Chief Development Officer on May 2, 2016. Mr. Yu leads our Corporate Development team in driving growth opportunities, while also establishing capital allocation parameters and portfolio mix. Mr. Yu also provides executive oversight to our Energy Services group, Tidal Energy. Previously, Mr. Yu served as Senior Vice President, Corporate Planning and Chief Development Officer. He has been the lead of our Corporate Development team since July 1, 2014.

Allen C. Capps is the Vice President and Chief Accounting Officer of Enbridge. Mr. Capps is responsible for our accounting operations and financial reporting functions, including internal and external financial reports. Prior to assuming his current role in 2017, Mr. Capps served as Vice President and Controller of Spectra Energy, responsible for the financial accounting and reporting functions.

ADDITIONAL INFORMATION

Additional information about us is available on our website at www.enbridge.com, on SEDAR at www.sedar.com and on EDGAR at www.sec.gov. The aforementioned information is made available in accordance with legal requirements and is not, unless otherwise specifically stated, incorporated by reference into this Annual Report on Form 10-K. We make available free of charge, through our website, annual reports on Form 10-K, quarterly reports on Form 10-Q and current reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as well as proxy statements, as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC. Reports, proxy statements and other information filed with the SEC may also be obtained through the SEC's website (www.sec.gov) or by visiting the Public Reference Room of the SEC at 100 F Street, N.E., Washington D.C. 20549 or calling the SEC at 1-800-SEC-0330.

ENBRIDGE ENERGY PARTNERS, L.P. AND ENBRIDGE ENERGY MANAGEMENT, L.L.C.

Additional information about EEP and Enbridge Energy Management, L.L.C. can be found in their Annual Reports on Form 10-Ks that have been filed with the SEC. These documents contain detailed disclosure with respect to EEP and Enbridge Energy Management, L.L.C., respectively, and are publicly available on EDGAR at www.sec.gov. No part of the Form10-Ks filed by EEP and Enbridge Energy Management, L.L.C. are, unless otherwise specifically stated, incorporated by reference into this Annual Report on Form 10-K.

ENBRIDGE GAS DISTRIBUTION INC.
Additional information about EGD can be found in its annual information form, financial statements and management's discussion and analysis (MD&A) for the year ended December 31, 2017 which have been filed with the securities commissions or similar authorities in each of the provinces of Canada. These documents contain detailed disclosure with respect to EGD and are publicly available on SEDAR at www.sedar.com. These documents are not, unless otherwise specifically stated, incorporated by reference into this Annual Report on Form 10-K.

ENBRIDGE INCOME FUND
Additional information about the Fund can be found in its annual information form, financial statements and MD&A as well as the financial statements and MD&A of EIPLP for the year ended December 31, 2017 which have been filed with the securities commissions or similar authorities in each of the provinces of Canada. These documents contain detailed disclosure with respect to the Fund and are publicly available on SEDAR at www.sedar.com under the Fund's profile. These documents are not, unless otherwise specifically stated, incorporated by reference into this Annual Report on Form 10-K.

ENBRIDGE INCOME FUND HOLDINGS INC.
Additional information about ENF can be found in its annual information form, financial statements and MD&A for the year ended December 31, 2017 which have been filed with the securities commissions or similar authorities in each of the provinces of Canada. These documents contain detailed disclosure with respect to ENF and are publicly available on SEDAR at www.sedar.com. These documents are not, unless otherwise specifically stated, incorporated by reference into this Annual Report on Form 10-K.

ENBRIDGE PIPELINES INC.
Additional information about EPI can be found in its annual information form, financial statements and MD&A for the year ended December 31, 2017 which have been filed with the securities commissions or similar authorities in each of the provinces of Canada. These documents contain detailed disclosure with respect to EPI and are publicly available on SEDAR at www.sedar.com. These documents are not, unless otherwise specifically stated, incorporated by reference into this Annual Report on Form 10-K.

SPECTRA ENERGY PARTNERS, L.P.
Additional information about SEP can be found in its Annual Report on Form10-K that has been filed with the SEC. This document contains detailed disclosure with respect to SEP, and is publicly available on EDGAR at www.sec.gov. No part of the Form 10-K filed by SEP is, unless otherwise specifically stated, incorporated by reference into this Annual Report on Form 10-K.

UNION GAS LIMITED
Additional information about Union Gas can be found in its annual information form, financial statements and MD&A for the year ended December 31, 2017 which have been filed with the securities commissions or similar authorities in each of the provinces of Canada. These documents contain detailed disclosure with respect to Union Gas and are publicly available on SEDAR at www.sedar.com. These documents are not, unless otherwise specifically stated, incorporated by reference into this Annual Report on Form 10-K.

WESTCOAST ENERGY INC.
Additional information about Westcoast Energy Inc. can be found in its annual information form, financial statements and MD&A for the year ended December 31, 2017 which have been filed with the securities commissions or similar authorities in each of the provinces of Canada. These documents contain detailed disclosure with respect to Westcoast Energy Inc. and are publicly available on SEDAR at www.sedar.com. These documents are not, unless otherwise specifically stated, incorporated by reference into this Annual Report on Form 10-K.

ITEM 1A. RISK FACTORS

Execution of our capital projects subjects us to various regulatory, development, operational and market risks that may affect our financial results.

Our ability to successfully execute the development of our organic growth projects is subject to various regulatory, development, operational and market risks, including:

- the ability to obtain necessary approvals and permits from governments and regulatory agencies on a timely basis and on acceptable terms and to maintain those issued approvals and permits and satisfy the terms and conditions imposed therein;
- potential changes in federal, state, provincial and local statutes and regulations, including environmental requirements, that may prevent a project from proceeding or increase the anticipated cost of the project;
- impediments on our ability to acquire or renew rights-of-way or land rights on a timely basis and on acceptable terms;
- opposition to our projects by third parties, including special interest groups;
- the availability of skilled labor, equipment and materials to complete projects;
- the ability to construct projects within anticipated costs, including the risk of cost overruns resulting from inflation or increased costs of equipment, materials or labor, contractor or supplier non-performance, weather, geologic conditions or other factors beyond our control, that may be material;
- general economic factors that affect the demand for our projects; and
- the ability to raise financing for these capital projects.

Any of these risks could prevent a project from proceeding, delay its completion or increase its anticipated cost. Recent projects that have experienced delays include the United States portion of the L3R Program (U.S. L3R Program) and NEXUS. In the fourth quarter of 2016, we determined Northern Gateway could not proceed as envisioned. New projects may not achieve their expected investment return, which could affect our financial results, and hinder our ability to secure future projects.

Cyber-attacks or security breaches could adversely affect our business, operations or financial results.

Our business is dependent upon information systems and other digital technologies for controlling our plants and pipelines, processing transactions and summarizing and reporting results of operations. The secure processing, maintenance and transmission of information is critical to our operations. A security breach of our network or systems could result in improper operation of our assets, potentially including delays in the delivery or availability of our customers' products, contamination or degradation of the products we transport, store or distribute, or releases of hydrocarbon products for which we could be held liable. Furthermore, we collect and store sensitive data in the ordinary course of our business, including personal identification information of our employees as well as our proprietary business information and that of our customers, suppliers, investors and other stakeholders. We have a cyber-security controls framework in place which has been derived from the National Institute of Standards and Technology Cyber-security Framework and International Organization for Standardization 27001 standards. We monitor our control effectiveness in an increasing threat landscape and continuously take action to improve our security posture. We have implemented a 7X24 security operations center to monitor, detect and investigate any anomalous activity in our network together with an incident response process that we test on a monthly basis. We conduct independent cyber-security audits and penetration tests on a regular basis to test that our preventative and detective controls are working as designed. Despite our security measures, our information systems may become the target of cyber-attacks or security breaches (including employee error, malfeasance or other breaches), which could compromise our network or systems and result in the release or loss of the information stored therein, misappropriation of assets, disruption to our operations or damage to our facilities. Our current insurance coverage programs do not

contain specific coverage for cyber-attacks or security breaches. As a result of a cyber-attack or security breach, we could also be liable under laws that protect the privacy of personal information, subject to regulatory penalties, experience damage to our reputation or a loss of consumer confidence in our products and services, or incur additional costs for remediation and modification or enhancement of our information systems to prevent future occurrences, all of which could adversely affect our business, operations or financial results.

Changes in our reputation with stakeholders, special interest groups, political leadership, the media or other entities could have negative impacts on our business, operations or financial results.

There could be negative impacts on our business, operations or financial results due to changes in our reputation with stakeholders, special interest groups (including non-governmental organizations), political leadership, the media or other entities. Public opinion may be influenced by certain media and special interest groups' negative portrayal of the industry in which we operate as well as their opposition to development projects, such as the Bakken Pipeline System. Potential impacts of a negative public opinion may include:
- loss of business;
- loss of ability to secure growth opportunities;
- delays in project execution;
- legal action;
- increased regulatory oversight or delays in regulatory approval; and
- loss of ability to hire and retain top talent.

We are also exposed to the risk of higher costs, delays or even project cancellations due to increasing pressure on governments and regulators by special interest groups. Recent judicial decisions have increased the ability of special interest groups to make claims and oppose projects in regulatory and legal forums. In addition to issues raised by groups focused on particular project impacts, we and others in the energy and pipeline businesses are facing opposition from organizations opposed to oil sands development and shipment of production from oil sands regions.

Pipeline operations involve numerous risks that may adversely affect our business and financial results.

Operation of complex pipeline systems, gathering, treating, storing and processing operations involves many risks, hazards and uncertainties. These events include adverse weather conditions, accidents, the breakdown or failure of equipment or processes, the performance of the facilities below expected levels of capacity and efficiency and catastrophic events such as explosions, fires, earthquakes, hurricanes, floods, landslides or other similar events beyond our control. These types of catastrophic events could result in loss of human life, significant damage to property, environmental pollution and impairment of our operations, any of which could also result in substantial losses for which insurance may not be sufficient or available and for which we may bear a part or all of the cost. We have experienced such events in the past, including in 2010 on Lines 6A and 6B Lakehead System. which is discussed in Part II. Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Legal and Other Updates. In addition, we could be subject to significant fines and penalties from regulators in connection with such events. Environmental incidents could also lead to an increased cost of operating and insuring our assets, thereby negatively impacting earnings. An environmental incident could have lasting reputational impacts to us and could impact our ability to work with various stakeholders. For pipeline and storage assets located near populated areas, including residential communities, commercial business centers, industrial sites and other public gathering locations, the level of damage resulting from these catastrophic events could be greater.

Our assets vary in age and were constructed over many decades which may cause our inspection, maintenance or repair costs to increase in the future.

Our pipelines vary in age and were constructed over many decades. Pipelines are generally long-lived assets, and pipeline construction and coating techniques have changed over time. Depending on the era of construction, some assets require more frequent inspections, which could result in increased maintenance or repair expenditures in the future. Any significant increase in these expenditures could adversely affect our business, operations or financial results.

A service interruption could have a significant impact on our operations, and negatively impact financial results, relationships with stakeholders and our reputation.

A service interruption due to a major power disruption or curtailment of commodity supply could have a significant impact on our operations and negatively impact financial results, relationships with stakeholders and our reputation. Specifically, for Gas Distribution, any prolonged interruptions would ultimately impact gas distribution customers. Service interruptions that impact our crude oil transportation services can negatively impact shippers' operations and earnings as they are dependent on our services to move their product to market or fulfill their own contractual arrangements.

Our operations involve safety risks to the public and to our workers and contractors.

Several of our pipelines and distribution systems and related assets are operated in close proximity to populated areas and a major incident could result in injury to members of the public. In addition, given the natural hazards inherent in our operations, our workers and contractors are subject to personal safety risks. A public safety incident or an injury to our workers or contractors could result in reputational damage to us, material repair costs or increased costs of operating and insuring our assets.

Our transformation projects may fail to fully deliver anticipated results.

We launched projects in 2016 to transform various processes, capabilities and reporting systems infrastructure to continuously improve effectiveness and efficiency across the organization. Transformation project risk is the risk that modernization projects carried out by us and our subsidiaries do not fully deliver anticipated results due to insufficiently addressing the risks associated with project execution and change management. This could result in negative financial, operational and reputational impacts.

An impairment of our assets, including goodwill, property, plant, and equipment, intangible assets, and/or equity method investments, could reduce our earnings.

GAAP requires us to test certain assets for impairment on either an annual basis or when events or circumstances occur which indicate that the carrying value of such assets might be impaired. The outcome of such testing could result in impairments of our assets including our goodwill, property, plant and equipment, intangible assets, and/or equity method investments. Additionally, any asset monetizations could result in impairments if such assets are sold or otherwise exchanged for amounts less than their carrying value. If we determine that an impairment has occurred, we would be required to take an immediate noncash charge to earnings.

There are utilization risks in respect to our assets.

In respect to our Liquids Pipeline assets, we are exposed to throughput risk under the CTS on the Canadian Mainline and under certain tolling agreements applicable to other Liquids Pipelines assets, such as the Lakehead System. A decrease in volumes transported can directly and adversely affect our revenues and earnings. Factors such as changing market fundamentals, capacity bottlenecks, operational incidents, regulatory restrictions, system maintenance and increased competition can all impact the utilization of our assets. Market fundamentals, such as commodity prices and price differentials, weather, gasoline price and consumption, alternative energy sources and global supply disruptions outside of our control can impact both the supply of and demand for crude oil and other liquid hydrocarbons transported on our pipelines.

In respect to our Gas Transmission and Midstream assets, gas supply and demand dynamics continue to change as a result of the development of non-conventional shale gas supplies. The increase in natural gas supply has resulted in declines in the price of natural gas in North America. As a result, a shift occurred to extraction of gas in richer, wet gas areas with higher NGL content which depressed activity in dry fields. This, in turn, has contributed to a resulting oversupply of pipeline takeaway capacity in some areas, which can adversely affect our revenues and earnings.

In respect to our Gas Distribution assets, customers are billed on a combination of both fixed charge and volumetric basis and EGD and Union Gas' ability to collect their respective total revenue requirement (the cost of providing service, including a reasonable return to the utility) depends on achieving the forecast distribution volume established in the rate-making process. The probability of realizing such volume is contingent upon four key forecast variables: weather, economic conditions, pricing of competitive energy sources and growth in the number of customers. Weather is a significant driver of delivery volumes, given that a significant portion of EGD and Union Gas' respective customer base uses natural gas for space heating. Distribution volume may also be impacted by the increased adoption of energy efficient technologies, along with more efficient building construction, that continue to place downward pressure on consumption. In addition, conservation efforts by customers may further contribute to a decline in annual average consumption. EGD and Union Gas have deferral accounts approved by the OEB that provide regulatory protection against the margin impacts associated with declining annual average consumption due to efficiencies and customers' conservation efforts. Sales and transportation service to large volume commercial and industrial customers is more susceptible to prevailing economic conditions. As well, the pricing of competitive energy sources affects volume distributed to these sectors as some customers have the ability to switch to an alternate fuel. Even in those circumstances where EGD and Union Gas each attains their respective total forecast distribution volume, they may not earn their respective expected ROE due to other forecast variables, such as the mix between the higher margin residential and commercial sectors and the lower margin industrial sector. EGD and Union Gas each remain at risk for the actual versus forecast large volume contract commercial and industrial volumes.

In respect to our Green Power and Transmission assets, earnings from these assets are highly dependent on weather and atmospheric conditions as well as continued operational availability of these energy producing assets. While the expected energy yields for Green Power and Transmission projects are predicted using long-term historical data, wind and solar resources are subject to natural variation from year to year and from season to season. Any prolonged reduction in wind or solar resources at any of the Green Power and Transmission facilities could lead to decreased earnings and cash flows for us. Additionally, inefficiencies or interruptions of Green Power and Transmission facilities due to operational disturbances or outages resulting from weather conditions or other factors, could also impact earnings.

Power produced from Green Power and Transmission assets is also often sold to a single counterparty under power purchase agreements or other long-term pricing arrangements. In this respect, the performance of the Green Power and Transmission assets is dependent on each counterparty performing its contractual obligations under the power purchase agreements or pricing arrangement applicable to it.

We rely on access to short-term and long-term capital markets to finance capital requirements and support liquidity needs, and cost effective access to those markets can be affected, particularly if we or our rated subsidiaries are unable to maintain an investment-grade credit rating.

A significant portion of our consolidated asset base is financed with debt. The maturity and repayment profile of debt used to finance investments often does not correlate to cash flows from assets. Accordingly, we rely on access to both short-term and long-term capital markets as a source of liquidity

for capital requirements not satisfied by cash flows from operations and to fund investments originally financed through debt. Our senior unsecured long-term debt is currently rated investment-grade by various rating agencies. If the rating agencies were to rate us or our rated subsidiaries below investment-grade, our borrowing costs would increase, perhaps significantly. Consequently, we would likely be required to pay a higher interest rate in future financings and our potential pool of investors and funding sources could decrease.

We maintain revolving credit facilities to provide back-up for commercial paper programs for borrowings and/or letters of credit at various entities. These facilities typically include financial covenants and failure to maintain these covenants at a particular entity could preclude that entity from issuing commercial paper or letters of credit or borrowing under the revolving credit facility, which could affect cash flows or restrict business. Furthermore, if our short-term debt rating were to be downgraded, access to the commercial paper market could be significantly limited. Although this would not affect our ability to draw under our credit facilities, borrowing costs could be significantly higher.

If we are not able to access capital at competitive rates, our ability to finance operations and implement our strategy may be affected. Restrictions on our ability to access financial markets may also affect our ability to execute our business plan as scheduled. An inability to access capital may limit our ability to pursue improvements or acquisitions that we may otherwise rely on for future growth. Any downgrade or other event negatively affecting the credit ratings of our subsidiaries could make their costs of borrowing higher or access to funding sources more limited, which in turn could increase our need to provide liquidity in the form of capital contributions or loans to such subsidiaries, thus reducing the liquidity and borrowing availability of the consolidated group.

Our forecasted assumptions may not materialize as expected on our expansion projects, acquisitions and divestitures.

We evaluate expansion projects, acquisitions and divestitures on an ongoing basis. Planning and investment analysis is highly dependent on accurate forecasting assumptions and to the extent that these assumptions do not materialize, financial performance may be lower or more volatile than expected. Volatility and unpredictability in the economy, both locally and globally, change in cost estimates, project scoping and risk assessment could result in a loss in our profits.

We may not be able to sell assets or, if we are able to sell assets, to raise a sufficient amount of capital from such asset sales. In addition, the timing to enter into and close any asset sales could be significantly different than our expected timeline.

We are planning to monetize certain assets to execute on our strategic priority to focus on core assets and to accelerate debt reduction and provide capital for capital and investment expenditures. Given the commodity markets, financial markets, and other challenges currently facing the energy sector, our competitors may also engage in asset sales leading to lower demand for the assets we wish to sell. We may not be able to sell the assets we identify for sale on favorable terms or at all. If we are able to sell assets, the timing of the receipt of the asset sale proceeds may not align with the timing of our capital requirements. A failure to raise sufficient capital from asset sales or a misalignment of the timing of capital raised and capital funding needs could have an adverse impact on our business, financial condition, results of operations, and cash flows.

Our operations are subject to pipeline safety laws and regulations, compliance with which may require significant capital expenditures, increase our cost of operations and affect or limit our business plans.

Many of our operations are regulated. The nature and degree of regulation and legislation affecting energy companies in Canada and the United States have changed significantly in past years and further substantial changes may occur.

On February 8, 2018, the Government of Canada introduced legislation to revise the process for assessing major resource projects. At this time, we are reviewing the proposed regulatory reforms and the effect upon us and our subsidiaries, whether adverse or favorable, if such legislation is passed in its current or revised form, is currently uncertain.

Compliance with legislative changes may impose additional costs on new pipeline projects as well as on existing operations. Failure to comply with applicable regulations could result in a number of consequences which may have an adverse effect on our operations, earnings, financial condition and cash flows.

Our operations are subject to numerous environmental laws and regulations, compliance with which may require significant capital expenditures, increase our cost of operations and affect or limit our business plans, or expose us to environmental liabilities.

We are subject to numerous environmental laws and regulations affecting many aspects of our present and future operations, including air emissions, water quality, wastewater discharges, solid waste and hazardous waste.

Failure to comply with environmental laws and regulations may result in the imposition of fines, penalties and injunctive measures affecting our operating assets. In addition, changes in environmental laws and regulations or the enactment of new environmental laws or regulations could result in a material increase in our cost of compliance with such laws and regulations. We may not be able to obtain or maintain all required environmental regulatory approvals for our operating assets or development projects. If there is a delay in obtaining any required environmental regulatory approvals, if we fail to obtain or comply with them, or if environmental laws or regulations change or are administered in a more stringent manner, the operations of facilities or the development of new facilities could be prevented, delayed or become subject to additional costs. We expect that costs we incur to comply with environmental regulations in the future will have a significant effect on our earnings and cash flows.

We are exposed to the credit risk of our customers.

We are exposed to the credit risk of our customers in the ordinary course of our business. Generally, our customers are rated investment-grade, are otherwise considered creditworthy or provide us security to satisfy credit concerns. A significant amount of our credit exposures for transmission, storage, and gathering and processing services are with customers who have an investment-grade rating (or the equivalent based on our evaluation) or are secured by collateral. However, we cannot predict to what extent our business would be impacted by deteriorating conditions in the economy, including possible declines in our customers’ creditworthiness. As a result of future capital projects for which natural gas and oil producers may be the primary customer, our credit exposure with below investment-grade customers may increase. It is possible that customer payment defaults, if significant, could adversely affect our earnings and cash flows.

Our business requires the retention and recruitment of a skilled workforce, and difficulties recruiting and retaining our workforce could result in a failure to implement our business plans.

Our operations and management require the retention and recruitment of a skilled workforce, including engineers, technical personnel and other professionals. We and our affiliates compete with other companies in the energy industry for this skilled workforce. If we are unable to retain current employees and/or recruit new employees of comparable knowledge and experience, our business could be negatively impacted. In addition, we could experience increased allocated costs to retain and recruit these professionals.

We are involved in numerous legal proceedings, the outcomes of which are uncertain, and resolutions adverse to us could adversely affect our financial results.

We are subject to numerous legal proceedings. Litigation is subject to many uncertainties, and we cannot predict the outcome of individual matters with assurance. It is reasonably possible that the final resolution of some of the matters in which we are involved could require additional expenditures, in excess of established reserves, over an extended period of time and in a range of amounts that could adversely affect our financial results.

Terrorist attacks and threats, escalation of military activity in response to these attacks or acts of war, and other civil unrest or activism could adversely affect our business, operations or financial results.

Terrorist attacks and threats, escalation of military activity or acts of war, or other civil unrest or activism may have significant effects on general economic conditions, fluctuations in consumer confidence and spending and market liquidity, each of which could adversely affect our business. Future terrorist attacks, rumors or threats of war, actual conflicts involving the United States, or Canada, or military or trade disruptions may significantly affect our operations and those of our customers. Strategic targets, such as energy related assets, may be at greater risk of future attacks than other targets in the United States and Canada. In addition, increased environmental activism against pipeline construction and operation could potentially result in work delays, reduced demand for our products and services, increased legislation or denial or delay of permits and rights-of-way. Finally, the disruption or a significant increase in energy prices could result in government-imposed price controls. It is possible that any of these occurrences, or a combination of them, could adversely affect our business, operations or financial results.

Our Liquids Pipelines results may be adversely affected by commodity prices.

Current oil sands production is very robust and is expected to grow in the future as producers actively improve the competitiveness of their existing projects; however, prolonged low prices negatively impact producers' balance sheets and their ability to invest. Sanctioned projects due to come on stream in the next 24 months are not as sensitive to short-term declines in crude oil prices, as investment commitments have already been made. A protracted long-term outlook for low crude oil prices could result in delay or cancellation of future projects. Wide commodity price basis between Western Canada and global tidewater markets have also negatively impacted producer netbacks and margins in the past years that largely resulted from pipeline infrastructure takeaway capacity from producing regions in Western Canada and North Dakota operating at capacity.

The tight oil plays of Western Canada and the Bakken region of North Dakota have short cycle break-even time horizons, typically less than 24 months, and high decline rates that can be well managed through active hedging programs and are positioned to react quickly at market signals. Accordingly, during periods of comparatively low prices, drilling programs, unsupported by hedging programs, will be reduced and as such supply growth from tight oil basins may be lower, which may impact volumes on our pipeline systems.

Our Gas Transmission and Midstream results may be adversely affected by commodity price volatility and risks associated with our hedging activities.

Our exposure to commodity price volatility is inherent to part of our natural gas processing activities. We employ a disciplined hedging program to manage this direct commodity price risk. Because we are not fully hedged, we may be adversely impacted by commodity price exposure on the commodities we receive in-kind as payment for our gathering, processing, treating and transportation services. As a result of our unhedged exposure and the pricing of our hedge positions, a substantial decline in the prices of these commodities could adversely affect our financial results.

Additionally, our hedging activities may not be as effective as we intend in reducing the volatility of our cash flows. To the extent that we engage in hedging activities to reduce our commodity price exposure, we likely will be prevented from realizing the full benefits of price increases above the level of the hedges. Our hedging activities can result in substantial losses if hedging arrangements are imperfect or ineffective and our hedging policies and procedures are not followed properly or do not work as intended. Further, hedging contracts are subject to the credit risk that the other party may prove unable or unwilling to perform its obligations under the contracts, particularly during periods of weak and volatile economic conditions. In addition, certain of the financial instruments we use to hedge our commodity risk exposures must be accounted for on a mark-to-market basis. This causes periodic earnings volatility due to fluctuations in commodity prices.

Our Energy Services results may be adversely affected by commodity price volatility.

Energy Services generates margin by capitalizing on quality, time and location differentials when opportunities arise. Volatility in commodity prices due to changing marketing conditions could limit margin opportunities and impede Energy Services' ability to cover capacity commitments. Furthermore, commodity prices could have negative earnings and cash flow impacts if the cost of the commodity is greater than resale prices achieved by us.

Our risk management policies cannot eliminate all risks. In addition, any non-compliance with our risk management policies could adversely affect our business, operations or financial results.

We use derivative financial instruments to manage the risks associated with movements in foreign exchange rates, interest rates, commodity prices and our share price to reduce volatility to our cash flows. Based on our risk management policies, all of our derivative financial instruments are associated with an underlying asset, liability and/or forecasted transaction. We do not enter into transactions with the objective of speculating on commodity prices or interest rates. These policies cannot, however, eliminate all risk of unauthorized trading and other speculative activity. Although this activity is monitored independently by our risk management function, we remain exposed to the risk of non-compliance with our risk management policies. We can provide no assurance that our risk management function will detect and prevent all unauthorized trading and other violations of our risk management policies and procedures, particularly if deception, collusion or other intentional misconduct is involved, and any such violations could adversely affect our business, operations or financial results.

The effects of United States Government policies on trade relations between Canada and the United States are uncertain.

The United States Government has continued interest in renegotiating and altering the North American Free Trade Agreement (NAFTA) with Canada and Mexico. NAFTA provides protection against tariffs, duties and other charges or fees and assures access by the signatories. The NAFTA negotiations have introduced a level of uncertainty in the energy markets. The outcome of the NAFTA negotiations could result in new rules or its collapse which may be disruptive to energy markets, and could jeopardize our ability to remain competitive and have a significant impact on us.

The effect of comprehensive United States tax reform legislation on us, whether adverse or favorable, is uncertain.

On December 22, 2017, President Trump signed into law H.R. 1, “An Act to provide for reconciliation pursuant to titles II and V of the concurrent resolution on the budget for fiscal year 2018” (informally titled the Tax Cuts and Jobs Act). The effect of the Tax Cuts and Jobs Act on us, our subsidiaries and our shareholders, whether adverse or favorable, is uncertain, but will become more clear as additional guidance is issued.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

Descriptions of our properties and maps depicting the locations of our liquids and natural gas systems are included in Item 1. Business.

In general, our systems are located on land owned by others and are operated under easements and rights-of-way, licenses, leases or permits that have been granted by private land owners, First Nations, Native American Tribes, public authorities, railways or public utilities. Our liquids systems have pumping stations, tanks, terminals and certain other facilities that are located on land that is owned by us and/or used by us under easements, licenses, leases or permits. Additionally, our natural gas systems have natural gas compressor stations, processing plants and treating plants, the vast majority of which are located on land that is owned by us, with the remainder used by us under easements, leases or permits.

Titles to our properties acquired in our liquids and natural gas systems are subject to encumbrances in some cases. We believe that none of these burdens should materially detract from the value of these properties or materially interfere with their use in the operation of our business.

ITEM 3. LEGAL PROCEEDINGS

We are involved in various legal and administrative proceedings and litigation arising in the ordinary course of business. The outcome of these matters is not predictable at this time. However, we believe that the ultimate resolution of these matters will not have a material adverse effect on our financial condition, results of operations or cash flows in future periods. Refer to Part II. Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Legal and Other Updates for discussion of other legal proceedings.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Our common stock is traded on the TSX and NYSE under the symbol "ENB." As at January 31, 2018, there were approximately 96,107 holders of record of our common stock. A substantially greater number of holders of our common stock are "street name" or beneficial holders, whose shares are held by banks, brokers and other financial institutions.

Common Stock Data by Quarter

The following table indicates the intra-day high and low prices of our common stock on the TSX (in Canadian dollars):

	Stock Price Range			
2017	Q1	Q2	Q3	Q4
High	$58.28	57.75	53.00	52.59
Low	53.87	49.61	48.98	43.91
2016				
High	$51.31	55.05	59.19	59.18
Low	40.03	48.73	50.76	53.91

The following table indicates the intra-day high and low prices of our common stock on the NYSE (in U.S. dollars):

	Stock Price Range			
2017	Q1	Q2	Q3	Q4
High	US$44.52	42.92	42.31	42.10
Low	40.25	37.37	39.01	34.39
2016				
High	US$39.40	43.39	45.77	45.09
Low	27.43	37.02	38.58	39.70

Dividends

The following table indicates the dividends paid per common share (in Canadian dollars):

	2017	2016
Q1	0.583	0.530
Q2	0.610	0.530
Q3	0.610	0.530
Q4	0.610	0.530

Consistent with our objective of delivering annual cash dividend increases, we announced a quarterly dividend of $0.671 per common share payable on March 1, 2018, which represents a 10 percent increase from the prior quarterly rate. We expect to continue our policy of paying regular cash dividends. The declaration and payment of dividends are subject to the sole discretion of our Board of Directors and will depend upon many factors, including the financial condition, earnings and capital requirements of our operating subsidiaries, covenants associated with certain debt obligations, legal requirements, regulatory constraints and other factors deemed relevant by our Board of Directors.

Securities Authorized for Issuance Under Equity Compensation Plans
Information in response to this item is incorporated by reference from our Proxy Statement to be filed with the SEC relating to our 2018 annual meeting of shareholders.
Recent Sales of Unregistered Equity Securities
On November 29, 2017, we entered into a private placement for common shares with three institutional investors. The issuance price was $44.84, with gross proceeds of $1.5 billion. We issued 33,456,003 common shares in reliance on Rule 506(b) of Regulation S. The proceeds were used to pay down short-term indebtedness pending reinvestment in capital projects.

On December 11, 2017, we issued 20,000,000 of Series 19 Preference Shares in Canada pursuant to a prospectus supplement to our Canadian base shelf prospectus in reliance on Regulation S. Please refer to Item 7 - Outstanding Share Data for further discussion of the transaction.
Issuer Purchases of Equity Securities
None.

Stock Performance Graph
The following graph reflects the comparative changes in the value from January 1, 2013 through December 31, 2017 of $100 invested in (1) Enbridge Inc.'s common shares traded on the TSX, (2) the S&P/TSX Composite index and (3) the peer group index (comprising CU, FTS, IPL, PPL, TRP, D, DTE, ETE, EPD, KMI, MMP, NI, OKE, PCG, PAA, SRE and WMB). The amounts included in the table were calculated assuming the reinvestment of dividends at the time dividends were paid.

	January 1,	December 31,				
	2013	2013	2014	2015	2016	2017
Enbridge Inc.	100.00	110.93	146.76	116.80	149.53	136.37
S&P/ TSX Composite	100.00	112.99	124.92	114.53	138.67	151.28
Peer Group[1]	100.00	126.35	158.17	121.45	158.82	163.06

1 For the purpose of the graph, it was assumed that CAD:USD conversion ratio remained at 1:1 for the years presented.

ITEM 6. SELECTED FINANCIAL DATA

The following selected financial data should be read in conjunction with Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations and Item 8. Financial Statements and Supplementary Data.

	Years Ended December 31,				
	2017[1]	2016[1]	2015[1]	2014	2013
(millions of Canadian dollars, except per share amounts)					
Consolidated Statements of Earnings					
Operating revenues	$44,378	$34,560	$33,794	$37,641	$32,918
Operating income	1,571	2,581	1,862	3,200	1,365
Earnings/(loss) from continuing operations	3,266	2,309	(159)	1,562	490
(Earnings)/loss attributable to noncontrolling interests and redeemable noncontrolling interests	(407)	(240)	410	(203)	135
Earnings attributable to controlling interests	2,859	2,069	251	1,405	629
Earnings/(loss) attributable to common shareholders	2,529	1,776	(37)	1,154	446
Common Stock Data					
Earnings/(loss) per common share					
Basic	1.66	1.95	(0.04)	1.39	0.55
Diluted	1.65	1.93	(0.04)	1.37	0.55
Dividends paid per common share	2.41	2.12	1.86	1.40	1.26

	December 31,				
	2017[1]	2016[1]	2015[1]	2014	2013
(millions of Canadian dollars)					
Consolidated Statements of Financial Position					
Total assets[2]	$162,093	$85,209	$84,154	$72,280	$57,196
Long-term debt including capital leases, less current portion	60,865	36,494	39,391	33,423	22,357

1 Our Consolidated Statements of Earnings and Consolidated Statements of Financial Position data reflect the following acquisitions, dispositions and impairment:

2017 - Spectra Merger Transaction, acquisition of public interest in Midcoast Energy Partners, L.P. and other impairment

2016 - Sandpiper Project impairment, gain on disposition of South Prairie Region assets, Tupper Plants acquisition and other

2015 - Goodwill impairment

2 We combined Cash and cash equivalents and other amounts previously presented as Bank indebtedness where the corresponding bank accounts are subject to pooling arrangements.

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ITEM 7. 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 "Forward-Looking Information", Part I. Item 1A. Risk Factors and our consolidated financial statements and the accompanying notes included in Part II. Item 8. Financial Statements and Supplementary Data of this Annual Report on Form 10-K.

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.

RESULTS OF OPERATIONS

	Year ended December 31,		
	2017	2016	2015
(millions of Canadian dollars, except per share amounts)			
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;

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- 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
(millions of Canadian dollars)			
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,	2017	2016	2015
(United States dollars per barrel)			
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
(thousands of barrels per day (bpd))					
Canadian Mainline[1]					
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 System[2]					
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
(United States dollar to Canadian dollar)					
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

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GAS TRANSMISSION AND MIDSTREAM

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

	2017	2016	2015
(millions of Canadian dollars)			
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
(millions of Canadian dollars)			
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
(millions of Canadian dollars)			
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
(millions of Canadian dollars)			
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
(millions of Canadian dollars)			
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 – COMMERCIALLY 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
(Canadian dollars, unless stated otherwise)							
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-	2019

						construction	
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-Parkway Expansion[5]	100	%	$0.6 billion	$0.6 billion	Complete	In service
19	Panhandle Reinforcement Project5	100	%	$0.3 billion	$0.2 billion	Complete	In service

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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.

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 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.

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.

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
(in millions of Canadian dollars, unless stated otherwise)		
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,	Maturity	2017 Total Facilities	Draws[1]	Available
(millions of Canadian dollars)				
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,	2017	2016	2015
(millions of Canadian dollars)			
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,	2017	2016	2015
(millions of Canadian dollars)			
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]
(Canadian dollars, unless otherwise stated)						
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.

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
6 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.

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
7 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 Serles 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
(millions of Canadian dollars)					
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'Energie 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
(millions of Canadian dollars)				
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

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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.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Our earnings, cash flows and other comprehensive income (OCI) are subject to movements in foreign exchange rates, interest rates, commodity prices and our share price.

The following summarizes the types of market risks to which we are exposed and the risk management instruments used to mitigate them. We use a combination of qualifying and non-qualifying derivative instruments to manage the risks noted below.

Foreign Exchange Risk

We generate certain revenues, incur expenses, and hold a number of investments and subsidiaries that are denominated in currencies other than Canadian dollars. As a result, our earnings, cash flows and OCI are exposed to fluctuations resulting from foreign exchange rate variability.

We employ financial derivative instruments to hedge foreign currency denominated earnings exposure. A combination of qualifying and non-qualifying derivative instruments are used to hedge anticipated foreign currency denominated revenues and expenses, and to manage variability in cash flows. We hedge certain net investments in United States dollar denominated investments and subsidiaries using foreign currency derivatives and United States dollar denominated debt.

Interest Rate Risk

Our earnings and cash flows are exposed to short-term interest rate variability due to the regular repricing of our variable rate debt, primarily commercial paper. Pay fixed-receive floating interest rate swaps are used to hedge against the effect of future interest rate movements. We have implemented a program to significantly mitigate the impact of short-term interest rate volatility on interest expense via execution of floating to fixed interest rate swaps with an average swap rate of 2.6%.

As a result of the Merger Transaction, we are exposed to changes in the fair value of fixed rate debt that arise as a result of the changes in market interest rates. Pay floating-receive fixed interest rate swaps are used to hedge against future changes to the fair value of fixed rate debt. We have assumed a program

within our subsidiaries to mitigate the impact of fluctuations in the fair value of fixed rate debt via execution of fixed to floating interest rate swaps with an average swap rate of 2.2%.

Our earnings and cash flows are also exposed to variability in longer term interest rates ahead of anticipated fixed rate term debt issuances. Forward starting interest rate swaps are used to hedge against the effect of future interest rate movements. We have assumed a program within some of our subsidiaries to mitigate our exposure to long-term interest rate variability on select forecast term debt issuances via execution of floating to fixed interest rate swaps with an average swap rate of 3.1%.

We also monitor our debt portfolio mix of fixed and variable rate debt instruments to maintain a consolidated portfolio of debt within the Board of Directors approved policy limit of a maximum of 25% floating rate debt as a percentage of total debt outstanding. Effective January 1, 2018, the Board of Directors approved a policy limit increase of a maximum of 30% floating rate debt as a percentage of total debt outstanding. We primarily use qualifying derivative instruments to manage interest rate risk.

Commodity Price Risk

Our earnings and cash flows are exposed to changes in commodity prices as a result of our ownership interests in certain assets and investments, as well as through the activities of our energy services subsidiaries. These commodities include natural gas, crude oil, power and NGL. We employ financial and physical derivative instruments to fix a portion of the variable price exposures that arise from physical transactions involving these commodities. We use primarily non-qualifying derivative instruments to manage commodity price risk.

Emission Allowance Price Risk

Emission allowance price risk is the risk of gain or loss due to changes in the market price of emission allowances that our gas distribution business is required to purchase for itself and most of its customers to meet GHG compliance obligations under the Ontario Cap and Trade framework. Similar to the gas supply procurement framework, the OEB's framework for emission allowance procurement allows recovery of fluctuations in emission allowance prices in customer rates, subject to OEB approval.

Equity Price Risk

Equity price risk is the risk of earnings fluctuations due to changes in our share price. We have exposure to our own common share price through the issuance of various forms of stock-based compensation, which affect earnings through revaluation of the outstanding units every period. We use equity derivatives to manage the earnings volatility derived from 1 form of stock-based compensation, restricted share units. We use a combination of qualifying and non-qualifying derivative instruments to manage equity price risk.

Market Risk Management

We have a Risk Policy to minimize the likelihood that adverse earnings impacts arising from movements in market prices will exceed a defined risk tolerance. We identify and measure all material market risks including commodity price risks, interest rate risks, foreign exchange risk, emission allowance price risk and equity price risk using a standardized measurement methodology. Our market risk metric consolidates the exposure after accounting for the impact of offsetting risks and limits the consolidated earnings volatility arising from market related risks to an acceptable approved risk tolerance threshold.

We use Earnings-at-Risk (EaR), a statistically derived measurement, to quantify losses that could potentially result from adverse market price movements over a one month holding period for price sensitive non-derivative exposures and for derivative instruments we hold or issue as recorded on the balance sheet as at December 31, 2017. EaR assumes no further mitigating actions are taken to hedge or otherwise minimize exposures. The selection of a one month holding period reflects the mix of price risk sensitive assets at Enbridge. EaR calculates the annual earnings impact of market price movements over a one month period assuming no action is taken to hedge or otherwise mitigate exposures. As a practical matter, a large portion of Enbridge's exposure could be hedged or unwound in a much shorter period if required to mitigate the risks.

The consolidated EaR policy limit for Enbridge is 5% of its forward 12 month forecast normalized earnings. EaR incorporates a Monte Carlo simulation, a 97.5 percent confidence level, a risk measurement horizon of one year (forward looking), a holding period of one month, and includes financial derivative instruments, other financial instruments, commodity derivative instruments, other commodity and executory contracts, positions and earnings or cash flows from anticipated transactions. EaR at December 31, 2017 and 2016 is 1.7% and 2.8% or $68 million and $59 million, respectively.

Effective January 1, 2018, the Board of Directors approved to change the market risk metric to Cash-Flows-at-Risk (CFaR) and the consolidated CFaR limit will be 3.5% of forward 12 month normalized cash flow. The policy change will align the market risk metric with other key results metrics in the organization.

LIQUIDITY RISK

Liquidity risk is the risk that we will not be able to meet our financial obligations, including commitments and guarantees, as they become due. In order to mitigate this risk, we forecast cash requirements over a 12 month rolling time period to determine whether sufficient funds will be available and maintain substantial capacity under our committed bank lines of credit to address any contingencies. Our primary sources of liquidity and capital resources are funds generated from operations, the issuance of commercial paper and draws under committed credit facilities and long-term debt, which includes debentures and medium-term notes. We also maintain current shelf prospectuses with securities regulators which enables, subject to market conditions, ready access to either the Canadian or United States public capital markets. In addition, we maintain sufficient liquidity through committed credit facilities with a diversified group of banks and institutions which, if necessary, enables us to fund all anticipated requirements for approximately one year without accessing the capital markets. We are in compliance with all the terms and conditions of our committed credit facility agreements and term debt indentures as at December 31, 2017. As a result, all credit facilities are available to us and the banks are obligated to fund and have been funding us under the terms of the facilities.

CREDIT RISK

Entering into derivative instruments may result in exposure to credit risk from the possibility that a counterparty will default on its contractual obligations. In order to mitigate this risk, we enter into risk management transactions primarily with institutions that possess investment grade credit ratings. Credit risk relating to derivative counterparties is mitigated by credit exposure limits and contractual requirements, netting arrangements, and ongoing monitoring of counterparty credit exposure using external credit rating services and other analytical tools.

We generally have a policy of entering into individual International Swaps and Derivatives Association, Inc. agreements or other similar derivative agreements with the majority of our financial derivative counterparties. These agreements provide for the net settlement of derivative instruments outstanding with specific counterparties in the event of bankruptcy or other significant credit events, and reduces our credit risk exposure on financial derivative asset positions outstanding with the counterparties in these particular circumstances.

Credit risk also arises from trade and other long-term receivables, and is mitigated through credit exposure limits and contractual requirements, assessment of credit ratings and netting arrangements. Within EGD and Union Gas, credit risk is mitigated by the utilities' large and diversified customer base and the ability to recover an estimate for doubtful accounts through the ratemaking process. We actively monitor the financial strength of large industrial customers and, in select cases, have obtained additional security to minimize the risk of default on receivables. Generally, we classify and provide for receivables older than 20 days as past due. The maximum exposure to credit risk related to non-derivative financial assets is their carrying value.

FAIR VALUE MEASUREMENTS

The most observable inputs available are used to estimate the fair value of its derivatives. When possible, we estimate the fair value of our derivatives based on quoted market prices from exchanges. If quoted market prices are not available, we use estimates from third party brokers. For non-exchange traded derivatives classified in Levels 2 and 3, we use standard valuation techniques to calculate the estimated fair value. These methods include discounted cash flows for forwards and swaps and Black-Scholes-Merton pricing models for options. Depending on the type of derivative and nature of the underlying risk, we use observable market prices (interest rates, foreign exchange rates, commodity prices and share prices, as applicable) and volatility as primary inputs to these valuation techniques. Finally, we consider our own credit default swap spread, as well as the credit default swap spreads associated with our counterparties, in our estimation of fair value.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA
Report of Independent Registered Public Accounting Firm

To the Shareholders and Directors of Enbridge Inc.

Opinions on the consolidated financial statements and internal control over financial reporting

We have audited the accompanying consolidated statements of financial position of Enbridge Inc. and its subsidiaries (the “Company”) as of December 31, 2017 and December 31, 2016, and the related consolidated statements of earnings, comprehensive income, changes in equity and cash flows for each of the three years in the period ended December 31, 2017, including the related notes (collectively referred to as the “consolidated financial statements”). We also have audited the Company's internal control over financial reporting as of December 31, 2017, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the consolidated financial position of the Company as of December 31, 2017 and December 31, 2016, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2017 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2017, based on criteria established in Internal Control - Integrated Framework (2013) issued by the COSO.

Basis for opinions

The Company’s management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the Management’s Annual Report on Internal Control over Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on the Company’s consolidated financial statements and on the Company’s internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

Definition and limitations of internal control over financial reporting

A Company’s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of consolidated financial statements for external purposes in accordance with generally accepted accounting principles. A Company’s internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the Company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of consolidated financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the Company are being made only in accordance with authorizations of management and directors of the Company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the Company’s assets that could have a material effect on the consolidated financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP

Calgary, Alberta
February 16, 2018

We have served as the Company’s auditor since 1949.

ENBRIDGE INC.
CONSOLIDATED STATEMENTS OF EARNINGS

Year ended December 31,	2017	2016	2015
(millions of Canadian dollars, except per share amounts)			
Operating revenues			
Commodity sales	26,286	22,816	23,842
Gas distribution sales	4,215	2,486	3,096
Transportation and other services	13,877	9,258	6,856
Total operating revenues	44,378	34,560	33,794
Operating expenses			
Commodity costs	26,065	22,409	22,949
Gas distribution costs	2,572	1,596	2,292
Operating and administrative	6,442	4,358	4,131
Depreciation and amortization	3,163	2,240	2,024
Impairment of long-lived assets (Note 7 and Note 10)	4,463	1,376	96
Impairment of goodwill (Note 7 and Note 15)	102	—	440
Total operating expenses	42,807	31,979	31,932
Operating income	1,571	2,581	1,862
Income from equity investments (Note 12)	1,102	428	475
Other income/(expense)			
Net foreign currency gain/(loss)	237	91	(884)
Gain on dispositions	16	848	94
Other	199	93	88
Interest expense (Note 17)	(2,556)	(1,590)	(1,624)
Earnings before income taxes	569	2,451	11
Income tax recovery/(expense) (Note 24)	2,697	(142)	(170)
Earnings/(loss)	3,266	2,309	(159)
(Earnings)/loss attributable to noncontrolling interests and redeemable noncontrolling interests	(407)	(240)	410
Earnings attributable to controlling interests	2,859	2,069	251
Preference share dividends	(330)	(293)	(288)
Earnings/(loss) attributable to common shareholders	2,529	1,776	(37)
Earnings/(loss) per common share attributable to common shareholders (Note 5)	1.66	1.95	(0.04)
Diluted earnings/(loss) per common share attributable to common shareholders (Note 5)	1.65	1.93	(0.04)

The accompanying notes are an integral part of these consolidated financial statements.

ENBRIDGE INC.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Year ended December 31,	2017	2016	2015
(millions of Canadian dollars)			
Earnings/(loss)	3,266	2,309	(159)
Other comprehensive income/(loss), net of tax			
Change in unrealized gain/(loss) on cash flow hedges	(21)	(138)	198
Change in unrealized gain/(loss) on net investment hedges	490	166	(903)
Other comprehensive income/(loss) from equity investees	(27)	—	30
Reclassification to earnings of (gain)/loss on cash flow hedges	313	116	(559)
Reclassification to earnings of pension and other postretirement benefits amounts	19	17	21
Actuarial gain/(loss) on pension plans and other postretirement benefits	8	(34)	51
Foreign currency translation adjustments	(3,060)	(712)	3,347
Other comprehensive income/(loss), net of tax	(2,278)	(585)	2,185
Comprehensive income	988	1,724	2,026
Comprehensive (income)/loss attributable to noncontrolling interests and redeemable noncontrolling interests	(160)	(229)	292
Comprehensive income attributable to controlling interests	828	1,495	2,318
Preference share dividends	(330)	(293)	(288)
Comprehensive income/(loss) attributable to common shareholders	498	1,202	2,030

The accompanying notes are an integral part of these consolidated financial statements.

ENBRIDGE INC.
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

Year ended December 31,	2017	2016	2015
(millions of Canadian dollars, except per share amounts)			
Preference shares (Note 20)			
Balance at beginning of year	7,255	6,515	6,515
Preference shares issued	492	740	—
Balance at end of year	7,747	7,255	6,515
Common shares (Note 20)			
Balance at beginning of year	10,492	7,391	6,669
Common shares issued	1,500	2,241	—
Common shares issued in Merger Transaction (Note 7)	37,429	—	—
Dividend Reinvestment and Share Purchase Plan	1,226	795	646
Shares issued on exercise of stock options	90	65	76
Balance at end of year	50,737	10,492	7,391
Additional paid-in capital			
Balance at beginning of year	3,399	3,301	2,549
Stock-based compensation	82	41	35
Fair value of outstanding earned stock-based compensation from Merger Transaction (Note 7)	77	—	—
Options exercised	(95)	(24)	(19)
Enbridge Energy Company Inc. common control transaction	76	—	—
Drop down of interest to Enbridge Energy Partners, L.P. (Note 19)	—	—	218
Dilution gain/(loss) and other (Note 19)	(345)	81	518
Balance at end of year	3,194	3,399	3,301
Retained earnings/(deficit)			
Balance at beginning of year	(716)	142	1,571
Earnings attributable to controlling interests	2,859	2,069	251
Preference share dividends	(330)	(293)	(288)
Common share dividends declared	(4,702)	(1,945)	(1,596)
Dividends paid to reciprocal shareholder	30	26	22
Reversal of cumulative redemption value adjustment attributable to Enbridge Commercial Trust (Note 19)	—	—	541
Redemption value adjustment attributable to redeemable noncontrolling interests (Note 19)	292	(686)	(359)
Adjustment for the recognition of unutilized tax deductions for stock based compensation expense	41	—	—
Adjustment relating to equity method investment	—	(29)	—
Other	58	—	—
Balance at end of year	(2,468)	(716)	142
Accumulated other comprehensive income/(loss) (Note 22)			
Balance at beginning of year	1,058	1,632	(435)
Other comprehensive income/(loss) attributable to common shareholders, net of tax	(2,031)	(574)	2,067
Balance at end of year	(973)	1,058	1,632
Reciprocal shareholding			
Balance at beginning of year (Note 12)	(102)	(83)	(83)
Issuance of treasury stock	—	(19)	—
Balance at end of year (Note 12)	(102)	(102)	(83)
Total Enbridge Inc. shareholders' equity	58,135	21,386	18,898

Noncontrolling interests (Note 19)			
Balance at beginning of year	577	1,300	2,015
Earnings/(loss) attributable to noncontrolling interests	232	(28)	(407)
Other comprehensive income/(loss) attributable to noncontrolling interests, net of tax			
Change in unrealized gain on cash flow hedges	15	4	161
Foreign currency translation adjustments	(431)	(44)	273
Reclassification to earnings of (gain)/loss on cash flow hedges	139	40	(319)
	(277)	—	115
Comprehensive income/(loss) attributable to noncontrolling interests	(45)	(28)	(292)
Noncontrolling interests resulting from Merger Transaction (Note 7)	8,955	—	—
Enbridge Energy Company, Inc. common control transaction	(343)	—	—
Distributions	(839)	(720)	(680)
Contributions	832	28	615
Deconsolidation of Sabal Trail Transmission, LLC	(2,318)	—	—
Drop down of interest to Enbridge Energy Partners, L.P.	—	—	(304)
Dilution gain/(loss)	832	—	(53)
Disposition of Olympic Pipeline	(24)	—	—
Other	(30)	(3)	(1)
Balance at end of year	7,597	577	1,300
Total equity	65,732	21,963	20,198
Dividends paid per common share	2.41	2.12	1.86

The accompanying notes are an integral part of these consolidated financial statements.

ENBRIDGE INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS

Year ended December 31,	2017	2016	2015
(millions of Canadian dollars)			
Operating activities			
Earnings/(loss)	3,266	2,309	(159)
Adjustments to reconcile earnings/(loss) to net cash provided by operating activities:			
Depreciation and amortization	3,163	2,240	2,024
Deferred income tax expense	(2,877)	43	7
Changes in unrealized (gain)/loss on derivative instruments, net (Note 23)	(1,242)	(509)	2,373
Earnings from equity investments	(1,102)	(656)	(483)
Distributions from equity investments	1,264	827	727
Impairment	4,565	1,620	536
(Gain)/loss on dispositions	(120)	(848)	(94)
Hedge ineffectiveness (Note 23)	(55)	61	(20)
Inventory revaluation allowance	56	245	410
Unrealized intercompany foreign exchange (gain)/loss	28	43	(131)
Other	50	198	69
Changes in environmental liabilities, net of recoveries	(98)	(4)	(43)
Changes in operating assets and liabilities (Note 26)	(314)	(358)	(645)
Net cash provided by operating activities	6,584	5,211	4,571
Investing activities			
Capital expenditures	(8,287)	(5,128)	(7,273)
Joint venture financing	(25)	(1)	—
Long-term investments	(3,525)	(467)	(622)
Distributions from equity investments in excess of cumulative earnings	125	—	—
Restricted long-term investments	(54)	(46)	(49)
Additions to intangible assets	(789)	(127)	(101)
Purchases of held-to-maturity securities	(529)	—	—
Proceeds from sales and maturities of held-to-maturity securities	584	—	—
Purchase of available-for-sale securities	(136)	—	—
Proceeds from sales and maturities of available-for-sale securities	99	—	—
Acquisitions	—	(644)	(106)
Cash acquired in Merger Transaction (Note 7)	682	—	—
Proceeds from dispositions	628	1,379	146
Reimbursement of capital expenditures	212	—	—
Affiliate loans, net	(22)	(118)	59
Changes in restricted cash	35	(40)	13
Net cash used in investing activities	(11,002)	(5,192)	(7,933)
Financing activities			
Net change in short-term borrowings (Note 2)	721	(248)	(487)
Net change in commercial paper and credit facility draws	(1,249)	(2,297)	1,507
Debenture and term note issues, net of issue costs	9,483	4,080	3,767
Debenture and term note repayments	(5,054)	(1,946)	(1,023)
Purchase of interest in consolidated subsidiary	(227)	—	—
Contributions from noncontrolling interests	832	28	615
Distributions to noncontrolling interests	(919)	(720)	(680)
Contributions from redeemable noncontrolling interests	1,178	591	670
Distributions to redeemable noncontrolling interests	(247)	(202)	(114)
Preference shares issued	489	737	—

Common shares issued	1,549	2,260	57
Preference share dividends	(330)	(293)	(288)
Common share dividends	(2,750)	(1,150)	(950)
Net cash provided by financing activities	3,476	840	3,074
Effect of translation of foreign denominated cash and cash equivalents	(72)	(19)	143
Net increase/(decrease) in cash and cash equivalents	(1,014)	840	(145)
Cash and cash equivalents at beginning of year	1,494	654	799
Cash and cash equivalents at end of year	480	1,494	654
Supplementary cash flow information			
Cash paid for income taxes	172	194	80
Cash paid for interest, net of amount capitalized	2,668	1,820	1,835
Property, plant and equipment non-cash accruals	889	773	1,222

The accompanying notes are an integral part of these consolidated financial statements.

ENBRIDGE INC.
CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

December 31,	2017	2016
(millions of Canadian dollars; number of shares in millions)		
Assets		
Current assets		
Cash and cash equivalents (Note 2)	480	1,494
Restricted cash	107	68
Accounts receivable and other (Note 8)	7,053	4,978
Accounts receivable from affiliates	47	14
Inventory (Note 9)	1,528	1,233
	9,215	7,787
Property, plant and equipment, net (Note 10)	90,711	64,284
Long-term investments (Note 12)	16,644	6,836
Restricted long-term investments (Note 13)	267	90
Deferred amounts and other assets	6,442	3,391
Intangible assets, net (Note 14)	3,267	1,573
Goodwill (Note 15)	34,457	78
Deferred income taxes (Note 24)	1,090	1,170
Total assets	162,093	85,209
Liabilities and equity		
Current liabilities		
Short-term borrowings (Note 17)	1,444	351
Accounts payable and other (Note 16)	9,478	7,295
Accounts payable to affiliates	157	122
Interest payable	634	333
Environmental liabilities	40	142
Current portion of long-term debt (Note 17)	2,871	4,100
	14,624	12,343
Long-term debt (Note 17)	60,865	36,494
Other long-term liabilities	7,510	4,981
Deferred income taxes (Note 24)	9,295	6,036
	92,294	59,854
Commitments and contingencies (Note 28)		
Redeemable noncontrolling interests (Note 19)	4,067	3,392
Equity		
Share capital (Note 20)		
Preference shares	7,747	7,255
Common shares (1,695 and 943 outstanding at December 31, 2017 and December 31, 2016, respectively)	50,737	10,492
Additional paid-in capital	3,194	3,399
Deficit	(2,468)	(716)
Accumulated other comprehensive income/(loss) (Note 22)	(973)	1,058
Reciprocal shareholding	(102)	(102)
Total Enbridge Inc. shareholders' equity	58,135	21,386
Noncontrolling interests (Note 19)	7,597	577
	65,732	21,963
Total liabilities and equity	162,093	85,209

Variable Interest Entities (Note 11)
The accompanying notes are an integral part of these consolidated financial statements.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
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1. BUSINESS OVERVIEW

The terms “we,” “our,” “us” and “Enbridge” as used in this report refer collectively to Enbridge Inc. and its subsidiaries unless the context suggests otherwise. These terms are used for convenience only and are not intended as a precise description of any separate legal entity within Enbridge Inc.

Enbridge is a publicly traded energy transportation and distribution company. We conduct our business through five business segments: Liquids Pipelines; Gas Transmission and Midstream; Gas Distribution; Green Power and Transmission; and Energy Services. These reporting segments are strategic business units established by senior management to facilitate the achievement of our long-term objectives, to aid in resource allocation decisions and to assess operational performance.

LIQUIDS PIPELINES
Liquids Pipelines consists of common carrier and contract pipelines that transport crude oil, natural gas liquids (NGL) and refined products and terminals in Canada and the United States, including Canadian Mainline, Lakehead Pipeline System (Lakehead System), Regional Oil Sands System, Mid-Continent and Gulf Coast, Southern Lights Pipeline, Express-Platte System, Bakken System, and Feeder Pipelines and Other.

GAS TRANSMISSION AND MIDSTREAM
Gas Transmission and Midstream, formerly referred to as Gas Pipelines and Processing, consists of investments in natural gas pipelines and gathering and processing facilities. Investments in natural gas pipelines include our interests in US Gas Transmission, Canadian Gas Transmission and Midstream, Alliance Pipeline, US Midstream and Other. Investments in natural gas processing include our interest in Aux Sable, a natural gas extraction and fractionation business located near the terminus of the Alliance Pipeline; Canadian Gas Transmission and Midstream assets located in northeast British Columbia and northwest Alberta; and DCP Midstream, LLC (DCP Midstream) assets located primarily in Texas and Oklahoma.

GAS DISTRIBUTION
Gas Distribution consists of our natural gas utility operations, the core of which are Enbridge Gas Distribution Inc. (EGD) and Union Gas Limited (Union Gas), which serves residential, commercial and industrial customers, primarily located in Ontario. This business segment also includes our investment in Noverco Inc. (Noverco) and Other Gas Distribution and Storage.

GREEN POWER AND TRANSMISSION
Green Power and Transmission consists of our investments in renewable energy assets and transmission facilities. Renewable energy assets consist of wind, solar, geothermal and waste heat recovery facilities and are located in Canada primarily in the provinces of Alberta, Ontario and Quebec and in the United States primarily in Colorado, Texas, Indiana and West Virginia. We also have assets under development located in Europe.

ENERGY SERVICES
The Energy Services businesses in Canada and the United States undertake physical commodity marketing activity and logistical services, oversee refinery supply services and manage our volume commitments on various pipeline systems.

ELIMINATIONS AND OTHER
In addition to the segments noted above, Eliminations and Other includes operating and administrative costs and foreign exchange costs which are not allocated to business segments. Also included in Eliminations and Other are new business development activities, general corporate investments and elimination of transactions between segments required to present financial performance and financial position on a consolidated basis.

ACQUISITION OF SPECTRA ENERGY CORP

On February 27, 2017, Enbridge and Spectra Energy Corp (Spectra Energy) combined in a stock-for-stock merger transaction (the Merger Transaction) for a purchase price of $37.5 billion. Under the terms of the Merger Transaction, Spectra Energy shareholders received 0.984 shares of Enbridge for each share of Spectra Energy common stock that they owned, giving us 100% ownership of Spectra Energy. Please refer to Note 7 - Acquisitions and Dispositions for further discussion of the transaction.

CANADIAN RESTRUCTURING PLAN

Effective September 1, 2015, under an agreement with Enbridge Income Fund (the Fund) and Enbridge Income Fund Holdings Inc. (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 (ECT), 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.

2. SIGNIFICANT ACCOUNTING POLICIES

These consolidated financial statements are prepared in accordance with generally accepted accounting principles in the United States of America (U.S. GAAP). Amounts are stated in Canadian dollars unless otherwise noted. As a Securities and Exchange Commission (SEC) registrant, we are permitted to use U.S. GAAP for purposes of meeting both our Canadian and United States continuous disclosure requirements.

BASIS OF PRESENTATION AND USE OF ESTIMATES

The preparation of financial statements in conformity with U.S. GAAP requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, as well as the disclosure of contingent assets and liabilities in the consolidated financial statements. Significant estimates and assumptions used in the preparation of the consolidated financial statements include, but are not limited to: carrying values of regulatory assets and liabilities (Note 6); purchase price allocations (Note 7); unbilled revenues; depreciation rates and carrying value of property, plant and equipment (Note 10); amortization rates of intangible assets (Note 14); measurement of goodwill (Note 15); fair value of asset retirement obligations (ARO) (Note 18); valuation of stock-based compensation (Note 21); fair value of financial instruments (Note 23); provisions for income taxes (Note 24); assumptions used to measure retirement and other postretirement benefit obligations (OPEB) (Note 25); commitments and contingencies (Note 28); and estimates of losses related to environmental remediation obligations (Note 28). Actual results could differ from these estimates.

Effective September 30, 2017, we combined Cash and cash equivalents and amounts previously presented as Bank indebtedness where the corresponding bank accounts are subject to cash pooling arrangements. As at December 31, 2017, $0.6 billion (December 31, 2016 - $0.6 billion) of Bank indebtedness has been combined within Cash and cash equivalents in our Consolidated Statements of Financial Position. Net cash provided by financing activities in the Consolidated Statements of Cash Flows for the years ended December 31, 2016 and 2015 have decreased by $0.3 billion and increased by $0.1 billion, respectively, to reflect this change.

PRINCIPLES OF CONSOLIDATION

The consolidated financial statements include our accounts and accounts of our subsidiaries and variable interest entities (VIEs) for which we are the primary beneficiary. A VIE is a legal entity that does not have sufficient equity at risk to finance its activities without additional subordinated financial support or is structured such that equity investors lack the ability to make significant decisions relating to the entity's

operations through voting rights or do not substantively participate in the gains and losses of the entity. Upon inception of a contractual agreement, we perform an assessment to determine whether the arrangement contains a variable interest in a legal entity and whether that legal entity is a VIE. The primary beneficiary has both the power to direct the activities of the VIE that most significantly impact the entity's economic performance and the obligation to absorb losses or the right to receive benefits from the VIE entity that could potentially be significant to the VIE. Where we conclude that we are the primary beneficiary of a VIE, we will consolidate the accounts of that VIE. We assess all variable interests in the entity and use our judgment when determining if we are the primary beneficiary. Other qualitative factors that are considered include decision-making responsibilities, the VIE capital structure, risk and rewards sharing, contractual agreements with the VIE, voting rights and level of involvement of other parties. We assess the primary beneficiary determination for a VIE on an ongoing basis, as there are changes in the facts and circumstances related to a VIE. The consolidated financial statements also include the accounts of any limited partnerships where we represent the general partner and, based on all facts and circumstances, control such limited partnerships, unless the limited partner has substantive participating rights or substantive kick-out rights. For certain investments where we retain an undivided interest in assets and liabilities, we record our proportionate share of assets, liabilities, revenues and expenses. If an entity is determined to not be a VIE, the voting interest entity model will be applied.

All significant intercompany accounts and transactions are eliminated upon consolidation. Ownership interests in subsidiaries represented by other parties that do not control the entity are presented in the consolidated financial statements as activities and balances attributable to noncontrolling interests and redeemable noncontrolling interests. Investments and entities over which we exercise significant influence are accounted for using the equity method.

As a result of the Canadian Restructuring Plan, ECT, our subsidiary, determines its equity investment earnings from EIPLP using the Hypothetical Liquidation at Book Value (HLBV) method. ECT applies the HLBV method to its equity method investments where cash distributions, including both preference and residual distributions, are not based on the investor's ownership percentages. Under the HLBV method, a calculation is prepared at each balance sheet date to determine the amount that ECT would receive if EIPLP were to liquidate all of its assets, as valued in accordance with U.S. GAAP, and distribute that cash to the investors. The difference between the calculated liquidation distribution amounts at the beginning and the end of the reporting period, after adjusting for capital contributions and distributions, is ECT's share of the earnings or losses from the equity investment for the period.

While ECT and EIPLP are both consolidated in these financial statements, the use of the HLBV method by ECT impacts the earnings attributable to redeemable noncontrolling interests reported on Enbridge's Consolidated Statements of Earnings. We continue to recognize Redeemable noncontrolling interests on the Consolidated Statements of Financial Position at the maximum redemption value of the trust units held by third parties, which references the market price of ENF common shares.

REGULATION

Certain parts of our businesses are subject to regulation by various authorities including, but not limited to, the National Energy Board (NEB), the Federal Energy Regulatory Commission (FERC), the Alberta Energy Regulator, the New Brunswick Energy and Utilities Board (EUB), the Ontario Energy Board (OEB) and La Régie de l'Energie du Québec. 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.

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). Long-term regulatory assets are recorded in Deferred amounts and other assets and current regulatory assets are recorded in Accounts receivable and other.

Long-term regulatory liabilities are included in Other long-term liabilities and current regulatory liabilities are recorded in Accounts payable and other. Regulatory assets are assessed for impairment if we identify an event indicative of possible impairment. The recognition of regulatory assets and liabilities is based on the actions, or expected future actions, of the regulator. 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.

Allowance for funds used during construction (AFUDC) is included in the cost of property, plant and equipment and is depreciated over future periods as part of the total cost of the related asset. AFUDC includes both an interest component and, if approved by the regulator, a cost of equity component, which are both capitalized based on rates set out in a regulatory agreement. In the absence of rate regulation, we would capitalize interest using a capitalization rate based on its cost of borrowing, whereas the capitalized equity component, the corresponding earnings during the construction phase and the subsequent depreciation would not be recognized.

For certain regulated operations to which U.S. GAAP guidance for phase-in plans applies, negotiated depreciation rates recovered in transportation tolls may be less than the depreciation expense calculated in accordance with U.S. GAAP in early years of long-term contracts but recovered in future periods when tolls exceed depreciation. Depreciation expense on such assets is recorded in accordance with U.S. GAAP and no deferred regulatory asset is recorded (Note 6).

With the approval of the applicable regulator, EGD, Union Gas and certain distribution operations capitalize a percentage of specified operating costs. These operations are authorized to charge depreciation and earn a return on the net book value of such capitalized costs in future years. To the extent that the regulator's actions differ from our expectations, the timing and amount of recovery or settlement of capitalized costs could differ significantly from those recorded. In the absence of rate regulation, a portion of such costs may be charged to current period earnings.

REVENUE RECOGNITION
For businesses that are not rate-regulated, revenues are recorded when products have been delivered or services have been performed, the amount of revenue can be reliably measured and collectability is reasonably assured. Customer credit worthiness is assessed prior to agreement signing, as well as throughout the contract duration. Certain revenues from liquids and gas pipeline businesses are recognized under the terms of committed delivery contracts rather than the cash tolls received.

Long-term take-or-pay contracts, under which shippers are obligated to pay fixed amounts rateably over the contract period regardless of volumes shipped, may contain make-up rights. Make-up rights are earned by shippers when minimum volume commitments are not utilized during the period but under certain circumstances can be used to offset overages in future periods, subject to expiry periods. We recognize revenues associated with make-up rights at the earlier of when the make-up volume is shipped, the make-up right expires or when it is determined that the likelihood that the shipper will utilize the make-up right is remote.

Certain offshore pipeline transportation contracts require Enbridge to provide transportation services for the life of the underlying producing fields. Under these arrangements, shippers pay Enbridge a fixed monthly toll for a defined period of time which may be shorter than the estimated reserve life of the underlying producing fields, resulting in a contract period which extends past the period of cash collection. Fixed monthly toll revenues are recognized ratably over the committed volume made available to shippers throughout the contract period, regardless of when cash is received. For the years ended December 31, 2017, 2016 and 2015, cash received net of revenue recognized for contracts under make-

up rights and similar deferred revenue arrangements was $196 million, $249 million, and $61 million, respectively.

For rate-regulated businesses, revenues are recognized in a manner that is consistent with the underlying agreements as approved by the regulators. Natural gas utilities revenues are recorded on the basis of regular meter readings and estimates of customer usage from the last meter reading to the end of the reporting period. Estimates are based on historical consumption patterns and heating degree days experienced. Heating degree days is a measure of coldness that is indicative of volumetric requirements for natural gas utilized for heating purposes in our distribution franchise area. Since July 1, 2011, Canadian Mainline (excluding Lines 8 and 9) earnings are governed by the Competitive Toll Settlement (CTS), under which revenues are recorded when services are performed. Effective on that date, we prospectively discontinued the application of rate-regulated accounting for those assets with the exception of flow-through income taxes covered by specific rate orders.

For our energy marketing contracts, an estimate of revenues and commodity costs for the month of December is included in the Consolidated Statements of Earnings for each year based on the best available volume and price data for the commodity delivered and received.

DERIVATIVE INSTRUMENTS AND HEDGING

Non-qualifying Derivatives

Non-qualifying derivative instruments are used primarily to economically hedge foreign exchange, interest rate and commodity price earnings exposure. Non-qualifying derivatives are measured at fair value with changes in fair value recognized in earnings in Transportation and other services revenues, Commodity costs, Operating and administrative expense, Other income/(expense) and Interest expense.

Derivatives in Qualifying Hedging Relationships

We use derivative financial instruments to manage our exposure to changes in commodity prices, foreign exchange rates, interest rates and certain compensation tied to our share price. Hedge accounting is optional and requires Enbridge to document the hedging relationship and test the hedging item's effectiveness in offsetting changes in fair values or cash flows of the underlying hedged item on an ongoing basis. We present the earnings effects of hedging items with the hedged transaction. Derivatives in qualifying hedging relationships are categorized as cash flow hedges, fair value hedges or net investment hedges.

Cash Flow Hedges

We use cash flow hedges to manage our exposure to changes in commodity prices, foreign exchange rates, interest rates and certain compensation tied to our share price. The effective portion of the change in the fair value of a cash flow hedging instrument is recorded in Other comprehensive income/(loss) (OCI) and is reclassified to earnings when the hedged item impacts earnings. Any hedge ineffectiveness is recorded in current period earnings.

If a derivative instrument designated as a cash flow hedge ceases to be effective or is terminated, hedge accounting is discontinued and the gain or loss at that date is deferred in OCI and recognized concurrently with the related transaction. If a hedged anticipated transaction is no longer probable, the gain or loss is recognized immediately in earnings. Subsequent gains and losses from derivative instruments for which hedge accounting has been discontinued are recognized in earnings in the period in which they occur.

Fair Value Hedges

We use fair value hedges to hedge the fair value of debt instruments. The change in the fair value of the hedging instrument is recorded in earnings with changes in the fair value of the hedged asset or liability that is designated as part of the hedging relationship. If a fair value hedge is discontinued or ceases to be effective, the hedged asset or liability, otherwise required to be carried at cost or amortized cost, ceases

to be remeasured at fair value and the cumulative fair value adjustment to the carrying value of the hedged item is recognized in earnings over the remaining life of the hedged item.

Net Investment Hedges

Gains and losses arising from translation of net investment in foreign operations from their functional currencies to Enbridge's Canadian dollar presentation currency are included in cumulative translation adjustments (CTA). We designate foreign currency derivatives and United States dollar denominated debt as hedges of net investments in United States dollar denominated foreign operations. As a result, the effective portion of the change in the fair value of the foreign currency derivatives as well as the translation of United States dollar denominated debt are reflected in OCI and any ineffectiveness is reflected in current period earnings. Amounts recognized previously in Accumulated other comprehensive income/(loss) (AOCI) are reclassified to earnings when there is a reduction of the hedged net investment resulting from disposal of a foreign operation.

Classification of Derivatives

We recognize the fair market value of derivative instruments on the Consolidated Statements of Financial Position as current and non-current assets or liabilities depending on the timing of the settlements and the resulting cash flows associated with the instruments. Fair value amounts related to cash flows occurring beyond one year are classified as non-current.

Cash inflows and outflows related to derivative instruments are classified as Operating activities on the Consolidated Statements of Cash Flows.

Balance Sheet Offset

Assets and liabilities arising from derivative instruments may be offset in the Consolidated Statements of Financial Position when we have the legal right and intention to settle them on a net basis.

Transaction Costs

Transaction costs are incremental costs directly related to the acquisition of a financial asset or the issuance of a financial liability. We incur transaction costs primarily from the issuance of debt and account for these costs as a deduction from Long-term debt on the Statements of Financial Position. These costs are amortized using the effective interest rate method over the term of the related debt instrument and are recorded in Interest expense.

EQUITY INVESTMENTS

Equity investments over which we exercise significant influence, but do not have controlling financial interests, are accounted for using the equity method. Equity investments are initially measured at cost and are adjusted for our proportionate share of undistributed equity earnings or loss. Equity investments are increased for contributions made to and decreased for distributions received from the investees. To the extent an equity investee undertakes activities necessary to commence its planned principal operations, we capitalize interest costs associated with its investment during such period.

RESTRICTED LONG-TERM INVESTMENTS

Long-term investments that are restricted as to withdrawal or usage, for the purposes of the NEB's LMCI, are presented as Restricted long-term investments on the Consolidated Statements of Financial Position.

OTHER INVESTMENTS

Generally, we classify equity investments in entities over which we do not exercise significant influence and that do not trade on an actively quoted market as other investments carried at cost. Financial assets in this category are initially recorded at fair value with no subsequent re-measurement. Any investments which do trade on an active market are classified as available for sale investments measured at fair value through OCI. Dividends received from investments carried at cost are recognized in earnings when the right to receive payment is established.

NONCONTROLLING INTERESTS
Noncontrolling interests represent ownership interests attributable to third parties in certain consolidated subsidiaries, limited partnerships and VIEs. The portion of equity not owned by us in such entities is reflected as Noncontrolling interests within the equity section of the Consolidated Statements of Financial Position and, in the case of redeemable noncontrolling interests, within the mezzanine section of the Consolidated Statements of Financial Position between long-term liabilities and equity.

The Fund’s noncontrolling interest holders have the option to redeem the Fund trust units for cash, subject to certain limitations. Redeemable noncontrolling interests are recognized at the maximum redemption value of the trust units held by third parties, which references the market price of ENF common shares. On a quarterly basis, changes in estimated redemption values are reflected as a charge or credit to retained earnings.

The use of the HLBV method by ECT impacts the earnings attributable to redeemable noncontrolling interests reported on our Consolidated Statements of Earnings.

INCOME TAXES
Income taxes are accounted for using the liability method. Deferred income tax assets and liabilities are recorded based on temporary differences between the tax bases of assets and liabilities and their carrying values for accounting purposes. Deferred income tax assets and liabilities are measured using the tax rate that is expected to apply when the temporary differences reverse. For our regulated operations, a deferred income tax liability or asset is recognized with a corresponding regulatory asset or liability, respectively, to the extent taxes can be recovered through rates. Any interest and/or penalty incurred related to tax is reflected in Income taxes.

FOREIGN CURRENCY TRANSACTIONS AND TRANSLATION
Foreign currency transactions are those transactions whose terms are denominated in a currency other than the currency of the primary economic environment in which Enbridge or a reporting subsidiary operates, referred to as the functional currency. Transactions denominated in foreign currencies are translated into the functional currency using the exchange rate prevailing at the date of transaction. Monetary assets and liabilities denominated in foreign currencies are translated to the functional currency using the rate of exchange in effect at the balance sheet date. Exchange gains and losses resulting from translation of monetary assets and liabilities are included in the Consolidated Statements of Earnings in the period in which they arise.

Gains and losses arising from translation of foreign operations’ functional currencies to our Canadian dollar presentation currency are included in the CTA component of AOCI and are recognized in earnings upon sale of the foreign operation. Asset and liability accounts are translated at the exchange rates in effect on the balance sheet date, while revenues and expenses are translated using monthly average exchange rates.

CASH AND CASH EQUIVALENTS
Cash and cash equivalents include short-term investments with a term to maturity of three months or less when purchased.

RESTRICTED CASH
Cash and cash equivalents that are restricted as to withdrawal or usage, in accordance with specific commercial arrangements, are presented as Restricted cash on the Consolidated Statements of Financial Position.

LOANS AND RECEIVABLES
Affiliate long-term notes receivable are measured at amortized cost using the effective interest rate method, net of any impairment losses recognized. Accounts receivable and other are measured at cost.

ALLOWANCE FOR DOUBTFUL ACCOUNTS
Allowance for doubtful accounts is determined based on collection history. When we have determined that further collection efforts are unlikely to be successful, amounts charged to the allowance for doubtful accounts are applied against the impaired accounts receivable.

NATURAL GAS IMBALANCES
The Consolidated Statements of Financial Position include in-kind balances as a result of differences in gas volumes received and delivered for customers. Since settlement of certain imbalances is in-kind, changes in the balances do not have an effect on our Consolidated Statements of Earnings or Consolidated Statements of Cash Flows. Most natural gas volumes owed to or by us are valued at natural gas market index prices as at the balance sheet dates.

INVENTORY
Inventory is comprised of natural gas in storage held in EGD and Union Gas, and crude oil and natural gas held primarily by energy services businesses in the Energy Services segment. Natural gas in storage in EGD and Union Gas is recorded at the quarterly prices approved by the OEB in the determination of distribution rates. The actual price of gas purchased may differ from the OEB approved price. The difference between the approved price and the actual cost of the gas purchased is deferred as a liability for future refund or as an asset for collection as approved by the OEB. Other commodities inventory is recorded at the lower of cost, as determined on a weighted average basis, or market value. Upon disposition, other commodities inventory is recorded to Commodity costs on the Consolidated Statements of Earnings at the weighted average cost of inventory, including any adjustments recorded to reduce inventory to market value.

PROPERTY, PLANT AND EQUIPMENT
Property, plant and equipment is recorded at historical cost. Expenditures for construction, expansion, major renewals and betterments are capitalized. Maintenance and repair costs are expensed as incurred. Expenditures for project development are capitalized if they are expected to have future benefit. We capitalize interest incurred during construction for non-rate-regulated assets. For rate-regulated assets, AFUDC is included in the cost of property, plant and equipment and is depreciated over future periods as part of the total cost of the related asset. AFUDC includes both an interest component and, if approved by the regulator, a cost of equity component.

Two primary methods of depreciation are utilized. 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 for property, plant and equipment 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 generally not reflected in earnings but are booked as an adjustment to accumulated depreciation.

DEFERRED AMOUNTS AND OTHER ASSETS
Deferred amounts and other assets primarily include: costs which regulatory authorities have permitted, or are expected to permit, to be recovered through future rates including deferred income taxes; contractual receivables under the terms of long-term delivery contracts; and derivative financial instruments.

INTANGIBLE ASSETS
Intangible assets consist primarily of certain software costs, customer relationships and emission allowances. We capitalize costs incurred during the application development stage of internal use software projects. Customer relationships represent the underlying relationship from long-term agreements with customers that are capitalized upon acquisition. Emission allowances, which are recorded at their original cost, are purchased in order to meet greenhouse gas (GHG) compliance obligations. Intangible assets are generally amortized on a straight-line basis over their expected lives,

commencing when the asset is available for use, with the exception of emission allowances, which are not amortized as they will be used to satisfy compliance obligations as they come due.

GOODWILL

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

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

IMPAIRMENT

We review the carrying values of our long-lived assets as events or changes in circumstances warrant. If it is determined that the carrying value of an asset exceeds the undiscounted cash flows expected from the asset, we calculate fair value based on the discounted cash flows and write the assets down to the extent that the carrying value exceeds the fair value.

With respect to investments in debt and equity securities, we assess at each balance sheet date whether there is objective evidence that a financial asset is impaired by completing a quantitative or qualitative analysis of factors impacting the investment. If there is objective evidence of impairment, we value the expected discounted cash flows using observable market inputs and determine whether the decline below carrying value is other than temporary. If the decline is determined to be other than temporary, an impairment charge is recorded in earnings with an offsetting reduction to the carrying value of the asset.

With respect to other financial assets, we assess the assets for impairment when there is no longer reasonable assurance of timely collection. If evidence of impairment is noted, we reduce the value of the financial asset to its estimated realizable amount, determined using discounted expected future cash flows.

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. AROs are 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.

RETIREMENT AND POSTRETIREMENT BENEFITS
We maintain pension plans which provide defined benefit and defined contribution pension benefits.

Defined benefit pension plan costs 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 levels, other cost escalations, retirement ages of employees and other actuarial factors including discount rates and mortality.

We use mortality tables issued by the Society of Actuaries in the United States (revised in 2016) and the Canadian Institute of Actuaries tables (revised in 2014) to measure our benefit obligations of our United States pension plan (the United States Plan) and our Canadian pension plans (the Canadian Plans), respectively. 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. Pension cost is charged to earnings and includes:

- Cost of pension plan benefits provided in exchange for employee services rendered during the year;
- Interest cost of pension plan obligations;
- Expected return on pension plan assets;
- Amortization of the prior service costs and amendments on a straight-line basis over the expected average remaining service period of the active employee group covered by the plans; and
- Amortization of cumulative unrecognized net actuarial gains and losses in excess of 10% of the greater of the accrued benefit obligation or the fair value of plan assets, over the expected average remaining service life of the active employee group covered by the plans.

Actuarial gains and losses arise from the difference between the actual and expected rate of return on plan assets for that period or from changes in actuarial assumptions used to determine the accrued benefit obligation, including discount rate, changes in headcount or salary inflation experience.

Pension plan assets are measured at fair value. The expected return on pension plan assets is determined using market related values and assumptions on the specific invested asset mix within the pension plans. The market related values reflect estimated return on investments consistent with long-term historical averages for similar assets.

For defined contribution plans, contributions made by Enbridge are expensed in the period in which the contribution occurs.

We also provide OPEB other than pensions, including group health care and life insurance benefits for eligible retirees, their spouses and qualified dependents. The cost of such benefits is accrued during the years in which employees render service.

The overfunded or underfunded status of defined benefit pension and OPEB plans is recognized as Deferred amounts and other assets, Accounts payable and other or Other long-term liabilities, on the Consolidated Statements of Financial Position. A plan's funded status is measured as the difference between the fair value of plan assets and the plan's projected benefit obligation. Any unrecognized actuarial gains and losses and prior service costs and credits that arise during the period are recognized as a component of OCI, net of tax.

Certain regulated utility operations of Enbridge record regulatory adjustments to reflect the difference between pension expense and OPEB costs for accounting purposes and the pension expense and OPEB costs for ratemaking purposes. Offsetting regulatory assets or liabilities are recorded to the extent pension expense or OPEB costs are expected to be collected from or refunded to customers, respectively, in future rates. In the absence of rate regulation, regulatory balances would not be recorded and pension and OPEB costs would be charged to earnings and OCI on an accrual basis.

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STOCK-BASED COMPENSATION
Incentive Stock Options (ISO) granted are recorded using the fair value method. Under this method, compensation expense is measured at the grant date based on the fair value of the ISO granted as calculated by the Black-Scholes-Merton model and is recognized on a straight-line basis over the shorter of the vesting period or the period to early retirement eligibility, with a corresponding credit to Additional paid-in capital. Balances in Additional paid-in capital are transferred to Share capital when the options are exercised.

Restricted Stock Units (RSU) are cash settled awards for which the related liability is remeasured each reporting period. RSUs vest at the completion of a 35-month term. During the vesting term, compensation expense is recorded based on the number of units outstanding and the current market price of Enbridge’s shares with an offset to Accounts payable and other or to Other long-term liabilities.

COMMITMENTS, CONTINGENCIES AND ENVIRONMENTAL LIABILITIES
We expense or capitalize, as appropriate, expenditures for ongoing compliance with environmental regulations that relate to past or current operations. We expense costs incurred for remediation of existing environmental contamination caused by past operations that do not benefit future periods by preventing or eliminating future contamination. We record liabilities for environmental matters when assessments indicate that remediation efforts are probable and the costs can be reasonably estimated. Estimates of environmental liabilities are based on currently available facts, existing technology and presently enacted laws and regulations taking into consideration the likely effects of inflation and other factors. These amounts also consider prior experience in remediating contaminated sites, other companies’ clean-up experience and data released by government organizations. Our estimates are subject to revision in future periods based on actual costs or new information and are included in Environmental liabilities and Other long-term liabilities in the Consolidated Statements of Financial Position at their undiscounted amounts. There is always a potential of incurring additional costs in connection with environmental liabilities due to variations in any or all of the categories described above, including modified or revised requirements from regulatory agencies, in addition to fines and penalties, as well as expenditures associated with litigation and settlement of claims. We evaluate recoveries from insurance coverage separately from the liability and, when recovery is probable, we record and report an asset separately from the associated liability in the Consolidated Statements of Financial Position.

Liabilities for other commitments and contingencies are recognized when, after fully analyzing available information, we determine it is either probable that an asset has been impaired, or that a liability has been incurred, and the amount of impairment or loss can be reasonably estimated. When a range of probable loss can be estimated, we recognize the most likely amount, or if no amount is more likely than another, the minimum of the range of probable loss is accrued. We expense legal costs associated with loss contingencies as such costs are incurred.

3. CHANGES IN ACCOUNTING POLICIES

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 (Note 15).

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 Tax Cuts and Jobs Act (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.

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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.

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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.

4. SEGMENTED INFORMATION

Effective December 31, 2017, we changed our segment-level profit measure to Earnings before interest, income taxes and depreciation and amortization 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.

Segmented information for the years ended December 31, 2017, 2016 and 2015 are as follows:

Year ended December 31, 2017	Liquids Pipelines	Gas Transmission and Midstream	Gas Distribution	Green Power and Transmission	Energy Services	Eliminations and Other	Consolidated
(millions of Canadian dollars)							
Revenues	8,913	7,067	4,992	534	23,282	(410)	44,378
Commodity and gas distribution costs	(18)	(2,834)	(2,689)	—	(23,508)	412	(28,637)
Operating and administrative	(2,949)	(1,756)	(960)	(163)	(47)	(567)	(6,442)
Impairment of long-lived assets	—	(4,463)	—	—	—	—	(4,463)
Impairment of goodwill	—	(102)	—	—	—	—	(102)
Income/(loss) from equity investments	416	653	23	6	8	(4)	1,102
Other income/(expense)	33	166	24	(5)	2	232	452
Earnings/(loss) before interest, income tax expense, and depreciation and amortization	6,395	(1,269)	1,390	372	(263)	(337)	6,288
Depreciation and amortization							(3,163)
Interest expense							(2,556)
Income tax recovery							2,697
Earnings							